February 8, 2024

Via email to: dcaldwell@bigriversteel.com & First Class Mail

Dean Caldwell
Director Environmental
Big River Steel LLC
P. O. Box 707
Osceola, AR 72370

Re: Notice of Final Permitting Decision; Permit No. 2305-AOP-R8

Dear Mr. Caldwell,

After considering the application and other applicable materials as required by APC&EC Rule 8.211 and Ark. Code Ann. § 8-4-101 *et seq*., this notice of final permitting decision is provided for:

Big River Steel LLC
2027 E. State Hwy 198
Osceola, AR 72370

Permit Number: 2305-AOP-R8

Permitting Decision: approval with permit conditions as set forth in final Permit No. 2305-AOP-R8

Accessing the Permitting Decision:
https://www.adeq.state.ar.us/downloads/WebDatabases/PermitsOnline/Air/2305-AOP-R8.pdf.

Accessing the Statement of Basis:
https://www.adeq.state.ar.us/downloads/WebDatabases/PermitsOnline/Air/2305-AOP-R8-SOB.pdf.

Rule 26.903 of the Rules of the Arkansas Operating Air Permit Program do not require a public notice or public comment period for Administrative Amendments.

Sincerely,

Demetria Kimbrough
Associate Director, Office of Air Quality, Division of Environmental Quality
5301 Northshore Drive, North Little Rock, AR 72118-5317

Enclosure: Certificate of Service
cc: stevefrey@kennedyjenks.com

CERTIFICATE OF SERVICE

I, Natasha Oates, hereby certify that the final permit decision notice has been mailed by first class mail to Big River Steel LLC, P. O. Box 707, Osceola, AR, 72370, on this 8th day of February, 2024.

Natasha Oates

Natasha Oates, AA, Office of Air Quality

RESPONSE TO COMMENTS

BIG RIVER STEEL LLC
PERMIT #2305-AOP-R8
AFIN: 47-00991

On December 24, 2023, the Director of the Arkansas Department of Energy and Environment, Division of Environmental Quality ("Division") gave notice of a draft permitting decision for the above referenced facility. On January 19, 2024, written comments on the draft permitting decision were submitted by the facility. The Division's response to these issues follows.

Note: The following page numbers and condition numbers refer to the draft permit. These references may have changed in the final permit based on changes made during the comment period.

Comment #1:

Page 6 of the draft permit includes the following paragraph:

The permitted emission changes to this permit as a result of this modification are as follows:

Increase of 44.2 tpy PM, increase of 30.5 tpy PM_{10}, increase of 0.6 tpy $PM_{2.5}$, increase of 2.2 tpy SO_2, increase of 13.6 tpy VOC, increase of 164.8 tpy CO, increase of 143.3 tpy NO_X, increase of 0.000903 tpy Lead, and increase of 216,882 tpy CO_2e.

BRS requests that the paragraph be edited as follows:

The permitted emission changes as a result of this modification are as follows: Increase of 68.5 tpy PM, increase of 70.0 tpy PM_{10}, increase of 70.0 tpy $PM_{2.5}$, increase of 1.52 tpy SO_2, increase of 16.37 tpy VOC, increase of 221.89 tpy CO, increase of 178.2 tpy NO_X, increase of 0.0013 tpy Lead, and increase of 298,980 tpy CO_2e. The change in emissions also reflects changes that occurred at the Exploratory Ventures, LLC Facility that is covered under Permit # 2445-AOP-R3. A Revision 3 request was submitted to the AEEDEQ and is under concurrent review. The Exploratory Ventures, LLC Facility and the BRS Facility are considered one stationary source for regulatory applicability purposes.

Also, the change in emissions do not account for reduction in estimated PM_{10} and $PM_{2.5}$ emission rates due to a revised calculation method to speciated PM_{10} and $PM_{2.5}$ emissions rates from cooling towers, as well as a change to the calculation method used for PM_{10} and $PM_{2.5}$ emission rates from natural gas fired boilers. Both of these changes would not be classified as a) physical changes or b) a change in the method of operation, which is required to trigger a modification under the Prevention of Significant Deterioration (PSD) major source construction permit regulations.

Rationale for Comment #1: The Exploratory Ventures, LLC Facility and the BRS Facility are considered one stationary source for regulatory applicability purposes. It is important that the permit emission changes reflect the combined impacts for the major stationary source, that the applicability of the Prevention of Significant Deterioration (PSD) construction permit requirements are correctly portrayed.

Response to Comment #1:

In the Summary of Permit Activity, the section being referred to by this comment on page 6 of the draft permit, the last sentence of the section tends to be used to outline the emissions increases and decreases as a result of the modifications to the permit. The numbers in this section outline the changes in total allowable emissions between the previous revision of the permit and the current revision. This section does not differentiate between whether the emissions are the result of a project determined to require PSD review or a non PSD project.

BRS and EV are considered one contiguous source by the clean air act and for PSD analysis, but they are split by facility request on the permit level. The Prevention of Significant Deterioration in the permit does discuss this matter as well as which pollutants required PSD review.

There were no changes made to the permit as a result of this comment.

Comment #2:

Page 39 lists the description of SN-74 as "Non-Contact Induced Draft Cooling Tower - Tower 1 MS: Spray Cooled EAF (Duct Only) (NCT 4.1/NCT 4.2) (Basin ID: NB 4)".

BRS requests that the permit text be edited as follows:

1. Non-Contact Induced Draft Cooling Tower - Melt Shop Tower 1: Spray Cooled EAF (Duct Only).
2. BRS is also requesting that the NCT and Basin ID information be deleted from all cooling tower descriptions throughout the permit.

Rationale for Comment #2: To correct the general description of cooling towers. NCT /Basin references are not required to identify the cooling towers.

Response to Comment #2:

The description for SN-74 has been updated as requested. All references to the NCT and basin ID information has been removed from the cooling tower sources. The source descriptions in SC #99 were also updated to match the descriptions for the sources elsewhere in the permit.

Comment #3:

For SN-51, BRS installed low NOx burners that can achieve BACT limit of 0.1 lb/MMBtu. As a result, SCR is not necessary to meet the BACT limit. Please remove reference to SCR throughout the permit for SN-51.

Rationale for Comment #3: SN-51 has an established BACT limit of 0.1 lb/MMBtu for emissions of NOx. The control technology listed reflects multiple techniques that were identified at the time that unit was added as technologies that could achieve that emission level, including Low NOx burners, SCR, Combustion of Clean Fuel and Good Combustion Practices. BRS has selected the installation of Low NOx burners that are capable of achieving the BACT limit of 0.1 lb/MMBtu for emissions of NOx.

Based on subsequent experience of the facility, BRS has been able to meet this BACT limit through its efficient process design and practices without having to rely on SCR. Thus, SCR is unnecessary to continue to specify in order to meet the demonstrated BACT limit, and thus should be removed from the permit. Nor would addition of SCR be demonstrated to achieve further reductions, because regardless of feasibility or infeasibility as an alternative control in the absence of other controls, it would not be anticipated to significantly further reduce emissions in combination with low NOx burners at such a small source of NOx, given that "low NOx inlet levels result in decreased NOx removal efficiencies" (EPA Air Pollution Control Cost Manual, edition 7 (June 2019) at section 2.2.2), and limitations on any control efficiency are further exacerbated by the facts that SCR are highly dependent on relatively stable gas flow rates, NOx concentrations, and temperature ranges that can require additional equipment to guarantee, all associated with their own increased energy from either natural gas or increased electricity load, both associated with their own emissions increases.

In addition, certain elements such as iron, nickel, chrome, and zinc can react with platinum catalysts to form compounds or alloys which are not catalytically active. These reactions are termed "catalytic poisoning" and can result in premature replacement of the catalyst. An EAF and LMS flue gas may contain a number of these catalytic poisons. In addition, any solid material in the gas stream can form deposits and result in fouling or masking of the catalytic surface. Fouling occurs when solids obstruct the cell openings within the catalyst. Masking occurs when a film forms on the surface of catalyst over time. The film prevents contact between the catalytic surface and the flue gas. Both of these conditions can result in frequent cleaning and/or replacement requirements. These both create a new solid waste stream, and result in operational disruptions.

BRS proposes that the description of the potential means for achieving the BACT limit be clarified to only continue to list only burning natural gas in this process (i.e., a clean burner fuel) and use of good combustion practices (i.e., routine burner maintenance), and low NOx burners. BRS is requesting that the reference to SCR be removed from the BACT analysis table under the control technology column, given that it is not needed to meet the BACT limit for the source, and its addition would not be demonstrated to result in further net efficiencies and would result in additional waste streams and operational issues. BRS can provide appropriate documentation from the natural gas fired burner system to demonstrate the burners are Low NOx and guaranteed to meet 0.1 lb of NOx/MMBtu.

Response to Comment #3:

The Best Available Control Technology (BACT) section of the PSD review is a requirement to both meet a certain emissions limit and to install and operate the control devices determined to be the BACT. Ability to meet the numerical emissions limit without the specified BACT does not remove the requirement to install that control technology. Additionally, it is not necessarily true that the alternative proposed is equivalent control since operation of SCR and Low NOx burners will resulting different emission profiles. Monitoring and testing requirements are also considered in establishing BACT. Low NO_X burners and SCR are the established BACT for this type of emission source and have been proven feasible in practice at another facility.

Revisions to a BACT limit cannot be made in a comment and would require a new permit revision with all appropriate justification and a 45 day EPA notice.

There were no changes made to the permit as a result of this comment.

Comment #4:

Page 76, for SN-20, SN-21, and SN-21C

BRS requests that the permit text be edited as follows:

"Tunnel Furnaces and Shuttle Zone"

Rationale for Comment #4: The shuttle zone is a separate emission source from the tunnel furnaces and thus clarifying the name of the shuttle zone throughout to read as "shuttle zone" instead of "tunnel furnace shuttle zone" throughout the permit will add clarity and be more accurate.

Response to Comment #4:

The section referenced on page 76 is from the permit history for the R6 version of the permit. This section is maintained for historical purposes and is accurate to how the sources were described in that BACT summary in that revision. There were no changes made to the permit as a result of this comment.

Comment #5:

Page 78

BRS requests that the permit text be edited as follows:

Upon ~~completion~~ commencement of operation of SN-107 and quantification of material HAP content, the facility is no longer subject to NESHAP Subparts CCCCCC and YYYYY as the facility will be a major source of HAPs.

Rationale for Comment #5: This revision clarifies that the trigger for applicability of a major source NESHAP is based on commencement of operation, rather than completion of construction, and likewise that it depends on actual emissions associated with operation, rather than emissions as predicted at the time of construction Furthermore, this clarifies that the HAP emissions associated with SN-107 (including whether it is a major source of HAP) may be dependent on the material HAP content ultimately used in the coating line..

Response to Comment #5:

This section, while part of the permit history, was added during this revision. The word "completion" in this section has been updated to "commencement of operation" for clarity sake. The addition of "and quantification of material HAP content" has not been made, as the source was evaluated in a way that would cause the facility to be considered a major source of HAPs. If the source does need to be reevaluated and that status changed for the facility, that would need to be handled in a full permit modification and not through part of a condition.

Comment #6:

Page 91 - As part of R8, BRS included the following in Table 12-1:

BRS requests that the permit text be edited as follows:

The permittee shall perform stack testing of SN-01 and SN-02 for NOx, SO2, CO, CO2, and VOC emissions. Testing shall be performed in accordance with Plantwide Conditions 3 and 4 and shall be repeated annually. The permittee shall measure NOx, SO2, CO2 and CO emissions in accordance with EPA Reference Methods 7E, 6C, 3A and 10, respectively.

Rationale for Comment #6: The rationale for this change is based on Permit Condition IV.29, which is included in Permit #: 2445-AOP-R0 and is listed below. As shown below the phrase "until six consecutive tests are passed" was added. Since BRS has already conducted, and passed, six consecutive tests, BRS is requesting this change to document the change from semi-annual to annual.

Permit #: 2445-AOP-R0 was issued to Exploratory Ventures, LLC (AFIN: 47-01073) and includes Condition IV.29, which states "The permittee shall perform stack testing of SN-01 and SN-02 for NOx, SO2, CO, CO2 and VOC emissions to show compliance with the emission limits in Specific Conditions #1 and #2. Testing shall be performed in accordance with Plantwide Conditions 3 and 4 and shall be repeated every six months until six consecutive tests are passed. The permittee shall then conduct subsequent testing annually. The permittee shall measure NOx, SO2, CO2 and CO emissions in accordance with EPA Reference Methods 7E, 6C, 3A and 10, respectively."

Response to Comment #6:

The condition has been updated as follows to clarify the facility's current testing status while maintaining the reasoning why the testing period was increased.

"The permittee shall perform stack testing of SN-01 and SN-02 for NO_x, SO_2, CO, CO_2 and VOC emissions. Testing shall be performed in accordance with Plantwide Conditions 3 and 4 and shall be repeated every six months until six consecutive tests are passed. As six consecutive tests have been passed for SN-01 and SN-02, the permittee shall conduct subsequent testing annually."

Comment #7:

Pages 153

BRS requests that the permit text be edited as follows:

Upon ~~completion~~ commencement of operation of SN-107 and quantification of material HAP content, the facility is no longer subject to NESHAP Subparts CCCCCC and YYYYY as the facility will be a major source of HAPs.

Rationale for Comment #7: This revision clarifies that the trigger for applicability of a major source NESHAP is based on commencement of operation, rather than completion of construction, and likewise that it depends on actual emissions associated with operation, rather than emissions as predicted at the time of construction. Furthermore, this clarifies that the HAP emissions associated with SN-107 (including whether it is a major source of HAP) may be dependent on the material HAP content ultimately used in the coating line.

Response to Comment #7:

Please see Response to Comment #5.

Comment #8:

Pages 93

BRS requests that the permit text be edited as follows:

Upon commencement of operation of SN-107, the facility must meet the following Case-by-Case MACT requirements for SN-01 and SN-02:

Rationale for Comment #8: This is a more accurate description.

Response to Comment #8:

Specific Condition #35 has been updated as requested.

DIVISION OF ENVIRONMENTAL QUALITY

OPERATING AIR PERMIT

PERMIT NUMBER: 2305-AOP-R8

IS ISSUED TO:
Big River Steel LLC
2027 E. State Hwy 198
Osceola, AR 72370
Mississippi County
AFIN: 47-00991

PURSUANT TO THE RULES OF THE ARKANSAS OPERATING AIR PERMIT PROGRAM, RULE 26: THIS PERMIT AUTHORIZES THE ABOVE REFERENCED PERMITTEE TO INSTALL, OPERATE, AND MAINTAIN THE EQUIPMENT AND EMISSION UNITS DESCRIBED IN THE PERMIT APPLICATION AND ON THE FOLLOWING PAGES. THIS PERMIT IS VALID BETWEEN:

February 8, 2024 AND February 7, 2029

THE PERMITTEE IS SUBJECT TO ALL LIMITS AND CONDITIONS CONTAINED HEREIN.

Signed:

Demetria Kimbrough	February 8, 2024
Associate Director, Office of Air Quality	Date
Division of Environmental Quality	

Table of Contents

Appendix I - 40 CFR Part 63 Subpart SSSS, *National Emission Standards for Hazardous Air Pollutants: Surface Coating of Metal Coil*
Appendix J - 40 CFR Part 63 Subpart CCC, *National Emission Standards for Hazardous Air Pollutants for Steel Pickling – HCl Process Facilities and Hydrochloric Acid Regeneration Plants*

List of Acronyms and Abbreviations

Ark. Code Ann.	Arkansas Code Annotated
AFIN	Arkansas DEQ Facility Identification Number
C.F.R.	Code of Federal Regulations
CO	Carbon Monoxide
COMS	Continuous Opacity Monitoring System
HAP	Hazardous Air Pollutant
Hp	Horsepower
lb/hr	Pound Per Hour
NESHAP	National Emission Standards (for) Hazardous Air Pollutants
MVAC	Motor Vehicle Air Conditioner
No.	Number
NO_x	Nitrogen Oxide
NSPS	New Source Performance Standards
PM	Particulate Matter
PM_{10}	Particulate Matter Equal To Or Smaller Than Ten Microns
$PM_{2.5}$	Particulate Matter Equal To Or Smaller Than 2.5 Microns
SNAP	Significant New Alternatives Program (SNAP)
SO_2	Sulfur Dioxide
SSM	Startup, Shutdown, and Malfunction Plan
Tpy	Tons Per Year
UTM	Universal Transverse Mercator
VOC	Volatile Organic Compound

SECTION I: FACILITY INFORMATION

PERMITTEE:	Big River Steel LLC
AFIN:	47-00991
PERMIT NUMBER:	2305-AOP-R8
FACILITY ADDRESS:	2027 E. State Hwy 198 Osceola, AR 72370
MAILING ADDRESS:	P. O. Box 707 Osceola, AR 72370
COUNTY:	Mississippi County
CONTACT NAME:	Dean Caldwell
CONTACT POSITION:	Director Environmental
TELEPHONE NUMBER:	(731) 234-2044
REVIEWING ENGINEER:	Jesse Smith
UTM North South (Y):	Zone 16: 3949595.58 m
UTM East West (X):	Zone 16: 232531.96 m

SECTION II: INTRODUCTION

Summary of Permit Activity

Big River Steel LLC owns and operates a steel mill located at 2027 E. State Hwy 198 in Osceola, AR. This steel mill is contiguous to the newer Exploratory Ventures, LLC (EV) steel mill, AFIN: 47-01073, and both are under common control of BRS or its parent company. Thus the EV and BRS steel mills constitute a single stationary source under the Clean Air Act. At the request of BRS and for administrative convenience, each facility has been issued its own air permit. This permitting action is to renew and modify the facility's Title V air permit. The permitting modification makes the following changes to the permit:

- Combined BACT limits for EAFs and LMFs at SN-01 and SN-02 as the sources share a common emission point
- Removed NESHAP EEEEE conditions for SN-01 and SN-02 as it was determined the subpart is not applicable to the facility
- Updated the name of the "Coil Coating Line" to "Color Coating Line"
- Updated the heat input of SN-53, SN-102, SN-108a, SN-108b, SN-108c, and SN-108d
- Revised the PM, PM_{10}, and $PM_{2.5}$ emission factor for SN-04, SN-22, SN-26, SN-27, and SN-101
- Addition of new natural gas sources SN-108e and SN-112 through SN-126.
- Update in kW rating for SN-67, SN-67B, and SN-67C
- Revised emission factors for PM_{10} and $PM_{2.5}$ from cooling tower sources
- Updated gallon per hour rates for multiple existing cooling towers and added four new cooling tower sources.
- Increased throughput of gasoline at SN-100 from 10,000 gallons per month to 500,000 gallons per rolling twelve-month period. NESHAP CCCCCC conditions updated due to the change in applicability.
- Addition of material handling units with self-maintaining air cleaner units, SN-127a, SN-127b, and SN-127c.
- Addition of pickling line process with a sedimentation system (SN-128) controlling HCl emissions.

The permitted emission changes to this permit as a result of this modification are as follows: Increase of 44.2 tpy PM, increase of 30.5 tpy PM_{10}, increase of 0.6 tpy $PM_{2.5}$, increase of 2.2 tpy SO_2, increase of 13.6 tpy VOC, increase of 164.8 tpy CO, increase of 143.3 tpy NO_X, increase of 0.000903 tpy Lead, and increase of 216,882 tpy CO2e.

Process Description

The facility consists of two Electric Arc Furnaces to melt scrap iron and steel, Ladle Metallurgy Furnaces (LMF) to adjust the chemistry, a RH Degasser and boiler for further refinement, and Casters.

The facility has been approved by the AEEDEQ to construct / operate the following:

- Horizontal Ladle Preheaters, Vertical Ladle Dryout Flash Preheater Stations, and Tundish Preheaters/Dryout Stands
- Tunnel Furnaces and Shuttle Zone
- A Pickling Line to clean steel of its rust, dirt and oil and supporting equipment including a sedimentation system
- A Push Pull Pickle Line
- Two (2) Galvanizing Lines to produce galvanized strips
- Batch Annealing Furnaces
- Two (2) Skin Pass Mills
- Two (2) Decarburizing Lines to reduce the carbon content at intermediate strip thickness
- Reversing Cold Mills to reduce the thickness of the steel to the desired specifications.
- An Annealing Pickling Line
- An Annealing and Coating Line for annealing of the cold rolled steel strip and application of an insulating coating
- Two (2) MgO Coating Lines to apply magnesia to the strip steel surface
- Two (2) Flattening Coating Lines to coat the steel strip with an insulation layer and subsequent flatness improvements
- A Color Coating Line
- Gasoline Storage Tanks and Dispensing Operations
- Emergency generators, cooling towers and other miscellaneous sources.
- A Hydrogen Plant

Specifics on each operation are found in the Specific Condition section.

Prevention of Significant Deterioration

This facility is considered contiguous and adjacent to the Exploratory Ventures, LLC (AFIN 47-01073) and this project includes the emissions changes made to that facility in Permit #2445-AOP-R3.

Due to the proposed net emission increases, PSD review is required for PM_{10}, $PM_{2.5}$, NO_X, CO, and GHG.

Ambient Impact Analysis

An applicant for a Prevention of Significant Deterioration (PSD) permit is required to conduct an air quality analysis of the ambient impacts associated with the construction and operation of the proposed new source or modification. The primary purpose of the air quality analysis is to demonstrate that new emissions emitted from a major stationary source, in conjunction with other applicable emissions from existing sources (including secondary emissions from growth associated with the new project), will not cause or contribute to a violation of any applicable National Ambient Air Quality Standard (NAAQS) or PSD increment.

PSD modeling is performed in two stages: the significance analysis and the full impact analysis. The significance analysis considers the net emissions change associated with PSD affected emissions units to determine if the increased emissions will have a significant impact upon the surrounding area. If the results of the significance analysis are below the corresponding Modeling Significance Levels, the full impact analysis is not required. The facility elected to perform full impact analysis for all emissions required for this PSD review.

A full impact analysis was required for PM_{10}, $PM_{2.5}$, NO_X, and CO. The full impact analysis modeling must show that the emissions from the facility and surrounding existing sources will not cause or contribute to a violation of any applicable National Ambient Air Quality Standard (NAAQS) or PSD increment. For the $PM_{2.5}$, Tier-1 Screening of Secondary $PM_{2.5}$ impacts using MERPS was used to estimate the concentration of $PM_{2.5}$ secondary formation from NO_X and SO_2. The concentration from secondary formation was added to the modeled concentration for primary $PM_{2.5}$. That value is represented in the table below with the concentrations for other pollutants.

Pollutant	Averaging Period	Maximum Predicted Increment Consumption ($\mu g/m^3$)	PSD Class II Increment ($\mu g/m^3$)	Percent of Class II Increment (%)
PM_{10}	24-hour	10.56	30	35.2
	Annual	2.61	17	13.4
NO_2	Annual	10.64	25	42.6
$PM_{2.5}$	24-hour	8.98	9	99.8
	Annual	2.38	4	59.5

Arkansas Rule 19 requires that if the issuance of a permit for any major stationary source or any major modification would result in the consumption of more than fifty percent of the available annual increment or eighty percent of any short term increment, the person applying for such a permit shall submit to the Department an assessment of the effects that the proposed consumption would have upon the industrial and economic development within the area of the proposed source and the alternatives to such consumption including alternate siting of the proposed source. To address this requirement, the facility submitted the following.

> As stated in Arkansas Regulation 19.904, subsection (c) (1), where air quality impact analysis required under this subpart indicated that the issuance of a permit for any major stationary source or for any major modification would result in the consumption of more than fifty (50%) of any available annual increment or eighty percent (80%) of any short term increment, the person applying for such a permit shall submit to the Division an assessment of the following factors:
>
> (a) Effect that the proposed consumption would have upon the industrial and economic development within the area of the proposed sources; and
>
> (b) Alternatives to such consumption, including alternative siting of the proposed source or portion thereof.
>
> The facility will have potential emission of $PM_{2.5}$ in and by itself that were predicted to be above 80% of the Class II increment (24-hour averaging period), but will be below the Class II Increment. Combined impacts from BRS and other increment consuming sources have shown predicted concentrations to be below the Class II increments for $PM_{2.5}$ and PM_{10}, respectively. The specific point of maximum predicted concentrations reside within close proximity of the existing BRS Mill or in the case of the facility along the property boundary or within a relative short distance of that boundary. Since the predicted concentration is representative of time and space, future growth in the area should not be limited. It is highly unlikely that future growth will take place near or in close proximity to the facility's property boundary or the existing BRS Mill's property boundary. For any future project going through PSD review, a separate analysis will be required as part of that application process and primary point of increment consumption will also be based on time and space and will most likely occur in the immediate vicinity of that source as well.
>
> Also as demonstrated to the AEEDEQ, the facility will meet the NAAQS established by EPA and as such will not be harmful to public health or the environment.

The full impact modeling analysis also requires modeling to show that the emissions from the facility and surrounding existing sources will not cause or contribute to a violation of any applicable National Ambient Air Quality Standard (NAAQS). For the $PM_{2.5}$, Tier-1 Screening of Secondary $PM_{2.5}$ impacts using MERPS was used to estimate the concentration of $PM_{2.5}$ secondary formation from NO_X and SO_2. The concentration from secondary formation was added to the modeled concentration for primary $PM_{2.5}$. The background concentration was determined by use of representative ambient air monitors in the area. BRS has a monitor onsite which is being used for NO_2, PM_{10} and $PM_{2.5}$ background concentrations. A summary of the results of the NAAQS analysis is in the table below.

Pollutant	Averaging Period	Maximum Modeled Impact ($\mu g/m^3$)	Background Concentration ($\mu g/m^3$)	Total Impact ($\mu g/m^3$)	NAAQS ($\mu g/m^3$)
PM_{10}	24-hour	9.46	41.90	51.36	150
$PM_{2.5}$	24-hour	6.8	11.83	19.34	35
	Annual	2.2	7.69	9.94	12
NO_2	1-hour	134.8	43.11	177.90	188
	Annual	10.1	6.32	16.40	100
CO	1-hour	1181.2	-	1181.2	40,000
	Annual	408.8	-	408.8	10,000

Additional Impact Review

An applicant for a Prevention of Significant Deterioration (PSD) permit must prepare additional impact analyses for each regulated air pollutant subject to a major modification under the PSD provisions. As noted above, this project is subject to PSD Review for emissions of PM_{10}, $PM_{2.5}$, NO_X, CO, and GHG. Three areas constitute the Additional Impact Review: a growth analysis, a soils and vegetation analysis, and a visibility analysis, which are discussed below:

Growth Analysis

The Growth Analysis estimates the impact of atmospheric emissions that will be generated by the projected growth from industrial, commercial, and residential growth associated with the project. The changes associated with these permit revisions will have limited, to no, effect on the future growth in the Osceola area. Operation of new equipment may require additional support personnel, who will reside in the general surrounding area.

Soils and Vegetation Analysis

A PSD applicant must also conduct a soil and vegetation air pollution impact analysis based on an inventory of the soils and vegetation types found in the impact area. For most types of soils and vegetation, ambient concentrations of criteria pollutants below the secondary NAAQS will not result in harmful effects. The proposed project will result in predicted impacts below the secondary NAAQS.

Class I Analysis

A screening analysis for visibility and deposition on the nearest Class I area was conducted during this permit's initial application. The emission increases due to this project are below the screening levels outlined in the FLAG document and therefore requires no further Class I analysis.

Best Available Control Technology

The PSD regulations mandate that a case-by-case Best Available Control Technology (BACT) analysis be performed on all new or modified affected sources at which a net emissions increase will occur. The following table is a summary of the BACT determinations made in this permit.

For more detailed discussion of BACT see the BACT analysis section of the permit application. The following summarizes the BACT analysis.

<table>
<tr><th colspan="5">BACT Analysis Summary</th></tr>
<tr><th>Source</th><th>Description</th><th>Pollutant</th><th>Control Technology</th><th>BACT Limit</th></tr>
<tr><td rowspan="11">SN-01 and SN-02</td><td rowspan="11">EAFs and LMFs</td><td>PM</td><td rowspan="8">Fabric Filter
Fabric Filter
Fabric Filter
Fabric Filter
Scrap management plan
Scrap management plan and good operating practices</td><td>0.0018 gr/dscf (filterable only)</td></tr>
<tr><td>PM_{10}</td><td>0.0024 gr/dscf</td></tr>
<tr><td>$PM_{2.5}$</td><td>0.0024 gr/dscf</td></tr>
<tr><td>Opacity</td><td>3% as a 6 minute average from baghouse
6% from melt shop</td></tr>
<tr><td>SO_2</td><td>0.2 lb/ton of steel produced</td></tr>
<tr><td>VOC</td><td>0.093 lb/ton steel produced</td></tr>
<tr><td>CO</td><td>2.02 lb/ton of steel produced</td></tr>
<tr><td>NO_X</td><td>0.35 lb/ton of steel produced</td></tr>
<tr><td>Lead</td><td>Fabric Filter</td><td>0.00056 lb/ton of steel produced</td></tr>
<tr><td>CO_2e</td><td>Good operating practices</td><td>622,380 tpy CO_2e</td></tr>
<tr><td colspan="3"></td></tr>
<tr><td rowspan="6">SN-04</td><td rowspan="6">RH Degasser Boiler</td><td>PM</td><td rowspan="6">Combustion of Natural gas and Good Combustion Practice</td><td>0.0075 lb/MMBTU</td></tr>
<tr><td>PM_{10}</td><td>0.0075 lb/MMBTU</td></tr>
<tr><td>$PM_{2.5}$</td><td>0.0075 lb/MMBTU</td></tr>
<tr><td>Opacity</td><td>5%</td></tr>
<tr><td>SO_2</td><td>0.000588 lb/MMBTU</td></tr>
<tr><td>VOC</td><td>0.0054 lb/MMBTU</td></tr>
</table>

BACT Analysis Summary				
Source	Description	Pollutant	Control Technology	BACT Limit
		CO		0.0824 lb/MMBTU
		NO_X	Low NOx burners Combustion of clean fuel Good Combustion Practices	0.035 lb/MMBTU
		GHG	Good operating practices Minimum Boiler Efficiency	CO_2 117 lb/MMBTU CH_4 0.0022 lb/MMBTU N_2O 0.0002 lb/MMBTU 75%
SN-22	Pickle Line Boiler	PM	Combustion of Natural gas and Good Combustion Practice	0.0075 lb/MMBTU
		PM_{10}		0.0075 lb/MMBTU
		$PM_{2.5}$		0.0075 lb/MMBTU
		Opacity		5%
		SO_2		0.000588 lb/MMBTU
		VOC		0.0054 lb/MMBTU
		CO		0.0824 lb/MMBTU
		NO_X	Low NOx burners Combustion of clean fuel Good Combustion Practices	0.035 lb/MMBTU
		GHG	Good operating practices Minimum Boiler Efficiency	CO_2 117 lb/MMBTU CH_4 0.0022 lb/MMBTU N_2O 0.0002 lb/MMBTU 75%
SN-26 and SN-27	Galvanizing Line Boilers 1 and 2	PM	Combustion of Natural gas and Good	0.0075 lb/MMBTU
		PM_{10}		0.0075 lb/MMBTU

BACT Analysis Summary				
Source	Description	Pollutant	Control Technology	BACT Limit
		$PM_{2.5}$	Combustion Practice	0.0075 lb/MMBTU
		Opacity		5%
		SO_2		0.000588 lb/MMBTU
		VOC		0.0054 lb/MMBTU
		CO		0.0824 lb/MMBTU
		NO_X	Low NOx burners Combustion of clean fuel Good Combustion Practices	0.035 lb/MMBTU
		GHG	Good operating practices Minimum Boiler Efficiency	CO_2 117 lb/MMBTU CH_4 0.0022 lb/MMBTU N_2O 0.0002 lb/MMBTU 75%
SN-101	Annealing Pickle Line Boiler	PM	Combustion of Natural gas and Good Combustion Practice	0.0075 lb/MMBTU
		PM_{10}		0.0075 lb/MMBTU
		$PM_{2.5}$		0.0075 lb/MMBTU
		Opacity		5%
		SO_2		0.000588 lb/MMBTU
		VOC		0.0054 lb/MMBTU
		CO		0.0824 lb/MMBTU
		NO_X	Low NOx burners Combustion of clean fuel Good Combustion Practices	0.035 lb/MMBTU
SN-108D	Color Coating Line RTO	PM	Good combustion practices	0.009 lb/MMBTU
		PM_{10}		0.009 lb/MMBTU

BACT Analysis Summary				
Source	Description	Pollutant	Control Technology	BACT Limit
		$PM_{2.5}$	Energy efficient burners Combustion of natural gas	0.009 lb/MMBTU
		Opacity		5%
		VOC		0.021 lb/MMBTU
		NO_X		0.85 lb/MMBTU
SN-108E	Color Coating Line Spray Passivation	PM	Good combustion practices Energy efficient burners Combustion of natural gas	0.0075 lb/MMBtu
		PM_{10}		0.0075 lb/MMBtu
		$PM_{2.5}$		0.0075 lb/MMBtu
		Opacity		5%
		CO		0.0824 lb/MMBtu
		NO_X		0.10 lb/MMbtu
		GHG		117 lb CO_2e/MMBtu
SN-112 SN-113 SN-114 SN-115 SN-116 SN-117 SN-118 SN-119	Space Heaters	PM	Good combustion practices Energy efficient burners Combustion of natural gas	0.0075 lb/MMBtu
		PM_{10}		0.0075 lb/MMBtu
		$PM_{2.5}$		0.0075 lb/MMBtu
		Opacity		5%
		CO		0.0824 lb/MMBtu
		NO_X		0.08 lb/MMbtu
		GHG		117 lb CO_2e/MMBtu
SN-120	Cold Mill Boiler NGO Line	PM	Good combustion practices Energy efficient burners Combustion of natural gas	0.0075 lb/MMBtu
		PM_{10}		0.0075 lb/MMBtu
		$PM_{2.5}$		0.0075 lb/MMBtu
		Opacity		5%
		CO		0.0824 lb/MMBtu
		NO_X		0.035 lb/MMBtu
		GHG		117 lb CO_2e/MMBtu
SN-121	Pots for GL	PM	Good	0.0075 lb/MMBtu

BACT Analysis Summary				
Source	Description	Pollutant	Control Technology	BACT Limit
SN-122 SN-123	Curing and Melting	PM_{10}	combustion practices Energy efficient burners Combustion of natural gas	0.0075 lb/MMBtu
		$PM_{2.5}$		0.0075 lb/MMBtu
		Opacity		5%
		CO		0.0824 lb/MMBtu
		NO_X		0.08 lb/MMBtu
		GHG		117 lb CO_2e/MMBtu
SN-124	Stingray Parts Washer SMS Hotmill Rollshop	PM	Good combustion practices Energy efficient burners Combustion of natural gas	0.0075 lb/MMBtu
		PM_{10}		0.0075 lb/MMBtu
		$PM_{2.5}$		0.0075 lb/MMBtu
		Opacity		5%
		CO		0.0824 lb/MMBtu
		NO_X		0.08 lb/MMBtu
		GHG		117 lb CO_2e/MMBtu
SN-125	Cold Mill Boiler	PM	Good combustion practices Energy efficient burners Combustion of natural gas	0.0075 lb/MMBtu
		PM_{10}		0.0075 lb/MMBtu
		$PM_{2.5}$		0.0075 lb/MMBtu
		Opacity		5%
		CO		0.0824 lb/MMBtu
		NO_X		0.035 lb/MMBtu
		GHG		117 lb CO_2e/MMBtu
SN-126	Color Coating Line Boiler	PM	Good combustion practices Energy efficient burners Combustion of natural gas	0.0075 lb/MMBtu
		PM_{10}		0.0075 lb/MMBtu
		$PM_{2.5}$		0.0075 lb/MMBtu
		Opacity		5%
		CO		0.0824 lb/MMBtu
		NO_X		0.035 lb/MMBtu

BACT Analysis Summary				
Source	Description	Pollutant	Control Technology	BACT Limit
		GHG		117 lb CO_2e/MMBtu
SN-109b, SN-129, SN-130, SN-131, SN-132	Cooling Towers	PM	Drift Eliminators Low TDS	0.0005 percent drift loss
		PM_{10}		
		$PM_{2.5}$		
		Opacity		5%
SN-127a SN-127b SN-127c	SMAC Dust Collectors	PM	Good operating practices	0.002 gr/dscf
		PM_{10}		0.002 gr/dscf
		$PM_{2.5}$		0.002 gr/dscf
		Opacity		5%

Rules and Regulations

The following table contains the rules and regulations applicable to this permit.

Rules and Regulations
Arkansas Air Pollution Control Code, Rule 18, effective March 14, 2016
Rules of the Arkansas Plan of Implementation for Air Pollution Control, Rule 19, effective May 6, 2022
Rules of the Arkansas Operating Air Permit Program, Rule 26, effective March 14, 2016
40 CFR 52.21, *Prevention of Significant Deterioration*
40 CFR Part 60, Subpart Dc - *Standards of Performance for Small Industrial-Commercial-Institutional Steam Generating Units*
40 CFR Part 60, Subpart AAa - *Standards of Performance for Electric Arc Furnaces and Argon-Oxygen Decarburization Vessels Constructed After August 7, 1983*
40 CFR Part 60, Subpart TT – *Standards of Performance for Metal Coil Surface Coating*
40 CFR Part 60 Subpart IIII, *Standards of Performance for Stationary Compression Ignition Internal Combustion Engines*
40 CFR Part 63 Subpart ZZZZ, *National Emission Standards for Hazardous Air Pollutants for Stationary Reciprocating Internal Combustions Engines*
40 CFR Part 63 Subpart DDDDD, *National Emission Standards for Hazardous Air Pollutants for Major Sources: Industrial, Commercial, and Institutional Boilers and Process Heaters*
40 CFR Part 63 Subpart SSSS, *National Emission Standards for Hazardous Air Pollutants: Surface Coating of Metal Coil*
40 CFR Part 63 Subpart CCC, *National Emission Standards for Hazardous Air Pollutants for Steel Pickling – HCl Process Facilities and Hydrochloric Acid Regeneration Plants*
40 CFR Part 63 Subpart YYYYY, *National Emission Standards for Hazardous Air Pollutants for Area Sources: Electric Arc Furnace Steel Making Facilities.*
40 CFR Part 63 Subpart CCCCCC, *National Emission Standards for Hazardous Air Pollutants for Source Category: Gasoline Dispensing Facilities*

Emission Summary

The following table is a summary of emissions from the facility. This table, in itself, is not an enforceable condition of the permit.

EMISSION SUMMARY				
Source Number	Description	Pollutant	Emission Rates	
			lb/hr	tpy
Total Allowable Emissions		PM	107.0	371.0
		PM_{10}	125.6	464.4
		$PM_{2.5}$	116.6	428.1
		SO_2	201.8	404.0
		VOC	127.5	397.8
		CO	1323.5	4992.7
		NO_X	732.0	1446.1
		Lead	0.28131139	1.16505013
		CO_2e	--	1,752,823
HAPs		Arsenic Cadmium Formaldehyde HCl Manganese Isophorone Mercury MIBK Toluene	0.0045084 0.006587 0.18548 0.9 0.1608673 7.0 0.0606134 2.7 2.7	0.0161139 0.02385 0.7001 3.2 0.804128 30.6 0.402652 11.8 11.8
Air Contaminants ***		H_2SO_4	6.2	2.0
SN-01	EAF I and LMF I	PM PM_{10} $PM_{2.5}$ SO_2 VOC CO NO_X Lead CO_2e Arsenic	16.2 21.6 21.6 65.0 23.3 505.0 87.5 0.14 -- 0.002	71.0 94.7 94.7 184.5 90.2 2050.0 307.5 0.58 311,190 0.007

EMISSION SUMMARY				
Source Number	Description	Pollutant	Emission Rates	
			lb/hr	tpy
		Cadmium	0.002	0.006
		Manganese	0.08	0.4
		Mercury	0.03	0.2
SN-02	EAF II and LMF II	PM	16.2	71.0
		PM_{10}	21.6	94.7
		$PM_{2.5}$	21.6	94.7
		SO_2	65.0	205.0
		VOC	23.3	95.3
		CO	505.0	2070.5
		NO_X	87.5	358.8
		Lead	0.14	0.58
		CO_2e	--	311,190
		Arsenic	0.002	0.007
		Cadmium	0.002	0.006
		Manganese	0.08	0.4
		Mercury	0.03	0.2
SN-01A	Lime Injector Burner I	PM	0.2	0.7
		PM_{10}	0.2	0.7
		$PM_{2.5}$	0.2	0.7
		SO_2	0.1	0.1
		VOC	0.1	0.5
		CO	1.6	6.7
		NO_X	1.9	8.1
		Lead	9.07 E-06	3.97 E-05
		CO_2e	--	9,481
SN-02A	Lime Injector Burner II	PM	0.2	0.7
		PM_{10}	0.2	0.7
		$PM_{2.5}$	0.2	0.7
		SO_2	0.1	0.1
		VOC	0.1	0.5
		CO	1.6	6.7
		NO_X	1.9	8.1
		Lead	9.07 E-06	3.97 E-05
		CO_2e	--	9,481
SN-03	RH Degasser	PM	0.1	0.1
		PM_{10}	0.1	0.1
		$PM_{2.5}$	0.1	0.1
		SO_2	0.1	0.1
		VOC	0.1	0.2
		CO	9.8	29.8

EMISSION SUMMARY				
Source Number	Description	Pollutant	Emission Rates	
			lb/hr	tpy
		NO_X	0.4	1.8
		Lead	0.000003	0.00002
		CO_2e	--	4,760
		Arsenic	0.000001	0.000005
		Cadmium	0.000006	0.00003
		Formaldehyde	0.004	0.0002
		Manganese	0.000002	0.000009
		Mercury	0.000002	0.00006
SN-04	RH Degasser Boiler	PM	0.7	3.0
		PM_{10}	0.7	3.0
		$PM_{2.5}$	0.7	3.0
		SO_2	0.1	0.3
		VOC	0.5	2.1
		CO	7.4	32.0
		NO_X	3.2	13.6
		Lead	0.00005	0.0002
		CO_2e	--	45,457
		Arsenic	0.00002	0.00008
		Cadmium	0.0001	0.0005
		Formaldehyde	0.007	0.03
		Manganese	0.00004	0.0002
		Mercury	0.00003	0.0001
SN-04A	RH Degasser Preheater Vessel Station	PM	0.1	0.1
		PM_{10}	0.1	0.1
		$PM_{2.5}$	0.1	0.1
		SO_2	0.1	0.1
		VOC	0.1	0.2
		CO	0.5	2.2
		NO_X	0.5	2.1
		Lead	0.000003	0.00002
		CO_2e	--	3,075
		Arsenic	0.000002	0.000006
		Cadmium	0.000007	0.00003
		Formaldehyde	0.0005	0.002
		Manganese	0.000003	0.00001
		Mercury	0.000002	0.000007
SN-04B	RH Degasser Top Part Dryer	PM	0.1	0.1
		PM_{10}	0.1	0.1
		$PM_{2.5}$	0.1	0.1
		SO_2	0.1	0.1

EMISSION SUMMARY				
Source Number	Description	Pollutant	Emission Rates	
			lb/hr	tpy
		VOC	0.1	0.1
		CO	0.2	0.5
		NO_X	0.2	0.5
		Lead	0.0000007	0.000004
		CO_2e	--	717
		Arsenic	0.0000003	0.000002
		Cadmium	0.000002	0.000007
		Formaldehyde	0.0002	0.0005
		Manganese	0.0000006	0.000003
		Mercury	0.0000004	0.000002
SN-04C	RH Degasser Nozzle Dryer	PM	0.1	0.1
		PM_{10}	0.1	0.1
		$PM_{2.5}$	0.1	0.1
		SO_2	0.1	0.1
		VOC	0.1	0.1
		CO	0.2	0.7
		NO_X	0.2	0.7
		Lead	0.0000009	0.000004
		CO_2e	--	922
		Arsenic	0.0000004	0.000002
		Cadmium	0.000002	0.000009
		Formaldehyde	0.0002	0.0006
		Manganese	0.0000007	0.000003
		Mercury	0.0000005	0.000003
SN-04D	RH Degasser Burner/Top Lance	PM	0.1	0.1
		PM_{10}	0.1	0.1
		$PM_{2.5}$	0.1	0.1
		SO_2	0.1	0.1
		VOC	0.1	0.3
		CO	0.8	3.3
		NO_X	0.8	3.2
		Lead	0.000005	0.00002
		CO_2e	--	4,612
		Arsenic	0.000002	0.000008
		Cadmium	0.00001	0.00005
		Formaldehyde	0.0007	0.003
		Manganese	0.000004	0.00002
		Mercury	0.000003	0.00001
SN-05	Horizontal Ladle Preheater 1	PM	0.1	0.3
		PM_{10}	0.1	0.3

EMISSION SUMMARY				
Source Number	Description	Pollutant	Emission Rates	
			lb/hr	tpy
		$PM_{2.5}$	0.1	0.3
		SO_2	0.1	0.1
		VOC	0.1	0.2
		CO	0.7	2.9
		NO_X	0.8	3.4
		Lead	0.000004	0.00002
		CO_2e	--	4,100
		Arsenic	0.000002	0.000007
		Cadmium	0.000009	0.00004
		Formaldehyde	0.0006	0.003
		Manganese	0.000003	0.00002
		Mercury	0.000003	0.000009
SN-06	Horizontal Ladle Preheater 2	PM	0.1	0.3
		PM_{10}	0.1	0.3
		$PM_{2.5}$	0.1	0.3
		SO_2	0.1	0.1
		VOC	0.1	0.2
		CO	0.7	2.9
		NO_X	0.8	3.4
		Lead	0.000004	0.00002
		CO_2e	--	4,100
		Arsenic	0.000002	0.000007
		Cadmium	0.000009	0.00004
		Formaldehyde	0.0006	0.003
		Manganese	0.000003	0.00002
		Mercury	0.000003	0.000009
SN-07	Horizontal Ladle Preheater 3	PM	0.1	0.3
		PM_{10}	0.1	0.3
		$PM_{2.5}$	0.1	0.3
		SO_2	0.1	0.1
		VOC	0.1	0.2
		CO	0.7	2.9
		NO_X	0.8	3.4
		Lead	0.000004	0.00002
		CO_2e	--	4,100
		Arsenic	0.000002	0.000007
		Cadmium	0.000009	0.00004
		Formaldehyde	0.0006	0.003
		Manganese	0.000003	0.00002
		Mercury	0.000003	0.000009

EMISSION SUMMARY				
Source Number	Description	Pollutant	Emission Rates	
			lb/hr	tpy
SN-08	Horizontal Ladle Preheater 4	PM	0.1	0.3
		PM_{10}	0.1	0.3
		$PM_{2.5}$	0.1	0.3
		SO_2	0.1	0.1
		VOC	0.1	0.2
		CO	0.7	2.9
		NO_X	0.8	3.4
		Lead	0.000004	0.00002
		CO_2e	--	4,100
		Arsenic	0.000002	0.000007
		Cadmium	0.000009	0.00004
		Formaldehyde	0.0006	0.003
		Manganese	0.000003	0.00002
		Mercury	0.000003	0.000009
SN-09	Horizontal Ladle Preheater 5	PM	0.1	0.3
		PM_{10}	0.1	0.3
		$PM_{2.5}$	0.1	0.3
		SO_2	0.1	0.1
		VOC	0.1	0.2
		CO	0.7	2.9
		NO_X	0.8	3.4
		Lead	0.000004	0.00002
		CO_2e	--	4,100
		Arsenic	0.000002	0.000007
		Cadmium	0.000009	0.00004
		Formaldehyde	0.0006	0.003
		Manganese	0.000003	0.00002
		Mercury	0.000003	0.000009
SN-10	Vertical Ladle Dryout Flash Preheater Station 1	PM	0.1	0.3
		PM_{10}	0.1	0.3
		$PM_{2.5}$	0.1	0.3
		SO_2	0.1	0.1
		VOC	0.1	0.2
		CO	0.7	2.9
		NO_X	0.8	3.4
		Lead	0.000004	0.00002
		CO_2e	--	4,100
		Arsenic	0.000002	0.000007
		Cadmium	0.000009	0.00004
		Formaldehyde	0.0006	0.003

EMISSION SUMMARY				
Source Number	Description	Pollutant	Emission Rates	
			lb/hr	tpy
		Manganese Mercury	0.000003 0.000003	0.00002 0.000009
SN-11	Vertical Ladle Dryout Flash Preheater Station 2	PM PM_{10} $PM_{2.5}$ SO_2 VOC CO NO_X Lead CO_2e Arsenic Cadmium Formaldehyde Manganese Mercury	0.1 0.1 0.1 0.1 0.1 0.7 0.8 0.000004 -- 0.000002 0.000009 0.0006 0.000003 0.000003	0.3 0.3 0.3 0.1 0.2 2.9 3.4 0.00002 4,100 0.000007 0.00004 0.003 0.00002 0.000009
SN-12	Vertical Ladle Dryout Flash Preheater Station 3	PM PM_{10} $PM_{2.5}$ SO_2 VOC CO NO_X Lead CO_2e Arsenic Cadmium Formaldehyde Manganese Mercury	0.1 0.1 0.1 0.1 0.1 0.7 0.8 0.000004 -- 0.000002 0.000009 0.0006 0.000003 0.000003	0.3 0.3 0.3 0.1 0.2 2.9 3.4 0.00002 4,100 0.000007 0.00004 0.003 0.00002 0.000009
SN-13	Vertical Ladle Dryout Flash Preheater Station 4	PM PM_{10} $PM_{2.5}$ SO_2 VOC CO NO_X Lead CO_2e Arsenic	0.1 0.1 0.1 0.1 0.1 0.7 0.8 0.000004 -- 0.000002	0.3 0.3 0.3 0.1 0.2 2.9 3.4 0.00002 4,100 0.000007

EMISSION SUMMARY				
Source Number	Description	Pollutant	Emission Rates	
			lb/hr	tpy
		Cadmium Formaldehyde Manganese Mercury	0.000009 0.0006 0.000003 0.000003	0.00004 0.003 0.00002 0.000009
SN-14	Caster #1	PM PM_{10} $PM_{2.5}$	0.4 0.4 0.4	1.3 1.3 1.3
SN-15	Caster #2	PM PM_{10} $PM_{2.5}$	0.4 0.4 0.4	1.3 1.3 1.3
SN-16	Tundish Preheaters/Dryout Stand 1	PM PM_{10} $PM_{2.5}$ SO_2 VOC CO NO_X Lead CO_2e Arsenic Cadmium Formaldehyde Manganese Mercury	0.1 0.1 0.1 0.1 0.1 0.8 0.9 0.000005 -- 0.000002 0.00001 0.0007 0.000004 0.000003	0.3 0.3 0.3 0.1 0.2 3.2 3.9 0.00002 5,125 0.000008 0.00005 0.003 0.00002 0.00001
SN-17	Tundish Preheaters/Dryout Stand 2	PM PM_{10} $PM_{2.5}$ SO_2 VOC CO NO_X Lead CO_2e Arsenic Cadmium Formaldehyde Manganese Mercury	0.1 0.1 0.1 0.1 0.1 0.8 0.9 0.000005 -- 0.000002 0.00001 0.0007 0.000004 0.000003	0.3 0.3 0.3 0.1 0.2 3.2 3.9 0.00002 5,125 0.000008 0.00005 0.003 0.00002 0.00001
SN-18	Tundish Preheater 3	PM PM_{10}	0.1 0.1	0.3 0.3

EMISSION SUMMARY				
Source Number	Description	Pollutant	Emission Rates	
			lb/hr	tpy
		$PM_{2.5}$	0.1	0.3
		SO_2	0.1	0.1
		VOC	0.1	0.2
		CO	0.8	3.2
		NO_X	0.9	3.9
		Lead	0.000005	0.00002
		CO_2e	--	5,125
		Arsenic	0.000002	0.000008
		Cadmium	0.00001	0.00005
		Formaldehyde	0.0007	0.003
		Manganese	0.000004	0.00002
		Mercury	0.000003	0.00001
SN-19	Tundish Preheater 4	PM	0.1	0.3
		PM_{10}	0.1	0.3
		$PM_{2.5}$	0.1	0.3
		SO_2	0.1	0.1
		VOC	0.1	0.2
		CO	0.8	3.2
		NO_X	0.9	3.9
		Lead	0.000005	0.00002
		CO_2e	--	5,125
		Arsenic	0.000002	0.000008
		Cadmium	0.00001	0.00005
		Formaldehyde	0.0007	0.003
		Manganese	0.000004	0.00002
		Mercury	0.000003	0.00001
SN-19A	Tundish Preheater 5	PM	0.1	0.3
		PM_{10}	0.1	0.3
		$PM_{2.5}$	0.1	0.3
		SO_2	0.1	0.1
		VOC	0.1	0.2
		CO	0.8	3.2
		NO_X	0.9	3.9
		Lead	0.000005	0.00002
		CO_2e	--	5,125
		Arsenic	0.000002	0.000008
		Cadmium	0.00001	0.00005
		Formaldehyde	0.0007	0.003
		Manganese	0.000004	0.00002
		Mercury	0.000003	0.00001

EMISSION SUMMARY				
Source Number	Description	Pollutant	Emission Rates	
			lb/hr	tpy
SN-19B	Tundish Preheater 6	PM	0.1	0.3
		PM_{10}	0.1	0.3
		$PM_{2.5}$	0.1	0.3
		SO_2	0.1	0.1
		VOC	0.1	0.2
		CO	0.8	3.2
		NO_X	0.9	3.9
		Lead	0.000005	0.00002
		CO_2e	--	5,125
		Arsenic	0.000002	0.000008
		Cadmium	0.00001	0.00005
		Formaldehyde	0.0007	0.003
		Manganese	0.000004	0.00002
		Mercury	0.000003	0.00001
SN-20	Tunnel Furnace 1	PM	1.7	7.2
		PM_{10}	1.7	7.2
		$PM_{2.5}$	1.7	7.2
		SO_2	0.2	0.6
		VOC	1.2	5.2
		CO	18.0	78.5
		NO_X	21.8	95.3
		Lead	0.0002	0.0006
		CO_2e	--	119,919
		Arsenic	0.00005	0.0002
		Cadmium	0.0003	0.002
		Formaldehyde	0.02	0.08
		Manganese	0.00009	0.0004
		Mercury	0.00006	0.0003
SN-21	Tunnel Furnace 2	PM	1.3	5.7
		PM_{10}	1.3	5.7
		$PM_{2.5}$	1.3	5.7
		SO_2	0.2	0.5
		VOC	1.0	4.1
		CO	14.2	62.2
		NO_X	17.3	75.6
		Lead	0.0001	0.0004
		CO_2e	--	98,395
		Arsenic	0.00004	0.0002
		Cadmium	0.0002	0.001
		Formaldehyde	0.02	0.06

EMISSION SUMMARY				
Source Number	Description	Pollutant	Emission Rates	
			lb/hr	tpy
		Manganese Mercury	0.00007 0.00005	0.0003 0.0002
SN-21C	Shuttle Zone	PM PM_{10} $PM_{2.5}$ SO_2 VOC CO NO_X Lead CO_2e Arsenic Cadmium Formaldehyde Manganese Mercury	0.6 0.6 0.6 0.1 0.5 6.6 8 0.00004 -- 0.00002 0.0001 0.01 0.00003 0.00002	2.7 2.7 2.7 0.3 1.9 28.9 35.1 0.0002 41,082 0.0001 0.0004 0.03 0.0001 0.0001
SN-22	Pickle Line Boiler	PM PM_{10} $PM_{2.5}$ SO_2 VOC CO NO_X Lead CO_2e Arsenic Cadmium Formaldehyde Manganese Mercury	0.4 0.4 0.4 0.1 0.3 4.5 1.9 0.00003 -- 0.00002 0.00006 0.004 0.00002 0.00002	1.8 1.8 1.8 0.2 1.3 19.4 8.3 0.0002 27,531 0.00005 0.0003 0.02 0.00009 0.00006
SN-23	Pickle Line Scale Dust	PM PM_{10} $PM_{2.5}$	1.0 1.0 1.0	4.4 4.4 4.4
SN-24	Pickling Section	HCl	0.2	0.6
SN-24A	Push Pull Pickle Line (PPPL) Scrubber Stack	PM PM_{10} $PM_{2.5}$ HCl	0.4 0.4 0.4 0.2	1.7 1.7 1.7 0.8
SN-25	Tandem Cold Mill	PM	4.8	20.7

EMISSION SUMMARY				
Source Number	Description	Pollutant	Emission Rates	
			lb/hr	tpy
		PM_{10} $PM_{2.5}$	12.5 12.5	54.7 54.7
SN-26	Galvanizing Line Boiler 1	PM PM_{10} $PM_{2.5}$ SO_2 VOC CO NO_X Lead CO_2e Arsenic Cadmium Formaldehyde Manganese Mercury	0.4 0.4 0.4 0.1 0.3 4.5 1.9 0.00003 -- 0.00002 0.00006 0.004 0.00002 0.00002	1.8 1.8 1.8 0.2 1.3 19.4 8.3 0.00002 27,531 0.00005 0.0003 0.02 0.00009 0.00006
SN-27	Galvanizing Line Boiler 2	PM PM_{10} $PM_{2.5}$ SO_2 VOC CO NO_X Lead CO_2e Arsenic Cadmium Formaldehyde Manganese Mercury	0.4 0.4 0.4 0.1 0.3 4.5 1.9 0.00003 -- 0.00002 0.00006 0.004 0.00002 0.00002	0.8 0.8 0.8 0.2 1.3 19.4 8.3 0.00002 27,531 0.00005 0.0003 0.02 0.00009 0.00006
SN-28	Galvanizing Line Preheater 1	PM PM_{10} $PM_{2.5}$ SO_2 VOC CO NO_X Lead CO_2e Arsenic	0.1 0.1 0.1 0.1 0.5 6.5 2.8 0.00004 -- 0.00002	0.5 0.5 0.5 0.2 1.9 28.2 12.0 0.0002 40,078 0.00007

EMISSION SUMMARY				
Source Number	Description	Pollutant	Emission Rates	
			lb/hr	tpy
		Cadmium Formaldehyde Manganese Mercury	0.00009 0.006 0.00003 0.00002	0.0004 0.03 0.0002 0.00009
SN-29	Galvanizing Line #2 Furnace	PM PM_{10} $PM_{2.5}$ SO_2 VOC CO NO_X Lead CO_2e Arsenic Cadmium Formaldehyde Manganese Mercury	0.2 0.2 0.2 0.1 0.9 12.4 5.3 0.0001 -- 0.00003 0.0002 0.02 0.00006 0.00004	0.8 0.8 0.8 0.4 3.6 54.3 23.1 0.0003 77,121 0.0002 0.0008 0.05 0.0003 0.0002
SN-34	Galvanizing Line Caustic Cleaning 1	PM PM_{10} $PM_{2.5}$	0.2 0.2 0.2	0.9 0.9 0.9
SN-35	Galvanizing Line Caustic Cleaning 2	PM PM_{10} $PM_{2.5}$	0.2 0.2 0.2	0.5 0.5 0.5
SN-36	Galvanizing Line Post Treatment 1	PM PM_{10} $PM_{2.5}$	0.1 0.1 0.1	0.3 0.3 0.3
SN-37	Galvanizing Line Post Treatment 2	PM PM_{10} $PM_{2.5}$	0.3 0.3 0.3	1.3 1.3 1.3
SN-38a	Skin Pass Mill #1	PM PM_{10} $PM_{2.5}$	0.6 1.5 1.5	2.5 6.6 6.6
SN-38b	Skin Pass Mill #2 (ACL)	PM PM_{10} $PM_{2.5}$	0.6 1.5 1.5	2.5 6.6 6.6
SN-39	Annealing Furnaces	PM PM_{10} $PM_{2.5}$ SO_2	0.9 0.9 0.9 0.1	3.9 3.9 3.9 0.3

EMISSION SUMMARY				
Source Number	Description	Pollutant	Emission Rates	
			lb/hr	tpy
		VOC CO NO_X Lead CO_2e Arsenic Cadmium Formaldehyde Manganese Mercury	0.7 9.8 11.8 0.0001 -- 0.00003 0.0002 0.009 0.00005 0.00003	2.8 42.6 51.7 0.0003 60,424 0.0001 0.0006 0.04 0.0002 0.0002
SN-40	Decarburizing Line 1 Furnace Section	PM PM_{10} $PM_{2.5}$ SO_2 VOC CO NO_X Lead CO_2e Arsenic Cadmium Formaldehyde Manganese Mercury	0.5 0.5 0.5 0.1 0.2 3.0 3.6 0.00002 -- 0.000008 0.00004 0.003 0.00002 0.00001	2.1 2.1 2.1 0.1 0.9 13.0 15.8 0.00008 18,449 0.00004 0.0002 0.02 0.00006 0.00005
SN-41	Decarburizing Line 1 Cleaning Section	PM PM_{10} $PM_{2.5}$	0.3 0.3 0.3	1.2 1.2 1.2
SN-42	Decarburizing Line 2 Furnace Section	PM PM_{10} $PM_{2.5}$ SO_2 VOC CO NO_X Lead CO_2e Arsenic Cadmium Formaldehyde Manganese	0.3 0.3 0.3 0.1 0.2 1.9 2.2 0.00002 -- 0.000005 0.00003 0.002 0.000009	1.3 1.3 1.3 0.1 0.6 8.0 9.7 0.00005 11,274 0.00002 0.0002 0.008 0.00004

EMISSION SUMMARY				
Source Number	Description	Pollutant	Emission Rates	
			lb/hr	tpy
		Mercury	0.000006	0.00003
SN-43	Decarburizing Line 2 Cleaning Section	PM PM_{10} $PM_{2.5}$	0.3 0.3 0.3	1.1 1.1 1.1
SN-44	Reversing Cold Mill 3	PM PM_{10} $PM_{2.5}$	1.5 4.0 4.0	6.6 17.4 17.4
SN-45	Reversing Cold Mill 1	PM PM_{10} $PM_{2.5}$	1.5 4.0 4.0	6.6 17.4 17.4
SN-46	Reversing Cold Mill 2	PM PM_{10} $PM_{2.5}$	1.5 4.0 4.0	6.6 17.4 17.4
SN-47	Annealing Pickling Line – Annealing Furnace	PM PM_{10} $PM_{2.5}$ SO_2 VOC CO NO_X Lead CO_2e Arsenic Cadmium Formaldehyde Manganese Mercury	0.9 0.9 0.9 0.1 0.4 5.5 6.6 0.00004 -- 0.00002 0.00008 0.005 0.00003 0.00002	3.8 3.8 3.8 0.2 1.6 23.9 29.0 0.0002 33,823 0.00006 0.00004 0.003 0.0002 0.00008
SN-48	Annealing Pickling Line – Scale Dust Exhaust	PM PM_{10} $PM_{2.5}$	0.7 0.7 0.7	3.0 3.0 3.0
SN-49	Annealing Pickling Line – Shot Blast	PM PM_{10} $PM_{2.5}$	0.7 0.7 0.7	3.0 3.0 3.0
SN-50	Annealing Pickling Line Pickling Section	HCl	0.2	0.7
SN-51	Annealing and Coating Line - Annealing Furnace	PM PM_{10} $PM_{2.5}$ SO_2	0.2 0.2 0.2 0.1	0.8 0.8 0.8 0.1

EMISSION SUMMARY				
Source Number	Description	Pollutant	Emission Rates	
			lb/hr	tpy
		VOC	0.1	0.4
		CO	1.1	4.7
		NO_X	1.3	5.7
		Lead	0.00001	0.00003
		CO_2e	--	6,663
		Arsenic	0.000003	0.00003
		Cadmium	0.00002	0.00007
		Formaldehyde	0.001	0.005
		Manganese	0.000005	0.00003
		Mercury	0.000004	0.00002
SN-52	Annealing and Coating Line – Cleaning Section	PM	0.3	1.0
		PM_{10}	0.3	1.0
		$PM_{2.5}$	0.3	1.0
SN-53	Annealing and Coating Line – Drying Furnace	PM	0.4	1.6
		PM_{10}	0.4	1.6
		$PM_{2.5}$	0.4	1.6
		SO_2	0.1	0.1
		VOC	0.6	2.6
		CO	10.0	44.0
		NO_X	5.6	24.5
		Lead	0.00002	0.00005
		CO_2e	--	11,439
		Arsenic	0.000005	0.00002
		Cadmium	0.00003	0.0002
		Formaldehyde	0.002	0.008
		Manganese	0.000009	0.00004
		Mercury	0.000006	0.00003
SN-54	MgO Coating Line 1 – Drying Furnace	PM	0.2	0.8
		PM_{10}	0.2	0.8
		$PM_{2.5}$	0.2	0.8
		SO_2	0.1	0.1
		VOC	0.1	0.4
		CO	1.2	4.8
		NO_X	1.4	5.9
		Lead	0.000007	0.00003
		CO_2e	--	6,816
		Arsenic	0.000003	0.00002
		Cadmium	0.00002	0.00007
		Formaldehyde	0.001	0.005
		Manganese	0.000005	0.00003

EMISSION SUMMARY				
Source Number	Description	Pollutant	Emission Rates	
			lb/hr	tpy
		Mercury	0.000004	0.00002
SN-55	MgO Coating Line 1 – Cleaning Section	PM PM_{10} $PM_{2.5}$	0.3 0.3 0.3	1.1 1.1 1.1
SN-56	MgO Coating Line 2 – Drying Furnace	PM PM_{10} $PM_{2.5}$ SO_2 VOC CO NO_X Lead CO_2e Arsenic Cadmium Formaldehyde Manganese Mercury	0.2 0.2 0.2 0.1 0.1 1.2 1.4 0.000007 -- 0.000003 0.00002 0.001 0.000005 0.000004	0.8 0.8 0.8 0.1 0.4 4.8 5.9 0.00003 6,816 0.00002 0.00007 0.005 0.00003 0.00002
SN-57	MgO Coating Line 2 – Cleaning Section	PM PM_{10} $PM_{2.5}$	0.3 0.3 0.3	1.1 1.1 1.1
SN-58	Flattening and Coating Line 1 – Furnace	PM PM_{10} $PM_{2.5}$ SO_2 VOC CO NO_X Lead CO_2e Arsenic Cadmium Formaldehyde Manganese Mercury	0.5 0.5 0.5 0.1 0.2 2.7 3.2 0.00002 -- 0.000007 0.00004 0.003 0.00002 0.000009	1.9 1.9 1.9 0.1 0.8 11.6 14.1 0.00007 16,399 0.00003 0.0002 0.002 0.00006 0.00004
SN-59	Flattening and Coating Line 1 – Cleaning Section	HCl	0.2	0.7
SN-60	Flattening and	PM	0.5	1.9

EMISSION SUMMARY				
Source Number	Description	Pollutant	Emission Rates	
			lb/hr	tpy
	Coating Line 2 – Furnace	PM_{10} $PM_{2.5}$ SO_2 VOC CO NO_X Lead CO_2e Arsenic Cadmium Formaldehyde Manganese Mercury	0.5 0.5 0.1 0.2 2.7 3.2 0.00002 -- 0.000007 0.00004 0.003 0.00002 0.000009	1.9 1.9 0.1 0.8 11.6 14.1 0.00007 16,399 0.00003 0.0002 0.002 0.00006 0.00004
SN-61	Flattening and Coating Line 2 – Cleaning Section	HCl	0.2	0.7
SN-62	Emergency Generator 1 (100.1 – Meltshop), Diesel Fired, 500 kW	PM PM_{10} $PM_{2.5}$ SO_2 VOC CO NO_X CO_2e H_2SO_4	0.3 0.3 0.3 5.1 1.5 3.6 3.1 -- 0.4	0.1 0.1 0.1 0.3 0.1 0.2 0.2 32 0.1
SN-63	Emergency Generator 2 (600.3 – ColdMill), Diesel Fired, 1600 kW	PM PM_{10} $PM_{2.5}$ SO_2 VOC CO NO_X CO_2e H_2SO_4	0.8 0.8 0.8 18.5 5.8 13.2 18.3 -- 1.4	0.1 0.1 0.1 1.0 0.3 0.7 1.0 145 0.1
SN-64	Emergency Generator 3 (400.1 – HSM/CCM), Diesel Fired, 1600 kW	PM PM_{10} $PM_{2.5}$ SO_2 VOC CO	0.8 0.8 0.8 18.5 5.8 13.2	0.1 0.1 0.1 1.0 0.3 0.7

EMISSION SUMMARY				
Source Number	Description	Pollutant	Emission Rates	
			lb/hr	tpy
		NO_X CO_2e H_2SO_4	18.3 -- 1.4	1.0 145 0.1
SN-65	Emergency Generator 4 (100.2 – Meltshop), Diesel Fired, 1600 kW	PM PM_{10} $PM_{2.5}$ SO_2 VOC CO NO_X CO_2e H_2SO_4	0.8 0.8 0.8 18.5 5.8 13.2 18.3 -- 1.4	0.1 0.1 0.1 1.0 0.3 0.7 1.0 145 0.1
SN-66	Emergency Generator 5 (100.4 – Meltshop), Diesel Fired, 2700 kW	PM PM_{10} $PM_{2.5}$ SO_2 VOC CO NO_X CO_2e H_2SO_4	0.8 0.8 0.8 0.1 1.0 7.3 31.4 -- 0.1	0.1 0.1 0.1 0.1 0.1 0.4 1.6 195 0.1
SN-67	Emergency Generator 6 (Kohler 400.3 – HSM/CCM), Diesel Fired, 1145 kW	PM PM_{10} $PM_{2.5}$ SO_2 VOC CO NO_X CO_2e H_2SO_4	0.4 0.4 0.4 0.1 0.5 3.1 13.4 -- 0.1	0.1 0.1 0.1 0.1 0.1 0.2 0.7 195 0.1
SN-67A	Emergency Generator 7 (DC Gen 1 – Employee Building), Diesel Fired, 2700 kW	PM PM_{10} $PM_{2.5}$ SO_2 VOC CO NO_X CO_2e H_2SO_4	0.8 0.8 0.8 0.1 1.0 7.3 31.4 -- 0.1	0.1 0.1 0.1 0.1 0.1 0.4 1.6 195 0.1

EMISSION SUMMARY				
Source Number	Description	Pollutant	Emission Rates	
			lb/hr	tpy
SN-67B	Emergency Generator 8 (CGL2.GEN.1 – CGL2 Zinc Pot), Diesel Fired, 1000 kW	PM PM_{10} $PM_{2.5}$ SO_2 VOC CO NO_X CO_2e H_2SO_4	0.2 0.2 0.2 0.1 0.1 1.1 12.9 -- 0.1	0.1 0.1 0.1 0.1 0.1 0.1 0.6 80 0.1
SN-67C	Emergency Generator 9 (800A1.SS3 – RCM/ACL), Diesel Fired, 1600 kW	PM PM_{10} $PM_{2.5}$ SO_2 VOC CO NO_X CO_2e H_2SO_4	0.4 0.4 0.4 0.1 0.3 1.8 20.7 -- 0.1	0.1 0.1 0.1 0.1 0.1 0.1 1.0 127 0.1
SN-67D	Emergency Generator 10, Diesel Fired, 1114 kW	PM PM_{10} $PM_{2.5}$ SO_2 VOC CO NO_X CO_2e H_2SO_4	0.1 0.1 0.1 0.1 0.1 1.3 13.7 -- 0.1	0.1 0.1 0.1 0.1 0.1 0.1 0.7 80 0.1
SN-67E	Emergency Generator 11 (CGL.GEN.1 – CGL) Diesel Fired, 350 kW	PM PM_{10} $PM_{2.5}$ SO_2 VOC CO NO_X CO_2e H_2SO_4	0.1 0.1 0.1 1.1 0.1 0.5 2.9 - 0.1	0.1 0.1 0.1 0.1 0.1 0.1 0.1 238 0.1
SN-68	Non-Contact Induced Draft Cooling Tower - Tower 1 MS	PM PM_{10} $PM_{2.5}$	0.2 0.2 0.1	0.9 0.7 0.1

EMISSION SUMMARY				
Source Number	Description	Pollutant	Emission Rates	
			lb/hr	tpy
SN-69	Non-Contact Induced Draft Cooling Tower - Tower 2 MS: Gas Cleaning Plant (GCP)	PM PM_{10} $PM_{2.5}$	0.4 0.3 0.1	1.6 1.1 0.1
SN-70	Non-Contact Induced Draft Cooling Tower - Tower 3 Caster/HM: Caster (CSP) Hotmill	PM PM_{10} $PM_{2.5}$	0.5 0.4 0.1	2.0 1.4 0.1
SN-71	Non-Contact Induced Draft Cooling Tower – Caster/Hot Mill	PM PM_{10} $PM_{2.5}$	0.5 0.4 0.1	2.1 1.5 0.1
SN-72A	Non-Contact Cooling Tower – Cold Mill APL/ACL Anneal and Coating/ RCM + CRL	PM PM_{10} $PM_{2.5}$	0.2 0.2 0.1	0.9 0.6 0.1
SN-72B	Non-Contact Cooling Tower – Cold Mill ACL Furnace	PM PM_{10} $PM_{2.5}$	0.2 0.1 0.1	0.6 0.5 0.1
SN-73	Non-Contact Induced Draft Cooling Tower - Cold Mill (PLTCM)	PM PM_{10} $PM_{2.5}$	0.4 0.3 0.1	1.5 1.0 0.1
SN-74	Non-Contact Induced Draft Cooling Tower - Melt Shop Tower 1: Spray Cooled EAF (Duct Only)	PM PM_{10} $PM_{2.5}$	0.4 0.3 0.1	1.5 1.0 0.1
SN-74A	Non-Contact Induced Draft Cooling Tower EAF / LMF 2 and DOC Spray Cool	PM PM_{10} $PM_{2.5}$	2.6 1.8 0.1	11.2 7.8 0.1
SN-74B	Non-Contact Cooling Tower EAF Closed Loop for Electrode Arms	PM PM_{10} $PM_{2.5}$	0.2 0.2 0.1	0.8 0.6 0.1
SN-75	Contact Induced Draft Cooling Tower	PM PM_{10}	0.2 0.1	0.5 0.4

EMISSION SUMMARY				
Source Number	Description	Pollutant	Emission Rates	
			lb/hr	tpy
	- Tower 2 MS: RH Degasser	$PM_{2.5}$	0.1	0.1
SN-76	Contact Induced Draft Cooling Tower - Tower 3 Caster: Caster (CSP) Only	PM PM_{10} $PM_{2.5}$	0.2 0.2 0.1	0.8 0.6 0.1
SN-77	Contact Induced Draft Cooling Tower - Tower 4 HM: Hot Mill (HSM)	PM PM_{10} $PM_{2.5}$	0.3 0.2 0.1	1.2 0.9 0.1
SN-78A	Contact Cooling Tower Hot Mill	PM PM_{10} $PM_{2.5}$	1.6 1.1 0.1	6.8 4.8 0.1
SN-78B	Contact Induced Draft Cooling Tower – Caster	PM PM_{10} $PM_{2.5}$	0.2 0.2 0.1	0.8 0.6 0.1
SN-79	Contact Induced Draft Cooling Tower Caster	PM PM_{10} $PM_{2.5}$	0.5 0.4 0.1	2.1 1.5 0.1
SN-80	Charging Crane	PM PM_{10} $PM_{2.5}$	0.1 0.1 0.1	0.1 0.1 0.1
SN-81	Scrap Yard Stockpiling	PM PM_{10} $PM_{2.5}$	0.1 0.1 0.1	0.5 0.2 0.1
SN-82	EAF Flux Receiving System	PM PM_{10} $PM_{2.5}$	0.1 0.1 0.1	0.1 0.1 0.1
SN-83	EAF Flux Storage and Handling System	PM PM_{10} $PM_{2.5}$	0.2 0.1 0.1	0.6 0.3 0.1
SN-84	Carbon Injection Receiving System	PM PM_{10} $PM_{2.5}$	0.1 0.1 0.1	0.1 0.1 0.1
SN-85	Carbon Injection Storage and Handling System	PM PM_{10} $PM_{2.5}$	0.1 0.1 0.1	0.2 0.1 0.1
SN-86	LMF Flux Receiving System	PM PM_{10} $PM_{2.5}$	0.1 0.1 0.1	0.1 0.1 0.1

EMISSION SUMMARY				
Source Number	Description	Pollutant	Emission Rates	
			lb/hr	tpy
SN-87	LMF Flux Storage and Handling System	PM PM_{10} $PM_{2.5}$	0.2 0.1 0.1	0.6 0.3 0.1
SN-88	Alloy Receiving System	PM PM_{10} $PM_{2.5}$	0.1 0.1 0.1	0.1 0.1 0.1
SN-89	Alloy Storage and Handling System	PM PM_{10} $PM_{2.5}$	0.1 0.1 0.1	0.1 0.1 0.1
SN-90	Alloy Delivery System – LMF	PM PM_{10} $PM_{2.5}$	0.1 0.1 0.1	0.1 0.1 0.1
SN-91	RH Degasser Alloy Deliver System	PM PM_{10} $PM_{2.5}$	0.1 0.1 0.1	0.1 0.1 0.1
SN-92	Inside Drop Point - Spent Refractory and Other Waste	PM PM_{10} $PM_{2.5}$	0.1 0.1 0.1	0.1 0.1 0.1
SN-93	Outside Drop Point - Spent Refractory and Other Waste	PM PM_{10} $PM_{2.5}$	0.1 0.1 0.1	0.1 0.1 0.1
SN-94	Inside Drop Point – EAF Dust	PM PM_{10} $PM_{2.5}$	0.1 0.1 0.1	0.1 0.1 0.1
SN-95	Drop Points Slag	PM PM_{10} $PM_{2.5}$	5.3 2.6 0.9	3.4 1.7 0.6
SN-96	Slag Handling and Conveying	PM PM_{10} $PM_{2.5}$	1.1 0.4 0.1	1.2 0.4 0.1
SN-97	Paved Roads	PM PM_{10} $PM_{2.5}$	0.7 0.2 0.1	2.9 0.6 0.2
SN-98	Unpaved Roads	PM PM_{10} $PM_{2.5}$	2.2 0.6 0.1	9.6 2.6 0.3
SN-99A	Feed Stock Piles - Wind Erosion	PM PM_{10} $PM_{2.5}$	0.9 0.5 0.1	3.7 1.9 0.3

EMISSION SUMMARY				
Source Number	Description	Pollutant	Emission Rates	
			lb/hr	tpy
SN-99B	Slag Piles – Wind Erosion	PM PM_{10} $PM_{2.5}$	0.2 0.1 0.1	0.6 0.3 0.1
SN-100	Gasoline Storage Tanks and Dispensing Operation	VOC	0.3	0.8
SN-101	Annealing Pickling Line Boiler	PM PM_{10} $PM_{2.5}$ SO_2 VOC CO NO_X Lead CO_2e Arsenic Cadmium Formaldehyde Manganese Mercury	0.4 0.4 0.4 0.1 0.3 4.5 1.9 0.00003 -- 0.00002 0.00006 0.004 0.00002 0.00002	1.8 1.8 1.8 0.2 1.3 19.4 8.3 0.0002 27,531 0.00005 0.0003 0.02 0.00009 0.00006
SN-102	Natural Gas Fired Cold Mill/Supporting Building Structures Space Heaters (136.5 MMBtu)	PM PM_{10} $PM_{2.5}$ SO_2 VOC CO NO_X Lead CO_2e Arsenic Cadmium Formaldehyde Manganese Mercury	1.1 1.1 1.1 0.1 0.8 11.2 11.0 0.00008 -- 0.00003 0.0002 0.01 0.00006 0.00004	4.5 4.5 4.5 0.4 3.3 49.3 47.8 0.0004 69,905 0.0002 0.0007 0.05 0.0003 0.0002
SN-103	EAF I/II Lime Injection Receiving, Storage, and Handling System	PM PM_{10} $PM_{2.5}$	0.1 0.1 0.1	0.4 0.4 0.4

EMISSION SUMMARY				
Source Number	Description	Pollutant	Emission Rates	
			lb/hr	tpy
SN-104A	Diesel Fired Emergency Water Pump 1 (EP2-A Line HM Tunnel Furnace), 282 hp	PM	0.6	0.1
		PM_{10}	0.6	0.1
		$PM_{2.5}$	0.6	0.1
		SO_2	0.5	0.1
		VOC	0.7	0.1
		CO	1.9	0.1
		NO_X	8.7	0.5
		CO_2e	-	6
		H_2SO_4	0.1	0.1
SN-104B	Diesel Fired Emergency Water Pump 2 (EP3 – ColdMill), 376 hp	PM	0.8	0.1
		PM_{10}	0.8	0.1
		$PM_{2.5}$	0.8	0.1
		SO_2	0.7	0.1
		VOC	0.9	0.1
		CO	2.5	0.2
		NO_X	11.7	0.6
		CO_2e	-	8
		H_2SO_4	0.1	0.1
SN-104C	Diesel Fired Emergency Water Pump 3 (EP6-B Line HM Tunnel Furnace), 282 hp	PM	0.6	0.1
		PM_{10}	0.6	0.1
		$PM_{2.5}$	0.6	0.1
		SO_2	0.5	0.1
		VOC	0.7	0.1
		CO	1.9	0.1
		NO_X	8.7	0.5
		CO_2e	-	6
		H_2SO_4	0.1	0.1
SN-104D	Diesel Fired Emergency Water Pump 4 (FP2 – Fire Line), 376 hp	PM	0.8	0.1
		PM_{10}	0.8	0.1
		$PM_{2.5}$	0.8	0.1
		SO_2	0.7	0.1
		VOC	0.9	0.1
		CO	2.5	0.2
		NO_X	11.7	0.6
		CO_2e	-	8
		H_2SO_4	0.1	0.1
SN-105	Color Coating Line – Pre-Cleaning Section	PM	0.3	1.2
		PM_{10}	0.3	1.2
		$PM_{2.5}$	0.3	1.2

EMISSION SUMMARY				
Source Number	Description	Pollutant	Emission Rates	
			lb/hr	tpy
SN-106	Color Coating Line – Cleaning Section	PM PM_{10} $PM_{2.5}$	0.3 0.3 0.3	1.2 1.2 1.2
SN-107	Color Coating Line – Prime/Finish Coating	VOC Isophorone MIBK Toluene	34.9 7.0 2.7 2.7	152.7 30.6 11.8 11.8
SN-108a	Color Coating Line – Chemical Dryer	PM PM_{10} $PM_{2.5}$ SO_2 VOC CO NO_X Lead CO_2e	0.1 0.1 0.1 0.1 0.1 0.4 0.3 0.000003 --	0.2 0.2 0.2 0.1 0.2 1.9 1.2 0.00002 2,768
SN-108b	Color Coating Line – Primer Oven	PM PM_{10} $PM_{2.5}$ SO_2 VOC CO NO_X Lead CO_2e	0.2 0.2 0.2 0.1 0.2 1.9 2.3 0.00001 --	0.8 0.8 0.8 0.1 0.6 8.3 10.1 0.00005 11,709
SN-108c	Color Coating Line – Finish Oven	PM PM_{10} $PM_{2.5}$ SO_2 VOC CO NO_X Lead CO_2e	0.3 0.3 0.3 0.1 0.2 2.3 1.4 0.00002 --	1.0 1.0 1.0 0.1 0.7 10.1 6.1 0.00007 14,350
SN-108d	Color Coating Line RTO	PM PM_{10} $PM_{2.5}$ SO_2 VOC CO	0.2 0.2 0.2 0.1 0.3 6.5	0.6 0.6 0.6 0.1 1.3 28.4

EMISSION SUMMARY				
Source Number	Description	Pollutant	Emission Rates	
			lb/hr	tpy
		NO_X Lead CO_2e	12.2 0.00001 --	53.6 0.00004 7,380
SN-108e	Color Coating Line Spray Passivation	PM PM_{10} $PM_{2.5}$ SO_2 VOC CO NO_X Lead CO_2e Arsenic Cadmium Formaldehyde Manganese Mercury	0.1 0.1 0.1 0.1 0.1 0.4 0.5 0.000003 -- 0.000001 0.000006 0.0004 0.000002 0.000002	0.2 0.2 0.2 0.1 0.2 1.8 2.2 0.00002 2,563 0.000005 0.00003 0.002 0.000009 0.000006
SN-109	Non-Contact Color Coating Line – Cooling Tower #1	PM PM_{10} $PM_{2.5}$	0.1 0.1 0.1	0.3 0.2 0.1
SN-109b	Non-Contact Color Coating Line – Cooling Tower #2	PM PM_{10} $PM_{2.5}$	0.1 0.1 0.1	0.2 0.1 0.1
SN-110a	Emergency Generator 12, Diesel Fired, 2700 kW	PM PM_{10} $PM_{2.5}$ SO_2 VOC CO NO_X CO_2e H_2SO_4	0.8 0.8 0.8 0.1 1.0 7.3 31.4 -- 0.1	0.1 0.1 0.1 0.1 0.1 0.4 1.6 195 0.1
SN-110b	Emergency Generator 13, Diesel Fired, 2700 kW	PM PM_{10} $PM_{2.5}$ SO_2 VOC CO NO_X CO_2e	0.8 0.8 0.8 0.1 1.0 7.3 31.4 --	0.1 0.1 0.1 0.1 0.1 0.4 1.6 195

EMISSION SUMMARY				
Source Number	Description	Pollutant	Emission Rates	
			lb/hr	tpy
		H_2SO_4	0.1	0.1
SN-110c	Emergency Generator 14, Diesel Fired, 2700 kW	PM PM_{10} $PM_{2.5}$ SO_2 VOC CO NO_X CO_2e H_2SO_4	0.8 0.8 0.8 0.1 1.0 7.3 31.4 -- 0.1	0.1 0.1 0.1 0.1 0.1 0.4 1.6 195 0.1
SN-110d	Emergency Generator 15, Diesel Fired, 2700 kW	PM PM_{10} $PM_{2.5}$ SO_2 VOC CO NO_X CO_2e H_2SO_4	0.8 0.8 0.8 0.1 1.0 7.3 31.4 -- 0.1	0.1 0.1 0.1 0.1 0.1 0.4 1.6 195 0.1
SN-110e	Emergency Generator 16, Diesel Fired, 2700 kW	PM PM_{10} $PM_{2.5}$ SO_2 VOC CO NO_X CO_2e H_2SO_4	0.8 0.8 0.8 0.1 1.0 7.3 31.4 -- 0.1	0.1 0.1 0.1 0.1 0.1 0.4 1.6 195 0.1
SN-111	Hydrogen Plant #2 Reformer Furnace (PHG830)	PM PM_{10} $PM_{2.5}$ SO_2 VOC CO NO_X Lead CO_2e	0.1 0.1 0.1 0.1 0.1 1.1 1.3 0.00001 --	0.5 0.5 0.5 0.1 0.3 4.5 5.5 0.00003 6,396
SN-112	Natural Gas Fired Waste Water Space	PM PM_{10}	0.1 0.1	0.3 0.3

EMISSION SUMMARY				
Source Number	Description	Pollutant	Emission Rates	
			lb/hr	tpy
	Heaters	$PM_{2.5}$	0.1	0.3
		SO_2	0.1	0.1
		VOC	0.1	0.2
		CO	0.5	2.4
		NO_X	0.6	2.4
		Lead	0.00000324	0.0000142
		CO_2e	-	3,383
		Arsenic	0.000002	0.000006
		Cadmium	0.000008	0.00004
		Formaldehyde	0.0005	0.003
		Manganese	0.000003	0.00002
		Mercury	0.000002	0.000008
SN-113	Natural Gas Fired North and South Wall Space Heaters	PM	0.1	0.1
		PM_{10}	0.1	0.1
		$PM_{2.5}$	0.1	0.1
		SO_2	0.1	0.1
		VOC	0.1	0.1
		CO	0.2	0.9
		NO_X	0.2	0.9
		Lead	0.00000118	0.00000515
		CO_2e	-	1,230
		Arsenic	0.0000005	0.000003
		Cadmium	0.000003	0.00002
		Formaldehyde	0.0002	0.0008
		Manganese	0.0000009	0.000004
		Mercury	0.0000007	0.000003
SN-114	Natural Gas Direct Fired Flack Facility Space Heaters	PM	0.5	2.2
		PM_{10}	0.5	2.2
		$PM_{2.5}$	0.5	2.2
		SO_2	0.1	0.2
		VOC	0.4	1.6
		CO	5.5	24.3
		NO_X	5.4	23.5
		Lead	0.0000329	0.000144
		CO_2e	-	34,279
		Arsenic	0.00002	0.00006
		Cadmium	0.00008	0.0004
		Formaldehyde	0.005	0.03
		Manganese	0.00003	0.0002
		Mercury	0.00002	0.00008

EMISSION SUMMARY				
Source Number	Description	Pollutant	Emission Rates	
			lb/hr	tpy
SN-115	Natural Gas Indirect Fired Flack Facility Space Heaters	PM	0.2	0.7
		PM_{10}	0.2	0.7
		$PM_{2.5}$	0.2	0.7
		SO_2	0.1	0.1
		VOC	0.1	0.5
		CO	1.6	6.8
		NO_X	1.5	6.6
		Lead	0.00000919	0.0000403
		CO_2e	-	9,609
		Arsenic	0.000004	0.00002
		Cadmium	0.00003	0.00009
		Formaldehyde	0.002	0.007
		Manganese	0.000007	0.00004
		Mercury	0.000005	0.00003
SN-116	Natural Gas Fired CGL Building Space Heaters	PM	0.2	0.7
		PM_{10}	0.2	0.7
		$PM_{2.5}$	0.2	0.7
		SO_2	0.1	0.1
		VOC	0.2	0.5
		CO	1.7	7.5
		NO_X	1.7	7.3
		Lead	0.0000101	0.0000443
		CO_2e	-	10,578
		Arsenic	0.000005	0.00002
		Cadmium	0.00003	0.0001
		Formaldehyde	0.002	0.007
		Manganese	0.000008	0.00004
		Mercury	0.000006	0.00003
SN-117	Natural Gas Fired ACL Building Space Heaters	PM	0.2	0.9
		PM_{10}	0.2	0.9
		$PM_{2.5}$	0.2	0.9
		SO_2	0.1	0.1
		VOC	0.2	0.7
		CO	2.1	9.4
		NO_X	2.1	9.0
		Lead	0.0000126	0.0000554
		CO_2e	-	13,223
		Arsenic	0.000006	0.00003
		Cadmium	0.00003	0.0002
		Formaldehyde	0.002	0.009

EMISSION SUMMARY				
Source Number	Description	Pollutant	Emission Rates	
			lb/hr	tpy
		Manganese Mercury	0.00001 0.000007	0.00005 0.00003
SN-118	Natural Gas Fired RCM Indirect Space Heaters	PM PM_{10} $PM_{2.5}$ SO_2 VOC CO NO_X Lead CO_2e Arsenic Cadmium Formaldehyde Manganese Mercury	0.1 0.1 0.1 0.1 0.1 0.5 0.5 0.00000306 - 0.000002 0.000007 0.0005 0.000003 0.000002	0.3 0.3 0.3 0.1 0.2 2.3 2.2 0.0000134 3,203 0.000006 0.00003 0.003 0.00002 0.000007
SN-119	Natural Gas Fired RCM Direct Space Heaters	PM PM_{10} $PM_{2.5}$ SO_2 VOC CO NO_X Lead CO_2e Arsenic Cadmium Formaldehyde Manganese Mercury	0.1 0.1 0.1 0.1 0.1 0.9 0.9 0.00000506 - 0.000003 0.00002 0.0008 0.000004 0.000003	0.4 0.4 0.4 0.1 0.3 3.8 3.7 0.0000222 5,289 0.000009 0.00005 0.004 0.00002 0.00002
SN-120	Cold Mill Boiler NGO Line	PM PM_{10} $PM_{2.5}$ SO_2 VOC CO NO_X Lead CO_2e Arsenic	0.7 0.7 0.7 0.1 0.5 7.3 3.1 0.0000433 - 0.00002	3.0 3.0 3.0 0.3 2.1 32.1 13.6 0.00019 45,459 0.00008

EMISSION SUMMARY				
Source Number	Description	Pollutant	Emission Rates lb/hr	Emission Rates tpy
		Cadmium Formaldehyde Manganese Mercury	0.0001 0.007 0.00004 0.00003	0.0005 0.03 0.0002 0.0001
SN-121	Ceramic Coating Pots for GI Curing and Zinc Melting	PM PM_{10} $PM_{2.5}$ SO_2 VOC CO NO_X Lead CO_2e Arsenic Cadmium Formaldehyde Manganese Mercury	0.1 0.1 0.1 0.1 0.1 0.3 0.3 0.00000182 - 0.0000008 0.000005 0.0003 0.000002 0.000001	0.2 0.2 0.2 0.1 0.1 1.4 1.3 0.00000799 1,907 0.000004 0.00002 0.002 0.000007 0.000005
SN-122	Ceramic Coating Pots for GL Curing and Zinc Melting	PM PM_{10} $PM_{2.5}$ SO_2 VOC CO NO_X Lead CO_2e Arsenic Cadmium Formaldehyde Manganese Mercury	0.1 0.1 0.1 0.1 0.1 0.3 0.3 0.00000182 - 0.0000008 0.000005 0.0003 0.000002 0.000001	0.2 0.2 0.2 0.1 0.1 1.4 1.3 0.00000799 1,907 0.000004 0.00002 0.002 0.000007 0.000005
SN-123	Pre-Melt Pot Curing and Zinc Melting	PM PM_{10} $PM_{2.5}$ SO_2 VOC CO NO_X Lead	0.1 0.1 0.1 0.1 0.1 0.2 0.2 0.00000092	0.1 0.1 0.1 0.1 0.1 0.7 0.7 0.000004

EMISSION SUMMARY				
Source Number	Description	Pollutant	Emission Rates	
			lb/hr	tpy
		CO_2e	-	953
		Arsenic	0.0000004	0.000002
		Cadmium	0.000003	0.000009
		Formaldehyde	0.0002	0.0006
		Manganese	0.0000007	0.000004
		Mercury	0.0000005	0.000003
SN-124	Heated Parts Washer SMS Hotmill Rollshop	PM	0.1	0.1
		PM_{10}	0.1	0.1
		$PM_{2.5}$	0.1	0.1
		SO_2	0.1	0.1
		VOC	0.1	0.1
		CO	0.1	0.4
		NO_X	0.1	0.4
		Lead	0.0000005	0.0000022
		CO_2e	-	513
		Arsenic	0.0000002	0.0000009
		Cadmium	0.000002	0.000005
		Formaldehyde	0.00008	0.0004
		Manganese	0.0000004	0.000002
		Mercury	0.0000003	0.000002
SN-125	Cold Mill Boiler	PM	0.7	3.0
		PM_{10}	0.7	3.0
		$PM_{2.5}$	0.7	3.0
		SO_2	0.1	0.3
		VOC	0.5	2.1
		CO	7.3	32.1
		NO_X	3.1	13.6
		Lead	0.0000433	0.00019
		CO_2e	-	45,459
		Arsenic	0.00002	0.00008
		Cadmium	0.0001	0.0005
		Formaldehyde	0.007	0.03
		Manganese	0.00004	0.0002
		Mercury	0.00003	0.0001
SN-126	Color Coating Line Boiler	PM	0.3	1.0
		PM_{10}	0.3	1.0
		$PM_{2.5}$	0.3	1.0
		SO_2	0.1	0.1
		VOC	0.2	0.7
		CO	2.3	10.2

EMISSION SUMMARY				
Source Number	Description	Pollutant	Emission Rates	
			lb/hr	tpy
		NO_X Lead CO_2e Arsenic Cadmium Formaldehyde Manganese Mercury	1.0 0.0000138 - 0.000006 0.00004 0.003 0.00002 0.000008	4.3 0.000061 14,424 0.00003 0.0002 0.01 0.00005 0.00004
SN-127a	Truck Dump and Silos SMAC Dust Collector	PM PM_{10} $PM_{2.5}$	2.0 2.0 2.0	8.5 8.5 8.5
SN-127b	Rail Loading Building SMAC Dust Collector	PM PM_{10} $PM_{2.5}$	0.6 0.6 0.6	2.7 2.7 2.7
SN-127c	Cold Mill Coil Entry SMAC Dust Collector	PM PM_{10} $PM_{2.5}$	0.4 0.4 0.4	1.7 1.7 1.7
SN-128	Pickling Section Sedimentation System	HCl	0.1	0.3
SN-129	Non-Contact Cooling Tower – Annealing Pickling Line (APL)	PM PM_{10} $PM_{2.5}$	0.6 0.4 0.1	2.5 1.7 0.1
SN-130	Non-Contact Cooling Tower – Reversing Cold Mill 3 (RCM3)	PM PM_{10} $PM_{2.5}$	0.6 0.4 0.1	2.5 1.7 0.1
SN-131	Non-Contact Cooling Tower – Decarburizing Coating Line (DCL) and High Temperature Annealing (HTA)	PM PM_{10} $PM_{2.5}$	0.6 0.4 0.1	2.5 1.7 0.1
SN-132	Non-Contact Cooling Tower – Flattening Coating Line (FCL)	PM PM_{10} $PM_{2.5}$	0.6 0.4 0.1	2.5 1.7 0.1

*$PM_{2.5}$ limits are source specific, if required. Not all sources have $PM_{2.5}$ limits.
**HAPs included in the VOC totals. Other HAPs are not included in any other totals unless specifically stated.

***Air Contaminants such as ammonia, acetone, and certain halogenated solvents are not VOCs or HAPs.

SECTION III: PERMIT HISTORY

Permit #2305-AOP-R0 was issued to Big River Steel LLC on September 18, 2013. This permit was the initial air permit for the facility. The facility required prevention of significant deterioration review to ensure the new source would not cause a significant deterioration of the local ambient air quality. PSD review was required for NO_X, CO, PM, PM_{10}, $PM_{2.5}$, SO_2, VOC, lead, and greenhouse gasses.

The PSD regulations mandate that a case-by-case Best Available Control Technology (BACT) analysis be performed on all new or modified affected sources at which a net emissions increase will occur. The following table is a summary of the BACT determinations made in 2305-AOP-R0.

BACT Analysis Summary				
Source	Description	Pollutant	Control Technology	BACT Limit
SN-01 and SN-02	EAFs	PM	Fabric Filter	0.0018 gr/dscf (filterable only)
		PM_{10}	Fabric Filter	0.0024 gr/dscf
		$PM_{2.5}$	Fabric Filter	0.0024 gr/dscf
		Opacity	Fabric Filter	3% as a 6 minute average 6% from melt shop
		SO_2	Scrap management plan	0.18 lb/ton of steel produced
		VOC	Scrap management plan and good operating practices	0.088 lb/ton steel produced
		CO		2 lb/ton of steel produced
		NO_X		0.3 lb/ton of steel produced
		Lead	Fabric Filter	0.00056 lb/ton of steel produced
SN-01 and SN-02	LMFs	PM	Fabric Filter	0.0018 gr/dscf (filterable only)
		PM_{10}	Fabric Filter	0.0024 gr/dscf
		$PM_{2.5}$	Fabric Filter	0.0024 gr/dscf
		Opacity	Fabric Filter	3% as a 6 minute average 6% from melt shop
		SO_2	Scrap management plan	0.02 lb/ton of steel produced

BACT Analysis Summary				
Source	Description	Pollutant	Control Technology	BACT Limit
		VOC	Scrap management plan and good operating practices	0.005 lb/ton of steel produced
		CO		0.02 lb/ton of steel produced
		NO_X		0.05 lb/ton of steel produced
		Lead	Fabric Filter	
SN-01, SN-02, and SN-03	Meltshop	GHG	Energy Efficiency improvements.	0.155 tons of CO_2e/Ton of Liquid steel produced.
SN-03	RH Degasser	CO (from degasser)	Flare	0.04 lb/ton of steel produced
		PM	Combustion of Natural gas and Good Combustion Practice	0.00052 lb/MMBTU
		PM_{10}		0.00052 lb/MMBTU
		$PM_{2.5}$		0.00052 lb/MMBTU
		Opacity		5%
		SO_2		0.000588 lb/MMBTU
		VOC		0.0054 lb/MMBTU
		CO		0.0824 lb/MMBTU
		NO_X		1.0 lb/MMBTU
		GHG	Good operating practices	CO_2 117 lb/MMBTU CH_4 0.0022 lb/MMBTU N_2O 0.0002 lb/MMBTU
SN-04	RH Degasser Boiler	PM	Combustion of Natural gas and Good Combustion Practice	0.00052 lb/MMBTU
		PM_{10}		0.00052 lb/MMBTU
		$PM_{2.5}$		0.00052 lb/MMBTU
		Opacity		5%
		SO_2		0.000588 lb/MMBTU
		VOC		0.0054 lb/MMBTU
		CO		0.0824 lb/MMBTU
		NO_X	Low NO_x burners Combustion of clean fuel Good Combustion Practices	0.035 lb/MMBTU

BACT Analysis Summary				
Source	Description	Pollutant	Control Technology	BACT Limit
		GHG	Good operating practices Minimum Boiler Efficiency	CO_2 117 lb/MMBTU CH_4 0.0022 lb/MMBTU N_2O 0.0002 lb/MMBTU 75%
SN-04A SN-04B SN-04C SN-04D	RH Degasser Vessel Preheater Station, Vessel Top Part Dryer, RH Vessel Nozzle Dryer RH Degasser Burner/Top Lance	PM	Combustion of Natural gas and Good Combustion Practice	0.00052 lb/MMBTU
		PM_{10}		0.00052 lb/MMBTU
		$PM_{2.5}$		0.00052 lb/MMBTU
		Opacity		5%
		SO_2		0.000588 lb/MMBTU
		VOC		0.0054 lb/MMBTU
		CO		0.0824 lb/MMBTU
		NO_X	Low NO_x burners Combustion of clean fuel Good Combustion Practices	0.08 lb/MMBTU
		GHG	Good operating practices	CO_2 117 lb/MMBTU CH_4 0.0022 lb/MMBTU N_2O 0.0002 lb/MMBTU
SN-05, SN-06, SN-07, SN-08, and SN-09	Ladle Preheaters	PM	Combustion of Natural gas and Good Combustion Practices	0.00052 lb/MMBTU
		PM_{10}		0.00052 lb/MMBTU
		$PM_{2.5}$		0.00052 lb/MMBTU
		Opacity		5%
		SO_2		0.000588 lb/MMBTU
		VOC		0.0054 lb/MMBTU
		CO		0.0824 lb/MMBTU
		NO_X	Low NO_x burners Combustion of clean fuel Good Combustion Practices	0.08 lb/MMBTU
		GHG	Good operating practices	CO_2 117 lb/MMBTU CH_4 0.0022 lb/MMBTU N_2O 0.0002 lb/MMBTU
SN-10 and SN-11	Ladle Dryout Station	PM	Combustion of Natural gas and Good Combustion Practice	0.00052 lb/MMBTU
		PM_{10}		0.00052 lb/MMBTU
		$PM_{2.5}$		0.00052 lb/MMBTU
		Opacity		5%
		SO_2		0.000588 lb/MMBTU

BACT Analysis Summary				
Source	Description	Pollutant	Control Technology	BACT Limit
		VOC		0.0054 lb/MMBTU
		CO		0.0824 lb/MMBTU
		NO_X	Low NO_x burners Combustion of clean fuel Good Combustion Practices	0.08 lb/MMBTU
		GHG	Good operating practices	CO_2 117 lb/MMBTU CH_4 0.0022 lb/MMBTU N_2O 0.0002 lb/MMBTU
SN-12 and SN-13	Vertical Ladle Holding Station	PM	Combustion of Natural gas and Good Combustion Practice	0.00052 lb/MMBTU
		PM_{10}		0.00052 lb/MMBTU
		$PM_{2.5}$		0.00052 lb/MMBTU
		Opacity		5%
		SO_2		0.000588 lb/MMBTU
		VOC		0.0054 lb/MMBTU
		CO		0.0824 lb/MMBTU
		NO_X	Low NO_x burners Combustion of clean fuel Good Combustion Practices	0.08 lb/MMBTU
		GHG	Good operating practices	CO_2 117 lb/MMBTU CH_4 0.0022 lb/MMBTU N_2O 0.0002 lb/MMBTU
SN-16, SN-17, SN-18, and SN-19	Tundish Preheaters/ Dryout Stand #1 and #2 Tundish Preheaters #3 & #4	PM	Combustion of Natural gas and Good Combustion Practice	0.00052 lb/MMBTU
		PM_{10}		0.00052 lb/MMBTU
		$PM_{2.5}$		0.00052 lb/MMBTU
		Opacity		5%
		SO_2		0.000588 lb/MMBTU
		VOC		0.0054 lb/MMBTU
		CO		0.0824 lb/MMBTU
		NO_X	Low NO_x burners Combustion of clean fuel Good Combustion Practices	0.08 lb/MMBTU
		GHG	Good operating practices	CO_2 117 lb/MMBTU CH_4 0.0022 lb/MMBTU N_2O 0.0002 lb/MMBTU

BACT Analysis Summary				
Source	Description	Pollutant	Control Technology	BACT Limit
SN-20 and SN-21	Tunnel Furnaces	PM	Combustion of Natural gas and Good Combustion Practice	0.00052 lb/MMBTU
		PM_{10}		0.00052 lb/MMBTU
		$PM_{2.5}$		0.00052 lb/MMBTU
		Opacity		5%
		SO_2		0.000588 lb/MMBTU
		VOC		0.0054 lb/MMBTU
		CO		0.0824 lb/MMBTU
		NO_X	Low NO_x burners Combustion of clean fuel Good Combustion Practices	0.1 lb/MMBTU
		GHG	Good operating practices	CO_2 117 lb/MMBTU CH_4 0.0022 lb/MMBTU N_2O 0.0002 lb/MMBTU
SN-22	Pickle Line Boiler	PM	Combustion of Natural gas and Good Combustion Practice	0.00052 lb/MMBTU
		PM_{10}		0.00052 lb/MMBTU
		$PM_{2.5}$		0.00052 lb/MMBTU
		Opacity		5%
		SO_2		0.000588 lb/MMBTU
		VOC		0.0054 lb/MMBTU
		CO		0.0824 lb/MMBTU
		NO_X	Low NO_x burners Combustion of clean fuel Good Combustion Practices	0.035 lb/MMBTU
		GHG	Good operating practices Minimum Boiler Efficiency	CO_2 117 lb/MMBTU CH_4 0.0022 lb/MMBTU N_2O 0.0002 lb/MMBTU 75%
SN-23	Pickle Line Scale Exhaust	PM	Fabric Filter	0.003 gr/dscf
		PM_{10}		
		$PM_{2.5}$		
		Opacity		5%
SN-23A	Tension Leveler Dust	PM	Fabric Filter	0.003 gr/dscf
		PM_{10}		

BACT Analysis Summary				
Source	Description	Pollutant	Control Technology	BACT Limit
	Exhaust	$PM_{2.5}$		
		Opacity		5%
SN-25	Tandem Cold Mill	PM	Mist Eliminator	0.0025 gr/dscf (filterable only)
		PM_{10}		0.0066 gr/dscf
		$PM_{2.5}$		0.0066 gr/dscf
		Opacity		
SN-26 and SN-27	Galvanizing Line Boiler	PM	Combustion of Natural gas and Good Combustion Practice	0.00052 lb/MMBTU
		PM_{10}		0.00052 lb/MMBTU
		$PM_{2.5}$		0.00052 lb/MMBTU
		Opacity		5%
		SO_2		0.000588 lb/MMBTU
		VOC		0.0054 lb/MMBTU
		CO		0.0824 lb/MMBTU
		NO_X	Low NO_x burners Combustion of clean fuel Good Combustion Practices	0.035 lb/MMBTU
		GHG	Good operating practices Minimum Boiler Efficiency	CO_2 117 lb/MMBTU CH_4 0.0022 lb/MMBTU N_2O 0.0002 lb/MMBTU 75%
SN-28 and SN-29	Galvanizing Line Preheater	PM	Combustion of Natural gas and Good Combustion Practice	0.00052 lb/MMBTU
		PM_{10}		0.00052 lb/MMBTU
		$PM_{2.5}$		0.00052 lb/MMBTU
		Opacity		5%
		SO_2		0.000588 lb/MMBTU
		VOC		0.0054 lb/MMBTU
		CO		0.0824 lb/MMBTU
		NO_X	SCR, Low NO_x burners Combustion of clean fuel Good Combustion Practices	0.035 lb/MMBTU
		GHG	Good operating practices	CO_2 117 lb/MMBTU CH_4 0.0022 lb/MMBTU N_2O 0.0002 lb/MMBTU

BACT Analysis Summary				
Source	Description	Pollutant	Control Technology	BACT Limit
SN-34, SN-35, SN-36, SN-37	Galvanizing Line Caustic Cleaning and Post Treatment	PM	Mist Eliminator	0.003 gr/dscf
		PM_{10}		
		$PM_{2.5}$		
		Opacity		5%
SN-38	Skin Pass Mill	PM	Mist Eliminator	0.0025 gr/dscf
		PM_{10}		0.0066 gr/dscf
		$PM_{2.5}$		
		Opacity		5%
SN-39	Annealing Furnaces	PM	Combustion of Natural gas and Good Combustion Practice	0.00052 lb/MMBTU
		PM_{10}		0.00052 lb/MMBTU
		$PM_{2.5}$		0.00052 lb/MMBTU
		Opacity		5%
		SO_2		0.000588 lb/MMBTU
		VOC		0.0054 lb/MMBTU
		CO		0.0824 lb/MMBTU
		NO_X	Low NO_x burners Combustion of clean fuel Good Combustion Practices	0.1 lb/MMBTU
		GHG	Good operating practices	CO_2 117 lb/MMBTU CH_4 0.0022 lb/MMBTU N_2O 0.0002 lb/MMBTU
SN-40, SN-42	Decarburizing Line Furnace Section	PM	Combustion of Natural gas and Good Combustion Practice	0.00052 lb/MMBTU
		PM_{10}		0.00052 lb/MMBTU
		$PM_{2.5}$		0.00052 lb/MMBTU
		Opacity		5%
		SO_2		0.000588 lb/MMBTU
		VOC		0.0054 lb/MMBTU
		CO		0.0824 lb/MMBTU
		NO_X	Low NO_x burners SCR Combustion of clean fuel Good Combustion Practices	0.1 lb/MMBTU
		GHG	Good operating practices	CO_2 117 lb/MMBTU CH_4 0.0022 lb/MMBTU N_2O 0.0002 lb/MMBTU

BACT Analysis Summary				
Source	Description	Pollutant	Control Technology	BACT Limit
SN-41, SN-43	Decarburizing Line Cleaning Sections	PM	Mist Eliminator	0.003 gr/dscf
		PM_{10}		
		$PM_{2.5}$		
		Opacity		
SN-44, SN-45, SN-46	Reversing Cold Mills	PM	Mist Eliminator	0.0025gr/dscf 0.0066 gr/dscf
		PM_{10}		
		$PM_{2.5}$		
		Opacity		
SN-47	Annealing Pickling Line Furnace Section	PM	Combustion of Natural gas and Good Combustion Practice	0.00052 lb/MMBTU
		PM_{10}		0.00052 lb/MMBTU
		$PM_{2.5}$		0.00052 lb/MMBTU
		Opacity		5%
		SO_2		0.000588 lb/MMBTU
		VOC		0.0054 lb/MMBTU
		CO		0.0824 lb/MMBTU
		NO_X	Low NO_x burners SCR Combustion of clean fuel Good Combustion Practices	0.1 lb/MMBTU
		GHG	Good operating practices	CO_2 117 lb/MMBTU CH_4 0.0022 lb/MMBTU N_2O 0.0002 lb/MMBTU
SN-48, SN-49	Annealing Pickling Line Scale Dust Exhaust and Shotblast	PM	Fabric Filter	0.003 gr/dscf
		PM_{10}		
		$PM_{2.5}$		
		Opacity		5%
SN-51	Annealing Coating Line Furnace Section	PM	Combustion of Natural gas and Good Combustion Practice	0.00052 lb/MMBTU
		PM_{10}		0.00052 lb/MMBTU
		$PM_{2.5}$		0.00052 lb/MMBTU
		Opacity		5%
		SO_2		0.000588 lb/MMBTU
		VOC		0.0054 lb/MMBTU
		CO		0.0824 lb/MMBTU

BACT Analysis Summary				
Source	Description	Pollutant	Control Technology	BACT Limit
		NO_X	Low NO_x burners SCR Combustion of clean fuel Good Combustion Practices	0.1 lb/MMBTU
		GHG	Good operating practices	CO_2 117 lb/MMBTU CH_4 0.0022 lb/MMBTU N_2O 0.0002 lb/MMBTU
SN-52	Annealing Coating Line Cleaning Section	PM	Mist Eliminator	0.003 gr/dscf
		PM_{10}		
		$PM_{2.5}$		
		Opacity		5%
SN-53	Annealing Coating Line Drying Furnace	PM	Combustion of Natural gas and Good Combustion Practice	0.00052 lb/MMBTU
		PM_{10}		0.00052 lb/MMBTU
		$PM_{2.5}$		0.00052 lb/MMBTU
		Opacity		5%
		SO_2		0.000588 lb/MMBTU
		CO		0.0824 lb/MMBTU
		VOC Natural gas Combustion	RTO	0.0054 lb/MMBTU
		NO_X	Low NO_x burners Combustion of clean fuel Good Combustion Practices	0.1 lb/MMBTU
		GHG	Good operating practices	CO_2 117 lb/MMBTU CH_4 0.0022 lb/MMBTU N_2O 0.0002 lb/MMBTU
SN-54, SN-56	MgO Coating Lines Drying Sections	PM	Combustion of Natural gas and Good Combustion Practice	0.00052 lb/MMBTU
		PM_{10}		0.00052 lb/MMBTU
		$PM_{2.5}$		0.00052 lb/MMBTU
		Opacity		5%
		SO_2		0.000588 lb/MMBTU
		VOC		0.0054 lb/MMBTU
		CO		0.0824 lb/MMBTU

BACT Analysis Summary				
Source	Description	Pollutant	Control Technology	BACT Limit
		NO_X	Low NO_x burners Combustion of clean fuel Good Combustion Practices	0.1 lb/MMBTU
		GHG	Good operating practices	CO_2 117 lb/MMBTU CH_4 0.0022 lb/MMBTU N_2O 0.0002 lb/MMBTU
SN-55, SN-57	MgO Coating Lines Cleaning Sections	PM	Mist Eliminator	0.003 gr/dscf
		PM_{10}		
		$PM_{2.5}$		
		Opacity		
SN-58, SN-60	Final Annealing and Coating Lines Furnace Sections	PM	Combustion of Natural gas and Good Combustion Practice	0.00052 lb/MMBTU
		PM_{10}		0.00052 lb/MMBTU
		$PM_{2.5}$		0.00052 lb/MMBTU
		Opacity		5%
		SO_2		0.000588 lb/MMBTU
		VOC		0.0054 lb/MMBTU
		CO		0.0824 lb/MMBTU
		NO_X	Low NO_x burners SCR Combustion of clean fuel Good Combustion Practices	0.1 lb/MMBTU
		GHG	Good operating practices	CO_2 117 lb/MMBTU CH_4 0.0022 lb/MMBTU N_2O 0.0002 lb/MMBTU
SN-62	Emergency Generator #1	PM	Good Operating Practices, limited hours of operation, Compliance with NSPS Subpart IIII	0.02 g/kW-Hr
		PM_{10}		0.02 g/kW-Hr
		$PM_{2.5}$		0.02 g/kW-Hr
		Opacity		20%
		SO_2		<0.0015% sulfur in fuel
		VOC		0.19 g/kW-Hr
		CO		3.5 g/kW-Hr
		NO_X		0.4 g/kW-Hr
		GHG	Good Combustion Practices	CO_2 163 lbs/MMBTU CH_4 0.0061 lbs/MMBTU N_2O 0.0013 lbs/MMBTU
SN-63,	Emergency	PM	Good Operating	0.04 g/kW-Hr

BACT Analysis Summary				
Source	Description	Pollutant	Control Technology	BACT Limit
SN-64, SN-65, SN-66, SN-67	Generators 2 through 6	PM_{10}	Practices, limited hours of operation, Compliance with NSPS Subpart IIII	0.04 g/kW-Hr
		$PM_{2.5}$		0.04 g/kW-Hr
		Opacity		20%
		SO_2		<0.0015% sulfur in fuel
		VOC		0.19 g/kW-Hr
		CO		3.5 g/kW-Hr
		NO_X		0.67 g/kW-Hr
		GHG	Good Combustion Practices	CO_2 163 lbs/MMBTU CH_4 0.0061 lbs/MMBTU N_2O 0.0013 lbs/MMBTU
SN-68, SN-69, SN-70, SN-71, SN-72, SN-73	Non-Contact Cooling Towers	PM	Drift Eliminators Low TDS	0.0005 percent drift loss
		PM_{10}		
		$PM_{2.5}$		
		Opacity		5%
SN-73, SN-74, SN-75, SN-76, SN-77, SN-78, SN-79	Contact Cooling Towers	PM	Drift Eliminators Low TDS	0.0005 percent drift loss
		PM_{10}		
		$PM_{2.5}$		
		Opacity		5%
SN-80	Charge Crane	PM	Dust Control Plan	0.1 lb/hr, 0.1 tpy
		PM_{10}		0.1 lb/hr, 0.1 tpy 0.1 tpy
		$PM_{2.5}$		0.1 lb/hr, 0.1 tpy
		Opacity		20%
SN-81	Scrap yard Stockpiling	PM	Dust Control Plan	0.1 lb/hr, 0.5 tpy
		PM_{10}		0.1 lb/hr, 0.2 tpy
		$PM_{2.5}$		0.1 lb/hr, 0.1 tpy
		Opacity		20%
SN-82	EAF Flux Receiving System	PM	Dust Control Plan Enclosed Receiving System with Fabric Filter	0.003 gr/dscf
		PM_{10}		
		$PM_{2.5}$		
		Opacity		5%

BACT Analysis Summary				
Source	Description	Pollutant	Control Technology	BACT Limit
SN-83	EAF Flux Storage and Handling System	PM PM_{10} $PM_{2.5}$	Dust Control Plan, Enclosed Conveyors with Fabric Filters Silos with Bin Vent Filters	0.003 gr/dscf 0.01 gr/dscf
		Opacity		5%
SN-84	Carbon Injection Receiving	PM PM_{10} $PM_{2.5}$	Dust Control Plan Enclosed Receiving System with Fabric Filter	0.003 gr/dscf
		Opacity		5%
SN-85	Carbon Injection Storage and Handling System	PM PM_{10} $PM_{2.5}$	Dust Control Plan, Enclosed Conveyors with Fabric Filters Silos with Bin Vent Filters	0.003 gr/dscf 0.01 gr/dscf
		Opacity		5%
SN-86	LMF Flux Receiving	PM PM_{10} $PM_{2.5}$	Dust Control Plan Enclosed Receiving System with Fabric Filter	0.003 gr/dscf
		Opacity		5%
SN-87	LMF Flux Storage and Handling System	PM PM_{10} $PM_{2.5}$	Dust Control Plan, Enclosed Conveyors with Fabric Filters Silos with Bin Vent Filters	0.003 gr/dscf 0.01 gr/dscf
		Opacity		5%
SN-88	Alloy Receiving System	PM PM_{10} $PM_{2.5}$	Dust Control Plan Enclosed Receiving System with Fabric Filter	0.003 gr/dscf
		Opacity		5%
SN-89	Alloy Storage and Handling System	PM PM_{10} $PM_{2.5}$	Dust Control Plan, Enclosed Conveyors with Fabric Filters Silos with Bin Vent Filters	0.003 gr/dscf 0.01 gr/dscf
		Opacity		5%
SN-90	Alloy Delivery	PM PM_{10}	Dust Control Plan, Enclosed	0.003 gr/dscf

BACT Analysis Summary				
Source	Description	Pollutant	Control Technology	BACT Limit
	System – LMF	$PM_{2.5}$	Conveyors with Fabric Filters Enclosed Receiving System with Fabric Filter Fabric Filters Silos with Bin Vent Filters	0.003 gr/dscf 0.01 gr/dscf
		Opacity		5%
SN-91	RH Degasser Alloy Deliver System	PM	Dust Control Plan, Enclosed Conveyors with Fabric Filters Enclosed Receiving System with Fabric Filter Fabric Filters Silos with Bin Vent Filters	0.003 gr/dscf 0.003 gr/dscf 0.01 gr/dscf
		PM_{10}		
		$PM_{2.5}$		
		Opacity		5%
SN-92	Inside Drop Point - Spent Refractory and Other Waste	PM	Dust Control Plan	0.1 lb/hr, 0.1 tpy
		PM_{10}		0.1 lb/hr, 0.1 tpy
		$PM_{2.5}$		0.1 lb/hr, 0.1 tpy
		Opacity		20%
SN-93	Outside Drop Point - Spent Refractory and Other Waste	PM	Dust Control Plan	0.1 lb/hr, 0.1 tpy
		PM_{10}		0.1 lb/hr, 0.1 tpy
		$PM_{2.5}$		0.1 lb/hr, 0.1 tpy
		Opacity		20%
SN-94	Inside Drop Point – EAF Dust	PM	Dust Control Plan	0.1 lb/hr, 0.1 tpy
		PM_{10}		0.1 lb/hr, 0.1 tpy
		$PM_{2.5}$		0.1 lb/hr, 0.1 tpy
		Opacity		20%
SN-95	Drop Points Slag	PM	Dust Control Plan	0.2 lb/hr, 0.8 tpy
		PM_{10}		0.1 lb/hr, 0.4 tpy
		$PM_{2.5}$		0.1 lb/hr, 0.1 tpy
		Opacity		20%
SN-96	Slag Handling and Conveying	PM	Dust Control Plan	0.2 lb/hr, 0.5 tpy
		PM_{10}		0.1 lb/hr, 0.2 tpy
		$PM_{2.5}$		0.1 lb/hr, 0.1 tpy
		Opacity		20%

BACT Analysis Summary				
Source	Description	Pollutant	Control Technology	BACT Limit
SN-97	Paved Roads	PM	Dust Control Plan	0.7 lb/hr, 2.9 tpy
		PM_{10}		0.2 lb/hr, 0.6 tpy
		$PM_{2.5}$		0.1 lb/hr, 0.2 tpy
SN-98	Unpaved Roads	PM	Dust Control Plan	2.2 lb/hr, 9.6 tpy
		PM_{10}		0.6 lb/hr, 2.6 tpy
		$PM_{2.5}$		0.1 lb/hr, 0.3 tpy
SN-99A	Feed Stock Piles - Wind Erosion	PM	Dust Control Plan	0.9 lb/hr, 3.7 tpy
		PM_{10}		0.5 lb/hr, 1.9 tpy
		$PM_{2.5}$		0.1 lb/hr, 0.3 tpy
		Opacity		20%
SN-99B	Slag Piles – Wind Erosion	PM	Dust Control Plan	0.2 lb/hr, 0.6 tpy
		PM_{10}		0.1 lb/hr, 0.3 tpy
		$PM_{2.5}$		0.1 lb/hr, 0.1 tpy
		Opacity		20%

Permit #2305-AOP-R1 was issued to Big River Steel LLC on August 31, 2015. This permitting action was necessary to add four insignificant activities to the permit. There were no changes to the permitted emission rates.

Permit #2305-AOP-R2 was issued to Big River Steel LLC on November 7, 2018. This permitting action was necessary to update phase 1 equipment. The cooling towers' drift eliminator rate was updated along with emissions changes due to size changes. SN-04, SN-22, SN-26, and SN-28 BACT and emission limits were updated due to testing results. The tundish and ladle heaters (SN-05 through SN-11, SN-16, and SN-17) BACT limit was increased to match the rate of similar sources. Some emergency generators (SN-63 through SN-65) were slightly larger than permitted and have been updated. This modification also added a gasoline dispensing operation and three insignificant activities. The permitted emission changes from this modification were as follows: increase of 2.2 tpy PM, increase of 1 tpy PM_{10}, increase of 0.4 tpy $PM_{2.5}$, increase of 0.4 tpy SO_2, increase of 0.5 tpy VOC, decrease of 7.7 tpy CO, decrease of 8.8 tpy NO_X, decrease of 0.00012 tpy Lead, and a decrease of 8,975 tpy CO_2e.

Permit #2305-AOP-R3 was issued to Big River Steel LLC on December 28, 2018. This permitting action was an administrative amendment to correct the previous final permit. The previous permit did not include changes made during the comment period. Those changes were as follows. The emission limits and BACT limits were updated for SN-05-SN-11, SN-16, SN-17, and SN-39. These units were also removed from the testing requirements in Specific Conditions #53 and #70. Permit condition #26 was updated to remove the requirement for monthly submittal and to clarify the recordkeeping portion of the requirement for tons of steel tapped from the EAFs. The permitted emission changes from this amendment were as follows: an increase of 4.4 tpy PM, an increase of 4.5 tpy PM_{10}, and an increase of 4.5 tpy $PM_{2.5}$. The following table is a summary of the BACT determinations made in 2305-AOP-R2 and 2305-AOP-R3.

BACT Analysis Summary				
Source	Description	Pollutant	Control Technology	BACT Limit
SN-04	RH Degasser Boiler	PM	Combustion of Natural gas and Good Combustion Practice	0.000938 lb/MMBTU
		PM_{10}		0.000938 lb/MMBTU
		$PM_{2.5}$		0.000938 lb/MMBTU
		Opacity		5%
		SO_2		0.000588 lb/MMBTU
		VOC		0.0054 lb/MMBTU
		CO		0.0824 lb/MMBTU
		NO_X	Low NO_x burners Combustion of clean fuel Good Combustion Practices	0.035 lb/MMBTU
		GHG	Good operating practices Minimum Boiler Efficiency	CO_2 117 lb/MMBTU CH_4 0.0022 lb/MMBTU N_2O 0.0002 lb/MMBTU 75%
SN-05, SN-06, SN-07, SN-08, and SN-09	Ladle Preheaters	PM	Combustion of Natural gas and Good Combustion Practices	0.0075 lb/MMBTU
		PM_{10}		0.0075 lb/MMBTU
		$PM_{2.5}$		0.0075 lb/MMBTU
		Opacity		5%
		SO_2		0.000588 lb/MMBTU
		VOC		0.0054 lb/MMBTU
		CO		0.0824 lb/MMBTU
		NO_X	Low NO_x burners Combustion of clean fuel Good Combustion Practices	0.095 lb/MMBTU
		GHG	Good operating practices	CO_2 117 lb/MMBTU CH_4 0.0022 lb/MMBTU N_2O 0.0002 lb/MMBTU
SN-10 and SN-11	Ladle Dryout Station	PM	Combustion of Natural gas and Good Combustion Practice	0.0075 lb/MMBTU
		PM_{10}		0.0075 lb/MMBTU
		$PM_{2.5}$		0.0075 lb/MMBTU
		Opacity		5%
		SO_2		0.000588 lb/MMBTU

BACT Analysis Summary				
Source	Description	Pollutant	Control Technology	BACT Limit
		VOC		0.0054 lb/MMBTU
		CO		0.0824 lb/MMBTU
		NO_X	Low NO_x burners Combustion of clean fuel Good Combustion Practices	0.095 lb/MMBTU
		GHG	Good operating practices	CO_2 117 lb/MMBTU CH_4 0.0022 lb/MMBTU N_2O 0.0002 lb/MMBTU
SN-16 and SN-17	Tundish Preheaters/ Dryout Stands #1 and #2	PM	Combustion of Natural gas and Good Combustion Practice	0.0075 lb/MMBTU
		PM_{10}		0.0075 lb/MMBTU
		$PM_{2.5}$		0.0075 lb/MMBTU
		Opacity		5%
		SO_2		0.000588 lb/MMBTU
		VOC		0.0054 lb/MMBTU
		CO		0.0824 lb/MMBTU
		NO_X	Low NO_x burners Combustion of clean fuel Good Combustion Practices	0.097 lb/MMBTU
		GHG	Good operating practices	CO_2 117 lb/MMBTU CH_4 0.0022 lb/MMBTU N_2O 0.0002 lb/MMBTU
SN-22	Pickle Line Boiler	PM	Combustion of Natural gas and Good Combustion Practice	0.00186 lb/MMBTU
		PM_{10}		0.00186 lb/MMBTU
		$PM_{2.5}$		0.00186 lb/MMBTU
		Opacity		5%
		SO_2		0.000588 lb/MMBTU
		VOC		0.0054 lb/MMBTU
		CO		0.0824 lb/MMBTU
		NO_X	Low NO_x burners Combustion of clean fuel Good Combustion Practices	0.035 lb/MMBTU

BACT Analysis Summary				
Source	Description	Pollutant	Control Technology	BACT Limit
		GHG	Good operating practices Minimum Boiler Efficiency	CO_2 117 lb/MMBTU CH_4 0.0022 lb/MMBTU N_2O 0.0002 lb/MMBTU 75%
SN-26	Galvanizing Line Boiler	PM	Combustion of Natural gas and Good Combustion Practice	0.00068 lb/MMBTU
		PM_{10}		0.00068 lb/MMBTU
		$PM_{2.5}$		0.00068 lb/MMBTU
		Opacity		5%
		SO_2		0.000588 lb/MMBTU
		VOC		0.0054 lb/MMBTU
		CO		0.0824 lb/MMBTU
		NO_X	Low NO_x burners Combustion of clean fuel Good Combustion Practices	0.035 lb/MMBTU
		GHG	Good operating practices Minimum Boiler Efficiency	CO_2 117 lb/MMBTU CH_4 0.0022 lb/MMBTU N_2O 0.0002 lb/MMBTU 75%
SN-28	Galvanizing Line Preheater	PM	Combustion of Natural gas and Good Combustion Practice	0.0012 lb/MMBTU
		PM_{10}		0.0012 lb/MMBTU
		$PM_{2.5}$		0.0012 lb/MMBTU
		Opacity		5%
		SO_2		0.000588 lb/MMBTU
		VOC		0.0054 lb/MMBTU
		CO		0.0824 lb/MMBTU
		NO_X	SCR, Low NO_x burners Combustion of clean fuel Good Combustion Practices	0.035 lb/MMBTU
		GHG	Good operating practices	CO_2 117 lb/MMBTU CH_4 0.0022 lb/MMBTU N_2O 0.0002 lb/MMBTU
SN-39	Annealing Furnaces	PM	Combustion of Natural gas and	0.0075 lb/MMBTU
		PM_{10}		0.0075 lb/MMBTU

BACT Analysis Summary				
Source	Description	Pollutant	Control Technology	BACT Limit
		$PM_{2.5}$	Good Combustion Practice	0.0075 lb/MMBTU
		Opacity		5%
		SO_2		0.000588 lb/MMBTU
		VOC		0.0054 lb/MMBTU
		CO		0.0824 lb/MMBTU
		NO_X	Low NO_x burners Combustion of clean fuel Good Combustion Practices	0.1 lb/MMBTU
		GHG	Good operating practices	CO_2 117 lb/MMBTU CH_4 0.0022 lb/MMBTU N_2O 0.0002 lb/MMBTU
SN-63, SN-64, and SN-65	Emergency Generators 2 through 4	PM	Good Operating Practices, limited hours of operation, Compliance with NSPS Subpart IIII	0.2 g/kW-Hr
		PM_{10}		0.2 g/kW-Hr
		$PM_{2.5}$		0.2 g/kW-Hr
		Opacity		20%
		SO_2		<0.0015% sulfur in fuel
		VOC		1.55 g/kW-Hr
		CO		3.5 g/kW-Hr
		NO_X		3.86 g/kW-Hr
		GHG	Good Combustion Practices	CO_2 163 lbs/MMBTU CH_4 0.0061 lbs/MMBTU N_2O 0.0013 lbs/MMBTU
SN-68, SN-69, SN-70, SN-73, and SN-74	Non-Contact Cooling Towers	PM	Drift Eliminators Low TDS	0.001 percent drift loss
		PM_{10}		
		$PM_{2.5}$		
		Opacity		5%
SN-75, SN-76, SN-77, and SN-79	Contact Cooling Towers	PM	Drift Eliminators Low TDS	0.001 percent drift loss
		PM_{10}		
		$PM_{2.5}$		
		Opacity		5%

Permit #2305-AOP-R4 was issued to Big River Steel LLC on April 5, 2019. This permitting action updated emissions and specifications of some Phase II equipment and added some new sources.

The Vertical Ladle Dryout Flash Preheater Stations SN-12 and SN-13 were updated to match the BACT and emission rates of the Phase I Ladle Dryout Stations SN-10 and SN-11. The same was true for the Tundish Preheaters (SN-17, SN-18, SN-19), Galvanizing Line Boiler 2 (SN-27), and Galvanizing Line Preheater 2 (SN-29) all being updated to match their Phase I counterpart. There were also two additional Tundish Preheaters added in this modification, SN-19A and SN-19B.

Emergency engines SN-62, SN-66, and SN-67 had their BACT limits updated to reflect the correct tier engine installed at each source. SN-66 and SN-67 also had their sizes updated to correctly reflect the installed source. Three new emergency engines, SN-67A, SN-67B, and SN-67C were also added to the permit during this modification.

Cooling towers SN-71, SN-72 (now SN-72A), and SN-78 (now SN-78A) were updated to reflect size and TDS limit changes. Four new cooling towers (SN-72B, SN-74A, SN-74B and SN-78B) were added to the permit.

Two new sources were added to the Cold Mill, an Annealing Pickle Line Boiler (SN-101), and 50 natural gas fired space heaters (SN-102).

The total permitted emission changes as a result of this modification were as follows: Increase of 43.8tpy PM, increase of 65.4 tpy of PM_{10} and $PM_{2.5}$, increase of 4.4 tpy SO_2, increase of 6.3 tpy VOC, increase of 72.3 tpy CO, increase of 63 tpy NO_X, and an increase of 0.00028 tpy Lead.

The following table is a summary of the BACT determinations made in 2305-AOP-R4.

BACT Analysis Summary				
Source	Description	Pollutant	Control Technology	BACT Limit
SN-10 SN-11 SN-12 SN-13	Vertical Ladle Dryout Flash Preheater Station	PM	Combustion of Natural gas and Good Combustion Practice	0.0075 lb/MMBTU
		PM_{10}		0.0075 lb/MMBTU
		$PM_{2.5}$		0.0075 lb/MMBTU
		Opacity		5%
		SO_2		0.000588 lb/MMBTU
		VOC		0.0054 lb/MMBTU
		CO		0.0824 lb/MMBTU
		NO_X	Low NOx burners Combustion of clean fuel Good Combustion Practices	0.095 lb/MMBTU
		GHG	Good operating practices	CO_2 117 lb/MMBTU CH_4 0.0022 lb/MMBTU N_2O 0.0002 lb/MMBTU
SN-16	Tundish	PM	Combustion of	0.0075 lb/MMBTU

BACT Analysis Summary				
Source	Description	Pollutant	Control Technology	BACT Limit
SN-17 SN-18 SN-19 SN-19A SN-19B	Preheaters/Dryout Stands #1 through #6	PM_{10}	Natural gas and Good Combustion Practice	0.0075 lb/MMBTU
		$PM_{2.5}$		0.0075 lb/MMBTU
		Opacity		5%
		SO_2		0.000588 lb/MMBTU
		VOC		0.0054 lb/MMBTU
		CO		0.0824 lb/MMBTU
		NO_X	Low NOx burners Combustion of clean fuel Good Combustion Practices	0.097 lb/MMBTU
		GHG	Good operating practices	CO_2 117 lb/MMBTU CH_4 0.0022 lb/MMBTU N_2O 0.0002 lb/MMBTU
SN-22	Pickle Line Boiler	PM	Combustion of Natural gas and Good Combustion Practice	0.00186 lb/MMBTU
		PM_{10}		0.00186 lb/MMBTU
		$PM_{2.5}$		0.00186 lb/MMBTU
		Opacity		5%
		SO_2		0.000588 lb/MMBTU
		VOC		0.0054 lb/MMBTU
		CO		0.0824 lb/MMBTU
		NO_X	Low NOx burners Combustion of clean fuel Good Combustion Practices	0.035 lb/MMBTU
		GHG	Good operating practices Minimum Boiler Efficiency	CO_2 117 lb/MMBTU CH_4 0.0022 lb/MMBTU N_2O 0.0002 lb/MMBTU 75%
SN-26 and SN-27	Galvanizing Line Boilers 1 and 2	PM	Combustion of Natural gas and Good Combustion Practice	0.00068 lb/MMBTU
		PM_{10}		0.00068 lb/MMBTU
		$PM_{2.5}$		0.00068 lb/MMBTU
		Opacity		5%
		SO_2		0.000588 lb/MMBTU
		VOC		0.0054 lb/MMBTU
		CO		0.0824 lb/MMBTU

BACT Analysis Summary				
Source	Description	Pollutant	Control Technology	BACT Limit
		NO_X	Low NOx burners Combustion of clean fuel Good Combustion Practices	0.035 lb/MMBTU
		GHG	Good operating practices Minimum Boiler Efficiency	CO_2 117 lb/MMBTU CH_4 0.0022 lb/MMBTU N_2O 0.0002 lb/MMBTU 75%
SN-28 and SN-29	Galvanizing Line Preheaters 1 and 2	PM	Combustion of Natural gas and Good Combustion Practice	0.0012 lb/MMBTU
		PM_{10}		0.0012 lb/MMBTU
		$PM_{2.5}$		0.0012 lb/MMBTU
		Opacity		5%
		SO_2		0.000588 lb/MMBTU
		VOC		0.0054 lb/MMBTU
		CO		0.0824 lb/MMBTU
		NO_X	SCR, Low NOx burners Combustion of clean fuel Good Combustion Practices	0.035 lb/MMBTU
		GHG	Good operating practices	CO_2 117 lb/MMBTU CH_4 0.0022 lb/MMBTU N_2O 0.0002 lb/MMBTU
SN-62	Emergency Generator #1	PM	Good Operating Practices, limited hours of operation, Compliance with NSPS Subpart IIII	0.2 g/kW-Hr
		PM_{10}		0.2 g/kW-Hr
		$PM_{2.5}$		0.2 g/kW-Hr
		Opacity		20%
		SO_2		<0.0015% sulfur in fuel
		VOC		1.0 g/kW-Hr
		CO		3.5 g/kW-Hr
		NO_X		3.0 g/kW-Hr
		GHG	Good Combustion Practices	CO_2 163 lbs/MMBTU CH_4 0.0061 lbs/MMBTU N_2O 0.0013 lbs/MMBTU
SN-63, SN-64, SN-65,	Emergency Generators 2 through 9	PM	Good Operating Practices, limited hours of operation,	0.2 g/kW-Hr
		PM_{10}		0.2 g/kW-Hr
		$PM_{2.5}$		0.2 g/kW-Hr

BACT Analysis Summary				
Source	Description	Pollutant	Control Technology	BACT Limit
SN-66, SN-67, SN-67A SN-67B, SN-67C		Opacity	Compliance with NSPS Subpart IIII	20%
		SO_2		<0.0015% sulfur in fuel
		VOC		1.55 g/kW-Hr
		CO		3.5 g/kW-Hr
		NO_X		4.86 g/kW-Hr
		GHG	Good Combustion Practices	CO_2 163 lbs/MMBTU CH_4 0.0061 lbs/MMBTU N_2O 0.0013 lbs/MMBTU
SN-68 SN-69, SN-70, SN-71, SN-72A, SN-72B, SN-73, SN-74, SN-74A, SN-74B	Non-Contact Cooling Towers	PM	Drift Eliminators Low TDS	0.001 percent drift loss
		PM_{10}		
		$PM_{2.5}$		
		Opacity		5%
SN-75, SN-76, SN-77, SN-78A, SN-78B, SN-79	Contact Cooling Towers	PM	Drift Eliminators Low TDS	0.001 percent drift loss
		PM_{10}		
		$PM_{2.5}$		
		Opacity		5%
SN-101	Annealing Pickle Line Boiler	PM	Combustion of Natural gas and Good Combustion Practice	0.00186 lb/MMBTU
		PM_{10}		0.00186 lb/MMBTU
		$PM_{2.5}$		0.00186 lb/MMBTU
		Opacity		5%
		SO_2		0.000588 lb/MMBTU
		VOC		0.0054 lb/MMBTU
		CO		0.0824 lb/MMBTU
		NO_X	Low NOx burners Combustion of clean fuel Good Combustion Practices	0.035 lb/MMBTU

BACT Analysis Summary				
Source	Description	Pollutant	Control Technology	BACT Limit
		GHG	Good operating practices Minimum Boiler Efficiency	CO_2 117 lb/MMBTU CH_4 0.0022 lb/MMBTU N_2O 0.0002 lb/MMBTU 75%
SN-102	Cold Mill Space Heaters - Natural Gas Fired (110 MMBtu)	PM	Combustion of Natural gas and Good Combustion Practice	0.0075 lb/MMBTU
		PM_{10}		0.0075 lb/MMBTU
		$PM_{2.5}$		0.0075 lb/MMBTU
		Opacity		5%
		SO_2		0.000588 lb/MMBTU
		VOC		0.0054 lb/MMBTU
		CO		0.0824 lb/MMBTU
		NO_X	Low NOx burners Combustion of clean fuel Good Combustion Practices	0.08 lb/MMBTU
		GHG	Good operating practices	CO_2 117 lb/MMBTU CH_4 0.0022 lb/MMBTU N_2O 0.0002 lb/MMBTU

Permit #2305-AOP-R5 was issued to Big River Steel LLC on July 12, 2019. This permitting modification increased the allowable production from EAF I (SN-01) from 1,700,000 tons to 2,050,000 tons of steel per rolling twelve months due to a higher demand for production. This modification resulted in the following permitted emission changes: increase of 14.5 tpy SO_2, increase of 11.1 tpy VOC, increase of 333 tpy CO, increase of 10 tpy NO_X, increase of 0.1 tpy of Lead, and increase of 53,130 tpy of CO_2e.

Permit #2305-AOP-R6 was issued to Big River Steel LLC on June 9, 2020. This permitting modification made the following changes to the existing permit:

- Added the following new sources to the permit: Lime Injector Burner I and II (SN-01A and SN-02A), Caster #1 and #2 (SN-14 and SN-15), Tunnel Furnace Shuttle Zone (SN-21C), Emergency Generator 10 and 11 (SN-67D and SN-67E), four emergency water pumps (SN-104A through SN-104D), and an EAF I/II Lime Injection System (SN-103).
- Updated BACT for some existing sources and included BACT analysis for new sources.
- Increased throughput for EAF II and LMF II (SN-02) to match the rates of EAF I and LMF I (SN-01).
- Increased $PM/PM_{10}/PM_{2.5}$ emissions from the tunnel furnaces (SN-20 and SN-21) due to an emission factor change.

- Increased the power rating of Emergency Generators 5 through 9 (SN-66, SN-67, SN-67A, SN-67B, and SN-67C) from 2000 kW each to 2700 kW each.
- Increased TDS limits for all permitted cooling tower sources by four times. The cooling towers require four passes, but the permit was currently limiting the TDS to the amount required in one pass. Emissions of cooling tower sources updated as well with this change.
- Increased throughput for the Carbon Injection Receiving system (SN-84) from 49,210 tons/year to 79,204 tons/year.
- Increased throughput to the slag handling operations (SN-95, SN-96, and SN-99B) from 488,980 tons/year to 650,000 tons/year.
- Added Air Products Cooling Towers #1 and #2 to the insignificant activities list.
- Some other miscellaneous changes to permit condition wording and error corrections.

The permitted emission changes for this permitting action were as follows: Increase of 29.7 tpy PM, increase of 29.0 tpy PM_{10}, increase of 28.6 tpy $PM_{2.5}$, increase of 31.2 tpy SO_2, increase of 17.4 tpy VOC, increase of 381.6 tpy CO, increase of 102.9 tpy NO_X, increase of 0.100079 tpy Lead, increase of 113,771 tpy CO_2e, and an increase of 0.7 tpy H_2SO_4.

The following table is a summary of the BACT determinations made in 2305-AOP-R6.

BACT Analysis Summary				
Source	Description	Pollutant	Control Technology	BACT Limit
SN-01A and SN-02A	Lime Injector Burners	PM	Combustion of Natural gas and Good Combustion Practices	0.0075 lb/MMBTU
		PM_{10}		0.0075 lb/MMBTU
		$PM_{2.5}$		0.0075 lb/MMBTU
		Opacity		5%
		CO		0.0824 lb/MMBTU
		NO_X	Low NOx burners Combustion of clean fuel Good Combustion Practices	0.095 lb/MMBTU
		GHG	Good operating practices	CO_2 117 lb/MMBTU CH_4 0.0022 lb/MMBTU N_2O 0.0002 lb/MMBTU
SN-14 and SN-15	Casters #1 and #2	PM	Good operating practices	0.062 lb/ton of liquid steel produced
		PM_{10}		
		$PM_{2.5}$		
SN-20, SN-21, and SN-21C	Tunnel Furnaces and Tunnel Furnace	PM	Combustion of Natural gas and Good Combustion Practice	0.0075 lb/MMBTU
		PM_{10}		0.0075 lb/MMBTU
		$PM_{2.5}$		0.0075 lb/MMBTU
		Opacity		5%

BACT Analysis Summary				
Source	Description	Pollutant	Control Technology	BACT Limit
	Shuttle Zone	SO_2		0.000588 lb/MMBTU
		VOC		0.0054 lb/MMBTU
		CO		0.0824 lb/MMBTU
		NO_X	Low NOx burners Combustion of clean fuel Good Combustion Practices	0.1 lb/MMBTU
		GHG	Good operating practices	CO_2 117 lb/MMBTU CH_4 0.0022 lb/MMBTU N_2O 0.0002 lb/MMBTU
SN-63, SN-64, SN-65, SN-66, SN-67, SN-67A SN-67B, SN-67C, SN-67D	Emergency Generators 2 through 10	PM	Good Operating Practices, limited hours of operation, Compliance with NSPS Subpart IIII	0.2 g/kW-Hr
		PM_{10}		0.2 g/kW-Hr
		$PM_{2.5}$		0.2 g/kW-Hr
		Opacity		20%
		SO_2		<0.0015% sulfur in fuel
		VOC		1.55 g/kW-Hr
		CO		3.5 g/kW-Hr
		NO_X		4.86 g/kW-Hr
		GHG	Good Combustion Practices	CO_2 163 lbs/MMBTU CH_4 0.0061 lbs/MMBTU N_2O 0.0013 lbs/MMBTU
SN-103	EAF I/II Lime Injection System	PM	Fabric Filter Enclosed Conveyors with Compressed Air Dust Control Plan Bin Vent Filter on Each Silo	0.1 lb/hr, 0.4 tpy
		PM_{10}		0.1 lb/hr, 0.4 tpy
		$PM_{2.5}$		0.1 lb/hr, 0.4 tpy
		Opacity		5%

Permit #2305-AOP-R7 was issued to Big River Steel LLC on March 18, 2021. This permitting modification makes the following changes to the existing permit:

- Updated the heat input on SN-29
- Inclusion of two additional Batch Annealing Furnaces (SN-39). Total heat input increased from 85.15 MMBtu/hr to 117.8 MMBtu/hr
- Revised the flow rates for SN-35 and SN-37
- Revised the heat input of SN-51 and SN-53. An inline skin pass mill also added to enhance the Annealing and Coating Line process.

- Revised PM, PM_{10}, and $PM_{2.5}$ emission factors for natural gas fired combustion sources to be consistent with previous changes to the permit, resulting in updated BACT for some sources.
- Added a new coil coating line, including a pre-treatment section, prime and finish coating, natural gas fired combustion devices, a cooling tower, and a truck washing operation.
- Incorporation of five new diesel fired emergency generators rated at 2700 kW each. Each of these generators may be operated for emergency backup purposes only and are limited to no more than 100 hours per year for readiness testing.
- Installation of a 500-gallon gasoline storage tank to support the slag handling operation.
- Installation of a new hydrogen plant.
- Updated insignificant activities, adding two new cutting activities.
- Specify opacity observation type and frequency for multiple sources which were not explicitly stated in the permit.

As a result of these changes to emissions, the facility was classified as a major source of HAPs. Relevant conditions were added from NESHAP Subparts CCC, SSSS, DDDDD, and EEEEE. Upon commencement of operation of SN-107, the facility is no longer subject to NESHAP Subparts CCCCCC and YYYYY as the facility will be a major source of HAPs. The permitted emission changes as a result of this modification were as follows: an increase of 8.6 tpy PM, an increase of 12.7 tpy PM_{10}, an increase of 12.7 tpy $PM_{2.5}$, an increase of 1 tpy SO_2, an increase of 154.8 tpy VOC, an increase of 99 tpy CO, an increase of 68 tpy NO_X, an increase of 0.00029 tpy Lead, an increase of 73,168 tpy CO_2e, an increase of 0.4 tpy H_2SO_4, and an increase of 54.3 tpy total HAPs.

The following table is a summary of the BACT determinations made in 2305-AOP-R7.

BACT Analysis Summary				
Source	Description	Pollutant	Control Technology	BACT Limit
SN-29	Galvanizing Line #2 Furnace	PM	Combustion of Natural gas and Good Combustion Practice	0.0012 lb/MMBTU
		PM_{10}		0.0012 lb/MMBTU
		$PM_{2.5}$		0.0012 lb/MMBTU
		Opacity		5%
		SO_2		0.000588 lb/MMBTU
		VOC		0.0054 lb/MMBTU
		CO		0.0824 lb/MMBTU
		NO_X	SCR, Low NOx burners Combustion of clean fuel Good Combustion Practices	0.035 lb/MMBTU

BACT Analysis Summary				
Source	Description	Pollutant	Control Technology	BACT Limit
		GHG	Good operating practices	CO_2 117 lb/MMBTU CH_4 0.0022 lb/MMBTU N_2O 0.0002 lb/MMBTU
SN-35 and SN-37	Galvanizing Line Caustic Cleaning and Post Treatment	PM	Mist Eliminator	0.003 gr/dscf
		PM_{10}		
		$PM_{2.5}$		
		Opacity		5%
SN-38a SN-38b	SN-38a Skin Pass Mill #1 SN-38b Skin Pass Mill #2 (ACL)	PM	Mist Eliminator	0.0025 gr/dscf
		PM_{10}		0.0066 gr/dscf
		$PM_{2.5}$		0.0066 gr/dscf
		Opacity		5%
SN-39	Annealing Furnaces	PM	Combustion of Natural gas and Good Combustion Practice	0.0075 lb/MMBTU
		PM_{10}		0.0075 lb/MMBTU
		$PM_{2.5}$		0.0075 lb/MMBTU
		Opacity		5%
		SO_2		0.000588 lb/MMBTU
		VOC		0.0054 lb/MMBTU
		CO		0.0824 lb/MMBTU
		NO_X	Low NOx burners Combustion of clean fuel Good Combustion Practices	0.1 lb/MMBTU
		GHG	Good operating practices	CO_2 117 lb/MMBTU CH_4 0.0022 lb/MMBTU N_2O 0.0002 lb/MMBTU
SN-40, SN-42	Decarburizing Line Furnace Section	PM	Combustion of Natural gas and Good Combustion Practice	0.013 lb/MMBTU
		PM_{10}		0.013 lb/MMBTU
		$PM_{2.5}$		0.013 lb/MMBTU
		Opacity		5%
		SO_2		0.000588 lb/MMBTU
		VOC		0.0054 lb/MMBTU
		CO		0.0824 lb/MMBTU

BACT Analysis Summary				
Source	Description	Pollutant	Control Technology	BACT Limit
		NO_X	Low NOx burners SCR Combustion of clean fuel Good Combustion Practices	0.1 lb/MMBTU
SN-47	Annealing Pickling Line Furnace Section	PM	Combustion of Natural gas and Good Combustion Practice	0.013 lb/MMBTU
		PM_{10}		0.013 lb/MMBTU
		$PM_{2.5}$		0.013 lb/MMBTU
		Opacity		5%
		SO_2		0.000588 lb/MMBTU
		VOC		0.0054 lb/MMBTU
		CO		0.0824 lb/MMBTU
		NO_X	Low NOx burners SCR Combustion of clean fuel Good Combustion Practices	0.1 lb/MMBTU
		GHG	Good operating practices	CO_2 117 lb/MMBTU CH_4 0.0022 lb/MMBTU N_2O 0.0002 lb/MMBTU
SN-51	Annealing and Coating Line Furnace Section	PM	Combustion of Natural gas and Good Combustion Practice	0.013 lb/MMBTU
		PM_{10}		0.013 lb/MMBTU
		$PM_{2.5}$		0.013 lb/MMBTU
		Opacity		5%
		SO_2		0.000588 lb/MMBTU
		VOC		0.0054 lb/MMBTU
		CO		0.0824 lb/MMBTU
		NO_X	Low NOx burners SCR Combustion of clean fuel Good Combustion Practices	0.1 lb/MMBTU
		GHG	Good operating practices	CO_2 117 lb/MMBTU CH_4 0.0022 lb/MMBTU N_2O 0.0002 lb/MMBTU
SN-53	Annealing and Coating Line	PM	Combustion of Natural gas and	0.016 lb/MMBTU
		PM_{10}		0.016 lb/MMBTU

BACT Analysis Summary				
Source	Description	Pollutant	Control Technology	BACT Limit
	Drying Furnace	$PM_{2.5}$	Good Combustion Practice	0.016 lb/MMBTU
		Opacity		5%
		SO_2		0.000588 lb/MMBTU
		CO		0.45 lb/MMBTU
		VOC Natural gas Combustion	RTO	0.0054 lb/MMBTU
		NO_X	Low NOx burners Combustion of clean fuel Good Combustion Practices	0.25 lb/MMBTU
		GHG	Good operating practices	CO_2 117 lb/MMBTU CH_4 0.0022 lb/MMBTU N_2O 0.0002 lb/MMBTU
SN-54, SN-56	MgO Coating Lines Drying Sections	PM	Combustion of Natural gas and Good Combustion Practice	0.013 lb/MMBTU
		PM_{10}		0.013 lb/MMBTU
		$PM_{2.5}$		0.013 lb/MMBTU
		Opacity		5%
		SO_2		0.000588 lb/MMBTU
		VOC		0.0054 lb/MMBTU
		CO		0.0824 lb/MMBTU
		NO_X	Low NOx burners Combustion of clean fuel Good Combustion Practices	0.1 lb/MMBTU
		GHG	Good operating practices	CO_2 117 lb/MMBTU CH_4 0.0022 lb/MMBTU N_2O 0.0002 lb/MMBTU
SN-58, SN-60	Flattening Coating Lines Furnace Sections	PM	Combustion of Natural gas and Good Combustion Practice	0.013 lb/MMBTU
		PM_{10}		0.013 lb/MMBTU
		$PM_{2.5}$		0.013 lb/MMBTU
		Opacity		5%
		SO_2		0.000588 lb/MMBTU
		VOC		0.0054 lb/MMBTU
		CO		0.0824 lb/MMBTU

BACT Analysis Summary				
Source	Description	Pollutant	Control Technology	BACT Limit
		NO_X	Low NOx burners SCR Combustion of clean fuel Good Combustion Practices	0.1 lb/MMBTU
		GHG	Good operating practices	CO_2 117 lb/MMBTU CH_4 0.0022 lb/MMBTU N_2O 0.0002 lb/MMBTU
SN-105, SN-106	Coil Coating Line – Pre-Cleaning and Cleaning Sections	PM	Mist eliminator Good operating practices	0.003 gr/dscf
		PM_{10}		0.003 gr/dscf
		$PM_{2.5}$		0.003 gr/dscf
		Opacity		5%
SN-107	Coil Coating Line – Prime/Finish Coating	VOC	Enclosed painting system Thermal oxidation Good work practices	152.6 tpy 99% Destruction
SN-108A, SN-108B, SN-108C	Coil Coating Line – Chemical Dryer, Primer Oven, and Finish Oven	PM	Good combustion practices Energy efficient burners Combustion of natural gas	0.0075 lb/MMBTU
		PM_{10}		0.0075 lb/MMBTU
		$PM_{2.5}$		0.0075 lb/MMBTU
		Opacity		5%
		VOC		0.0054 lb/MMBTU
		NO_X		0.05 lb/MMBTU
SN-108D	Coil Coating Line – Finish Oven	PM	Good combustion practices Energy efficient burners Combustion of natural gas	0.009 lb/MMBTU
		PM_{10}		0.009 lb/MMBTU
		$PM_{2.5}$		0.009 lb/MMBTU
		Opacity		5%
		VOC		0.0054 lb/MMBTU
		NO_X		0.25 lb/MMBTU
SN-110a, SN-110b, SN-110c, SN-110d, SN-110e	Emergency Generators 12 through 16	PM	Good Operating Practices, limited hours of operation, Compliance with NSPS Subpart IIII	0.2 g/kW-Hr
		PM_{10}		0.2 g/kW-Hr
		$PM_{2.5}$		0.2 g/kW-Hr
		Opacity		20%
		SO_2		<0.0015% sulfur in fuel
		VOC		1.55 g/kW-Hr
		CO		3.5 g/kW-Hr
		NO_X		4.86 g/kW-Hr

BACT Analysis Summary				
Source	Description	Pollutant	Control Technology	BACT Limit
		GHG	Good Combustion Practices	CO_2 163 lbs/MMBTU CH_4 0.0061 lbs/MMBTU N_2O 0.0013 lbs/MMBTU
SN-109	Contact Cooling Towers	PM	Drift Eliminators Low TDS	0.001 percent drift loss
		PM_{10}		
		$PM_{2.5}$		
		Opacity		5%
SN-111	Hydrogen Plant #2 Reformer Furnace (PHG830)	PM	Combustion of Natural gas and Good Combustion Practice	0.0075 lb/MMBTU
		PM_{10}		0.0075 lb/MMBTU
		$PM_{2.5}$		0.0075 lb/MMBTU
		Opacity		5%
		VOC		0.0054 lb/MMBTU
		NO_X	Low NOx burners Combustion of clean fuel Good Combustion Practices	0.1 lb/MMBTU

SECTION IV: SPECIFIC CONDITIONS

Melt Shop

SN-01 EAF I and LMF I
SN-01A Lime Injector Burner I

SN-02 EAF II and LMF II
SN-02A Lime Injector Burner II

SN-14 Caster #1
SN-15 Caster #2

Source Description

The steel facility will receive scrap iron and steel by barge, rail, and truck. The scrap will be unloaded and stockpiled on site. The scrap will be moved from the storage piles and placed in charging buckets. These charging buckets will be used to load one of the plants two Electric Arc Furnaces, EAF I (SN-01) or EAF II (SN-02). In the EAF, additional raw materials are added through various feed systems and the charged steel is melted using electric arc applied through carbon electrodes. The two EAFs are capable of producing on average 250 tons per hour of liquid steel each. The liquid steel is then transferred to the Ladle Metallurgy Furnaces (LMF) and / or the RH Degasser for further refinement. Each EAF is equipped with a natural gas fired lime injection burner each rated at 18.5 MMBtu/hr and assigned SN-01A and SN-02A, respectively.

In the LMF the chemistry and temperature of the molten steel is further refined while it is still in the ladle. The liquid steel proceeds from the LMF to the RH Degasser, SN-03, and back to the LMF if needed, or to the Casters, SN-14 and SN-15 depending on the type of steel being produced.

EAF I and LMF I are routed to a single baghouse. EAF II and LMF II are also routed to a single baghouse.

Specific Conditions

1. The permittee shall not exceed the emission rates set forth in the following table. The permittee shall demonstrate compliance with this condition by Specific Conditions #5, #12, and #25. [Rule 19.901 *et seq.* and 40 C.F.R. § 52 Subpart E]

SN	Description	Pollutant	lb/hr	tpy
SN-01	EAF I and LMF I	PM	16.2	71.0
		PM_{10}	21.6	94.7
		$PM_{2.5}$	21.6	94.7
		SO_2	65.0	184.5
		VOC	23.3	90.2
		CO	505.0	2050.0
		NO_X	87.5	307.5
		Lead	0.14	0.58
		CO_2e	--	311,190
SN-01A	Lime Injector Burner I	PM	0.2	0.7
		PM_{10}	0.2	0.7
		$PM_{2.5}$	0.2	0.7
		SO_2	0.1	0.1
		VOC	0.1	0.5
		CO	1.6	6.7
		NO_X	1.9	8.1
		Lead	9.07 E-06	3.97 E-05
		CO_2e	--	9,481
SN-02	EAF II and LMF II	PM	16.2	71.0
		PM_{10}	21.6	94.7
		$PM_{2.5}$	21.6	94.7
		SO_2	65.0	205.0
		VOC	23.3	95.3
		CO	505.0	2070.5
		NO_X	87.5	358.8
		Lead	0.14	0.58
		CO_2e	--	311,190
SN-02A	Lime Injector Burner II	PM	0.2	0.7
		PM_{10}	0.2	0.7
		$PM_{2.5}$	0.2	0.7
		SO_2	0.1	0.1
		VOC	0.1	0.5
		CO	1.6	6.7
		NO_X	1.9	8.1
		Lead	9.07 E-06	3.97 E-05
		CO_2e	--	9,481
SN-14	Caster #1	PM	0.4	1.3
		PM_{10}	0.4	1.3
		$PM_{2.5}$	0.4	1.3
SN-15	Caster #2	PM	0.4	1.3
		PM_{10}	0.4	1.3
		$PM_{2.5}$	0.4	1.3

2. The permittee shall not exceed the emission rates set forth in the following table and must install the control devices or implement the pollution prevention measures set forth in the following table. Compliance with these emission limits shall be demonstrated by compliance with Specific Conditions #4, #5, and #12 through #26. [Rule 19.901 *et seq.* and 40 C.F.R. § 52 Subpart E]

BACT Analysis Summary				
Source	Description	Pollutant	Control Technology	BACT Limit
SN-01 and SN-02	EAFs and LMFs	PM	Fabric Filter	0.0018 gr/dscf (filterable only)
		PM_{10}	Fabric Filter	0.0024 gr/dscf
		$PM_{2.5}$	Fabric Filter	0.0024 gr/dscf
		Opacity	Fabric Filter	3% as a 6 minute average from baghouse 6% from melt shop
		SO_2	Scrap management plan	0.2 lb/ton of steel produced
		VOC	Scrap management plan and good operating practices	0.093 lb/ton steel produced
		CO		2.02 lb/ton of steel produced
		NO_X		0.35 lb/ton of steel produced
		Lead	Fabric Filter	0.00056 lb/ton of steel produced
		CO_2e	Good operating practices	622,380 tpy CO_2e
SN-01A and SN-02A	Lime Injector Burners	PM	Combustion of Natural gas and Good Combustion Practices	0.0075 lb/MMBTU
		PM_{10}		0.0075 lb/MMBTU
		$PM_{2.5}$		0.0075 lb/MMBTU
		Opacity		5%
		CO		0.0824 lb/MMBTU
		NO_X	Low NOx burners Combustion of clean fuel Good Combustion Practices	0.10 lb/MMBTU

BACT Analysis Summary				
Source	Description	Pollutant	Control Technology	BACT Limit
		GHG	Good operating practices	CO_2 117 lb/MMBTU CH_4 0.0022 lb/MMBTU N_2O 0.0002 lb/MMBTU
SN-14 and SN-15	Casters #1 and #2	PM PM_{10} $PM_{2.5}$	Good operating practices	0.062 lb/ton of liquid steel produced

3. The permittee shall not exceed the emission rates set forth in the following table. Compliance with these emission limits shall be demonstrated by compliance with Conditions 4 and 12-23 and 27 through 42. [Rule 18.801 and Ark. Code Ann. § 8-4-203 as referenced by Ark. Code Ann. §§ 8-4-304 and 8-4-311]

Source	Description	Pollutant	lb/hr	tpy
SN-01	EAF I and LMF I	Arsenic Cadmium Manganese Mercury	0.002 0.002 0.08 0.03	0.007 0.006 0.4 0.2
SN-02	EAF II and LMF II	Arsenic Cadmium Manganese Mercury	0.002 0.002 0.08 0.03	0.007 0.006 0.4 0.2

4. Visible emissions may not exceed the limits specified in the following table of this permit as measured by EPA Reference Method 9. Compliance with this condition will be shown by combustion of natural gas only and Plantwide Condition 5.

Source	Limit	Regulatory Citation
SN-01A and SN-02A	5%	Rule 19.901 *et seq.* and 40 C.F.R. § 52 Subpart E

5. The permittee shall perform stack testing of SN-01 and SN-02. Testing shall be performed initially and annually thereafter in accordance Plantwide Condition 3 and 4, and EPA Reference Method 5D as found in 40 CFR, Part 60, Appendix A. The sampling time and sampling volume for each run shall be at least 4 hours and 4.50 dscm (160 dscf). The permittee shall report all emissions measured using Method 5D as filterable PM, PM_{10}, or $PM_{2.5}$ or may conduct separate filterable PM_{10} testing using EPA Reference Method 201 or 201A. The permittee shall also conduct test for condensable particulate emissions concurrently using EPA reference Method 202 and include these results in PM_{10} and $PM_{2.5}$ values for compliance with emission rates. The report shall include

information specified in § 60.276a(f) of 40 CFR, Part 60, Subpart AAa. Testing shall be conducted when the EAF is operated at or near its capacity based on the specific type of steel to be produced. A targeted capacity would be 250 tons/hour of steel. If the production rate is less than 250 tons/hour, the tested emission rates shall be scaled up to 250 ton/hour and compared to the permitted emission rates. If the production rate is above 250 tons/hour, the tested rate would be compared directly to the permitted emission rate. [Rule 19.304 and 40 C.F.R. §§ 60.275a(e)(1) Subpart AAa and Rule 19.702 and 40 C.F.R. § 52 Subpart E]

6. Unless the presence of inclement weather makes concurrent testing infeasible, the permittee shall conduct the performance tests required by Specific Conditions #5, #9, and #15, concurrently. [Rule 19.304 and 40 C.F.R. §§ 60.275a(e)(4) and 60.275a(j)]

7. The permittee shall submit to the Department a written report of the results of the performance test required by Specific Condition #5. The report shall include information specified in §60.276a(f) of 40 CFR, Part 60, Subpart AAa, and the information required under Plantwide Condition 4. [Rule 19.705 and 40 C.F.R. § 52 Subpart E and Rule 19.304 and 40 C.F.R. § 60. 276a(f)]

8. The permittee shall not discharge into the atmosphere any gases from the EAF Baghouses, SN-01 and SN-02, exhibiting 3 percent opacity or greater. [Rule 19.304 and 40 C.F.R. § 60.272a(a)(2)]

9. The permittee shall perform observations of the opacity of the visible emissions from EAF Baghouses, SN-01 and SN-02 by a certified visible emission observer as follows: Visible emission observations are conducted at least once per day when the furnace is operating in the melting and refining period. These observations shall be taken in accordance with Method 9, and, for at least three 6-minute periods, the opacity shall be recorded for any point(s) where visible emissions are observed. Where it is possible to determine that a number of visible emission sites relate to only one incident of the visible emissions, only one set of three 6-minute observations will be required. In this case, Method 9 observations must be made for the site of highest opacity that directly relates to the cause (or location) of visible emissions observed during a single incident. Records shall be maintained of any 6-minute average that is in excess of 3% opacity. Reports of exceedances shall be submitted in accordance with Specific Condition 10. Should the permittee install a single stack to its melt shop baghouse the permittee shall install and operate a bag leak detection system in accordance with §60.273a(c), (e), (f), and (g). The permittee shall maintain records for each bag leak detection system as outlined in §60.276a(h). [Rule 19.304 and 40 C.F.R. § 60 Subpart AAa]

10. The permittee shall submit a written report of exceedances of the EAF baghouse opacity and the EAF Melt Shop opacity to the Department semi-annually in accordance with General Provision 7. For the purposes of these reports, exceedances are defined as all 6-minute periods during which the average opacity is 3 percent or greater at the EAF baghouse, and all 6-minute periods during which the average opacity is 6 percent or

greater at the EAF Melt Shop due solely to the operations of the EAF. Opacity observations shall be recorded on a visible emissions observation form. The information presented in Figures 9-1 and 9-2 to EPA Method 9 shall be recorded. [Rule 19.304 and 40 C.F.R. § 60 Subpart AAa]

11. The permittee shall not discharge into the atmosphere any gases which exit from EAF Melt Shop which exceed 6 percent opacity or greater due solely to the operations of the EAF. Exceedances shall be defined as all 6-minute periods during which the average opacity is 6 percent or greater. This opacity limit shall apply at all times that either of the EAFs is in operation and due solely to the operations of the electric arc furnace. [Rule 19.304 and 40 C.F.R. § 60 Subpart AAa]

12. The permittee shall either (a) install, calibrate, and maintain a monitoring device that allows the pressure in the free space inside each EAF to be monitored, pursuant to 40 CFR §60.274a(f), or (b) perform daily observations of shop opacity, pursuant to 40 CFR §60.273a(d). The permittee shall notify the Department which method it elects within 180 days before startup of SN-01 or 02. If the permittee elects to conduct opacity observations or in the case of a failure of the monitoring device, the permittee must perform daily observations of shop opacity, pursuant to 40 C.F.R. § 60.273a(d) until the monitoring device is back in operation. The permittee shall conduct these daily opacity readings on the EAF Melt Shop as follows: Shop opacity observations shall be conducted at least once per day when the furnace(s) is operating in the meltdown and refining period. Shop opacity shall be determined as the arithmetic average of 24 or more consecutive 15-second opacity observations of emissions from the shop taken in accordance with Method 9. Shop opacity shall be recorded for any point(s) where visible emissions are observed in proximity to an affected EAF. Where it is possible to determine that a number of visible emission sites relate to only one incident of visible emissions, only one observation of shop opacity will be required. In this case, the shop opacity observations must be made for the site of highest opacity that directly relates to the cause (or location) of visible emissions observed during a single incident. Records of these opacity observations shall be kept on site and made available for inspection upon request. Reports of exceedances shall be submitted in accordance with Specific Condition 10. If the permittee elects to install a monitoring device in lieu of continuing to perform opacity observations, the permittee must notify the department of this change within 30 days of installing a monitoring device that allows the pressure inside the free space inside each EAF to be monitored. [Rule 19.304 and 40 C.F.R. § 60 Subpart AAa]

13. The permittee shall check and record the control system fan motor amperes and damper positions on a once per shift basis. [Rule 19.304 and 40 C.F.R. § 60 Subpart AAa]

14. The permittee shall comply with 40 C.F.R. §60.274a(c), and shall conduct a compliance test to re-establish these parameters as specified in 40 C.F.R. § 60.274a(c) within 180 days after the effective date of Permit #2305-AOP-R0. [Rule 19.304 and 40 C.F.R. § 60 Subpart AAa]

15. The permittee shall determine baseline values of the fan motor amperes and damper positions during annual performance testing in accordance with Specific Condition 6 to demonstrate compliance with the operating parameters monitored by the permittee pursuant to Specific Condition 13. The values of these parameters as determined during the most recent demonstration of compliance shall be maintained at the appropriate level for each applicable period. [Rule 19.304 and 40 C.F.R. § 60 Subpart AAa]

16. The permittee shall perform monthly operational status inspections of the equipment that is important to the performance of the total capture system (i.e., pressure sensors, dampers, and damper switches). This inspection shall include observations of the physical appearance of the equipment (e.g., presence of holes in ductwork or hoods, flow constrictions caused by dents or accumulated dust in ductwork, and fan erosion). Any deficiencies shall be noted and proper maintenance performed. [Rule 19.304 and 40 C.F.R. § 60 Subpart AAa]

17. The permittee shall maintain records of all data obtained under Specific Condition 15 and all monthly operational status inspections performed under Specific Condition #16. [Rule 19.304 and 40 C.F.R. § 60 Subpart AAa]

18. For the pressure device installed in Specific Condition 12, the pressure shall be recorded as 15-minute integrated averages. The monitoring device may be installed in any appropriate location in the EAF duct prior to the introduction of ambient air such that reproducible results will be obtained. The pressure monitoring device shall have an accuracy of ∀5 mm of water gauge over its normal operating range and shall be calibrated according to the manufacturer's instructions. [Rule 19.304 and 40 C.F.R. § 60 Subpart AAa]

19. For the pressure device installed in Specific Condition 12, during each performance testing conducted in accordance with Specific Condition 4, the permittee shall determine baseline values of the pressure in the free space inside the furnace during the meltdown and refining period(s). The pressure determined during the most recent demonstration of particulate emission compliance shall be maintained at all times when the EAF is operating in a meltdown and refining period. [Rule 19.304 and 40 C.F.R. § 60 Subpart AAa]

20. Operation of the EAFs at a furnace static pressure that exceeds the value established under Specific Condition 19 will require the permittee to perform an opacity reading at the Melt Shop. Operation of the EAFs at this rate may be considered by the Department to be unacceptable operation and maintenance of the affected facility, if operation at such rates results in opacity readings at the Melt Shop Building greater than 6%. Operation at such values shall be reported to the Department semiannually. [Rule 19.304 and 40 C.F.R. § 60 Subpart AAa]

21. The permittee shall maintain records which demonstrate compliance with Specific Condition 19 and may be used by the Department for enforcement purposes. The records shall be updated on a daily basis, shall be kept on site, and shall be provided to Department personnel upon request. [Rule 19.304 and 40 C.F.R. § 60 Subpart AAa]

22. During any performance test conducted in accordance with Specific Condition 4, the owner or operator shall monitor the following information for all heats covered by the test:
    (1) Charge weights and materials, tap weights and materials;
    (2) Heat times, including start and stop times, and a log of process operation, including periods of no operation during testing and, the pressure inside an EAF when direct-shell evacuation control systems are used;
    (3) Control device operation log; and
    (4) Continuous monitor or Reference Method 9 data.

    [Rule 19.304 and 40 C.F.R. § 60 Subpart AAa]

23. The permittee shall retain all records of the measurements required by Specific Conditions 12 through 22 for at least two years following the date of the measurement. [Rule 19.304 and 40 C.F.R. § 60 Subpart AAa]

24. The permittee shall perform stack testing of SN-01 and SN-02 for NO_x, SO_2, CO, CO_2 and VOC emissions. Testing shall be performed in accordance with Plantwide Conditions 3 and 4 and shall be repeated every six months until six consecutive tests are passed. As six consecutive tests have been passed for SN-01 and SN-02, the permittee shall conduct subsequent testing annually. The permittee shall measure NO_x, SO_2, CO_2 and CO emissions in accordance with EPA Reference Methods 7E, 6C, 3A and 10, respectively. The permittee shall measure the total VOC emissions using EPA Reference Method 25A, from which it will subtract out methane (CH_4) and ethane (C_2H_6) emissions from the EAF baghouse using EPA Reference Method 18 to arrive at applicable VOC levels for purposes of this permit. Semiannual stack testing for a pollutant is not required if the permittee elects to operate a CEMS for that pollutant at SN-01 and SN-02. Testing shall be conducted when the EAF is operated at or near its capacity based on the specific type of steel to be produced. A targeted capacity would be 250 tons/hour of steel. If the production rate is less than 250 tons/hour, the tested emission rates shall be scaled up to 250 ton/hour and compared to the permitted emission rates. If the production rate is above 250 tons/hour, the tested rate would be compared directly to the permitted emission rate. [Rule 19.901 and 40 C.F.R. § 52 Subpart E]

25. The permittee shall keep record of the total number of tons of steel tapped from the EAFs during each of the previous twelve months updated on a monthly basis and submitted in accordance with General Provision #7. For each month, the emission factor from the nearest preceding stack test shall be multiplied by the total tons of steel tapped during

that month, to establish the amount of each pollutant emitted during that month. The emissions so calculated for each of the last twelve months shall be added together and expressed as tons of pollutant per year. The sum of the last twelve months shall not exceed the ton per year limits for SN-01 and SN-02 in Specific Condition #1. If more than one stack test is conducted during a month, the calculation for that month shall be modified so that the total number of tons of steel tapped during the period between two consecutive stack tests shall be multiplied by the emission factor established by the stack test at the beginning of any such period. This record must be updated by the 15th day of the following month. [Rule 19.705, Ark. Code Ann. § 8-4-203 as referenced by Ark. Code Ann. §§ 8-4-304 and 8-4-311, and 40 C.F.R. § 70.6]

26. The permittee shall perform stack testing of SN-01 and SN-02 for lead (Pb) emissions. Testing shall be performed in accordance with Plantwide Conditions 3 and 4 and shall be repeated annually thereafter. The permittee shall measure lead emissions in accordance with EPA Reference Method 12 or other alternate method, provided the Department approves the alternate method prior to use. Testing shall be conducted when the EAF is operated at or near its capacity based on the specific type of steel to be produced. A targeted capacity would be 250 tons/hour of steel. If the production rate is less than 250 tons/hour, the tested emission rates shall be scaled up to 250 ton/hour and compared to the permitted emission rates. If the production rate is above 250 tons/hour, the tested rate would be compared directly to the permitted emission rate. [Rule 19.702 and 40 C.F.R. § 52 Subpart E]

27. The permittee is currently subject to NESHAP YYYYY as the facility is an area source and must comply with Specific Conditions #28 through #34. Upon commencement of operation of SN-107, the facility will instead be a major source of HAPs and this subpart and its conditions will no longer be applicable and the facility must instead comply with Specific Condition #35. [Rule 19.304 and 40 C.F.R. § 63 Subpart YYYYY]

28. The permittee shall for metallic scrap utilized in the EAF meet the prepare and implement a pollution prevention plan as required in §63.10685(a)(1) or the scrap restrictions of § 63.10685(a)(2). [Rule 19.304 and 40 C.F.R. § 63 Subpart YYYYY]

29. The permittee shall for scrap containing motor vehicle scrap participate in and purchase motor vehicle scrap from providers who participate in a program for the removal of mercury switches as required in §63.10685(b)(2) that is approved by the Administrator of 40 CFR Part 63, Subpart YYYYY, prepare and submit for approval a site specific plan for removal of mercury switches as required in 63.10685(b)(1), or certify the scrap does not contain motor vehicle scrap. For scrap that does not contain motor vehicle scrap the permittee must maintain records of documentation that the scrap does not contain motor vehicle scrap. [Rule 19.304 and 40 C.F.R. § 63 Subpart YYYYY]

30. The permittee shall maintain the records required in §63.10 and records which demonstrate compliance with the requirements of the pollution prevention plan and scrap

restrictions of Specific Condition 27, with the mercury requirements in Specific Condition 29, and the requirements of required in §63.10685(c). Additionally the permittee must maintain records identifying each scrap provider and documenting the scrap provider's participation in an approved mercury switch program. If the motor vehicle scrap is purchased from a broker, the permittee must maintain records identifying each broker and documentation that all scrap provided by the broker was provided by other scrap providers who participate in an approved mercury switch removal program. [Rule 19.304 and 40 C.F.R. § 63 Subpart YYYYY]

31. The permittee must submit semiannual compliance reports to the Administrator of 40 CFR Part 63, Subpart YYYYY for the control of contaminates from scrap according to the requirements of §63.10(a)(3). The report must clearly identify any deviation from the requirements of §63.10685(a) and (b) outlined in Specific Conditions 27 and 29. [Rule 19.304 and 40 C.F.R. § 63 Subpart YYYYY]

32. The permittee must install, operate, and maintain a capture system that collects the emissions from each EAF and conveys the collected emissions to a pollutant control device for the removal of particulate matter. [Rule 19.304 and 40 C.F.R. § 63 Subpart YYYYY]

33. The permittee must not discharge from SN-01or SN-02 any gasses from an EAF which exhibit a 6% opacity or greater or contain in excess of 0.0052 gr/dscf. [Rule 19.304 and 40 C.F.R. § 63 Subpart YYYYY]

34. The permittee must monitor the baghouses, SN-01or SN-02 according to the compliance assurance monitoring requirements outlined in Specific Conditions 12 through 21. [Rule 19.304 and 40 C.F.R. § 63 Subpart YYYYY]

35. Upon commencement of operation of SN-107, the facility must meet the following Case-by-Case requirements for SN-01 and SN-02:
    a. Install, operate, and maintain a capture system that collects emissions from each EAF and conveys the collected emissions to a control device for the removal of particulate matter (PM);
    b. An EAF must not discharge from a control device and contain in excess of 0.0018 grains of PM per dry standard cubic foot (gr/dscf);
    c. Any exit from a Melt Shop using an EAF is not allowed to exhibit 6% opacity or greater; and
    d. The requirements of 40 C.F.R. § 63.10685 which identifies specific requirements for the control of contaminants from scrap. The primary requirement is to prepare / implement a plan to minimize scrap steel containing mercury.

[Rule 19.304, 40 C.F.R. § 63.43, and Ark. Code Ann. § 8-4-203 as referenced by Ark. Code Ann. §§ 8-4-304 and 8-4-311]

36. A reasonable possibility exists that the modification resulting in issuance of Permit No. 2305-AOP-R5 may result in a significant increase for SO_2, VOC, CO, and NO_X. The applicable requirements of "reasonable possibility" include, but are not limited to, the following:

a. Before beginning actual construction of the project, the permittee shall document and maintain a record of the following information: [40 C.F.R. §52.21 (r)(6)(i)]

i. A description of the project;

ii. Identification of the emissions unit(s) whose emissions of a regulated NSR pollutant could be affected by the project; and

iii. A description of the applicability test used to determine that the project is not a major modification for any regulated NSR pollutant, including the baseline actual emissions, the projected actual emissions, the amount of emissions excluded under paragraph (b)(41)(ii)(c) of 40 C.F.R. §52.21 and an explanation for why such amount was excluded, and any netting calculations, if applicable.

b. The permittee shall monitor the emissions of any regulated NSR pollutant that could increase as a result of the project and that is emitted by any emissions unit identified in Specific Condition 27 (a)(ii); and calculate and maintain a record of the annual emissions, in tons per year on a calendar year basis, for a period of 5 years following resumption of regular operations after the change, or for a period of 10 years following resumption of regular operations after the change if the project increases the design capacity or potential to emit that regulated NSR pollutant at such an emissions unit. [40 C.F.R. §52.21 (r)(6)(iii)]

c. The permittee shall submit a report if the annual emissions, in tons per year, from the project identified in Specific Condition 27 (a)(i), exceed the baseline actual emissions (as documented and maintained pursuant Specific Condition 27 (a)(iii)), by a significant amount (*i.e.* 40 tons SO_2, 40 tons VOC, 100 tons CO, or 40 tons NO_X), and if such emissions differ from the preconstruction projection as documented and maintained pursuant to Specific Condition 27 (a)(iii). Such report shall be submitted within 60 days after the end of such year. The report shall contain the following: [40 C.F.R. §52.21 (r)(6)(v)]

i. The name, address and telephone number of the major stationary source;

ii. The annual emissions as calculated pursuant to Specific Condition 27.; and

iii. Any other information that the owner or operator wishes to include in the report (e.g., an explanation as to why the emissions differ from the preconstruction projection).

d. The permittee shall make the information required to be documented and maintained pursuant to Specific Condition 27 available for review upon a request for inspection by ADEQ, the EPA, or the general public. [40 C.F.R. §70.4(b)(3)(viii)]

RH Degasser and Boiler

SN-03 RH Degasser

SN-04 RH Degasser Boiler

SN-04A RH Degasser Vessel Preheater Station
SN-04B RH Vessel Top Part Dryer
SN-04C RH Vessel Nozzle Dryer
SN-04D RH Degasser Burner/Top Lance

SN-91 RH Degasser Alloy Delivery System

Source Description

The Rührstahl - Herraeus (RH) Degasser, SN-03, removes carbon, nitrogen and hydrogen from the liquid steel in order to produce certain specialty steel grades. The RH Degasser is equipped with an open design flare to control CO emissions. The RH Degasser is capable processing 250 tons of steel per hour. The RH Degasser Flare is equipped with a 5 MMBTU/hr of natural gas assist and pilot flame.

The RH Degasser Boiler, SN-04 is used to provide steam and heat to the RH Degasser. It is an 88.7 MMBTU/hr natural gas fired boiler.

The RH Degasser Vessel Preheater Station, SN-04A, the RH Vessel Top Part Dryer, SN-04B, the RH Vessel Nozzle Dryer, SN-04C, and RH Degasser Burner/Top Lance, SN-04D are all natural gas fired burners to support the RH Degasser. The RH Degasser Vessel Preheater Station, SN-04A, is rated at 6 MMBTU/hr. The RH Vessel Top Part Dryer, SN-04B, is rated at 1.4 MMBTU.hr. The RH Vessel Nozzle Dryer, SN-04C, is rated at 1.8 MMBTU/hr. The RH Degasser Burner/Lance, SN-04D is rated at 9 MMBTU/hr.

The RH Degasser Alloy Delivery System, SN-91, is used to transport and feed alloy materials into the RH Degasser. .

Specific Conditions

37. The permittee shall not exceed the emission rates set forth in the following table. The permittee shall demonstrate compliance with this condition by compliance with Specific Conditions 40, 41, 44 and 50. [Rule 19.901 *et seq.* and 40 C.F.R. § 52 Subpart E]

SN	Description	Pollutant	lb/hr	tpy
SN-03	RH Degasser	PM	0.1	0.1
		PM_{10}	0.1	0.1
		$PM_{2.5}$	0.1	0.1
		SO_2	0.1	0.1
		VOC	0.1	0.2
		CO	9.8	29.8
		NO_X	0.4	1.8
		Lead	0.000003	0.00002
		CO_2e	--	4,760
SN-04	RH Degasser Boiler	PM	0.7	3.0
		PM_{10}	0.7	3.0
		$PM_{2.5}$	0.7	3.0
		SO_2	0.1	0.3
		VOC	0.5	2.1
		CO	7.4	32.0
		NO_X	3.2	13.6
		Lead	0.00005	0.0002
		CO_2e	--	45,457
SN-04A	RH Degasser Preheater Vessel Station	PM	0.1	0.1
		PM_{10}	0.1	0.1
		$PM_{2.5}$	0.1	0.1
		SO_2	0.1	0.1
		VOC	0.1	0.2
		CO	0.5	2.2
		NO_X	0.5	2.1
		Lead	0.000003	0.00002
		CO_2e	--	3,075
SN-04B	RH Degasser Top Part Dryer	PM	0.1	0.1
		PM_{10}	0.1	0.1
		$PM_{2.5}$	0.1	0.1
		SO_2	0.1	0.1
		VOC	0.1	0.1
		CO	0.2	0.5
		NO_X	0.2	0.5
		Lead	0.0000007	0.000004
		CO_2e	--	717

SN	Description	Pollutant	lb/hr	tpy
SN-04C	RH Degasser Nozzle Dryer	PM PM_{10} $PM_{2.5}$ SO_2 VOC CO NO_X Lead CO_2e	0.1 0.1 0.1 0.1 0.1 0.2 0.2 0.0000009 --	0.1 0.1 0.1 0.1 0.1 0.7 0.7 0.000004 922
SN-04D	RH Degasser Burner/Top Lance	PM PM_{10} $PM_{2.5}$ SO_2 VOC CO NO_X Lead CO_2e	0.1 0.1 0.1 0.1 0.1 0.8 0.8 0.000005 --	0.1 0.1 0.1 0.1 0.3 3.3 3.2 0.00002 4,612
SN-91	RH Degasser Alloy Delivery System	PM PM_{10} $PM_{2.5}$	0.1 0.1 0.1	0.1 0.1 0.1

38. The permittee shall not exceed the emission rates set forth in the following table. The permittee shall demonstrate compliance with this condition by compliance with Specific Conditions 40, 41, 45, 49 and 50. [Rule 18.801 and Ark. Code Ann. § 8-4-203 as referenced by Ark. Code Ann. §§ 8-4-304 and 8-4-311]

SN	Description	Pollutant	lb/hr	tpy
SN-03	RH Degasser	Arsenic Cadmium Formaldehyde Manganese Mercury	0.000001 0.000006 0.004 0.000002 0.000002	0.000005 0.00003 0.0002 0.000009 0.00006
SN-04	RH Degasser Boiler	Arsenic Cadmium Formaldehyde Manganese Mercury	0.00002 0.0001 0.007 0.00004 0.00003	0.00008 0.0005 0.03 0.0002 0.0001

SN	Description	Pollutant	lb/hr	tpy
SN-04A	RH Degasser Preheater Vessel Station	Arsenic Cadmium Formaldehyde Manganese Mercury	0.000002 0.000007 0.0005 0.000003 0.000002	0.000006 0.00003 0.002 0.00001 0.000007
SN-04B	RH Degasser Top Part Dryer	Arsenic Cadmium Formaldehyde Manganese Mercury	0.0000003 0.000002 0.0002 0.0000006 0.0000004	0.000002 0.000007 0.0005 0.000003 0.000002
SN-04C	RH Degasser Nozzle Dryer	Arsenic Cadmium Formaldehyde Manganese Mercury	0.0000004 0.000002 0.0002 0.0000007 0.0000005	0.000002 0.000009 0.0006 0.000003 0.000003
SN-04D	RH Degasser Burner/Top Lance	Arsenic Cadmium Formaldehyde Manganese Mercury	0.000002 0.00001 0.0007 0.000004 0.000003	0.000008 0.00005 0.003 0.00002 0.00001

39. The permittee shall not exceed the emission rates set forth in the following table and must install the control devices or implement the pollution prevention measures set forth in the following table. Compliance with this condition will be show by compliance with Specific Conditions 40, 41, 44 and 50. [Rule 19.901 *et seq.* and 40 C.F.R. § 52 Subpart E]

BACT Analysis Summary				
Source	Description	Pollutant	Control Technology	BACT Limit
SN-03	RH Degasser	CO (from degasser)	Flare	0.04 lb/ton of steel produced
		PM	Combustion of Natural gas and Good Combustion Practice	0.00052 lb/MMBTU
		PM_{10}		0.00052 lb/MMBTU
		$PM_{2.5}$		0.00052 lb/MMBTU
		Opacity		5%
		SO_2		0.000588 lb/MMBTU
		VOC		0.0054 lb/MMBTU
		CO (from natural gas combustion)		0.0824 lb/MMBTU

BACT Analysis Summary				
Source	Description	Pollutant	Control Technology	BACT Limit
		NO_X		1.0 lb/MMBTU
		GHG	Good operating practices	CO_2 117 lb/MMBTU CH_4 0.0022 lb/MMBTU N_2O 0.0002 lb/MMBTU
SN-04	RH Degasser Boiler	PM	Combustion of Natural gas and Good Combustion Practice	0.0075 lb/MMBTU
		PM_{10}		0.0075 lb/MMBTU
		$PM_{2.5}$		0.0075 lb/MMBTU
		Opacity		5%
		SO_2		0.000588 lb/MMBTU
		VOC		0.0054 lb/MMBTU
		CO		0.0824 lb/MMBTU
		NO_X	Low NOx burners Combustion of clean fuel Good Combustion Practices	0.035 lb/MMBTU
		GHG	Good operating practices Minimum Boiler Efficiency	CO_2 117 lb/MMBTU CH_4 0.0022 lb/MMBTU N_2O 0.0002 lb/MMBTU 75%
SN-04A SN-04B SN-04C SN-04D	RH Degasser Vessel Preheater Station, Vessel Top Part Dryer, RH Vessel Nozzle Dryer RH Degasser Burner/Top Lance	PM	Combustion of Natural gas and Good Combustion Practice	0.00052 lb/MMBTU
		PM_{10}		0.00052 lb/MMBTU
		$PM_{2.5}$		0.00052 lb/MMBTU
		Opacity		5%
		SO_2		0.000588 lb/MMBTU
		VOC		0.0054 lb/MMBTU
		CO		0.0824 lb/MMBTU
		NO_X	Low NOx burners Combustion of clean fuel Good Combustion Practices	0.08 lb/MMBTU
		GHG	Good operating practices	CO_2 117 lb/MMBTU CH_4 0.0022 lb/MMBTU N_2O 0.0002 lb/MMBTU

BACT Analysis Summary				
Source	Description	Pollutant	Control Technology	BACT Limit
SN-91	RH Degasser Alloy Deliver System	PM PM_{10} $PM_{2.5}$	Dust Control Plan, Enclosed Conveyors with Fabric Filters Enclosed Receiving System with Fabric Filter Fabric Filters Silos with Bin Vent Filters	0.003 gr/dscf 0.003 gr/dscf 0.01 gr/dscf
		Opacity		5%

40. The permittee shall install and operate alarm system to notify the operator of the presence of a pilot flame or other possible flare malfunction. The permittee shall perform monthly visual confirmation of the pilot lights, semi-annually remove the strainer and check for debris, and annual test fire to ensure pilot light. The permittee shall maintain logs of all flare inspection and maintenance activities. These logs shall be kept on site and made available to Department personnel upon request. [Rule 19.901, Rule 19.304, 40 C.F.R. § 52 Subpart E, and 40 C.F.R. § 64]

41. The permittee shall record and monthly maintain records of the amounts of natural gas combusted in the RH Degasser Boiler, SN-04, during each month. These records shall be kept on site and available for inspection upon request. [Rule 19.901, Rule 19.304, and 40 C.F.R. § 60 Subpart Dc]

42. Visible emissions may not exceed the limits specified in the following table of this permit as measured by EPA Reference Method 9. Compliance with this condition will be shown by Specific Condition #43 and Plantwide Condition 5 for SN-03 and SN-91. Compliance with this condition will be shown by combustion of natural gas only and Plantwide Condition 5 for SN-04, SN-04A, SN-04B, SN-04C, and SN-04D.

Source	Limit	Regulatory Citation
SN-03 SN-04 SN-04A SN-04B SN-04C SN-04D	5%	Rule 19.901 *et seq.* and 40 C.F.R. § 52 Subpart E
SN-91	5%	Rule 19.901 *et seq.* and 40 C.F.R. § 52 Subpart E

43. The permittee shall conduct weekly observations of the opacity from SN-03 and SN-91. If visible emissions are detected, then the permittee shall immediately conduct a 6-minute opacity reading in accordance with EPA Reference Method 9. The result of these observations or readings shall be recorded in a log that shall be kept on site and made available for inspection upon request. [Rule 19.705 and 40 C.F.R. § 52 Subpart E]

44. The permittee shall test the RH Degasser Boiler, SN-04 for $PM_{2.5}$, CO, and NO_x emissions. This test shall be conducted in accordance with Plantwide Condition 3 and EPA Reference Method 201 with 202, 10, and 7E for $PM_{2.5}$, CO, and NO_x respectively and repeated every 5 years after the initial test. The test for $PM_{2.5}$ shall include filterable and condensable emissions. [Rule 19.901 and 40 C.F.R. § 52 Subpart E]

45. The permittee shall test the RH Degasser, SN-03, to show the flare is designed and operated in accordance with 40 C.F.R. 60.18(b) through (f). This test includes a Method 22 for opacity, measurement of the actual gas flow rate and, calculations of the heating value of the gas (if complying with 60.18(c)(3)(ii) and (c)(4)). This test shall be conducted in accordance with Plantwide Condition 3. This test has been performed and passed on all requirements on November 7, 2019. [Rule 19.702 and 40 C.F.R. § 52 Subpart E]

46. Within 15 days of completing testing of the EAF Baghouses SN-01 and SN-02 for CO_2 emissions as required in Specific Condition 24 the permittee shall notify the department that it will either 1) test the exhaust for either CO or total carbon from the RH Degasser before it arrives at the flare or 2) will use the highest measured CO2 tested rate that occurred in the previous 12 month period. The measured CO or total carbon will be used to calculate a CO_2 emission from the degasser assuming the flare is at least 98% efficient. The test may be conducted using EPA Reference Method 10 or a method approved in advance by the Department. The results of either option combined with the testing required in Specific Condition 24 will be used to show compliance with the lb/ton of steel BACT limit for the Melt Shop. [Rule 19.901 *et seq.* and 40 C.F.R. § 52 Subpart E]

47. The permittee shall not process more than 680,000 tons of alloying materials through SN-91 in any consecutive rolling 12-month period. [Rule 19.901 *et seq.* and 40 C.F.R. § 52 Subpart E]

48. The permittee shall maintain monthly records of the amount of alloying materials processed through SN-91. The records shall include the amount processed for the previous 12 months and the 12-month rolling total processed. These records shall be updated by the 15th day of the month following the month to which the records pertain, kept onsite and submitted in accordance with General Provision 7 and made available to Department personnel upon request. [Rule 19.901 *et seq.* and 40 C.F.R. § 52 Subpart E]

49. The permittee shall not process more than 1,500,000 tons of steel through the RH Degasser, SN-03 in any consecutive rolling 12-month period. [Rule 19.901 *et seq.* and 40 C.F.R. § 52 Subpart E]

50. The permittee shall maintain monthly records of the amount of steel processed in SN-03. These records shall include the monthly total of steel processed and the 12-month rolling total of steel processed. These records shall be updated by the 15th day of the month following the month to which the records pertain, kept on site, made available to Department personnel upon request, and submitted in accordance with General Provision 7. [Rule 19.901 *et seq.* and 40 C.F.R. § 52 Subpart E]

Melt Shop Natural Gas Sources

SN-05 Horizontal Ladle Preheater 1
SN-06 Horizontal Ladle Preheater 2
SN-07 Horizontal Ladle Preheater 3
SN-08 Horizontal Ladle Preheater 4
SN-09 Horizontal Ladle Preheater 5

SN-10 Vertical Ladle Dryout Flash Preheater Stations
SN-11 Vertical Ladle Dryout Flash Preheater Stations
SN-12 Vertical Ladle Dryout Flash Preheater Stations
SN-13 Vertical Ladle Dryout Flash Preheater Stations

SN-16 Tundish Preheaters/Dryout Stand #1
SN-17 Tundish Preheaters/Dryout Stand #2
SN-18 Tundish Preheater/Dryout Stand #3
SN-19 Tundish Preheater/Dryout Stand #4
SN-19A Tundish Preheater/Dryout Stand #5
SN-19B Tundish Preheater/Dryout Stand #6

Source Description

The Horizontal Ladle Preheaters, SN-05, SN-06, SN-07, SN-08 and SN-09 are natural gas fired burners used to raise the temperature of ladles prior to the transfer of molten steel from the EAFs. Each Horizontal Ladle Preheater is rated at 8 MMBTU/hr.

The Vertical Ladle Dryout Flash Preheater Stations, SN-10, SN-11, SN-12, and SN-13, are natural gas fired heaters used to cure new refractory linings after they are replaced. Each of the Vertical Ladle Dryout Flash Preheater Stations are rated at 8 MMBTU/hr.

The Tundish Preheaters/Dryout Stand, SN-16, SN-17, SN-18, SN-19, SN-19A, and SN-19B are natural gas fired heaters used to raise the temperature of tundishes prior to transfer of molten steel to the ladles. Each of the Tundish Preheaters/Dryout Stand is rated at 9 MMBTU/hr.

Specific Conditions

51. The permittee shall not exceed the emission rates set forth in the following table. The permittee shall demonstrate compliance with this condition by compliance with Plantwide Condition 5. [Rule 19.901 *et seq.* and 40 C.F.R. § 52 Subpart E]

SN	Description	Pollutant	lb/hr	tpy
SN-05	Horizontal Ladle Preheater 1	PM	0.1	0.3
		PM_{10}	0.1	0.3
		$PM_{2.5}$	0.1	0.3
		SO_2	0.1	0.1
		VOC	0.1	0.2
		CO	0.7	2.9
		NO_X	0.8	3.4
		Lead	0.000004	0.00002
		CO_2e	--	4,100
SN-06	Horizontal Ladle Preheater 2	PM	0.1	0.3
		PM_{10}	0.1	0.3
		$PM_{2.5}$	0.1	0.3
		SO_2	0.1	0.1
		VOC	0.1	0.2
		CO	0.7	2.9
		NO_X	0.8	3.4
		Lead	0.000004	0.00002
		CO_2e	--	4,100
SN-07	Horizontal Ladle Preheater 3	PM	0.1	0.3
		PM_{10}	0.1	0.3
		$PM_{2.5}$	0.1	0.3
		SO_2	0.1	0.1
		VOC	0.1	0.2
		CO	0.7	2.9
		NO_X	0.8	3.4
		Lead	0.000004	0.00002
		CO_2e	--	4,100
SN-08	Horizontal Ladle Preheater 4	PM	0.1	0.3
		PM_{10}	0.1	0.3
		$PM_{2.5}$	0.1	0.3
		SO_2	0.1	0.1
		VOC	0.1	0.2
		CO	0.7	2.9
		NO_X	0.8	3.4
		Lead	0.000004	0.00002
		CO_2e	--	4,100

SN	Description	Pollutant	lb/hr	tpy
SN-09	Horizontal Ladle Preheater 5	PM	0.1	0.3
		PM_{10}	0.1	0.3
		$PM_{2.5}$	0.1	0.3
		SO_2	0.1	0.1
		VOC	0.1	0.2
		CO	0.7	2.9
		NO_X	0.8	3.4
		Lead	0.000004	0.00002
		CO_2e	--	4,100
SN-10	Vertical Ladle Dryout Flash Preheater Station 1	PM	0.1	0.3
		PM_{10}	0.1	0.3
		$PM_{2.5}$	0.1	0.3
		SO_2	0.1	0.1
		VOC	0.1	0.2
		CO	0.7	2.9
		NO_X	0.8	3.4
		Lead	0.000004	0.00002
		CO_2e	--	4,100
SN-11	Vertical Ladle Dryout Flash Preheater Station 2	PM	0.1	0.3
		PM_{10}	0.1	0.3
		$PM_{2.5}$	0.1	0.3
		SO_2	0.1	0.1
		VOC	0.1	0.2
		CO	0.7	2.9
		NO_X	0.8	3.4
		Lead	0.000004	0.00002
		CO_2e	--	4,100
SN-12	Vertical Ladle Dryout Flash Preheater Station 3	PM	0.1	0.3
		PM_{10}	0.1	0.3
		$PM_{2.5}$	0.1	0.3
		SO_2	0.1	0.1
		VOC	0.1	0.2
		CO	0.7	2.9
		NO_X	0.8	3.4
		Lead	0.000004	0.00002
		CO_2e	--	4,100

SN	Description	Pollutant	lb/hr	tpy
SN-13	Vertical Ladle Dryout Flash Preheater Station 4	PM	0.1	0.3
		PM_{10}	0.1	0.3
		$PM_{2.5}$	0.1	0.3
		SO_2	0.1	0.1
		VOC	0.1	0.2
		CO	0.7	2.9
		NO_X	0.8	3.4
		Lead	0.000004	0.00002
		CO_2e	--	4,100
SN-16	Tundish Preheaters/Dryout Stand #1	PM	0.1	0.3
		PM_{10}	0.1	0.3
		$PM_{2.5}$	0.1	0.3
		SO_2	0.1	0.1
		VOC	0.1	0.2
		CO	0.8	3.2
		NO_X	0.9	3.9
		Lead	0.000005	0.00002
		CO_2e	--	5,125
SN-17	Tundish Preheaters/Dryout Stand #2	PM	0.1	0.3
		PM_{10}	0.1	0.3
		$PM_{2.5}$	0.1	0.3
		SO_2	0.1	0.1
		VOC	0.1	0.2
		CO	0.8	3.2
		NO_X	0.9	3.9
		Lead	0.000005	0.00002
		CO_2e	--	5,125
SN-18	Tundish Preheater/Dryout Stand #3	PM	0.1	0.3
		PM_{10}	0.1	0.3
		$PM_{2.5}$	0.1	0.3
		SO_2	0.1	0.1
		VOC	0.1	0.2
		CO	0.8	3.2
		NO_X	0.9	3.9
		Lead	0.000005	0.00002
		CO_2e	--	5,125

SN	Description	Pollutant	lb/hr	tpy
SN-19	Tundish Preheater/Dryout Stand # 4	PM PM_{10} $PM_{2.5}$ SO_2 VOC CO NO_X Lead CO_2e	0.1 0.1 0.1 0.1 0.1 0.8 0.9 0.000005 --	0.3 0.3 0.3 0.1 0.2 3.2 3.9 0.00002 5,125
SN-19A	Tundish Preheater/Dryout Stand # 5	PM PM_{10} $PM_{2.5}$ SO_2 VOC CO NO_X Lead CO_2e	0.1 0.1 0.1 0.1 0.1 0.8 0.9 0.000005 --	0.3 0.3 0.3 0.1 0.2 3.2 3.9 0.00002 5,125
SN-19B	Tundish Preheater/Dryout Stand # 6	PM PM_{10} $PM_{2.5}$ SO_2 VOC CO NO_X Lead CO_2e	0.1 0.1 0.1 0.1 0.1 0.8 0.9 0.000005 --	0.3 0.3 0.3 0.1 0.2 3.2 3.9 0.00002 5,125

52. The permittee shall not exceed the emission rates set forth in the following table. The permittee shall demonstrate compliance with this condition by compliance with Plantwide Condition 5. [Rule 18.801 and Ark. Code Ann. § 8-4-203 as referenced by Ark. Code Ann. §§ 8-4-304 and 8-4-311]

SN	Description	Pollutant	lb/hr	tpy
SN-05	Horizontal Ladle Preheater 1	Arsenic Cadmium Formaldehyde Manganese Mercury	0.000002 0.000009 0.0006 0.000003 0.000003	0.000007 0.00004 0.003 0.00002 0.000009

SN	Description	Pollutant	lb/hr	tpy
SN-06	Horizontal Ladle Preheater 2	Arsenic Cadmium Formaldehyde Manganese Mercury	0.000002 0.000009 0.0006 0.000003 0.000003	0.000007 0.00004 0.003 0.00002 0.000009
SN-07	Horizontal Ladle Preheater 3	Arsenic Cadmium Formaldehyde Manganese Mercury	0.000002 0.000009 0.0006 0.000003 0.000003	0.000007 0.00004 0.003 0.00002 0.000009
SN-08	Horizontal Ladle Preheater 4	Arsenic Cadmium Formaldehyde Manganese Mercury	0.000002 0.000009 0.0006 0.000003 0.000003	0.000007 0.00004 0.003 0.00002 0.000009
SN-09	Horizontal Ladle Preheater 5	Arsenic Cadmium Formaldehyde Manganese Mercury	0.000002 0.000009 0.0006 0.000003 0.000003	0.000007 0.00004 0.003 0.00002 0.000009
SN-10	Vertical Ladle Dryout Flash Preheater Stations	Arsenic Cadmium Formaldehyde Manganese Mercury	0.000002 0.000009 0.0006 0.000003 0.000003	0.000007 0.00004 0.003 0.00002 0.000009
SN-11	Vertical Ladle Dryout Flash Preheater Stations	Arsenic Cadmium Formaldehyde Manganese Mercury	0.000002 0.000009 0.0006 0.000003 0.000003	0.000007 0.00004 0.003 0.00002 0.000009
SN-12	Vertical Ladle Holding Station 1	Arsenic Cadmium Formaldehyde Manganese Mercury	0.000002 0.000009 0.0006 0.000003 0.000003	0.000007 0.00004 0.003 0.00002 0.000009
SN-13	Vertical Ladle Holding Station 2	Arsenic Cadmium Formaldehyde Manganese Mercury	0.000002 0.000009 0.0006 0.000003 0.000003	0.000007 0.00004 0.003 0.00002 0.000009

SN	Description	Pollutant	lb/hr	tpy
SN-16	Tundish Preheaters/Dryout Stand #1	Arsenic Cadmium Formaldehyde Manganese Mercury	0.000002 0.00001 0.0007 0.000004 0.000003	0.000008 0.00005 0.003 0.00002 0.00001
SN-17	Tundish Preheaters/Dryout Stand #2	Arsenic Cadmium Formaldehyde Manganese Mercury	0.000002 0.00001 0.0007 0.000004 0.000003	0.000008 0.00005 0.003 0.00002 0.00001
SN-18	Tundish Preheater 3	Arsenic Cadmium Formaldehyde Manganese Mercury	0.000002 0.00001 0.0007 0.000004 0.000003	0.000008 0.00005 0.003 0.00002 0.00001
SN-19	Tundish Preheater 4	Arsenic Cadmium Formaldehyde Manganese Mercury	0.000002 0.00001 0.0007 0.000004 0.000003	0.000008 0.00005 0.003 0.00002 0.00001
SN-19A	Tundish Preheater 5	Arsenic Cadmium Formaldehyde Manganese Mercury	0.000002 0.00001 0.0007 0.000004 0.000003	0.000008 0.00005 0.003 0.00002 0.00001
SN-19B	Tundish Preheater 6	Arsenic Cadmium Formaldehyde Manganese Mercury	0.000002 0.00001 0.0007 0.000004 0.000003	0.000008 0.00005 0.003 0.00002 0.00001

53. The permittee shall not exceed the emission rates set forth in the following table and must install the control devices or implement the pollution prevention measures set forth in the following table. Compliance with this condition will be show by compliance with Plantwide Condition 5. [Rule 19.901 *et seq.* and 40 C.F.R. § 52 Subpart E]

BACT Analysis Summary				
Source	Description	Pollutant	Control Technology	BACT Limit
SN-05, SN-06, SN-07, SN-08,	Ladle Preheaters	PM	Combustion of Natural gas and Good Combustion Practices	0.0075 lb/MMBTU
		PM_{10}		0.0075 lb/MMBTU
		$PM_{2.5}$		0.0075 lb/MMBTU
		Opacity		5%

BACT Analysis Summary				
Source	Description	Pollutant	Control Technology	BACT Limit
SN-09		SO_2		0.000588 lb/MMBTU
		VOC		0.0054 lb/MMBTU
		CO		0.0824 lb/MMBTU
		NO_X	Low NOx burners Combustion of clean fuel Good Combustion Practices	0.095 lb/MMBTU
		GHG	Good operating practices	CO_2 117 lb/MMBTU CH_4 0.0022 lb/MMBTU N_2O 0.0002 lb/MMBTU
SN-10 SN-11 SN-12 SN-13	Ladle Dryout Station	PM	Combustion of Natural gas and Good Combustion Practice	0.0075 lb/MMBTU
		PM_{10}		0.0075 lb/MMBTU
		$PM_{2.5}$		0.0075 lb/MMBTU
		Opacity		5%
		SO_2		0.000588 lb/MMBTU
		VOC		0.0054 lb/MMBTU
		CO		0.0824 lb/MMBTU
		NO_X	Low NOx burners Combustion of clean fuel Good Combustion Practices	0.095 lb/MMBTU
		GHG	Good operating practices	CO_2 117 lb/MMBTU CH_4 0.0022 lb/MMBTU N_2O 0.0002 lb/MMBTU
SN-16 SN-17 SN-18 SN-19 SN-19A SN-19B	Tundish Preheaters/Dryout Stands #1 through #6	PM	Combustion of Natural gas and Good Combustion Practice	0.0075 lb/MMBTU
		PM_{10}		0.0075 lb/MMBTU
		$PM_{2.5}$		0.0075 lb/MMBTU
		Opacity		5%
		SO_2		0.000588 lb/MMBTU
		VOC		0.0054 lb/MMBTU
		CO		0.0824 lb/MMBTU
		NO_X	Low NOx burners Combustion of clean fuel Good Combustion Practices	0.097 lb/MMBTU
		GHG	Good operating practices	CO_2 117 lb/MMBTU CH_4 0.0022 lb/MMBTU N_2O 0.0002 lb/MMBTU

54. Visible emissions may not exceed the limits specified in the following table of this permit as measured by EPA Reference Method 9. Compliance with this condition will be shown by combustion of natural gas only and Plantwide Condition 5.

Source	Limit	Regulatory Citation
SN-05, SN-06, SN-07, SN-08, SN-09, SN-10, SN-11, SN-12, SN-13, SN-16, SN-17, SN-18, SN-19, SN-19A, SN-19B	5%	Rule 19.901 *et seq.* and 40 C.F.R. § 52 Subpart E

Tunnel Furnaces

SN-20 Tunnel Furnace 1

SN-21 Tunnel Furnace 2

SN-21C Shuttle Zone

Source Description

After being cast into thin slabs, the steel enters the tunnel furnace lines. The tunnel furnaces are used to raise the slab temperatures from casting temperatures to rolling temperatures and to equalize the temperatures over the entire slab. Tunnel Furnace #1 (SN-20) has a combined total heat input of 217.6 MMBtu/hr from a series of individual natural-gas fired burners, Tunnel Furnace #2 (SN-21) has a combined total heat input capacity of 172.5 MMBtu/hr from a series of individual natural-gas fired burners and the Shuttle Zone (SN-21C) has a heat input capacity of 80.2 MMBtu/hr from a series of individual natural gas-fired burners.

Specific Conditions

55. The permittee shall not exceed the emission rates set forth in the following table. The permittee shall demonstrate compliance with this condition by compliance with Plantwide Condition 5. [Rule 19.901 *et seq.* and 40 C.F.R. § 52 Subpart E]

SN	Description	Pollutant	lb/hr	tpy
SN-20	Tunnel Furnace 1	PM	1.7	7.2
		PM_{10}	1.7	7.2
		$PM_{2.5}$	1.7	7.2
		SO_2	0.2	0.6
		VOC	1.2	5.2
		CO	18.0	78.5
		NO_X	21.8	95.3
		Lead	0.0002	0.0006
		CO_2e	--	119,919
SN-21	Tunnel Furnace 2	PM	1.3	5.7
		PM_{10}	1.3	5.7
		$PM_{2.5}$	1.3	5.7
		SO_2	0.2	0.5
		VOC	1.0	4.1
		CO	14.2	62.2
		NO_X	17.3	75.6
		Lead	0.0001	0.0004
		CO_2e	--	98,395

SN	Description	Pollutant	lb/hr	tpy
SN-21C	Shuttle Zone	PM PM_{10} $PM_{2.5}$ SO_2 VOC CO NO_X Lead CO_2e	0.6 0.6 0.6 0.1 0.5 6.6 8 0.00004 --	2.7 2.7 2.7 0.3 1.9 28.9 35.1 0.0002 41,082

56. The permittee shall not exceed the emission rates set forth in the following table. Compliance with this condition will be show by compliance with Plantwide Condition 5. [Rule 19.901 *et seq.* and 40 C.F.R. § 52 Subpart E]

BACT Analysis Summary				
Source	Description	Pollutant	Control Technology	BACT Limit
SN-20, SN-21, and SN-21C	Tunnel Furnaces and Shuttle Zone	PM	Combustion of Natural gas and Good Combustion Practice	0.0075 lb/MMBTU
		PM_{10}		0.0075 lb/MMBTU
		$PM_{2.5}$		0.0075 lb/MMBTU
		Opacity		5%
		SO_2		0.000588 lb/MMBTU
		VOC		0.0054 lb/MMBTU
		CO		0.0824 lb/MMBTU
		NO_X	Low NOx burners Combustion of clean fuel Good Combustion Practices	0.1 lb/MMBTU
		GHG	Good operating practices	CO_2 117 lb/MMBTU CH_4 0.0022 lb/MMBTU N_2O 0.0002 lb/MMBTU

57. The permittee shall not exceed the emission rates set forth in the following table. The permittee shall demonstrate compliance with this condition by compliance with Plantwide Condition 5. [Rule 18.801 and Ark. Code Ann. § 8-4-203 as referenced by Ark. Code Ann. §§ 8-4-304 and 8-4-311]

SN	Description	Pollutant	lb/hr	tpy
SN-20	Tunnel Furnace 1	Arsenic Cadmium Formaldehyde Manganese Mercury	0.00005 0.0003 0.02 0.00009 0.00006	0.0002 0.002 0.08 0.0004 0.0003
SN-21	Tunnel Furnace 2	Arsenic Cadmium Formaldehyde Manganese Mercury	0.00004 0.0002 0.02 0.00007 0.00005	0.0002 0.001 0.06 0.0003 0.0002
SN-21C	Shuttle Zone	Arsenic Cadmium Formaldehyde Manganese Mercury	0.00002 0.0001 0.01 0.00003 0.00002	0.0001 0.0004 0.03 0.0001 0.0001

58. Visible emissions may not exceed the limits specified in the following table of this permit as measured by EPA Reference Method 9. Compliance with this condition will be shown by combustion of natural gas only and Plantwide Condition 5.

Source	Limit	Regulatory Citation
SN-20, SN-21, and SN-21C	5%	Rule 19.901 *et seq.* and 40 C.F.R. § 52 Subpart E

Cold Mill Operations

SN-22 Pickle Line Boiler
SN-23 Pickle Line Scale Dust
SN-24 Pickling Section
SN-128 Pickle Line Sedimentation System

SN-24A Push Pull Pickle Line (PPPL) Scrubber Stack

SN-25 Pickling Line Tandem Cold Mill

SN-26 Galvanizing Line Boiler 1
SN-27 Galvanizing Line Boiler 2
SN-28 Galvanizing Line Preheater 1
SN-29 Galvanizing Line #2 Furnace
SN-34 Galvanizing Line Caustic Cleaning 1
SN-35 Galvanizing Line Caustic Cleaning 2
SN-36 Galvanizing Line Post Treatment 1
SN-37 Galvanizing Line Post Treatment 2

SN-38 Skin Pass Mill

SN-39 Annealing Furnaces

SN-40 Decarburizing Line 1 Furnace Section
SN-41 Decarburizing Line 1 Cleaning Section
SN-42 Decarburizing Line 2 Furnace Section
SN-43 Decarburizing Line 2 Cleaning Section

SN-44 Reversing Cold Mill 1 (NGO – ACL Process Line)
SN-45 Reversing Cold Mill 2
SN-46 Reversing Cold Mill 3

SN-47 Annealing Pickling Line – Annealing Furnace
SN-48 Annealing Pickling Line – Scale Dust Exhaust
SN-49 Annealing Pickling Line – Shot Blast
SN-51 Annealing and Coating Line - Annealing Furnace
SN-52 Annealing and Coating Line – Cleaning Section
SN-53 Annealing and Coating Line – Drying Furnace and RTO

SN-54 MgO Coating Line 1 – Drying Furnace
SN-55 MgO Coating Line 1 – Cleaning Section
SN-56 MgO Coating Line 2 – Drying Furnace
SN-57 MgO Coating Line 2 – Cleaning Section

SN-58 Flattening Coating Line 1 – Furnace
SN-59 Flattening Coating Line 1 – Cleaning Section
SN-60 Flattening Coating Line 2 – Furnace
SN-61 Flattening Coating Line 2 – Cleaning Section

SN-101 Annealing Pickling Line – Boiler Natural Gas Fired

SN-102 Natural Gas Fired Cold Mill/Supporting Building Structures Space Heaters

SN-105 Color Coating Line – Pre-Cleaning Section
SN-106 Color Coating Line – Cleaning Section
SN-107 Color Coating Line – Prime/Finish Coating

SN-108a Color Coating Line Chemical Dryer
SN-108b Color Coating Line Primer Oven
SN-108c Color Coating Line Finish Oven
SN-108d Color Coating Line RTO
SN-108e Color Coating Line Spray Passivation

SN-112 Natural Gas Fired Waste Water Space Heaters
SN-113 Natural Gas Fired North and South Wall Space Heaters
SN-114 Natural Gas Direct Fired Flack Facility Space Heaters
SN-115 Natural Gas Indirect Fired Flack Facility Space Heaters
SN-116 Natural Gas Fired CGL Building Space Heaters
SN-117 Natural Gas Fired ACL Building Space Heaters
SN-118 Natural Gas Fired RCM Indirect Space Heaters
SN-119 Natural Gas Fired RCM Direct Space Heaters

SN-120 Cold Mill Boiler NGO Line
SN-121 Ceramic Coating Pots for GI Curing and Zinc Melting
SN-122 Ceramic Coating Pots for GL Curing and Zinc Melting
SN-123 Pre-Melt Pot Curing and Zinc Melting
SN-124 Heated Parts Washer SMS Hotmill Rollshop

SN-125 Cold Mill Boiler
SN-126 Color Coating Line Boiler

Source Description

Pickling Line / Push Pull Pickle Line

Pickling Section, SN-24, pickling is the process that cleans a steel coil of its rust, dirt and oil so the metal can be further processed. The steel coil is unwound and sent through a series of hydrochloric acid baths that remove the oxides. The steel sheet is then rinsed and dried. A wet scrubber is used to control the HCl emissions.

The Pickling Line Tandem Cold Mill, SN-25, is a cold rolling process directly coupled with the pickling line. The process consists of removal of hot strip scale and a rolling operation to final material thickness. The steel coil is unwound and passed between sets of work rolls that are compressed by hydraulically-forced backup rolls. The oil emissions from the pickling line tandem cold mill will be reduced by a mist eliminator.

The Pickle Line Boiler, SN-22 is a 53.7 MMBTU/hr natural gas fired boiler that provides steam to the pickling line.

Pickle Line Scale Dust, SN-23, scale dust will be generated from the uncoiling, flattening and scale breaking of the steel. The scale dust emissions are controlled by a fabric filter.

The Push Pull Pickle Line (PPPL) has been assigned emission source ID # SN-24A. This represents the scrubber exhaust stack associated with this line.

The Pickle Line Sedimentation System, SN-128, is used to control HCl emissions from the sedimentation system.

Galvanizing Line

The Cold Mill will incorporate two continuous galvanizing lines to produce galvanized strips. BRS has designed the galvanizing line to double as a continuous annealing line.

The Galvanizing Line Boiler 1 and 2, SN-26 and SN-27, are 53.7 MMBTU/hr each natural gas fired boilers that provide steam to the galvanizing line.

The Galvanizing Line Preheater 1, SN-28, is a 78.2 MMBtu/hr natural gas fired heater that provides heat for the galvanizing line. The exhaust stack associated with SN-28 also includes volume air the Continuous Line Dryer that is included in the permit as an insignificant activity.

Galvanizing Line #2 Furnace, SN-29, has a heat input of 150.5 MMBtu/hr which includes two separate heating zones.

Galvanizing Line Caustic Cleaning 1, SN-34, and Galvanizing Line #2 Pre-Cleaning Section, SN-35, are the pre-cleaning sections of the galvanizing process. These sources are equipped with mist eliminators to reduce the emissions of particulate matter from caustic cleaning.

Galvanizing Line Post Treatment 1, SN-36, and Galvanizing Line #2 Cleaning Station,SN-37, are the cleaning sections of the galvanizing line. These sources are equipped with mist eliminators to reduce the emissions of particulate matter.

The Skin Pass Mill, SN-38a, adjusts the final mechanical properties, flatness, and surface finish of the cold rolled strip. A mist eliminator is used to reduce the particulate matter from the emulsion applied to the rolling material. The Skin Pass Mill can process 160 tons per hour of steel.

The Skin Pass Mill (ACL), SN-38b, adjusts the final mechanical properties, flatness, and surface finish of the cold rolled strip. A mist eliminator is used to reduce the particulate matter from the emulsion applied to the rolling material. The Skin Pass Mill can process 160 tons per hour of steel.

The Annealing Furnaces, SN-39, will consist of 15 annealing furnace bases for a total of 117.9 MMBTU/hr.   Eleven (11) annealing furnace bases installed to provide cooling. These bases are not natural gas fired.

Decarburizing Line

The decarburizing lines reduce the carbon content at intermediate strip thickness. The decarburizing line consists of two sections the cleaning section, SN-41 and SN-43, and the furnace section, SN-40 and SN-42. Each of the two decarburization lines is capable of processing 30 tons of steel per hour. The furnace sections are natural gas fired burners with a heat input of 36 MMBTU/hr for SN-40 and 22 MMBTU/hr for SN-42.

Reversing Cold Mill

The Reversing Cold Mill 1 (NGO – ACL Process Line), 2, and 3, SN-45, SN-46, and SN-44 reduce the thickness of the steel to the desired specifications. Each reversing mill is capable of processing 45 tons per hour of steel. A set of rolls applies pressure to the steel while maintaining the shape and width. The steel runs back and forth between rollers which reduce the thickness further with each pass.   As the steel passes through the rolls, it is re-coiled onto the delivery tension reel. From there it goes back through the rolls in reverse reducing the steel thickness further. An emulsion is added to the strip surface during the rolling. Mist eliminators are employed to reduce emissions of particulate matter. The Cold Mill also contains a boiler (SN-125) with a heat input of 88.7 MMBtu/hr.

Annealing Pickling Line

Annealing Pickling Line – Annealing Furnace, SN-47, is a 66 MMBTU/hr natural gas fired heater to provide heat to the annealing pickling line for hot strip annealing.

Annealing Pickling Line – Scale Dust Exhaust, SN-48, this process will involve removal of scale from the steel strip surface.

Annealing Pickling Line – Shot Blast, SN-49, is the mechanical cleaning at the annealing pickling section with a shot blast machine.   A fabric filter will be used to reduce emissions from the shot blast machine.

Annealing Pickling Line - Pickling Section, SN-50, pickling is the process that cleans a steel coil of its rust, dirt and oil so the metal can be further processed. A wet scrubber is used to control HCl emissions.

Annealing Pickling Line – Boiler, SN-101, is a 53.7 MMBTU/hr natural gas fired boiler which provides steam to the Annealing Pickling Line.

Annealing and Coating Line

The annealing and coating line will be used for annealing of the cold roll steel strip and application of an insulating coating.

Annealing and Coating Line - Annealing Furnace, SN-51, is a 13.0 MMBTU/hr natural gas fired annealing furnace in the annealing and coating line.

Annealing and Coating Line – Cleaning Section, SN-52, uses a caustic solution to clean the steel. A mist eliminator is used to reduce emissions.

Annealing and Coating Line – Drying Furnace & RTO, SN-53, is a 22.3 MMBTU/hr natural gas fired combustion device. An insulating coating is applied to the steel. An RTO, with a heat input of 2.0 MMBtu/hr, will be used to reduce VOC emissions from the insulating coating. Total heat input for the Drying Furnace & RTO is 17 MMBtu/hr.

MgO Coating Lines

The MgO coating apply magnesia to the strip steel surface. The application of this material is required to avoid the steel sticking during high temperature annealing. There are two MgO coating lines each with a furnace section and a cleaning section.

MgO Coating Line 1 – Drying Furnace, SN-54, is a 13.2 MMBTU/hr natural gas fired combustion device used to provide heat to the MgO coating line.

MgO Coating Line 1 – Cleaning Section, SN-55, uses sodium hydroxide to clean the strip steel. A mist eliminator is used to reduce emissions.

MgO Coating Line 2 – Drying Furnace, SN-56, is a 13.2 MMBTU/hr natural gas fired combustion device used to provide heat to the MgO coating line.

MgO Coating Line 2 – Cleaning Section, SN-57, uses sodium hydroxide to clean the strip steel. A mist eliminator is used to reduce emissions.

Flattening Coating Lines

The Flattening Coating Lines (FCL) are used to coat the steel strip with an insulation layer and subsequent flatness improvements. The process line does involve an annealing process. This is the final step in producing a grain oriented product.

Flattening Coating Line 1 (FCL 1) – Furnace, SN-58, is natural gas fired and has a maximum heat input of 32 MMBTU/hr.

Flattening Coating Line 1 (FCL 1) – Cleaning Section, SN-59, is a cleaning and pickling section which uses hydrochloric acid to clean the steel strip. A wet scrubber will be used to help control emissions.

Flattening Coating Line 2 (FCL 2) – Furnace, SN-60, is natural gas fired and has a maximum heat input of 32 MMBTU/hr.

Flattening Coating Line 2(FCL 2) – Cleaning Section, SN-61, is a cleaning and pickling section which uses hydrochloric acid to clean the steel strip. A wet scrubber will be used to help control emissions.

Natural Gas Fired Cold Mill/Supporting Building Structures Space Heaters, SN-102, has fifty (50) heaters to support the Cold Mill. The heaters have a total heat input of 136.5 MMBtu/hr.

Color Coating Line

SN-105 Color Coating Line – Pre-Cleaning Section is arranged in front of the entry loop accumulator to clean the strip surfaces from residual oil and iron fines from the cold rolling process by means of process steps like spray cleaning, cascade rinsing and drying.

SN-106 Color Coating Line – Cleaning Section, the main cleaning section, consists of a two-stage alkaline spray cleaning section with an additional brushing stage in-between. In each spraying section, the nozzle bars can be switched on-off by automatic valves section wise to control the pickling efficiency.

SN-107 Color Coating Line – Prime/Finish Coating, the pain coating section, is comprised of the roller coating machine with the power and finish coaters for coating both strip sides.

The color coating line consists of several natural gas fired combustion devices: SN-108a Color Coating Line Chemical Dryer – 5.4 MMBtu/hr, SN-108b Color Coating Line Primer Oven – 22.8 MMBtu/hr, SN-108c Color Coating Line Finish Oven – 28.0 MMBtu/hr, SN-108d Color Coating Line RTO – 14.4 MMBtu/hr, SN-108e Color Coating Line Spray Passivation – 5.0 MMBtu/hr, and SN-126 Color Coating Line Boiler – 53.7 MMBtu/hr.

Miscellaneous Natural Gas Sources

The following list multiple miscellaneous natural gas sources as well as their heat input value: SN-112 Natural Gas Fired Waste Water Space Heaters – 6.6 MMBtu/hr, SN-113 Natural Gas

Fired North and South Wall Space Heaters – 2.4 MMBtu/hr, SN-114 Natural Gas Direct Fired Flack Facility Space Heaters – 67.1 MMBtu/hr, SN-115 Natural Gas Indirect Fired Flack Facility Space Heaters – 18.8 MMBtu/hr, SN-116 Natural Gas Fired CGL Building Space Heaters – 20.6 MMBtu/hr, SN-117 Natural Gas Fired ACL Building Space Heaters – 25.8 MMBtu/hr, SN-118 Natural Gas Fired RCM Indirect Space Heaters – 6.3 MMBtu/hr, SN-119 Natural Gas Fired RCM Direct Space Heaters – 10.3 MMBtu/hr, SN-120 Cold Mill Boiler NGO Line – 88.7 MMBtu/hr, SN-121 Ceramic Coating Pots for GI Curing and Zinc Melting – 3.7 MMBtu/hr, SN-122 Ceramic Coating Pots for GL Curing and Zinc Melting – 3.7 MMBtu/hr, SN-123 Pre-Melt Pot Curing and Zinc Melting – 1.9 MMBtu/hr, and SN-124 Heated Parts Washer SMS Hotmill Rollshop – 1.0 MMBtu/hr.

Specific Conditions

59. The permittee shall not exceed the emission rates set forth in the following table. The permittee shall demonstrate compliance with this condition by compliance with Specific Conditions 63 through 81. [Rule 19.901 *et seq.* and 40 C.F.R. § 52 Subpart E]

SN	Description	Pollutant	lb/hr	tpy
SN-22	Pickle Line Boiler	PM PM_{10} $PM_{2.5}$ SO_2 VOC CO NO_X Lead CO_2e	0.4 0.4 0.4 0.1 0.3 4.5 1.9 0.00003 --	1.8 1.8 1.8 0.2 1.3 19.4 8.3 0.0002 27,531
SN-23	Pickle Line Scale Dust	PM PM_{10} $PM_{2.5}$	1.0 1.0 1.0	4.4 4.4 4.4
SN-24A	Push Pull Pickle Line (PPPL) Scrubber Stack	PM PM_{10} $PM_{2.5}$	0.4 0.4 0.4	1.7 1.7 1.7
SN-25	Tandem Cold Mill	PM PM_{10} $PM_{2.5}$	4.8 12.5 12.5	20.7 54.7 54.7

SN	Description	Pollutant	lb/hr	tpy
SN-26	Galvanizing Line Boiler 1	PM PM_{10} $PM_{2.5}$ SO_2 VOC CO NO_X Lead CO_2e	0.4 0.4 0.4 0.1 0.3 4.5 1.9 0.00003 --	1.8 1.8 1.8 0.2 1.3 19.4 8.3 0.00002 27,531
SN-27	Galvanizing Line Boiler 2	PM PM_{10} $PM_{2.5}$ SO_2 VOC CO NO_X Lead CO_2e	0.4 0.4 0.4 0.1 0.3 4.5 1.9 0.00003 --	1.8 1.8 1.8 0.2 1.3 19.4 8.3 0.00002 27,531
SN-28	Galvanizing Line Preheater 1	PM PM_{10} $PM_{2.5}$ SO_2 VOC CO NO_X Lead CO_2e	0.1 0.1 0.1 0.1 0.5 6.5 2.8 0.00004 --	0.5 0.5 0.5 0.2 1.9 28.2 12.0 0.0002 40,078
SN-29	Galvanizing Line #2 Furnace	PM PM_{10} $PM_{2.5}$ SO_2 VOC CO NO_X Lead CO_2e	0.2 0.2 0.2 0.1 0.9 12.4 5.3 0.0001 --	0.8 0.8 0.8 0.4 3.6 54.3 23.1 0.0003 77,121
SN-34	Galvanizing Line Caustic Cleaning 1	PM PM_{10} $PM_{2.5}$	0.2 0.2 0.2	0.9 0.9 0.9
SN-35	Galvanizing Line Caustic Cleaning 2	PM PM_{10} $PM_{2.5}$	0.2 0.2 0.2	0.5 0.5 0.5

SN	Description	Pollutant	lb/hr	tpy
SN-36	Galvanizing Line Post Treatment 1	PM PM_{10} $PM_{2.5}$	0.1 0.1 0.1	0.3 0.3 0.3
SN-37	Galvanizing Line Post Treatment 2	PM PM_{10} $PM_{2.5}$	0.3 0.3 0.3	1.3 1.3 1.3
SN-38	Skin Pass Mill	PM PM_{10} $PM_{2.5}$	0.6 1.5 1.5	2.5 6.6 6.6
SN-38b	Skin Pass Mill (ACL)	PM PM_{10} $PM_{2.5}$	0.6 1.5 1.5	2.5 6.6 6.6
SN-39	Annealing Furnaces	PM PM_{10} $PM_{2.5}$ SO_2 VOC CO NO_X Lead CO_2e	0.9 0.9 0.9 0.1 0.7 9.8 11.8 0.0001 --	3.9 3.9 3.9 0.3 2.8 42.6 51.7 0.0003 60,424
SN-40	Decarburizing Line 1 Furnace Section	PM PM_{10} $PM_{2.5}$ SO_2 VOC CO NO_X Lead CO_2e	0.5 0.5 0.5 0.1 0.2 3.0 3.6 0.00002 --	2.1 2.1 2.1 0.1 0.9 13.0 15.8 0.00008 18,449
SN-41	Decarburizing Line 1 Cleaning Section	PM PM_{10} $PM_{2.5}$	0.3 0.3 0.3	1.2 1.2 1.2
SN-42	Decarburizing Line 2 Furnace Section	PM PM_{10} $PM_{2.5}$ SO_2 VOC CO NO_X Lead CO_2e	0.3 0.3 0.3 0.1 0.2 1.9 2.2 0.00002 --	1.3 1.3 1.3 0.1 0.6 8.0 9.7 0.00005 11,274

SN	Description	Pollutant	lb/hr	tpy
SN-43	Decarburizing Line 2 Cleaning Section	PM PM_{10} $PM_{2.5}$	0.3 0.3 0.3	1.1 1.1 1.1
SN-44	Reversing Cold Mill 3	PM PM_{10} $PM_{2.5}$	1.5 4.0 4.0	6.6 17.4 17.4
SN-45	Reversing Cold Mill 1	PM PM_{10} $PM_{2.5}$	1.5 4.0 4.0	6.6 17.4 17.4
SN-46	Reversing Cold Mill 2	PM PM_{10} $PM_{2.5}$	1.5 4.0 4.0	6.6 17.4 17.4
SN-47	Annealing Pickling Line – Annealing Furnace	PM PM_{10} $PM_{2.5}$ SO_2 VOC CO NO_X Lead CO_2e	0.9 0.9 0.9 0.1 0.4 5.5 6.6 0.00004 --	3.8 3.8 3.8 0.2 1.6 23.9 29.0 0.0002 33,823
SN-48	Annealing Pickling Line – Scale Dust Exhaust	PM PM_{10} $PM_{2.5}$	0.7 0.7 0.7	3.0 3.0 3.0
SN-49	Annealing Pickling Line – Shot Blast	PM PM_{10} $PM_{2.5}$	0.7 0.7 0.7	3.0 3.0 3.0
SN-51	Annealing and Coating Line - Annealing Furnace	PM PM_{10} $PM_{2.5}$ SO_2 VOC CO NO_X Lead CO_2e	0.2 0.2 0.2 0.1 0.1 1.1 1.3 0.00001 --	0.8 0.8 0.8 0.1 0.4 4.7 5.7 0.00003 6,663
SN-52	Annealing and Coating Line – Cleaning Section	PM PM_{10} $PM_{2.5}$	0.3 0.3 0.3	1.0 1.0 1.0

SN	Description	Pollutant	lb/hr	tpy
SN-53	Annealing and Coating Line – Drying Furnace	PM PM_{10} $PM_{2.5}$ SO_2 VOC CO NO_X Lead CO_2e	0.4 0.4 0.4 0.1 0.6 10.0 5.6 0.00002 --	1.6 1.6 1.6 0.1 2.6 44.0 24.5 0.00005 11,439
SN-54	MgO Coating Line 1 – Drying Furnace	PM PM_{10} $PM_{2.5}$ SO_2 VOC CO NO_X Lead CO_2e	0.2 0.2 0.2 0.1 0.1 1.2 1.4 0.000007 --	0.8 0.8 0.8 0.1 0.4 4.8 5.9 0.00003 6,816
SN-55	MgO Coating Line 1 – Cleaning Section	PM PM_{10} $PM_{2.5}$	0.3 0.3 0.3	1.1 1.1 1.1
SN-56	MgO Coating Line 2 – Drying Furnace	PM PM_{10} $PM_{2.5}$ SO_2 VOC CO NO_X Lead CO_2e	0.2 0.2 0.2 0.1 0.1 1.2 1.4 0.000007 --	0.8 0.8 0.8 0.1 0.4 4.8 5.9 0.00003 6,816
SN-57	MgO Coating Line 2 – Cleaning Section	PM PM_{10} $PM_{2.5}$	0.3 0.3 0.3	1.1 1.1 1.1
SN-58	Flattening Coating Line 1 – Furnace	PM PM_{10} $PM_{2.5}$ SO_2 VOC CO NO_X Lead CO_2e	0.5 0.5 0.5 0.1 0.2 2.7 3.2 0.00002 --	1.9 1.9 1.9 0.1 0.8 11.6 14.1 0.00007 16,399

SN	Description	Pollutant	lb/hr	tpy
SN-60	Flattening Coating Line 2 – Furnace	PM PM_{10} $PM_{2.5}$ SO_2 VOC CO NO_X Lead CO_2e	0.5 0.5 0.5 0.1 0.2 2.7 3.2 0.00002 --	1.9 1.9 1.9 0.1 0.8 11.6 14.1 0.00007 16,399
SN-101	Annealing Pickling Line Boiler	PM PM_{10} $PM_{2.5}$ SO_2 VOC CO NO_X Lead CO_2e	0.4 0.4 0.4 0.1 0.3 4.5 1.9 0.00003 --	1.8 1.8 1.8 0.2 1.3 19.4 8.3 0.0002 27,531
SN-102	Cold Mill Space Heaters – Natural Gas Fired (136.5 MMBtu)	PM PM_{10} $PM_{2.5}$ SO_2 VOC CO NO_X Lead CO_2e	1.1 1.1 1.1 0.1 0.8 11.2 11.0 0.00008 --	4.5 4.5 4.5 0.4 3.3 49.3 47.8 0.0004 69,905
SN-105	Color Coating Line – Pre-Cleaning Section	PM PM_{10} $PM_{2.5}$	0.3 0.3 0.3	1.2 1.2 1.2
SN-106	Color Coating Line – Cleaning Section	PM PM_{10} $PM_{2.5}$	0.3 0.3 0.3	1.2 1.2 1.2
SN-107	Color Coating Line – Prime/Finish Coating	VOC	34.9	152.7

SN	Description	Pollutant	lb/hr	tpy
SN-108a	Color Coating Line – Chemical Dryer	PM	0.1	0.2
		PM_{10}	0.1	0.2
		$PM_{2.5}$	0.1	0.2
		SO_2	0.1	0.1
		VOC	0.1	0.2
		CO	0.4	1.9
		NO_X	0.3	1.2
		Lead	0.000003	0.00002
		CO_2e	--	2,768
SN-108b	Color Coating Line – Primer Oven	PM	0.2	0.8
		PM_{10}	0.2	0.8
		$PM_{2.5}$	0.2	0.8
		SO_2	0.1	0.1
		VOC	0.2	0.6
		CO	1.9	8.3
		NO_X	2.3	10.1
		Lead	0.00001	0.00005
		CO_2e	--	11,709
SN-108c	Color Coating Line – Finish Oven	PM	0.3	1.0
		PM_{10}	0.3	1.0
		$PM_{2.5}$	0.3	1.0
		SO_2	0.1	0.1
		VOC	0.2	0.7
		CO	2.3	10.1
		NO_X	1.4	6.1
		Lead	0.00002	0.00007
		CO_2e	--	14,350
SN-108d	Color Coating Line RTO	PM	0.2	0.6
		PM_{10}	0.2	0.6
		$PM_{2.5}$	0.2	0.6
		SO_2	0.1	0.1
		VOC	0.3	1.3
		CO	6.5	28.4
		NO_X	12.2	53.6
		Lead	0.00001	0.00004
		CO_2e	--	7,380

SN	Description	Pollutant	lb/hr	tpy
SN-108e	Color Coating Line Spray Passivation	PM	0.1	0.2
		PM_{10}	0.1	0.2
		$PM_{2.5}$	0.1	0.2
		SO_2	0.1	0.1
		VOC	0.1	0.2
		CO	0.4	1.8
		NO_X	0.5	2.2
		Lead	0.000003	0.00002
		CO_2e	--	2,563
SN-112	Natural Gas Fired Waste Water Space Heaters	PM	0.1	0.3
		PM_{10}	0.1	0.3
		$PM_{2.5}$	0.1	0.3
		SO_2	0.1	0.1
		VOC	0.1	0.2
		CO	0.5	2.4
		NO_X	0.6	2.4
		Lead	0.00000324	0.0000142
		CO_2e	-	3,383
SN-113	Natural Gas Fired North and South Wall Space Heaters	PM	0.1	0.1
		PM_{10}	0.1	0.1
		$PM_{2.5}$	0.1	0.1
		SO_2	0.1	0.1
		VOC	0.1	0.1
		CO	0.2	0.9
		NO_X	0.2	0.9
		Lead	0.00000118	0.00000515
		CO_2e	-	1,230
SN-114	Natural Gas Direct Fired Flack Facility Space Heaters	PM	0.5	2.2
		PM_{10}	0.5	2.2
		$PM_{2.5}$	0.5	2.2
		SO_2	0.1	0.2
		VOC	0.4	1.6
		CO	5.5	24.3
		NO_X	5.4	23.5
		Lead	0.0000329	0.000144
		CO_2e	-	34,279

SN	Description	Pollutant	lb/hr	tpy
SN-115	Natural Gas Indirect Fired Flack Facility Space Heaters	PM	0.2	0.7
		PM_{10}	0.2	0.7
		$PM_{2.5}$	0.2	0.7
		SO_2	0.1	0.1
		VOC	0.1	0.5
		CO	1.6	6.8
		NO_X	1.5	6.6
		Lead	0.00000919	0.0000403
		CO_2e	-	9,609
SN-116	Natural Gas Fired CGL Building Space Heaters	PM	0.2	0.7
		PM_{10}	0.2	0.7
		$PM_{2.5}$	0.2	0.7
		SO_2	0.1	0.1
		VOC	0.2	0.5
		CO	1.7	7.5
		NO_X	1.7	7.3
		Lead	0.0000101	0.0000443
		CO_2e	-	10,578
SN-117	Natural Gas Fired ACL Building Space Heaters	PM	0.2	0.9
		PM_{10}	0.2	0.9
		$PM_{2.5}$	0.2	0.9
		SO_2	0.1	0.1
		VOC	0.2	0.7
		CO	2.1	9.4
		NO_X	2.1	9.0
		Lead	0.0000126	0.0000554
		CO_2e	-	13,223
SN-118	Natural Gas Fired RCM Indirect Space Heaters	PM	0.1	0.3
		PM_{10}	0.1	0.3
		$PM_{2.5}$	0.1	0.3
		SO_2	0.1	0.1
		VOC	0.1	0.2
		CO	0.5	2.3
		NO_X	0.5	2.2
		Lead	0.00000306	0.0000134
		CO_2e	-	3,203

SN	Description	Pollutant	lb/hr	tpy
SN-119	Natural Gas Fired RCM Direct Space Heaters	PM	0.1	0.4
		PM_{10}	0.1	0.4
		$PM_{2.5}$	0.1	0.4
		SO_2	0.1	0.1
		VOC	0.1	0.3
		CO	0.9	3.8
		NO_X	0.9	3.7
		Lead	0.00000506	0.0000222
		CO_2e	-	5,289
SN-120	Cold Mill Boiler NGO Line	PM	0.7	3.0
		PM_{10}	0.7	3.0
		$PM_{2.5}$	0.7	3.0
		SO_2	0.1	0.3
		VOC	0.5	2.1
		CO	7.3	32.1
		NO_X	3.1	13.6
		Lead	0.0000433	0.00019
		CO_2e	-	45,459
SN-121	Ceramic Coating Pots for GI Curing and Zinc Melting	PM	0.1	0.2
		PM_{10}	0.1	0.2
		$PM_{2.5}$	0.1	0.2
		SO_2	0.1	0.1
		VOC	0.1	0.1
		CO	0.3	1.4
		NO_X	0.3	1.3
		Lead	0.00000182	0.00000799
		CO_2e	-	1,907
SN-122	Ceramic Coating Pots for GL Curing and Zinc Melting	PM	0.1	0.2
		PM_{10}	0.1	0.2
		$PM_{2.5}$	0.1	0.2
		SO_2	0.1	0.1
		VOC	0.1	0.1
		CO	0.3	1.4
		NO_X	0.3	1.3
		Lead	0.00000182	0.00000799
		CO_2e	-	1,907

SN	Description	Pollutant	lb/hr	tpy
SN-123	Pre-Melt Pot Curing and Zinc Melting	PM PM_{10} $PM_{2.5}$ SO_2 VOC CO NO_X Lead CO_2e	0.1 0.1 0.1 0.1 0.1 0.2 0.2 0.00000092 -	0.1 0.1 0.1 0.1 0.1 0.7 0.7 0.000004 953
SN-124	Heated Parts Washer SMS Hotmill Rollshop	PM PM_{10} $PM_{2.5}$ SO_2 VOC CO NO_X Lead CO_2e	0.1 0.1 0.1 0.1 0.1 0.1 0.1 0.0000005 -	0.1 0.1 0.1 0.1 0.1 0.4 0.4 0.0000022 513
SN-125	Cold Mill Boiler	PM PM_{10} $PM_{2.5}$ SO_2 VOC CO NO_X Lead CO_2e	0.7 0.7 0.7 0.1 0.5 7.3 3.1 0.0000433 -	3.0 3.0 3.0 0.3 2.1 32.1 13.6 0.00019 45,459
SN-126	Color Coating Line Boiler	PM PM_{10} $PM_{2.5}$ SO_2 VOC CO NO_X Lead CO_2e	0.3 0.3 0.3 0.1 0.2 2.3 1.0 0.0000138 -	1.0 1.0 1.0 0.1 0.7 10.2 4.3 0.000061 14,424

60. The permittee shall not exceed the emission rates set forth in the following table and must install the control devices or implement the pollution prevention measures set forth in the following table. Compliance with this condition will be show by compliance with Specific Conditions 63 through 81. [Rule 19.901 *et seq.* and 40 C.F.R. § 52 Subpart E]

BACT Analysis Summary				
Source	Description	Pollutant	Control Technology	BACT Limit
SN-22	Pickle Line Boiler	PM	Combustion of Natural gas and Good Combustion Practice	0.0075 lb/MMBTU
		PM_{10}		0.0075 lb/MMBTU
		$PM_{2.5}$		0.0075 lb/MMBTU
		Opacity		5%
		SO_2		0.000588 lb/MMBTU
		VOC		0.0054 lb/MMBTU
		CO		0.0824 lb/MMBTU
		NO_X	Low NOx burners Combustion of clean fuel Good Combustion Practices	0.035 lb/MMBTU
		GHG	Good operating practices Minimum Boiler Efficiency	CO_2 117 lb/MMBTU CH_4 0.0022 lb/MMBTU N_2O 0.0002 lb/MMBTU 75%
SN-23	Pickle Line Scale Exhaust	PM	Fabric Filter	0.003 gr/dscf
		PM_{10}		
		$PM_{2.5}$		
		Opacity		5%
SN-24A	Push Pull Pickle Line (PPPL) Scrubber Stack	PM	Scrubber	0.003 gr/dscf
		PM_{10}		
		$PM_{2.5}$		
		Opacity		5%
SN-25	Tandem Cold Mill	PM	Mist Eliminator	0.0025 gr/dscf (filterable only)
		PM_{10}		0.0066 gr/dscf
		$PM_{2.5}$		0.0066 gr/dscf
		Opacity		5%
SN-26 and SN-27	Galvanizing Line Boilers 1 and 2	PM	Combustion of Natural gas and Good Combustion Practice	0.0075 lb/MMBTU
		PM_{10}		0.0075 lb/MMBTU
		$PM_{2.5}$		0.0075 lb/MMBTU
		Opacity		5%
		SO_2		0.000588 lb/MMBTU

BACT Analysis Summary				
Source	Description	Pollutant	Control Technology	BACT Limit
		VOC		0.0054 lb/MMBTU
		CO		0.0824 lb/MMBTU
		NO_X	Low NOx burners Combustion of clean fuel Good Combustion Practices	0.035 lb/MMBTU
		GHG	Good operating practices Minimum Boiler Efficiency	CO_2 117 lb/MMBTU CH_4 0.0022 lb/MMBTU N_2O 0.0002 lb/MMBTU 75%
SN-28 and SN-29	Galvanizing Line Preheater 1 and Galvanizing Line #2 Furnace	PM	Combustion of Natural gas and Good Combustion Practice	0.0012 lb/MMBTU
		PM_{10}		0.0012 lb/MMBTU
		$PM_{2.5}$		0.0012 lb/MMBTU
		Opacity		5%
		SO_2		0.000588 lb/MMBTU
		VOC		0.0054 lb/MMBTU
		CO		0.0824 lb/MMBTU
		NO_X	SCR, Low NOx burners Combustion of clean fuel Good Combustion Practices	0.035 lb/MMBTU
		GHG	Good operating practices	CO_2 117 lb/MMBTU CH_4 0.0022 lb/MMBTU N_2O 0.0002 lb/MMBTU
SN-34, SN-35, SN-36, SN-37	Galvanizing Line Caustic Cleaning and Post Treatment	PM	Mist Eliminator	0.003 gr/dscf
		PM_{10}		
		$PM_{2.5}$		
		Opacity		5%
SN-38a SN-38b	Skin Pass Mill #1 Skin Pass Mill #2 (ACL)	PM	Mist Eliminator	0.0025 gr/dscf
		PM_{10}		0.0066 gr/dscf
		$PM_{2.5}$		

BACT Analysis Summary				
Source	Description	Pollutant	Control Technology	BACT Limit
		Opacity		5%
SN-39	Annealing Furnaces	PM	Combustion of Natural gas and Good Combustion Practice	0.0075 lb/MMBTU
		PM_{10}		0.0075 lb/MMBTU
		$PM_{2.5}$		0.0075 lb/MMBTU
		Opacity		5%
		SO_2		0.000588 lb/MMBTU
		VOC		0.0054 lb/MMBTU
		CO		0.0824 lb/MMBTU
		NO_X	Low NOx burners Combustion of clean fuel Good Combustion Practices	0.1 lb/MMBTU
		GHG	Good operating practices	CO_2 117 lb/MMBTU CH_4 0.0022 lb/MMBTU N_2O 0.0002 lb/MMBTU
SN-40, SN-42	Decarburizing Line Furnace Section	PM	Combustion of Natural gas and Good Combustion Practice	0.013 lb/MMBTU
		PM_{10}		0.013 lb/MMBTU
		$PM_{2.5}$		0.013 lb/MMBTU
		Opacity		5%
		SO_2		0.000588 lb/MMBTU
		VOC		0.0054 lb/MMBTU
		CO		0.0824 lb/MMBTU
		NO_X	Low NOx burners SCR Combustion of clean fuel Good Combustion Practices	0.1 lb/MMBTU
		GHG	Good operating practices	CO_2 117 lb/MMBTU CH_4 0.0022 lb/MMBTU N_2O 0.0002 lb/MMBTU
SN-41, SN-43	Decarburizing Line Cleaning Sections	PM	Mist Eliminator	0.003 gr/dscf
		PM_{10}		
		$PM_{2.5}$		
		Opacity		5%

BACT Analysis Summary				
Source	Description	Pollutant	Control Technology	BACT Limit
SN-44, SN-45, SN-46	Reversing Cold Mills	PM	Mist Eliminator	0.0025gr/dscf
		PM_{10}		0.0066 gr/dscf
		$PM_{2.5}$		
		Opacity		5%
SN-47	Annealing Pickling Line Furnace Section	PM	Combustion of Natural gas and Good Combustion Practice	0.013 lb/MMBTU
		PM_{10}		0.013 lb/MMBTU
		$PM_{2.5}$		0.013 lb/MMBTU
		Opacity		5%
		SO_2		0.000588 lb/MMBTU
		VOC		0.0054 lb/MMBTU
		CO		0.0824 lb/MMBTU
		NO_X	Low NOx burners SCR Combustion of clean fuel Good Combustion Practices	0.1 lb/MMBTU
		GHG	Good operating practices	CO_2 117 lb/MMBTU CH_4 0.0022 lb/MMBTU N_2O 0.0002 lb/MMBTU
SN-48, SN-49	Annealing Pickling Line Scale Dust Exhaust and Shotblast	PM	Fabric Filter	0.003 gr/dscf
		PM_{10}		
		$PM_{2.5}$		
		Opacity		5%
SN-51	Annealing and Coating Line Furnace Section	PM	Combustion of Natural gas and Good Combustion Practice	0.013 lb/MMBTU
		PM_{10}		0.013 lb/MMBTU
		$PM_{2.5}$		0.013 lb/MMBTU
		Opacity		5%
		SO_2		0.000588 lb/MMBTU
		VOC		0.0054 lb/MMBTU
		CO		0.0824 lb/MMBTU

BACT Analysis Summary				
Source	Description	Pollutant	Control Technology	BACT Limit
		NO_X	Low NOx burners SCR Combustion of clean fuel Good Combustion Practices	0.1 lb/MMBTU
		GHG	Good operating practices	CO_2 117 lb/MMBTU CH_4 0.0022 lb/MMBTU N_2O 0.0002 lb/MMBTU
SN-52	Annealing and Coating Line Cleaning Section	PM	Mist Eliminator	0.003 gr/dscf
		PM_{10}		
		$PM_{2.5}$		
		Opacity		5%
SN-53	Annealing and Coating Line Drying Furnace	PM	Combustion of Natural gas and Good Combustion Practice	0.016 lb/MMBTU
		PM_{10}		0.016 lb/MMBTU
		$PM_{2.5}$		0.016 lb/MMBTU
		Opacity		5%
		SO_2		0.000588 lb/MMBTU
		CO		0.45 lb/MMBTU
		VOC Natural gas Combustion	RTO	0.0054 lb/MMBTU
		NO_X	Low NOx burners Combustion of clean fuel Good Combustion Practices	0.25 lb/MMBTU
		GHG	Good operating practices	CO_2 117 lb/MMBTU CH_4 0.0022 lb/MMBTU N_2O 0.0002 lb/MMBTU
SN-54, SN-56	MgO Coating Lines Drying Sections	PM	Combustion of Natural gas and Good Combustion Practice	0.013 lb/MMBTU
		PM_{10}		0.013 lb/MMBTU
		$PM_{2.5}$		0.013 lb/MMBTU
		Opacity		5%
		SO_2		0.000588 lb/MMBTU
		VOC		0.0054 lb/MMBTU

BACT Analysis Summary				
Source	Description	Pollutant	Control Technology	BACT Limit
		CO		0.0824 lb/MMBTU
		NO_X	Low NOx burners Combustion of clean fuel Good Combustion Practices	0.1 lb/MMBTU
		GHG	Good operating practices	CO_2 117 lb/MMBTU CH_4 0.0022 lb/MMBTU N_2O 0.0002 lb/MMBTU
SN-55, SN-57	MgO Coating Lines Cleaning Sections	PM	Mist Eliminator	0.003 gr/dscf
		PM_{10}		
		$PM_{2.5}$		
		Opacity		5%
SN-58, SN-60	Flattening Coating Lines Furnace Sections	PM	Combustion of Natural gas and Good Combustion Practice	0.013 lb/MMBTU
		PM_{10}		0.013 lb/MMBTU
		$PM_{2.5}$		0.013 lb/MMBTU
		Opacity		5%
		SO_2		0.000588 lb/MMBTU
		VOC		0.0054 lb/MMBTU
		CO		0.0824 lb/MMBTU
		NO_X	Low NOx burners SCR Combustion of clean fuel Good Combustion Practices	0.1 lb/MMBTU
		GHG	Good operating practices	CO_2 117 lb/MMBTU CH_4 0.0022 lb/MMBTU N_2O 0.0002 lb/MMBTU
SN-101	Annealing Pickle Line Boiler	PM	Combustion of Natural gas and Good Combustion Practice	0.0075 lb/MMBTU
		PM_{10}		0.0075 lb/MMBTU
		$PM_{2.5}$		0.0075 lb/MMBTU
		Opacity		5%
		SO_2		0.000588 lb/MMBTU
		VOC		0.0054 lb/MMBTU
		CO		0.0824 lb/MMBTU

BACT Analysis Summary				
Source	Description	Pollutant	Control Technology	BACT Limit
		NO_X	Low NOx burners Combustion of clean fuel Good Combustion Practices	0.035 lb/MMBTU
SN-102	Cold Mill Space Heaters - Natural Gas Fired (136.5 MMBtu)	PM	Combustion of Natural gas and Good Combustion Practice	0.0075 lb/MMBTU
		PM_{10}		0.0075 lb/MMBTU
		$PM_{2.5}$		0.0075 lb/MMBTU
		Opacity		5%
		SO_2		0.000588 lb/MMBTU
		VOC		0.0054 lb/MMBTU
		CO		0.0824 lb/MMBTU
		NO_X	Low NOx burners Combustion of clean fuel Good Combustion Practices	0.08 lb/MMBTU
		GHG	Good operating practices	CO_2 117 lb/MMBTU CH_4 0.0022 lb/MMBTU N_2O 0.0002 lb/MMBTU
SN-105, SN-106	Color Coating Line – Pre-Cleaning and Cleaning Sections	PM	Mist eliminator Good operating practices	0.003 gr/dscf
		PM_{10}		0.003 gr/dscf
		$PM_{2.5}$		0.003 gr/dscf
		Opacity		5%
SN-107	Color Coating Line – Prime/Finish Coating	VOC	Enclosed painting system Thermal oxidation Good work practices	152.6 tpy 99% Destruction
SN-108A, SN-108B, SN-108C	Color Coating Line – Chemical Dryer, Primer Oven, and Finish Oven	PM	Good combustion practices Energy efficient	0.0075 lb/MMBTU
		PM_{10}		0.0075 lb/MMBTU
		$PM_{2.5}$		0.0075 lb/MMBTU
		Opacity		5%
		VOC		0.0054 lb/MMBTU

BACT Analysis Summary				
Source	Description	Pollutant	Control Technology	BACT Limit
		NO_X	burners Combustion of natural gas	0.05 lb/MMBTU
SN-108D	Color Coating Line RTO	PM	Good combustion practices Energy efficient burners Combustion of natural gas	0.009 lb/MMBTU
		PM_{10}		0.009 lb/MMBTU
		$PM_{2.5}$		0.009 lb/MMBTU
		Opacity		5%
		VOC		0.021 lb/MMBTU
		NO_X		0.85 lb/MMBTU
SN-108E	Color Coating Line Spray Passivation	PM	Good combustion practices Energy efficient burners Combustion of natural gas	0.0075 lb/MMBtu
		PM_{10}		0.0075 lb/MMBtu
		$PM_{2.5}$		0.0075 lb/MMBtu
		Opacity		5%
		CO		0.0824 lb/MMBtu
		NO_X		0.10 lb/MMbtu
		GHG		117 lb CO_2e/MMBtu
SN-112 SN-113 SN-114 SN-115 SN-116 SN-117 SN-118 SN-119	Space Heaters	PM	Good combustion practices Energy efficient burners Combustion of natural gas	0.0075 lb/MMBtu
		PM_{10}		0.0075 lb/MMBtu
		$PM_{2.5}$		0.0075 lb/MMBtu
		Opacity		5%
		CO		0.0824 lb/MMBtu
		NO_X		0.08 lb/MMbtu
		GHG		117 lb CO_2e/MMBtu
SN-120	Cold Mill Boiler NGO Line	PM	Good combustion practices Energy efficient burners Combustion of natural gas	0.0075 lb/MMBtu
		PM_{10}		0.0075 lb/MMBtu
		$PM_{2.5}$		0.0075 lb/MMBtu
		Opacity		5%
		CO		0.0824 lb/MMBtu
		NO_X		0.035 lb/MMBtu
		GHG		117 lb CO_2e/MMBtu
SN-121 SN-122 SN-123	Pots for GL Curing and Melting	PM	Good combustion practices Energy efficient burners	0.0075 lb/MMBtu
		PM_{10}		0.0075 lb/MMBtu
		$PM_{2.5}$		0.0075 lb/MMBtu
		Opacity		5%
		CO		0.0824 lb/MMBtu
		NO_X		0.08 lb/MMBtu

BACT Analysis Summary				
Source	Description	Pollutant	Control Technology	BACT Limit
		GHG	Combustion of natural gas	117 lb CO_2e/MMBtu
SN-124	Stingray Parts Washer SMS Hotmill Rollshop	PM	Good combustion practices Energy efficient burners Combustion of natural gas	0.0075 lb/MMBtu
		PM_{10}		0.0075 lb/MMBtu
		$PM_{2.5}$		0.0075 lb/MMBtu
		Opacity		5%
		CO		0.0824 lb/MMBtu
		NO_X		0.08 lb/MMBtu
		GHG		117 lb CO_2e/MMBtu
SN-125	Cold Mill Boiler	PM	Good combustion practices Energy efficient burners Combustion of natural gas	0.0075 lb/MMBtu
		PM_{10}		0.0075 lb/MMBtu
		$PM_{2.5}$		0.0075 lb/MMBtu
		Opacity		5%
		CO		0.0824 lb/MMBtu
		NO_X		0.035 lb/MMBtu
		GHG		117 lb CO_2e/MMBtu
SN-126	Color Coating Line Boiler	PM	Good combustion practices Energy efficient burners Combustion of natural gas	0.0075 lb/MMBtu
		PM_{10}		0.0075 lb/MMBtu
		$PM_{2.5}$		0.0075 lb/MMBtu
		Opacity		5%
		CO		0.0824 lb/MMBtu
		NO_X		0.035 lb/MMBtu
		GHG		117 lb CO_2e/MMBtu

61. The permittee shall not exceed the emission rates set forth in the following table. The permittee shall demonstrate compliance with this condition by compliance with Plantwide Condition 5. [Rule 18.801 and Ark. Code Ann. § 8-4-203 as referenced by Ark. Code Ann. §§ 8-4-304 and 8-4-311]

SN	Description	Pollutant	lb/hr	tpy
SN-22	Pickle Line Boiler	Arsenic Cadmium Formaldehyde Manganese Mercury	0.00002 0.00006 0.004 0.00002 0.00002	0.00005 0.0003 0.02 0.00009 0.00006
SN-24	Pickling Section	HCl	0.2	0.6

SN	Description	Pollutant	lb/hr	tpy
SN-24A	Push Pull Pickle Line (PPPL) Scrubber Stack	HCl	0.2	0.8
SN-26	Galvanizing Line Boiler 1	Arsenic Cadmium Formaldehyde Manganese Mercury	0.00002 0.00006 0.004 0.00002 0.00002	0.00005 0.0003 0.02 0.00009 0.00006
SN-27	Galvanizing Line Boiler 2	Arsenic Cadmium Formaldehyde Manganese Mercury	0.00002 0.00006 0.004 0.00002 0.00002	0.00005 0.0003 0.02 0.00009 0.00006
SN-28	Galvanizing Line Preheater 1	Arsenic Cadmium Formaldehyde Manganese Mercury	0.00002 0.00009 0.006 0.00003 0.00002	0.00007 0.0004 0.03 0.0002 0.00009
SN-29	Galvanizing Line #2 Furnace	Arsenic Cadmium Formaldehyde Manganese Mercury	0.00003 0.0002 0.02 0.00006 0.00004	0.0002 0.0008 0.05 0.0003 0.0002
SN-39	Annealing Furnaces	Arsenic Cadmium Formaldehyde Manganese Mercury	0.00003 0.0002 0.009 0.00005 0.00003	0.0001 0.0006 0.04 0.0002 0.0002
SN-40	Decarburizing Line 1 Furnace Section	Arsenic Cadmium Formaldehyde Manganese Mercury	0.000008 0.00004 0.003 0.00002 0.00001	0.00004 0.0002 0.02 0.00006 0.00005
SN-42	Decarburizing Line 2 Furnace Section	Arsenic Cadmium Formaldehyde Manganese Mercury	0.000005 0.00003 0.002 0.000009 0.000006	0.00002 0.0002 0.008 0.00004 0.00003
SN-47	Annealing Pickling Line – Annealing Furnace	Arsenic Cadmium Formaldehyde Manganese Mercury	0.00002 0.00008 0.005 0.00003 0.00002	0.00006 0.00004 0.003 0.0002 0.00008

SN	Description	Pollutant	lb/hr	tpy
SN-50	Annealing Pickling Line Pickling Section	HCl	0.2	0.7
SN-51	Annealing and Coating Line - Annealing Furnace	Arsenic Cadmium Formaldehyde Manganese Mercury	0.000003 0.00002 0.001 0.000005 0.000004	0.00003 0.00007 0.005 0.00003 0.00002
SN-53	Annealing and Coating Line – Drying Furnace	Arsenic Cadmium Formaldehyde Manganese Mercury	0.000005 0.00003 0.002 0.000009 0.000006	0.00002 0.0002 0.008 0.00004 0.00003
SN-54	MgO Coating Line 1 – Drying Furnace	Arsenic Cadmium Formaldehyde Manganese Mercury	0.000003 0.00002 0.001 0.000005 0.000004	0.00002 0.00007 0.005 0.00003 0.00002
SN-56	MgO Coating Line 2 – Drying Furnace	Arsenic Cadmium Formaldehyde Manganese Mercury	0.000003 0.00002 0.001 0.000005 0.000004	0.00002 0.00007 0.005 0.00003 0.00002
SN-58	Flattening Coating Line 1 – Furnace	Arsenic Cadmium Formaldehyde Manganese Mercury	0.000007 0.00004 0.003 0.00002 0.000009	0.00003 0.0002 0.002 0.00006 0.00004
SN-59	Flattening Coating Line 1 – Cleaning Section	HCl	0.2	0.7
SN-60	Flattening Coating Line 2 – Furnace	Arsenic Cadmium Formaldehyde Manganese Mercury	0.000007 0.00004 0.003 0.00002 0.000009	0.00003 0.0002 0.002 0.00006 0.00004
SN-61	Flattening Coating Line 2 – Cleaning Section	HCl	0.2	0.7
SN-101	Annealing Pickling Line Boiler	Arsenic Cadmium Formaldehyde Manganese Mercury	0.00002 0.00006 0.004 0.00002 0.00002	0.00005 0.0003 0.02 0.00009 0.00006

SN	Description	Pollutant	lb/hr	tpy
SN-102	Cold Mill Space Heaters – Natural Gas Fired (136.5 MMBtu)	Arsenic Cadmium Formaldehyde Manganese Mercury	0.00003 0.0002 0.01 0.00006 0.00004	0.0002 0.0007 0.05 0.0003 0.0002
SN-107	Color Coating Line – Prime/Finish Coating	Isophorone MIBK Toluene	7.0 2.7 2.7	30.6 11.8 11.8
SN-108e	Color Coating Line Spray Passivation	Arsenic Cadmium Formaldehyde Manganese Mercury	0.000001 0.000006 0.0004 0.000002 0.000002	0.000005 0.00003 0.002 0.000009 0.000006
SN-112	Natural Gas Fired Waste Water Space Heaters	Arsenic Cadmium Formaldehyde Manganese Mercury	0.000002 0.000008 0.0005 0.000003 0.000002	0.000006 0.00004 0.003 0.00002 0.000008
SN-113	Natural Gas Fired North and South Wall Space Heaters	Arsenic Cadmium Formaldehyde Manganese Mercury	0.0000005 0.000003 0.0002 0.0000009 0.0000007	0.000003 0.00002 0.0008 0.000004 0.000003
SN-114	Natural Gas Direct Fired Flack Facility Space Heaters	Arsenic Cadmium Formaldehyde Manganese Mercury	0.00002 0.00008 0.005 0.00003 0.00002	0.00006 0.0004 0.03 0.0002 0.00008
SN-115	Natural Gas Indirect Fired Flack Facility Space Heaters	Arsenic Cadmium Formaldehyde Manganese Mercury	0.000004 0.00003 0.002 0.000007 0.000005	0.00002 0.00009 0.007 0.00004 0.00003
SN-116	Natural Gas Fired CGL Building Space Heaters	Arsenic Cadmium Formaldehyde Manganese Mercury	0.000005 0.00003 0.002 0.000008 0.000006	0.00002 0.0001 0.007 0.00004 0.00003
SN-117	Natural Gas Fired ACL Building Space Heaters	Arsenic Cadmium Formaldehyde Manganese Mercury	0.000006 0.00003 0.002 0.00001 0.000007	0.00003 0.0002 0.009 0.00005 0.00003

SN	Description	Pollutant	lb/hr	tpy
SN-118	Natural Gas Fired RCM Indirect Space Heaters	Arsenic Cadmium Formaldehyde Manganese Mercury	0.000002 0.000007 0.0005 0.000003 0.000002	0.000006 0.00003 0.003 0.00002 0.000007
SN-119	Natural Gas Fired RCM Direct Space Heaters	Arsenic Cadmium Formaldehyde Manganese Mercury	0.000003 0.00002 0.0008 0.000004 0.000003	0.000009 0.00005 0.004 0.00002 0.00002
SN-120	Cold Mill Boiler NGO Line	Arsenic Cadmium Formaldehyde Manganese Mercury	0.00002 0.0001 0.007 0.00004 0.00003	0.00008 0.0005 0.03 0.0002 0.0001
SN-121	Ceramic Coating Pots for GI Curing and Zinc Melting	Arsenic Cadmium Formaldehyde Manganese Mercury	0.0000008 0.000005 0.0003 0.000002 0.000001	0.000004 0.00002 0.002 0.000007 0.000005
SN-122	Ceramic Coating Pots for GL Curing and Zinc Melting	Arsenic Cadmium Formaldehyde Manganese Mercury	0.0000008 0.000005 0.0003 0.000002 0.000001	0.000004 0.00002 0.002 0.000007 0.000005
SN-123	Pre-Melt Pot Curing and Zinc Melting	Arsenic Cadmium Formaldehyde Manganese Mercury	0.0000004 0.000003 0.0002 0.0000007 0.0000005	0.000002 0.000009 0.0006 0.000004 0.000003
SN-124	Heated Parts Washer SMS Hotmill Rollshop	Arsenic Cadmium Formaldehyde Manganese Mercury	0.0000002 0.000002 0.00008 0.0000004 0.0000003	0.0000009 0.000005 0.0004 0.000002 0.000002
SN-125	Cold Mill Boiler	Arsenic Cadmium Formaldehyde Manganese Mercury	0.00002 0.0001 0.007 0.00004 0.00003	0.00008 0.0005 0.03 0.0002 0.0001

SN	Description	Pollutant	lb/hr	tpy
SN-126	Color Coating Line Boiler	Arsenic Cadmium Formaldehyde Manganese Mercury	0.000006 0.00004 0.003 0.00002 0.000008	0.00003 0.0002 0.01 0.00005 0.00004
SN-128	Pickling Section Sedimentation System	HCl	0.1	0.3

62. Visible emissions may not exceed the limits specified in the following table of this permit as measured by EPA Reference Method 9. The permittee shall show compliance with this condition by combustion of natural gas only at SN-22, SN-26, and SN-27, compliance with Specific Condition 63, and Plantwide Condition 5.

Source	Limit	Regulatory Citation
SN-22, SN-23, SN-24A, SN-25, SN-26, SN-27, SN-28, SN-29, SN-34, SN-35, SN-36, SN-37, SN-38, SN-39, SN-40, SN-41, SN-42, SN-43, SN-44, SN-45, SN-46, SN-47, SN-48, SN-49, SN-51, SN-52, SN-53, SN-54, SN-55, SN-56, SN-57, SN-58, SN-60, SN-101, SN-102, SN-105, SN-106, SN-107, SN-108A-E, SN-112, SN-113, SN-114, SN-115, SN-116, SN-117, SN-118, SN-119, SN-120, SN-121, SN-122, SN-123, SN-124, SN-125, SN-126	5%	Rule 19.901 *et seq.* and 40 C.F.R. § 52 Subpart E

63. The permittee shall conduct weekly observations of the opacity from the buildings and/or process stacks containing the sources listed in Specific Condition 62 except specifically SN-22, SN-26, and SN-27. If visible emissions are detected, then the permittee shall immediately conduct a 6-minute opacity reading in accordance with EPA Reference Method 9. The result of these observations or readings shall be recorded in a log that shall be kept on site and made available for inspection upon request. [Rule 19.901 and 40 CFR 52, Subpart E]

64. The permittee shall record and maintain records of the amounts of natural gas combusted in the boilers, SN-22, SN-26, SN-27, SN-101, SN-125, and SN-126, during each month.

These records shall be kept on site and available for inspection upon request. [Rule 19.304 and 40 C.F.R. § 60 Subpart Dc]

65. The permittee, for the annealing coating line dryer, SN-53, and the color coating line, SN-105 through SN-108D, on and after the compliance date on which 40 CFR 60.8 requires the performance test to be completed shall not cause to be discharged to the atmosphere more than: 0.14 kg VOC/l of coating solids applied or 10% of the VOC's applied (90% emissions reduction) for each calendar month operated at the most recently demonstrated overall efficiency. [Rule 19.304 and 40 C.F.R. § 60 Subpart TT]

66. The permittee shall conduct an initial performance test as required under 40 CFR 60.8(a) and thereafter a performance test every calendar month for the annealing coating line (SN-53) and the color coating line (SN-105 through SN-108D) according to the procedures of 40 CFR 60.463. The permittee shall use the procedures specified in 40 CFR 60.463(c) (1) for determining the monthly volume-weighted average emissions of VOC's in kg/l of coating solids applied. The permittee shall use the procedures specified in 40 CFR 60.463(c) (2) to show compliance with the emission limits specified under 40 CFR 60.462(a)(2) or (3) and Specific Condition 65. The permittee shall use the method and procedures outlined in 40 CFR 60.466 during these tests as appropriate. NSPS Subpart TT states section 40 CFR 60.8 (d) and (f) do not apply to this testing. The initial testing must be conducted in accordance with General Provision 3 of this permit. [Rule 19.304 and 40 C.F.R. § 60 Subpart TT]

67. The permittee shall where the compliance with the numerical limit specified in 60.462(a)(2) shall compute and record the average VOC content of the coatings applied during each calendar month for the annealing coating line (SN-53) and color coating line (SN-105 through SN-107) according the equations in 40 CFR 60.463. [Rule 19.304 and 40 C.F.R. § 60 Subpart TT]

68. The permittee shall install, calibrate, operate, and maintain a device that continuously records the combustion temperature of the effluent gasses of the RTO on SN-53 and SN-SN-108D. This device shall have an accuracy ±2.5°C or ±0.75 percent of the temperature being measured expressed in degrees Celsius, whichever is greater. The permittee shall record all periods (during actual coating operations) in excess of 3 hours duration which the average temperature in the RTO remains more than 28°C below the temperature at which the compliance was measured in the most recent measurement of the RTOs efficiency required in Specific Condition 66. [Rule 19.304 and 40 C.F.R. § 60 Subpart TT]

69. The permittee shall in the initial compliance report required by 40 CFR 60.8 include the weighted average of the VOC content of coatings used during a period of one calendar month for the annealing coating line (SN-53) and color coating line (SN-105 through SN-107). The permittee shall also include the data outlined in 40 CFR 60.465(b). [Rule 19.304 and 40 C.F.R. § 60 Subpart TT]

70. Upon commencement of operation of SN-107, the facility will be considered a major source of HAPs and be subject to the requirements of NESHAP Subpart SSSS and NESHAP Subpart CCC. Applicable conditions include, but are not limited to, Specific Conditions #71 through #77 below. [Rule 19.304 and 40 C.F.R. §§ 63 Subparts CCC and SSSS]

71. Each annealing coating line (SN-53) and color coating line (SN-105 through SN-108D) affected source subject to NESHAP Subpart SSSS must limit organic HAP emissions to the level specified below:
    a. No more than 2 percent of the organic HAP applied for each month during the each 12-month compliance period (98 percent reduction); or
    b. No more than 0.046 kilogram of organic HAP per liter of solids applied during each 12-month compliance period; or
    c. If the permittee uses an oxidizer to control organic HAP emissions, operate the oxidizer such that an outlet organic HAP concentration of no greater than 20 parts per million by volume (ppmv) on a dry basis is achieved and the efficiency of the capture system is 100 percent.

    [Rule 19.304 and 40 C.F.R. § 63.5120]

72. The permittee must demonstrate compliance with on these following standards for the annealing coating line (SN-53) and color coating line (SN-105 through SN-108D)
    a. Use of "as purchased" compliant coatings – Each coating material used during the 12- month compliance period does not exceed 0.046 kg HAP per liter solids.
    b. Use of "as applied" compliant coatings – Each coating material used does not exceed 0.046 kg HAP per liter solids on a rolling 12-month average as applied basis, determined monthly, or average of all coating materials used does not exceed 0.046 kg HAP per liter solids on a rolling 12-month average as applied basis, determined monthly.
    c. Use of a capture system and control device – Overall organic HAP control efficiency is at least 98 percent on a monthly basis for individual or groups of color coating lines, or overall organic HAP control efficiency is at least 98 percent during performance tests conducted according to Table 1 to § 63.5170 and operating limits are achieved continuously for individual color coating lines, or oxidizer outlet HAP concentration is no greater than 20 ppmv and there is 100-percent capture efficiency during performance tests conducted according to Table 1 to § 63.5170 and operating limits are achieved continuously for individual color coating lines.
    d. Use of a combination of compliant coatings and control devices and maintaining an acceptable equivalent emission rate – Average equivalent emission rate does not exceed 0.046 kg HAP per liter solids on a rolling 12-month average as applied basis, determined monthly.

    [Rule 19.304 and Table 1 to NESHAP Subpart SSSS]

73. The permittee must submit the reports and notifications specified in § 63.5180 for the annealing coating line (SN-53) and color coating line (SN-105 through SN-108D). The

facility must submit these notifications and reports to EPA through CEDRI as outlined in § 63.5181. The permittee must maintain all records specified in § 63.5190. [Rule 19.702 and 40 C.F.R. § 63 Subpart SSSS]

74. The facility is subject to the requirements of 40 C.F.R. § 63 Subpart CCC. The requirements of this subpart apply to, at minimum, the following sources: SN-24, SN-24A, SN-50, SN-59, SN-61, and SN-128. [Rule 19.702 and 40 C.F.R. 63 Subpart CCC]

75. No owner or operator of a new or reconstructed affected continuous pickling line, SN-24, SN-24A, SN-50, SN-59, SN-61, and SN-128, at a steel pickling facility shall cause or allow to be discharged into the atmosphere from the affected pickling line any gases that contain HCl in a concentration in excess of 6 ppmv or HCl at a mass emission rate that corresponds to a collection efficiency of less than 99 percent. [Rule 19.702 and 40 C.F.R. § 63.1158(a)]

76. The permittee must prepare an operation and maintenance plan for each emission control device associated with SN-24, SN-24A, SN-50, SN-59, SN-61, and SN-128 as outlined in § 63.1160 (b) including an inspection of each scrubber at intervals of no less than 3 months. The permittee shall conduct an initial performance test for each process or emission control device to determine and demonstrate compliance with the emission limitation according to the requirements in § 63.7 of subpart A. Performance tests shall be conducted using the test methods specified in § 63.1161(d). [Rule 19.702 and 40 C.F.R. § 63 Subpart CCC]

77. The permittee must submit the reports and notifications specified in § 63.1163 for SN-24, SN-24A, SN-50, SN-59, SN-61, and SN-128. The facility must submit these notifications and reports to EPA through CEDRI as outlined in §63.1164. The permittee must maintain all records specified in § 63.1165. [Rule 19.702 and 40 C.F.R. § 63 Subpart CCC]

78. The permittee shall test the Boilers SN-22, SN-26, SN-27, SN-101, SN-125, and SN-126 for $PM_{2.5}$, CO, and NO_x emissions. This test shall be conducted in accordance with Plantwide Condition 3 and EPA Reference Method 202, 10, and 7E for $PM_{2.5}$, CO, and NO_x respectively and repeated every 5 years after the initial test. The test for $PM_{2.5}$ shall include filterable and condensable emissions. [Rule 19.702 and 40 C.F.R. § 52 Subpart E]

79. The permittee shall test the sources in the table below for $PM_{2.5}$, and PM_{10}. This test shall be conducted in accordance with Plantwide Condition 3 and EPA Reference Method 202 for $PM_{2.5}$ and PM_{10}. The test for $PM_{2.5}$ shall include filterable and condensable emissions. This test has been performed and passed on all requirements for SN-28 or SN-29. [Rule 19.702 and 40 C.F.R. § 52 Subpart E]

Source
SN-28 or SN-29

80. The permittee shall test SN-24, SN-24A, SN-50, SN-59, SN-61, and SN-128 for HCl emissions. This test shall be conducted in accordance with Plantwide Condition 3 and EPA Reference Method 26. [Rule 18.1002 and Ark. Code Ann. § 8-4-203 as referenced by Ark. Code Ann. §§ 8-4-304 and 8-4-311]

81. The permittee shall test SN-28 and SN-29 for NO_X emissions. This test shall be conducted in accordance with Plantwide Condition 3 and EPA Reference Method 7E and repeated annually thereafter. [Rule 19.901 and 40 C.F.R. § 52 Subpart E]

82. Upon commencement of operation of SN-107, the facility will be considered a major source of HAPs and be subject to the requirements of NESHAP Subpart DDDDD. Applicable conditions include, but are not limited to, Specific Conditions #83 through #86 below. [Rule 19.304 and 40 C.F.R. §§ 63 Subparts CCC and SSSS]

83. The facility is subject to the requirements of 40 C.F.R. § 63 Subpart DDDDD. The requirements of this subpart apply to, at minimum, the following sources: SN-04, SN-22, SN-26, SN-27 and SN-101. [Rule 19.702 and 40 C.F.R. § 63 Subpart DDDDD]

84. The permittee shall conduct a tune-up of the boilers (SN-04, SN-22, SN-26, SN-27, SN-101, SN-125, and SN-126) or process heaters 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. [Rule 19.702, 40 C.F.R. § 63.7500(a)(1) and Table 3 to Subpart DDDDD]

85. The permittee must conduct each annual tune-up of each boiler, (SN-04, SN-22, SN-26, SN-27 SN-101, SN-125, and SN-126) no more than 13 months after the previous tune-up. The tune-up must be conducted as follows:
    a. While burning the type of fuel that provided the majority of the heat input to the boiler over the 12 months prior to the tune-up.
    b. As applicable, inspect the burner, and clean or replace any components of the burner as necessary.
    c. 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.
    d. Inspect the system controlling the air-to-fuel ratio as applicable and ensure that it is correctly calibrated and functioning properly.
    e. Optimize total emissions of CO. The optimization should be consistent with the manufacturer's specifications, if available, and with any NOX requirement to which the unit is subject.
    f. 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

g. Maintain on-site and submit, if requested by the Division, a report containing the following information:
    i. 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;
    ii. A description of any corrective actions taken as a part of the tune-up; and
    iii. 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.

[Rule 19.702 and 40 C.F.R. § 63.7540]

86. The permittee must submit all notifications and reports as outlined in 40 C.F.R. §§ 63.7545 and 63.7550 respectively for SN-04, SN-22, SN-26, SN-27 and SN-101. The permittee must keep a record of each notification and report submitted, including all documentation supporting any notifications or semiannual compliance reports. The records must be in a form suitable and ready for expeditious review and kept for a period of 5 years following the date of each occurrence, measurement, maintenance, corrective action, report, or record. The permittee must keep each record on site, or they must be accessible from on site, for at least 2 years after the date of each occurrence, measurement, corrective action, report, or record. Records may be kept offsite for the remaining 3 years. [Rule 19.702 and 40 C.F.R. § 63 Subpart DDDDD]

Emergency Engines

SN-62 Emergency Generator 1 (100.1 – Meltshop), Diesel Fired, 500 kW
SN-63 Emergency Generator 2 (600.3 – ColdMill), Diesel Fired, 1600 kW
SN-64 Emergency Generator 3 (400.1 – HSM/CCM), Diesel Fired, 1600 kW
SN-65 Emergency Generator 4 (100.2 – Meltshop), Diesel Fired, 1600 kW

SN-66 Emergency Generator 5 (100.4 – Meltshop), Diesel Fired, 2700 kW
SN-67 Emergency Generator 6 (Kohler 400.3 – HSM/CCM), Diesel Fired, 1145 kW
SN-67A Emergency Generator 7 (DC Gen 1 – Employee Building), Diesel Fired, 2700 kW
SN-67B Emergency Generator 8 (CGL2.GEN.1 – CGL2 Zinc Pot), Diesel Fired, 1000 kW
SN-67C Emergency Generator 9 (800A1.SS3 – RCM/ACL), Diesel Fired, 1600 kW

SN-67D Emergency Generator 10, Diesel Fired, 1114 kW

SN-67E Emergency Generator 11 (CGL.GEN.1 – CGL) Diesel Fired, 350 kW

SN-104A Diesel Fired Emergency Water Pump 1 (EP2-A Line HM Tunnel Furnace), 282 hp
SN-104B Diesel Fired Emergency Water Pump 2 (EP3 – ColdMill), 376 hp
SN-104C Diesel Fired Emergency Water Pump 3 (EP6-B Line HM Tunnel Furnace), 282 hp
SN-104D Diesel Fired Emergency Water Pump 4 (FP2 – Fire Line), 376 hp

SN-110a Emergency Generator 12, Diesel Fired, 2700 kW
SN-110b Emergency Generator 13, Diesel Fired, 2700 kW
SN-110c Emergency Generator 14, Diesel Fired, 2700 kW
SN-110d Emergency Generator 15, Diesel Fired, 2700 kW
SN-110e Emergency Generator 16, Diesel Fired, 2700 kW

Source Description

The emergency generators are diesel fired generators which provide electrical power in the event of power failure.

Specific Conditions

87. The permittee shall not exceed the emission rates set forth in the following table. The permittee shall demonstrate compliance with this condition by compliance Specific Conditions 91 and 93 through 96. [Rule 19.901 *et seq.* and 40 C.F.R. § 52 Subpart E]

SN	Description	Pollutant	lb/hr	tpy
SN-62	Emergency Generator 1 (100.1 – Meltshop), Diesel Fired, 500 kW	PM PM_{10} $PM_{2.5}$ SO_2 VOC CO NO_X CO_2e	0.3 0.3 0.3 5.1 1.5 3.6 3.1 --	0.1 0.1 0.1 0.3 0.1 0.2 0.2 32
SN-63	Emergency Generator 2 (600.3 – ColdMill), Diesel Fired, 1600 kW	PM PM_{10} $PM_{2.5}$ SO_2 VOC CO NO_X CO_2e	0.8 0.8 0.8 18.5 5.8 13.2 18.3 --	0.1 0.1 0.1 1.0 0.3 0.7 1.0 145
SN-64	Emergency Generator 3 (400.1 – HSM/CCM), Diesel Fired, 1600 kW	PM PM_{10} $PM_{2.5}$ SO_2 VOC CO NO_X CO_2e	0.8 0.8 0.8 18.5 5.8 13.2 18.3 --	0.1 0.1 0.1 1.0 0.3 0.7 1.0 145
SN-65	Emergency Generator 4 (100.2 – Meltshop), Diesel Fired, 1600 kW	PM PM_{10} $PM_{2.5}$ SO_2 VOC CO NO_X CO_2e	0.8 0.8 0.8 18.5 5.8 13.2 18.3 --	0.1 0.1 0.1 1.0 0.3 0.7 1.0 145
SN-66	Emergency Generator 5 (100.4 – Meltshop), Diesel Fired, 2700 kW	PM PM_{10} $PM_{2.5}$ SO_2 VOC CO NO_X CO_2e	0.8 0.8 0.8 0.1 1.0 7.3 31.4 --	0.1 0.1 0.1 0.1 0.1 0.4 1.6 195

SN	Description	Pollutant	lb/hr	tpy
SN-67	Emergency Generator 6 (Kohler 400.3 – HSM/CCM), Diesel Fired, 1145 kW	PM PM_{10} $PM_{2.5}$ SO_2 VOC CO NO_X CO_2e	0.4 0.4 0.4 0.1 0.5 3.1 13.4 --	0.1 0.1 0.1 0.1 0.1 0.2 0.7 195
SN-67A	Emergency Generator 7 (DC Gen 1 – Employee Building), Diesel Fired, 2700 kW	PM PM_{10} $PM_{2.5}$ SO_2 VOC CO NO_X CO_2e	0.8 0.8 0.8 0.1 1.0 7.3 31.4 --	0.1 0.1 0.1 0.1 0.1 0.4 1.6 195
SN-67B	Emergency Generator 8 (CGL2.GEN.1 – CGL2 Zinc Pot), Diesel Fired, 1000 kW	PM PM_{10} $PM_{2.5}$ SO_2 VOC CO NO_X CO_2e	0.2 0.2 0.2 0.1 0.1 1.1 12.9 --	0.1 0.1 0.1 0.1 0.1 0.1 0.6 80
SN-67C	Emergency Generator 9 (800A1.SS3 – RCM/ACL), Diesel Fired, 1600 kW	PM PM_{10} $PM_{2.5}$ SO_2 VOC CO NO_X CO_2e	0.4 0.4 0.4 0.1 0.3 1.8 20.7 --	0.1 0.1 0.1 0.1 0.1 0.1 1.0 127
SN-67D	Emergency Generator 10, Diesel Fired, 1114 kW	PM PM_{10} $PM_{2.5}$ SO_2 VOC CO NO_X CO_2e	0.1 0.1 0.1 0.1 0.1 1.3 13.7 --	0.1 0.1 0.1 0.1 0.1 0.1 0.7 80

SN	Description	Pollutant	lb/hr	tpy
SN-67E	Emergency Generator 11 (CGL.GEN.1 – CGL) Diesel Fired, 350 kW	PM PM_{10} $PM_{2.5}$ SO_2 VOC CO NO_X CO_2e	0.1 0.1 0.1 1.1 0.1 0.5 2.9 -	0.1 0.1 0.1 0.1 0.1 0.1 0.1 238
SN-104A	Diesel Fired Emergency Water Pump 1 (EP2-A Line HM Tunnel Furnace), 282 hp	PM PM_{10} $PM_{2.5}$ SO_2 VOC CO NO_X CO_2e	0.6 0.6 0.6 0.5 0.7 1.9 8.7 -	0.1 0.1 0.1 0.1 0.1 0.1 0.5 6
SN-104B	Diesel Fired Emergency Water Pump 2 (EP3 – ColdMill), 376 hp	PM PM_{10} $PM_{2.5}$ SO_2 VOC CO NO_X CO_2e	0.8 0.8 0.8 0.7 0.9 2.5 11.7 -	0.1 0.1 0.1 0.1 0.1 0.2 0.6 8
SN-104C	Diesel Fired Emergency Water Pump 3 (EP6-B Line HM Tunnel Furnace), 282 hp	PM PM_{10} $PM_{2.5}$ SO_2 VOC CO NO_X CO_2e	0.6 0.6 0.6 0.5 0.7 1.9 8.7 -	0.1 0.1 0.1 0.1 0.1 0.1 0.5 6
SN-104D	Diesel Fired Emergency Water Pump 4 (FP2 – Fire Line), 376 hp	PM PM_{10} $PM_{2.5}$ SO_2 VOC CO NO_X CO_2e	0.8 0.8 0.8 0.7 0.9 2.5 11.7 -	0.1 0.1 0.1 0.1 0.1 0.2 0.6 8

SN	Description	Pollutant	lb/hr	tpy
SN-110a	Emergency Generator 12, Diesel Fired, 2700 kW	PM PM_{10} $PM_{2.5}$ SO_2 VOC CO NO_X CO_2e	0.8 0.8 0.8 0.1 1.0 7.3 31.4 --	0.1 0.1 0.1 0.1 0.1 0.4 1.6 195
SN-110b	Emergency Generator 13, Diesel Fired, 2700 kW	PM PM_{10} $PM_{2.5}$ SO_2 VOC CO NO_X CO_2e	0.8 0.8 0.8 0.1 1.0 7.3 31.4 --	0.1 0.1 0.1 0.1 0.1 0.4 1.6 195
SN-110c	Emergency Generator 14, Diesel Fired, 2700 kW	PM PM_{10} $PM_{2.5}$ SO_2 VOC CO NO_X CO_2e	0.8 0.8 0.8 0.1 1.0 7.3 31.4 --	0.1 0.1 0.1 0.1 0.1 0.4 1.6 195
SN-110d	Emergency Generator 15, Diesel Fired, 2700 kW	PM PM_{10} $PM_{2.5}$ SO_2 VOC CO NO_X CO_2e	0.8 0.8 0.8 0.1 1.0 7.3 31.4 --	0.1 0.1 0.1 0.1 0.1 0.4 1.6 195
SN-110e	Emergency Generator 16, Diesel Fired, 2700 kW	PM PM_{10} $PM_{2.5}$ SO_2 VOC CO NO_X CO_2e	0.8 0.8 0.8 0.1 1.0 7.3 31.4 --	0.1 0.1 0.1 0.1 0.1 0.4 1.6 195

88. The permittee shall not exceed the emission rates set forth in the following table and must install the control devices or implement the pollution prevention measures set forth in the

following table. Compliance with this condition will be show by compliance with Specific Conditions 91 and 93 through 96. [Rule 19.901 *et seq.* and 40 C.F.R. § 52 Subpart E]

BACT Analysis Summary

Source	Description	Pollutant	Control Technology	BACT Limit
SN-62	Emergency Generator #1	PM	Good Operating Practices, limited hours of operation, Compliance with NSPS Subpart IIII	0.2 g/kW-Hr
		PM_{10}		0.2 g/kW-Hr
		$PM_{2.5}$		0.2 g/kW-Hr
		Opacity		20%
		SO_2		<0.0015% sulfur in fuel
		VOC		1.0 g/kW-Hr
		CO		3.5 g/kW-Hr
		NO_X		3.0 g/kW-Hr
		GHG	Good Combustion Practices	CO_2 163 lbs/MMBTU CH_4 0.0061 lbs/MMBTU N_2O 0.0013 lbs/MMBTU
SN-63, SN-64, SN-65, SN-66, SN-67, SN-67A SN-67B, SN-67C, SN-67D, SN-67E, SN-110a, SN-110b, SN-110c, SN-110d, SN-110e	Emergency Generators 2 through 16	PM	Good Operating Practices, limited hours of operation, Compliance with NSPS Subpart IIII	0.2 g/kW-Hr
		PM_{10}		0.2 g/kW-Hr
		$PM_{2.5}$		0.2 g/kW-Hr
		Opacity		20%
		SO_2		<0.0015% sulfur in fuel
		VOC		1.55 g/kW-Hr
		CO		3.5 g/kW-Hr
		NO_X		4.86 g/kW-Hr
		GHG	Good Combustion Practices	CO_2 163 lbs/MMBTU CH_4 0.0061 lbs/MMBTU N_2O 0.0013 lbs/MMBTU

89. The permittee shall not exceed the emission rates set forth in the following table. The permittee shall demonstrate compliance with this condition by compliance with Specific Conditions 91 and 93 through 96. [Rule 18.801 and Ark. Code Ann. § 8-4-203 as referenced by Ark. Code Ann. §§ 8-4-304 and 8-4-311]

SN	Description	Pollutant	lb/hr	tpy
SN-62	Emergency Generator 1 (100.1 – Meltshop), Diesel Fired, 500 kW	H_2SO_4	0.4	0.1

SN	Description	Pollutant	lb/hr	tpy
SN-63	Emergency Generator 2 (600.3 – ColdMill), Diesel Fired, 1600 kW	H_2SO_4	1.4	0.1
SN-64	Emergency Generator 3 (400.1 – HSM/CCM), Diesel Fired, 1600 kW	H_2SO_4	1.4	0.1
SN-65	Emergency Generator 4 (100.2 – Meltshop), Diesel Fired, 1600 kW	H_2SO_4	1.4	0.1
SN-66	Emergency Generator 5 (100.4 – Meltshop), Diesel Fired, 2700 kW	H_2SO_4	0.1	0.1
SN-67	Emergency Generator 6 (Kohler 400.3 – HSM/CCM), Diesel Fired, 1145 kW	H_2SO_4	0.1	0.1
SN-67A	Emergency Generator 7 (DC Gen 1 – Employee Building), Diesel Fired, 2700 kW	H_2SO_4	0.1	0.1
SN-67B	Emergency Generator 8 (CGL2.GEN.1 – CGL2 Zinc Pot), Diesel Fired, 1000 kW	H_2SO_4	0.1	0.1
SN-67C	Emergency Generator 9 (800A1.SS3 – RCM/ACL), Diesel Fired, 1000 kW	H_2SO_4	0.1	0.1
SN-67D	Emergency Generator 10, Diesel Fired, 1114 kW	H_2SO_4	0.1	0.1
SN-67E	Emergency Generator 11 (CGL.GEN.1 – CGL) Diesel Fired, 350 kW	H_2SO_4	0.1	0.1
SN-104A	Diesel Fired Emergency Water Pump 1 (EP2-A Line HM Tunnel Furnace), 282 hp	H_2SO_4	0.1	0.1
SN-104B	Diesel Fired Emergency Water Pump 2 (EP3 – ColdMill), 376 hp	H_2SO_4	0.1	0.1
SN-104C	Diesel Fired Emergency Water Pump 3 (EP6-B	H_2SO_4	0.1	0.1

SN	Description	Pollutant	lb/hr	tpy
	Line HM Tunnel Furnace), 282 hp			
SN-104D	Diesel Fired Emergency Water Pump 4 (FP2 – Fire Line), 376 hp	H_2SO_4	0.1	0.1
SN-110a	Emergency Generator 12, Diesel Fired, 2700 kW	H_2SO_4	0.1	0.1
SN-110b	Emergency Generator 13, Diesel Fired, 2700 kW	H_2SO_4	0.1	0.1
SN-110c	Emergency Generator 14, Diesel Fired, 2700 kW	H_2SO_4	0.1	0.1
SN-110d	Emergency Generator 15, Diesel Fired, 2700 kW	H_2SO_4	0.1	0.1
SN-110e	Emergency Generator 16, Diesel Fired, 2700 kW	H_2SO_4	0.1	0.1

90. The permittee shall not exceed 20% opacity from the Sources SN-62, SN-63, SN-64, SN-65, SN-66, SN-67, SN-67A, SN-67B, SN-67C, SN-67D, SN-67E, SN-104A, SN-104B, SN-104C, SN-104D, SN-110A, SN-110B, SN-110C, SN-110D and SN-110E. Compliance with this condition will be shown by combustion of low sulfur diesel fuel only and Plantwide Condition 5. [Rule 19.901 *et seq.* and 40 C.F.R. § 52 Subpart E]

91. The permittee shall not operate any single emergency engine, SN-62, SN-63, SN-64, SN-65, SN-66, SN-67, SN-67A, SN-67B, SN-67C, SN-67D, SN-67E, SN-104A, SN-104B, SN-104C, SN-104D, SN-110A, SN-110B, SN-110C, SN-110D and SN-110E more than 100 hours, for maintenance and readiness testing, in any consecutive 12 month period. The permittee shall maintain records of the hours of operation of each generator each month. These records shall be updated by the fifteenth day of the month following the month that the records represent, kept on site, made available to Department personnel upon request and submitted in accordance with General Provision 7. [Rule 19.705, Ark. Code Ann. § 8-4-203 as referenced by Ark. Code Ann. §§ 8-4-304 and 8-4-311, 40 C.F.R. § 70.6, and 40 C.F.R. § 60 Subpart IIII]

92. The permittee shall comply with the provisions of 40 C.F.R. Part 63 Subpart ZZZZ for SN-62, SN-63, SN-64, SN-65, SN-66, SN-67, SN-67A, SN-67B, SN-67C, SN-67D, SN-67E, SN-104A, SN-104B, SN-104C, SN-104D, SN-110A, SN-110B, SN-110C, SN-

110D and SN-110E by complying with the provisions of 40 C.F.R. Part 60 Subpart IIII. [Rule 19.304 and 40 C.F.R. § 63 Subpart ZZZZ]

93. The permittee shall comply with the emissions standards specified in § 60.4202 of 40 C.F.R. Part 60 Subpart IIII for SN-62, SN-63, SN-64, SN-65, SN-66, SN-67, SN-67A, SN-67B, and SN-67C, SN-67D, SN-67E, SN-104A, SN-104B, SN-104C, SN-104D, SN-110a, SN-110b, SN-110c, SN-110d, and SN-110e. The permittee shall operate and maintain the emergency generators, SN-62, SN-63, SN-64, SN-65, SN-66, SN-67, SN-67A, SN-67B, SN-67C, SN-67D, SN-67E, SN-104A, SN-104B, SN-104C, SN-104D, SN-110a, SN-110b, SN-110c, SN-110d, and SN-110e according to the manufacturer's written instruction or procedures developed by the permittee and approved by the generator manufacturer, over the life of the entire engine. [Rule 19.304 and 40 C.F.R. § 60 Subpart IIII]

94. The permittee shall install a non-resettable hour meter on the Emergency Generators, SN-62, SN-63, SN-64, SN-65, SN-66, SN-67, SN-67A, SN-67B, SN-67C, SN-67D, SN-67E, SN-104A, SN-104B, SN-104C, SN-104D, SN-110a, SN-110b, SN-110c, SN-110d, and SN-110e. [Rule 19.304 and 40 C.F.R. § 60 Subpart IIII]

95. The permittee shall use a diesel fuel that meets the requirements of 40 C.F.R. 80.510(b) in the generators, SN-62, SN-63, SN-64, SN-65, SN-66, SN-67, SN-67A, SN-67B, SN-67C, SN-67D, SN-67E, SN-104A, SN-104B, SN-104C, SN-104D, SN-110a, SN-110b, SN-110c, SN-110d, and SN-110e. [Rule 19.304 and 40 C.F.R. § 60 Subpart IIII]

96. If the generators, SN-62, SN-63, SN-64, SN-65, SN-66, SN-67, SN-67A, SN-67B, SN-67C, SN-67D, SN-67E, SN-104A, SN-104B, SN-104C, SN-104D, SN-110a, SN-110b, SN-110c, SN-110d, and SN-110e are equipped with a diesel particulate filter to comply with emission standards, the diesel particulate filter must be installed with a back pressure monitor that notifies the permittee when the high backpressure limit of the engine is approached. [Rule 19.304 and 40 C.F.R. § 60 Subpart IIII]

Cooling Towers

SN-68 Non-Contact Induced Draft Cooling Tower - Tower 1 MS
SN-69 Non-Contact Induced Draft Cooling Tower - Tower 2 MS: Gas Cleaning Plant (GCP)
SN-70 Non-Contact Induced Draft Cooling Tower - Tower 3 Caster/HM: Caster (CSP) Hotmill
SN-71 Non-Contact Induced Draft Cooling Tower – Caster/Hot Mill
SN-72A Non-Contact Cooling Tower – Cold Mill APL/ACL Anneal and Coating/ RCM + CRL
SN-72B Non-Contact Cooling Tower – Cold Mill ACL Furnace
SN-73 Non-Contact Induced Draft Cooling Tower - Cold Mill (PLTCM)
SN-74 Non-Contact Induced Draft Cooling Tower - Melt Shop Tower 1: Spray Cooled EAF (Duct Only)
SN-74A Non-Contact Induced Draft Cooling Tower EAF / LMF 2 and DOC Spray Cool
SN-74B Non-Contact Cooling Tower EAF Closed Loop for Electrode Arms
SN-75 Contact Induced Draft Cooling Tower - Tower 2 MS: RH Degasser
SN-76 Contact Induced Draft Cooling Tower - Tower 3 Caster: Caster (CSP) Only
SN-77 Contact Induced Draft Cooling Tower - Tower 4 HM: Hot Mill (HSM)
SN-78A Contact Cooling Tower Hot Mill
SN-78B Contact Induced Draft Cooling Tower Caster
SN-79 Contact Induced Draft Cooling Tower – Tower 6: Laminar (part of Hot Mill)
SN-109 Non-Contact Color Coating Line – Cooling Tower #1
SN-109b Non-Contact Color Coating Line – Cooling Tower #2
SN-129 Non-Contact Cooling Tower – Annealing Pickling Line (APL)
SN-130 Non-Contact Cooling Tower – Reversing Cold Mill 3 (RCM3)
SN-131 Non-Contact Cooling Tower – Decarburizing Coating Line (DCL) and High Temperature Annealing (HTA)
SN-132 Non-Contact Cooling Tower – Flattening Coating Line (FCL)

Source Description

The facility has a number of cooling towers which remove heat from process water.

SN-68 is a 499,866 gallon per hour Non-Contact Induced Draft Cooling Tower – Tower 1 MS.

SN-69 is a 885,070 gallon per hour Non-Contact Induced Cooling Tower – Tower 2 MS: Gas Cleaning Plant (GCP).

SN-70 is a 1,104,356 gallon per hour Non-Contact Induced Draft Cooling Tower – Caster and Hot Mill Tower 3 Caster/HM: Caster (CSP) Hot mill.

SN-71 is a 631,438 gallon per hour Non-Contact Induced Draft Cooling Tower – Caster/Hot Mill.

SN-72A(Non-Contact Cooling Tower – Cold Mill APL/ACL Anneal and Coating/ RCM + CRL is a 486,128 gallon per hour Non-Contact Induced Draft Cooling Tower.

SN-72B (Non-Contact Cooling Tower – Cold Mill ACL Furnace is a 333,948 gallon per hour Non-Contact Induced Draft Cooling Tower.

SN-73 is a 806,775 gallon per hour Non-Contact Induced Draft Cooling Tower – Cold Mill (PLTCM).

SN-74 is a 813,207 gallon per hour Non-Contact Induced Draft Cooling Tower - Melt Shop Tower 1: Spray Cooled EAF (Duct Only).

SN-74A (Non-Contact Induced Draft Cooling Tower EAF / LMF 2 and DOC Spray Cool is a 3,454,943 gallon per hour Non-Contact Induced Draft Cooling Tower.

SN-74B (Non-Contact Cooling Tower – EAF Closed Loop for Electrode Arms is a 449,000 gallon per hour Non-Contact Induced Draft Cooling Tower.

SN-75 is a 224,768 gallon per hour Contact Induced Draft Cooling Tower - Melt Shop Tower 2 MS: RH Degasser.

SN-76 is a 307,793 gallon per hour Contact Induced Draft Cooling Tower - Caster Tower 3 Caster: Caster (CSP) Only.

SN-77 is a 585,670 gallon per hour Contact Induced Draft Cooling Tower - Hot Mill Tower 4 HM: Hot Mill (HM)

SN-78A (Contact Cooling Tower – Hot Mill is a 2,113,600 gallon per hour Contact Induced Cooling Tower.

SN-78B (Contact Induced Draft Cooling Tower – Caster is a 413,433 gallon per hour Contact Induced Draft Cooling Tower.

SN-79 is a 1,001,318 gallon per hour Induced Draft Contact Cooling Tower a – Laminar Tower 6: Laminar (part of Hot Mill).

SN-109 Color Coating Line – Cooling Tower #1 is a 75,000 gallon/hour cooling tower.

SN-109b Color Coating Line – Cooling Tower #2 is a 75,000 gallon/hour cooling tower.

SN-129 Non-Contact Cooling Tower – Annealing Pickling Line (APL) is a 1,500,000 gallon/hour cooling tower.

SN-130 Non-Contact Cooling Tower – Reversing Cold Mill 3 (RCM3) is a 1,500,000 gallon/hour cooling tower.

SN-131 Non-Contact Cooling Tower – Decarburizing Coating Line (DCL) is a 1,500,000 gallon/hour cooling tower.

SN-132 Non-Contact Cooling Tower – Flattening Coating Line (FCL) is a 1,500,000 gallon/hour cooling tower.

Specific Conditions

97. The permittee shall not exceed the emission rates set forth in the following table. The permittee shall demonstrate compliance with this condition by compliance with Specific Conditions #99 and #100. [Rule 19.901 *et seq.* and 40 C.F.R. § 52 Subpart E]

SN	Description	Pollutant	lb/hr	tpy
SN-68	Non-Contact Induced Draft Cooling Tower - Tower 1 MS	PM PM_{10} $PM_{2.5}$	0.2 0.2 0.1	0.9 0.7 0.1
SN-69	Non-Contact Induced Draft Cooling Tower - Tower 2 MS: Gas Cleaning Plant (GCP)	PM PM_{10} $PM_{2.5}$	0.4 0.3 0.1	1.6 1.1 0.1
SN-70	Non-Contact Induced Draft Cooling Tower - Tower 3 Caster/HM: Caster (CSP) Hotmill	PM PM_{10} $PM_{2.5}$	0.5 0.4 0.1	2.0 1.4 0.1
SN-71	Non-Contact Induced Draft Cooling Tower – Caster/Hot Mill	PM PM_{10} $PM_{2.5}$	0.5 0.4 0.1	2.1 1.5 0.1
SN-72A	Non-Contact Cooling Tower – Cold Mill APL/ACL Anneal and Coating/ RCM + CRL	PM PM_{10} $PM_{2.5}$	0.2 0.2 0.1	0.9 0.6 0.1
SN-72B	Non-Contact Cooling Tower – Cold Mill ACL Furnace	PM PM_{10} $PM_{2.5}$	0.2 0.1 0.1	0.6 0.5 0.1
SN-73	Non-Contact Induced Draft Cooling Tower - Cold Mill (PLTCM)	PM PM_{10} $PM_{2.5}$	0.4 0.3 0.1	1.5 1.0 0.1
SN-74	Non-Contact Induced Draft Cooling Tower - Melt Shop Tower 1: Spray Cooled EAF (Duct Only)	PM PM_{10} $PM_{2.5}$	0.4 0.3 0.1	1.5 1.0 0.1
SN-74A	Non-Contact Induced Draft Cooling Tower EAF / LMF 2 and DOC Spray Cool	PM PM_{10} $PM_{2.5}$	2.6 1.8 0.1	11.2 7.8 0.1

SN	Description	Pollutant	lb/hr	tpy
SN-74B	Non-Contact Cooling Tower EAF Closed Loop for Electrode Arms	PM PM_{10} $PM_{2.5}$	0.2 0.2 0.1	0.8 0.6 0.1
SN-75	Contact Induced Draft Cooling Tower - Tower 2 MS: RH Degasser	PM PM_{10} $PM_{2.5}$	0.2 0.1 0.1	0.5 0.4 0.1
SN-76	Contact Induced Draft Cooling Tower - Tower 3 Caster: Caster (CSP) Only	PM PM_{10} $PM_{2.5}$	0.2 0.2 0.1	0.8 0.6 0.1
SN-77	Contact Induced Draft Cooling Tower - Tower 4 HM: Hot Mill (HSM)	PM PM_{10} $PM_{2.5}$	0.3 0.2 0.1	1.2 0.9 0.1
SN-78A	Contact Cooling Tower Hot Mill	PM PM_{10} $PM_{2.5}$	1.6 1.1 0.1	6.8 4.8 0.1
SN-78B	Contact Induced Draft Cooling Tower – Caster	PM PM_{10} $PM_{2.5}$	0.2 0.2 0.1	0.8 0.6 0.1
SN-79	Contact Induced Draft Cooling Tower Caster	PM PM_{10} $PM_{2.5}$	0.5 0.4 0.1	2.1 1.5 0.1
SN-109	Non-Contact Color Coating Line – Cooling Tower #1	PM PM_{10} $PM_{2.5}$	0.1 0.1 0.1	0.3 0.2 0.1
SN-109b	Non-Contact Color Coating Line – Cooling Tower #2	PM PM_{10} $PM_{2.5}$	0.1 0.1 0.1	0.2 0.1 0.1
SN-129	Non-Contact Cooling Tower – Annealing Pickling Line (APL)	PM PM_{10} $PM_{2.5}$	0.6 0.4 0.1	2.5 1.7 0.1
SN-130	Non-Contact Cooling Tower – Reversing Cold Mill 3 (RCM3)	PM PM_{10} $PM_{2.5}$	0.6 0.4 0.1	2.5 1.7 0.1
SN-131	Non-Contact Cooling Tower – Decarburizing Coating Line (DCL) and High Temperature Annealing (HTA)	PM PM_{10} $PM_{2.5}$	0.6 0.4 0.1	2.5 1.7 0.1

SN	Description	Pollutant	lb/hr	tpy
SN-132	Non-Contact Cooling Tower – Flattening Coating Line (FCL)	PM PM_{10} $PM_{2.5}$	0.6 0.4 0.1	2.5 1.7 0.1

98. The permittee shall not exceed the emission rates set forth in the following table and must install the control devices or implement the pollution prevention measures set forth in the following table. Compliance with this condition will be show by compliance with Specific Condition #99 and #100. [Rule 19.901 *et seq.* and 40 C.F.R. § 52 Subpart E]

BACT Analysis Summary				
Source	Description	Pollutant	Control Technology	BACT Limit
SN-68 SN-69, SN-70, SN-71, SN-72A, SN-72B, SN-73, SN-74, SN-74A, SN-74B, SN-109	Non-Contact Cooling Towers	PM PM_{10} $PM_{2.5}$	Drift Eliminators Low TDS	0.001 percent drift loss
		Opacity		5%
SN-75, SN-76, SN-77, SN-78A, SN-78B, SN-79	Contact Cooling Towers	PM PM_{10} $PM_{2.5}$	Drift Eliminators Low TDS	0.001 percent drift loss
		Opacity		5%
SN-109b, SN-129, SN-130, SN-131, SN-132	Cooling Towers	PM PM_{10} $PM_{2.5}$	Drift Eliminators Low TDS	0.0005 percent drift loss
		Opacity		5%

99. The permittee shall not exceed the emission rates set forth in the following table. The permittee shall demonstrate compliance with this condition by compliance with Specific Condition #100. [Rule 19.901 *et seq.* and 40 C.F.R. § 52 Subpart E]

SN	Description	TDS Limit
SN-68	Non-Contact Induced Draft Cooling Tower - Tower 1 MS	4800

SN	Description	TDS Limit
SN-69	Non-Contact Induced Draft Cooling Tower - Tower 2 MS: Gas Cleaning Plant (GCP)	4800
SN-70	Non-Contact Induced Draft Cooling Tower - Tower 3 Caster/HM: Caster (CSP) Hotmill	4800
SN-71	Non-Contact Induced Draft Cooling Tower – Caster/Hot Mill	8800
SN-72A	Non-Contact Cooling Tower – Cold Mill APL/ACL Anneal and Coating/ RCM + CRL	4800
SN-72B	Non-Contact Cooling Tower – Cold Mill ACL Furnace	4800
SN-73	Non-Contact Induced Draft Cooling Tower - Cold Mill (PLTCM)	4800
SN-74	Non-Contact Induced Draft Cooling Tower - Melt Shop Tower 1: Spray Cooled EAF (Duct Only)	4800
SN-74A	Non-Contact Induced Draft Cooling Tower EAF / LMF 2 and DOC Spray Cool	8800
SN-74B	Non-Contact Cooling Tower EAF Closed Loop for Electrode Arms	4800
SN-75	Contact Induced Draft Cooling Tower - Tower 2 MS: RH Degasser	5600
SN-76	Contact Induced Draft Cooling Tower - Tower 3 Caster: Caster (CSP) Only	6800

SN	Description	TDS Limit
SN-77	Contact Induced Draft Cooling Tower - Tower 4 HM: Hot Mill (HSM)	5600
SN-78A	Contact Cooling Tower Hot Mill	8800
SN-78B	Contact Induced Draft Cooling Tower – Caster	4800
SN-79	Contact Induced Draft Cooling Tower Caster	5600
SN-109	Non-Contact Color Coating Line – Cooling Tower #1	8800
SN-109b	Non-Contact Color Coating Line – Cooling Tower #2	8800
SN-129	Non-Contact Cooling Tower – Annealing Pickling Line (APL)	8800
SN-130	Non-Contact Cooling Tower – Reversing Cold Mill 3 (RCM3)	8800
SN-131	Non-Contact Cooling Tower – Decarburizing Coating Line (DCL) and High Temperature Annealing (HTA)	8800
SN-132	Non-Contact Cooling Tower – Flattening Coating Line (FCL)	8800

100. The permittee will test the TDS of each of the cooling towers following the methodology approved by the Department on April 30, 2019. This testing shall be conducted in accordance with Plantwide Condition #3. The results of this testing are not required to be submitted to the Division unless specifically requested by the Division. The results shall be kept on site and made available to Division personnel upon request. [Rule 19.705, Ark. Code Ann. § 8-4-203 as referenced by Ark. Code Ann. §§ 8-4-304 and 8-4-311, and 40 C.F.R. § 70.6]

101. Visible emissions may not exceed the limits specified in the following table of this permit as measured by EPA Reference Method 9. Compliance with this condition will be shown

by proper maintenance according to the defined maintenance procedures and Plantwide Condition #5.

Source	Limit	Regulatory Citation
SN-68 SN-69, SN-70, SN-71, SN-72A, SN-72B, SN-73, SN-74, SN-74A, SN-74B, SN-75, SN-76, SN-77, SN-78A, SN-78B, SN-79, SN-109, SN-109b, SN-129, SN-130, SN-131, and SN-132	5%	Rule 19.901 *et seq.* and 40 C.F.R. § 52 Subpart E

Miscellaneous Operations

SN-80 Charging Crane
SN-81 Scrap Yard Stockpiling
SN-82 EAF Flux Receiving System
SN-83 EAF Flux Storage and Handling System
SN-84 Carbon Injection Receiving System
SN-85 Carbon Injection Storage and Handling System
SN-86 LMF Flux Receiving System
SN-87 LMF Flux Storage and Handling System
SN-88 Alloy Receiving System
SN-89 Alloy Storage and Handling System
SN-90 Alloy Delivery System – LMF
SN-92 Inside Drop Point - Spent Refractory and Other Waste
SN-93 Outside Drop Point - Spent Refractory and Other Waste
SN-94 Inside Drop Point – EAF Dust
SN-99A Wind Erosion
SN-103 EAF I/II Lime Injection Receiving, Storage, and Handling System
SN-127a Truck Dump and Silos SMAC Dust Collector
SN-127b Rail Loading Building SMAC Dust Collector
SN-127c Cold Mill Coil Entry SMAC Dust Collector

Source Description

Charging Crane, SN-80, loads scrap from the scrap yard for charging into the EAF.

Scrap Yard Stockpiling, SN-81, is the emissions from loading of scrap steel from trucks or railcars to the scrapyard.

The EAF Flux Receiving System, SN-82, includes the truck and rail unloading of the flux materials for the EAF.

The EAF Flux Storage and Handling System, SN-83, includes the transport and storage of the flux materials for the EAF. A total of 10 silos will store HBI/DRI, dolomite, and lime. Each silo will have a capacity of 9,000 ft^3 and will be equipped with bin vent filters.

Carbon Injection Receiving System, SN-84, includes the truck and rail unloading of the carbon for the carbon injection into the EAF.

Carbon Injection Storage and Handling System, SN-85, includes the transport and storage of the carbon for the carbon into the EAF. There are four storage silos, each with a capacity of 8,000 ft^3.

LMF Flux Receiving System, SN-86, includes the truck and rail unloading of the flux materials for the LMF.

LMF Flux Storage and Handling System, SN-87, includes the transport and storage of the flux materials for the EAF. Six silos will store bauxite, CAL/A, dolomite, and lime. Each silo will have a capacity of 9,000 ft^3 and will be equipped with bin vent filters.

Alloy Receiving System, SN-88, includes the truck and rail unloading of the alloy materials for the LMF.

Alloy Storage and Handling System, SN-89, includes the transport and storage of the alloy materials for the EAF. A total of seven silos will store FeSn, SiMn, FeCr. Each silo will have a capacity of 9,000 ft^3 and will be equipped with bin vent filters.

Alloy Delivery System – LMF, SN-90, Alloy materials (FeSn, SiMn, FeCr) will be used to support the LMF operations. A stocking pocket belt conveyor will also be used to transfer the materials from the silos to weight hoppers that will be used to load alloy materials into the LMF stations.

RH Degasser Alloy Deliver System, SN-91. The alloy system will also be used to transport and feed alloy materials into the RH degasser. A stocking pocket conveyor will be used to transfer materials to the feed hoppers that will then be used to feed the RH degasser.

Inside Drop Point - Spent Refractory and Other Waste, SN-92, accounts for the emissions from placing of refractory material into the appropriate storage area/ container.

Outside Drop Point - Spent Refractory and Other Waste, SN-93, accounts for the placement of refractory material into outdoor storage area / container.

Inside Drop Point – EAF Dust, SN-94, accounts for the emissions of transfer of EAF baghouse dust into appropriate storage containers.

Wind Erosion, SN-99, is the emission from outdoor slag and storage piles due to wind erosion.

EAF I/II Lime Injection Receiving, Storage, and Handling System, SN-103, accounts for the emissions from the transport and storage of the various types of lime for injection into EAF I and II.

Self-Maintaining Air Cleaner (SMAC) dust collectors, SN-127a through SN-127c, are installed in sensitive areas to protect sensitive equipment from unwanted dust that may be present.

Specific Conditions

102. The permittee shall not exceed the emission rates set forth in the following table. The permittee shall demonstrate compliance with this condition compliance with Specific Conditions 104 and 105 and Plantwide Condition 5. [Rule 19.901 *et seq.* and 40 C.F.R. § 52 Subpart E]

SN	Description	Pollutant	lb/hr	tpy
SN-80	Charging Crane	PM PM_{10} $PM_{2.5}$	0.1 0.1 0.1	0.1 0.1 0.1
SN-81	Scrap Yard Stockpiling	PM PM_{10} $PM_{2.5}$	0.1 0.1 0.1	0.5 0.2 0.1
SN-82	EAF Flux Receiving System	PM PM_{10} $PM_{2.5}$	0.1 0.1 0.1	0.1 0.1 0.1
SN-83	EAF Flux Storage and Handling System	PM PM_{10} $PM_{2.5}$	0.2 0.1 0.1	0.6 0.3 0.1
SN-84	Carbon Injection Receiving System	PM PM_{10} $PM_{2.5}$	0.1 0.1 0.1	0.1 0.1 0.1
SN-85	Carbon Injection Storage and Handling System	PM PM_{10} $PM_{2.5}$	0.1 0.1 0.1	0.2 0.1 0.1
SN-86	LMF Flux Receiving System	PM PM_{10} $PM_{2.5}$	0.1 0.1 0.1	0.1 0.1 0.1
SN-87	LMF Flux Storage and Handling System	PM PM_{10} $PM_{2.5}$	0.2 0.1 0.1	0.6 0.3 0.1
SN-88	Alloy Receiving System	PM PM_{10} $PM_{2.5}$	0.1 0.1 0.1	0.1 0.1 0.1
SN-89	Alloy Storage and Handling System	PM PM_{10} $PM_{2.5}$	0.1 0.1 0.1	0.1 0.1 0.1
SN-90	Alloy Delivery System – LMF	PM PM_{10} $PM_{2.5}$	0.1 0.1 0.1	0.1 0.1 0.1
SN-92	Inside Drop Point - Spent Refractory and Other Waste	PM PM_{10} $PM_{2.5}$	0.1 0.1 0.1	0.1 0.1 0.1
SN-93	Outside Drop Point - Spent Refractory and Other Waste	PM PM_{10} $PM_{2.5}$	0.1 0.1 0.1	0.1 0.1 0.1

SN	Description	Pollutant	lb/hr	tpy
SN-94	Inside Drop Point – EAF Dust	PM PM_{10} $PM_{2.5}$	0.1 0.1 0.1	0.1 0.1 0.1
SN-99A	Feed Stock Piles - Wind Erosion	PM PM_{10} $PM_{2.5}$	0.9 0.5 0.1	3.7 1.9 0.3
SN-103	EAF I/II Lime Injection Receiving, Storage, and Handling System	PM PM_{10} $PM_{2.5}$	0.1 0.1 0.1	0.4 0.4 0.4
SN-127a	Truck Dump and Silos SMAC Dust Collector	PM PM_{10} $PM_{2.5}$	2.0 2.0 2.0	8.5 8.5 8.5
SN-127b	Rail Loading Building SMAC Dust Collector	PM PM_{10} $PM_{2.5}$	0.6 0.6 0.6	2.7 2.7 2.7
SN-127c	Cold Mill Coil Entry SMAC Dust Collector	PM PM_{10} $PM_{2.5}$	0.4 0.4 0.4	1.7 1.7 1.7

103. The permittee shall not exceed the emission rates set forth in the following table and must install the control devices or implement the pollution prevention measures set forth in the following table. Compliance with this condition will be show by compliance with Specific Conditions 104 and 105 and Plantwide Condition 5. [Rule 19.901 *et seq.* and 40 C.F.R. § 52 Subpart E]

BACT Analysis Summary				
Source	Description	Pollutant	Control Technology	BACT Limit
SN-82	EAF Flux Receiving System	PM	Dust Control Plan Enclosed Receiving System with Fabric Filter	0.003 gr/dscf
		PM_{10}		
		$PM_{2.5}$		
		Opacity		5%
SN-83	EAF Flux Storage and Handling System	PM PM_{10} $PM_{2.5}$	Dust Control Plan, Enclosed Conveyors with Fabric Filters Silos with Bin Vent Filters	0.003 gr/dscf 0.01 gr/dscf
		Opacity		5%
SN-84	Carbon Injection Receiving	PM	Dust Control Plan Enclosed Receiving System with Fabric Filter	0.003 gr/dscf
		PM_{10}		
		$PM_{2.5}$		
		Opacity		5%

BACT Analysis Summary

Source	Description	Pollutant	Control Technology	BACT Limit
SN-85	Carbon Injection Storage and Handling System	PM PM_{10} $PM_{2.5}$	Dust Control Plan, Enclosed Conveyors with Fabric Filters Silos with Bin Vent Filters	0.003 gr/dscf 0.01 gr/dscf
		Opacity		5%
SN-86	LMF Flux Receiving	PM PM_{10} $PM_{2.5}$	Dust Control Plan Enclosed Receiving System with Fabric Filter	0.003 gr/dscf
		Opacity		5%
SN-87	LMF Flux Storage and Handling System	PM PM_{10} $PM_{2.5}$	Dust Control Plan, Enclosed Conveyors with Fabric Filters Silos with Bin Vent Filters	0.003 gr/dscf 0.01 gr/dscf
		Opacity		5%
SN-88	Alloy Receiving System	PM PM_{10} $PM_{2.5}$	Dust Control Plan Enclosed Receiving System with Fabric Filter	0.003 gr/dscf
		Opacity		5%
SN-89	Alloy Storage and Handling System	PM PM_{10} $PM_{2.5}$	Dust Control Plan, Enclosed Conveyors with Fabric Filters Silos with Bin Vent Filters	0.003 gr/dscf 0.01 gr/dscf
		Opacity		5%
SN-90	Alloy Delivery System – LMF	PM PM_{10} $PM_{2.5}$	Dust Control Plan, Enclosed Conveyors with Fabric Filters Enclosed Receiving System with Fabric Filter Fabric Filters Silos with Bin Vent Filters	0.003 gr/dscf 0.003 gr/dscf 0.01 gr/dscf
		Opacity		5%
SN-92	Inside Drop Point - Spent Refractory and Other Waste	PM	Dust Control Plan	0.1 lb/hr, 0.1 tpy
		PM_{10}		0.1 lb/hr, 0.1 tpy
		$PM_{2.5}$		0.1 lb/hr, 0.1 tpy
		Opacity		20%
SN-93	Outside Drop Point - Spent Refractory and	PM	Dust Control Plan	0.1 lb/hr, 0.1 tpy
		PM_{10}		0.1 lb/hr, 0.1 tpy

BACT Analysis Summary				
Source	Description	Pollutant	Control Technology	BACT Limit
	Other Waste	$PM_{2.5}$		0.1 lb/hr, 0.1 tpy
		Opacity		20%
SN-94	Inside Drop Point – EAF Dust	PM	Dust Control Plan	0.1 lb/hr, 0.1 tpy
		PM_{10}		0.1 lb/hr, 0.1 tpy
		$PM_{2.5}$		0.1 lb/hr, 0.1 tpy
		Opacity		20%
SN-99A	Feed Stock Piles - Wind Erosion	PM	Dust Control Plan	0.9 lb/hr, 3.7 tpy
		PM_{10}		0.5 lb/hr, 1.9 tpy
		$PM_{2.5}$		0.1 lb/hr, 0.3 tpy
		Opacity		20%
SN-103	EAF I/II Lime Injection Receiving, Storage, and Handling System	PM	Fabric Filter Enclosed Conveyors with Compressed Air Dust Control Plan Bin Vent Filter on Each Silo	0.1 lb/hr, 0.4 tpy
		PM_{10}		0.1 lb/hr, 0.4 tpy
		$PM_{2.5}$		0.1 lb/hr, 0.4 tpy
		Opacity		5%
SN-127a SN-127b SN-127c	SMAC Dust Collectors	PM	Good operating practices	0.002 gr/dscf
		PM_{10}		0.002 gr/dscf
		$PM_{2.5}$		0.002 gr/dscf
		Opacity		5%

104. The permittee shall not receive more than material than in the table below in any consecutive rolling 12 month period. [Rule 19.901 *et seq.* and 40 C.F.R. § 52 Subpart E]

Source	Consecutive rolling 12 month limit (tons/year)
SN-82	175,830
SN-84	79,204
SN-86	175,830
SN-88	680,000
SN-90	680,000
SN-103	210,240

105. The permittee shall maintain monthly records of the amount of materials received in the sources in Specific Condition 104. These records shall include the monthly total of material received and the rolling 12 month total of material received. These records shall be updated by the 15th day of the month following the month to which the records pertain, kept on site, made available to Department personnel upon request, and submitted in accordance with General Provision 7. [Rule 19.901 *et seq.* and 40 C.F.R. § 52 Subpart E]

106. Visible emissions may not exceed the limits specified in the following table of this permit as measured by EPA Reference Method 9. For SN-103, compliance with this condition shall be shown by compliance with the opacity requirements for the melt shop. For all other listed sources, compliance with this condition will be shown by compliance with Specific Condition #107 and Plantwide Condition 5.

Source	Limit	Regulatory Citation
SN-82, SN-83, SN-84, SN-85, SN-86, SN-87, SN-88, SN-89, SN-90, and SN-103	5%	Rule 19.901 *et seq.* and 40 C.F.R. § 52 Subpart E
SN-92, SN-93, SN-94, and SN-99A	20%	Rule 19.901 *et seq.* and 40 C.F.R. § 52 Subpart E

107. The permittee shall conduct weekly observations of the opacity from SN-82 through SN-94. If visible emissions are detected, the permittee shall conduct a 6-minute opacity reading in accordance with Method 9 at the point where visible emissions were detected. The results of these observations shall be recorded in a log which shall be kept on site and made available for inspection upon request. [Rule 19.901 *et seq.* and 40 C.F.R. § 52 Subpart E]

108. The permittee may install sealed conveyors or sealed pneumatic conveyors that have no vents to the atmosphere. The permittee is not required to vent the conveyors to a baghouse if no vent is needed. [Rule 19.705, Ark. Code Ann. § 8-4-203 as referenced by Ark. Code Ann. §§ 8-4-304 and 8-4-311, and 40 C.F.R. § 70.6]

109. The permittee shall implement a fugitive emission dust control plan to control dust emissions from the sources specified to require a dust control plan in Specific Condition 103. [Rule 19.705, Ark. Code Ann. § 8-4-203 as referenced by Ark. Code Ann. §§ 8-4-304 and 8-4-311, and 40 C.F.R. § 70.6]

Slag Handling

SN-95 Drop Points Slag
SN- 96 Slag Handling and Conveying
SN-99B Slag Storage Piles

Source Description

SN-95 and SN-96 include conveyors, screening and crushing equipment used to primarily handle slag however on occasion, other miscellaneous solids may be processed.

Wind Erosion, SN-99, is the emission from outdoor slag and storage piles due to wind erosion.

Specific Conditions

110. The permittee shall not exceed the emission rates set forth in the following table. The permittee shall demonstrate compliance with this condition by compliance with Specific Conditions 111 and 112. [Rule 19.901 *et seq.* and 40 C.F.R. § 52 Subpart E]

SN	Description	Pollutant	lb/hr	tpy
SN-95	Drop Points Slag	PM PM_{10} $PM_{2.5}$	5.3 2.6 0.9	3.4 1.7 0.6
SN-96	Slag Handling and Conveying	PM PM_{10} $PM_{2.5}$	1.1 0.4 0.1	1.2 0.4 0.1
SN-99B	Slag Storage Piles	PM PM_{10} $PM_{2.5}$	0.2 0.1 0.1	0.6 0.3 0.1

111. The permittee shall not process more than 650,000 tons of slag in any consecutive rolling 12 month period. [Rule 19.901 *et seq.* and 40 C.F.R. § 52 Subpart E]

112. The permittee shall maintain monthly records of the amount of slag processed. These records shall include the monthly total of slag processed and the rolling 12 month total of slag processed. These records shall be updated by the 15th day of the month following the month to which the records pertain, kept on site, made available to Department personnel upon request, and submitted in accordance with General Provision 7. [Rule 19.901 *et seq.* and 40 C.F.R. § 52 Subpart E]

113. Visible emissions may not exceed the limits specified in the following table of this permit as measured by EPA Reference Method 9.

Source	Limit	Regulatory Citation
SN-95 SN-96 SN-99B	20%	Rule 19.901 *et seq.* and 40 C.F.R. § 52 Subpart E

114. The permittee shall conduct weekly observations of the opacity from each slag processing transfer point and conveyor at the slag processing area. If visible emissions are detected, the permittee shall conduct a 6-minute opacity reading in accordance with Method 9 at the point where visible emissions were detected. The results of these observations shall be recorded in a log which shall be kept on site and made available for inspection upon request. [Rule 19.901 *et seq.* and 40 C.F.R. § 52 Subpart E]

Roadway Sources

SN-97 Paved Roads
SN-98 Unpaved Roads

Source Description

SN-97 accounts for emissions from paved roadways and SN-98 accounts for emission from unpaved roadways.

Specific Conditions

115. The permittee shall not exceed the emission rates set forth in the following table. Compliance with this condition will be shown by application of dust suppressant as necessary to control dust emissions. [Rule 19.901 *et seq.* and 40 C.F.R. § 52 Subpart E]

SN	Description	Pollutant	lb/hr	tpy
SN-97	Paved Roads	PM PM_{10} $PM_{2.5}$	0.7 0.2 0.1	2.9 0.6 0.2
SN-98	Unpaved Roads	PM PM_{10} $PM_{2.5}$	2.2 0.6 0.1	9.6 2.6 0.3

116. Dust suppression activities should be conducted in a manner and at a rate of application that will not cause runoff from the area being applied. Best Management Practices (40 CFR §122.44(k)) should be used around streams and waterbodies to prevent the dust suppression agent from entering Waters of the State. Except for potable water, no agent shall be applied within 100 feet of wetlands, lakes, ponds, springs, streams, or sinkholes. Failure to meet this condition may require the permittee to obtain a National Pollutant Discharge Elimination System (NPDES) permit in accordance with 40 CFR §122.1(b). [A.C.A. §8-4-203 as referenced by A.C.A. §8-4-304 and §8-4-311]

117. The permittee shall implement a fugitive emission dust control plan to control dust emissions from the roadways. [Rule 19.705, Ark. Code Ann. § 8-4-203 as referenced by Ark. Code Ann. §§ 8-4-304 and 8-4-311, and 40 C.F.R. § 70.6]

Gasoline Storage Tanks and Dispensing Operation

SN-100 Gasoline Storage and Dispensing

Source Description

SN-100 accounts for emissions from gasoline storage tanks and refueling operations.

Specific Conditions

118. The permittee shall not exceed the emission rates set forth in the following table. The permittee shall demonstrate compliance with this condition by compliance with Specific Conditions #119 and #120. [Rule 19.501 *et seq.* and 40 C.F.R. § 52 Subpart E]

SN	Pollutant	lb/hr	tpy
SN-100	VOC	0.3	0.8

119. The permittee shall maintain a throughput of no more than 500,000 gallons of gasoline through SN-100 per rolling 12-month period. [Rule 19.705 and Ark. Code. Ann. § 8-4-203 as referenced by §§ 8-4-304 and 8-4-311]

120. The permittee shall maintain monthly records to demonstrate compliance with Specific Condition #119. Material Data Safety Sheets or other equivalent documents for gasoline shall be maintained on-site and made available upon request. The permittee shall update these records by the fifteenth day of the month following the month to which the records pertain. The twelve month rolling totals and each individual month's data for gasoline usage shall be maintained on-site and made available to Department personnel upon request. [Rule 19.705 and Ark. Code Ann. § 8-4-203 as referenced by §§ 8-4-304 and 8-4-311]

121. The permittee is currently subject to NESHAP CCCCCC as the facility is an area source and must comply with Specific Conditions #122 and #123. Upon commencement of operation of SN-107, the facility will instead be a major source of HAPs and this subpart and its conditions will no longer be applicable. [Rule 19.304 and 40 C.F.R. § 63 Subpart CCCCCC]

122. The permittee is subject to and shall comply with the applicable provisions of 40 C.F.R. Part 63, Subpart CCCCCC – *National Emission Standards for Hazardous Air Pollutants for Gasoline Dispensing Facilities* (Appendix A). *Gasoline Dispensing Facility (GDF)* is defined in § 63.11132 as any stationary facility which dispenses gasoline into the fuel tank of a motor vehicle, motor vehicle engine, nonroad vehicle, or nonroad engine, including a nonroad vehicle or nonroad engine used solely for competition. The facility, an area source of HAPs, is a GDF. The affected source includes each gasoline cargo tank

during the delivery of product to a GDF and also includes each storage tank. [Rule 19.304 and 40 C.F.R. 63 Subpart CCCCCC]

123. The permittee must comply with the requirements in § 63.11116 and § 63.11117 as the facility has a monthly throughput of more than 10,000 gallons of gasoline. Requirements of § 63.11116 are as follows:
   a. The permittee must not allow gasoline to be handled in a manner that would result in vapor releases to the atmosphere for extended periods of time. Measures to be taken include, but are not limited to, the following:
      i. Minimize gasoline spills;
      ii. Clean up spills as expeditiously as practicable;
      iii. Cover all open gasoline containers and all gasoline storage tank fill-pipes with a gasketed seal when not in use; and
      iv. Minimize gasoline sent to open waste collection systems that collect and transport gasoline to reclamation and recycling devices, such as oil/water separators.
   b. The permittee is not required to submit notifications or reports as specified in §§ 63.11125, 63.11126, or subpart A of 40 C.F.R. Part 63, but the permittee must have records available within 24 hours of a request by the Department to document the facility's gasoline throughput.
   c. The permittee must comply with the requirements of 40 C.F.R. 63 Subpart CCCCCC by the applicable dates specified in § 63.11113.
   d. Portable gasoline containers that meet the requirements of 40 C.F.R. Part 59, Subpart F, are considered acceptable for compliance with § 63.11116(a)(3).

   [Rule 19.304, 40 C.F.R. §§ 63.11111(b) and 63.11116(a) through (d)]

124. The permittee must only load gasoline into storage tanks by utilizing submerged filling. The submerged fill pipes must be no more than 6 inches from the bottom of the tank. Gasoline storage tanks with a capacity of less than 250 gallons are not required to comply with the submerged fill requirements. [Rule 19.304 and 40 C.F.R. § 63.11117]

Hydrogen Plant #2 Reformer Furnace (PHG830)

SN-111 Hydrogen Plant #2 Reformer Furnace (PHG830)

Source Description

Hydrogen Plant #2 Reformer Furnace (PHG830), SN-111, is a 12.5 MMBtu/hr furnace that supports the hydrogen plant.

Specific Conditions

125. The permittee shall not exceed the emission rates set forth in the following table. The permittee shall demonstrate compliance with this condition by combustion of only natural gas. [Rule 19.501 *et seq.* and 40 C.F.R. § 52 Subpart E]

SN	Description	Pollutant	lb/hr	tpy
SN-111	Hydrogen Plant #2 Reformer Furnace (PHG830)	PM PM_{10} $PM_{2.5}$ SO_2 VOC CO NO_X Lead CO_2e	0.1 0.1 0.1 0.1 0.1 1.1 1.3 0.00001 --	0.5 0.5 0.5 0.1 0.3 4.5 5.5 0.00003 6,396

126. The permittee shall not exceed the emission rates set forth in the following table. Compliance with this condition will be show by compliance with Plantwide Condition 5. [Rule 19.901 *et seq.* and 40 C.F.R. § 52 Subpart E]

BACT Analysis Summary				
Source	Description	Pollutant	Control Technology	BACT Limit
SN-111	Hydrogen Plant #2 Reformer Furnace (PHG830)	PM	Combustion of Natural gas and Good Combustion Practice	0.0075 lb/MMBTU
		PM_{10}		0.0075 lb/MMBTU
		$PM_{2.5}$		0.0075 lb/MMBTU
		Opacity		5%
		VOC		0.0054 lb/MMBTU

BACT Analysis Summary				
Source	Description	Pollutant	Control Technology	BACT Limit
		NO_X	Low NOx burners Combustion of clean fuel Good Combustion Practices	0.1 lb/MMBTU

127. Visible emissions may not exceed the limits specified in the following table of this permit as measured by EPA Reference Method 9. Compliance with this condition will be shown by combustion of natural gas only and Plantwide Condition 5.

Source	Limit	Regulatory Citation
SN-111	5%	Rule 19.901 *et seq.* and 40 C.F.R. § 52 Subpart E

SECTION V: COMPLIANCE PLAN AND SCHEDULE

Big River Steel LLC will continue to operate in compliance with those identified regulatory provisions. The facility will examine and analyze future rules and regulations that may apply and determine their applicability with any necessary action taken on a timely basis.

SECTION VI: PLANTWIDE CONDITIONS

1. The permittee shall notify the Director in writing within thirty (30) days after commencing construction, completing construction, first placing the equipment and/or facility in operation, and reaching the equipment and/or facility target production rate. [Rule 19.704, 40 C.F.R. § 52 Subpart E, and Ark. Code Ann. § 8-4-203 as referenced by Ark. Code Ann. §§ 8-4-304 and 8-4-311]

2. If the permittee fails to start construction within eighteen months or suspends construction for eighteen months or more, the Director may cancel all or part of this permit. [Rule 19.410(B) and 40 C.F.R. § 52 Subpart E]

3. The permittee must test any equipment scheduled for testing, unless otherwise stated in the Specific Conditions of this permit or by any federally regulated requirements, within the following time frames: (1) new equipment or newly modified equipment within sixty (60) days of achieving the maximum production rate, but no later than 180 days after initial start up of the permitted source or (2) operating equipment according to the time frames set forth by the Division of Environmental Quality or within 180 days of permit issuance if no date is specified. The permittee must notify the Division of Environmental Quality of the scheduled date of compliance testing at least fifteen (15) business days in advance of such test. The permittee shall submit the compliance test results to the Division of Environmental Quality within sixty (60) calendar days after completing the testing. [Rule 19.702 and/or Rule 18.1002 and Ark. Code Ann. § 8-4-203 as referenced by Ark. Code Ann. §§ 8-4-304 and 8-4-311]

4. The permittee must provide:

    a. Sampling ports adequate for applicable test methods;
    b. Safe sampling platforms;
    c. Safe access to sampling platforms; and
    d. Utilities for sampling and testing equipment.

    [Rule 19.702 and/or Rule 18.1002 and Ark. Code Ann. § 8-4-203 as referenced by Ark. Code Ann. §§ 8-4-304 and 8-4-311]

5. The permittee must operate the equipment, control apparatus and emission monitoring equipment within the design limitations. The permittee shall maintain the equipment in good condition at all times. [Rule 19.303 and Ark. Code Ann. § 8-4-203 as referenced by Ark. Code Ann. §§ 8-4-304 and 8-4-311]

6. This permit subsumes and incorporates all previously issued air permits for this facility. [Rule 26 and Ark. Code Ann. § 8-4-203 as referenced by Ark. Code Ann. §§ 8-4-304 and 8-4-311]

7. Unless otherwise specified in the permit, approval to construct any new major stationary source or a major modification subject to 40 C.F.R. § 52.21 shall become invalid if construction is not commenced within 18 months after receipt of such approval, if construction is discontinued for a period of 18 months or more, or if construction is not completed within a reasonable time. The Division of Environmental Quality may extend the 18-month period upon a satisfactory showing that an extension is justified. [Rule 19.901 *et seq.* and 40 C.F.R. § 52 Subpart E]

8. The permittee shall install, operate, and maintain ambient air monitors for PM_{10}, $PM_{2.5}$, and NO_2. The permittee shall submit a monitoring protocol to the Department within 180 days of the anticipated startup date of the facility. The Department must approve of the monitoring protocol prior to installation of the monitors. The monitors shall be installed and operating within 180 days of the startup of the EAFs. [Rule 19.901 et seq. and 40 C.F.R. Part 52, Subpart E]

SECTION VII: INSIGNIFICANT ACTIVITIES

The Division of Environmental Quality deems the following types of activities or emissions as insignificant on the basis of size, emission rate, production rate, or activity in accordance with Group A of the Insignificant Activities list found in Rule 18 and Rule 19 Appendix A. Group B insignificant activities may be listed but are not required to be listed in permits. Insignificant activity emission determinations rely upon the information submitted by the permittee in an application dated August 14, 2023. [Rule 26.304 and Ark. Code Ann. § 8-4-203 as referenced by Ark. Code Ann. §§ 8-4-304 and 8-4-311]

Description	Category
Reformer Furnace (PHG830)	A-1
Water Bath Vaporizer	A-1
Tundish Dryer	A-1
Continuous Galvanizing Line Dryer	A-1
Laboratory Test Furnace	A-1
Diesel Fuel Tanks	A-3
Engine Oil Tank	A-3
Steel Cutting	A-7
Railcar Cutting Operation	A-7
Tundish Cutting Operation	A-7
Induced Draft Mechanical Cooling Tower	A-13
Fourteen 22,500 gal HCL tanks	A-13
7,000 and 500 gal Diesel Exhaust Fluid Storage Tank	A-13
Air Products Cooling Towers BRS #1 and #2	A-13

SECTION VIII: GENERAL PROVISIONS

1. Any terms or conditions included in this permit which specify and reference Arkansas Pollution Control & Ecology Commission Rule 18 or the Arkansas Water and Air Pollution Control Act (Ark. Code Ann. § 8-4-101 *et seq.*) as the sole origin of and authority for the terms or conditions are not required under the Clean Air Act or any of its applicable requirements, and are not federally enforceable under the Clean Air Act. Arkansas Pollution Control & Ecology Commission Rule 18 was adopted pursuant to the Arkansas Water and Air Pollution Control Act (Ark. Code Ann. § 8-4-101 *et seq.*). Any terms or conditions included in this permit which specify and reference Arkansas Pollution Control & Ecology Commission Rule 18 or the Arkansas Water and Air Pollution Control Act (Ark. Code Ann. § 8-4-101 *et seq.*) as the origin of and authority for the terms or conditions are enforceable under this Arkansas statute. [40 C.F.R. § 70.6(b)(2)]

2. This permit shall be valid for a period of five (5) years beginning on the date this permit becomes effective and ending five (5) years later. [40 C.F.R. § 70.6(a)(2) and Rule 26.701(B)]

3. The permittee must submit a complete application for permit renewal at least six (6) months before permit expiration. Permit expiration terminates the permittee's right to operate unless the permittee submitted a complete renewal application at least six (6) months before permit expiration. If the permittee submits a complete application, the existing permit will remain in effect until the Division of Environmental Quality takes final action on the renewal application. The Division of Environmental Quality will not necessarily notify the permittee when the permit renewal application is due. [Rule 26.406]

4. Where an applicable requirement of the Clean Air Act, as amended, 42 U.S.C. 7401, *et seq.* (Act) is more stringent than an applicable requirement of regulations promulgated under Title IV of the Act, the permit incorporates both provisions into the permit, and the Director or the Administrator can enforce both provisions. [40 C.F.R. § 70.6(a)(1)(ii) and Rule 26.701(A)(2)]

5. The permittee must maintain the following records of monitoring information as required by this permit.

    a. The date, place as defined in this permit, and time of sampling or measurements;
    b. The date(s) analyses performed;
    c. The company or entity performing the analyses;
    d. The analytical techniques or methods used;
    e. The results of such analyses; and
    f. The operating conditions existing at the time of sampling or measurement.

    [40 C.F.R. § 70.6(a)(3)(ii)(A) and Rule 26.701(C)(2)]

6. The permittee must retain the records of all required monitoring data and support information for at least five (5) years from the date of the monitoring sample, measurement, report, or application. Support information includes all calibration and maintenance records and all original strip chart recordings for continuous monitoring instrumentation, and copies of all reports required by this permit. [40 C.F.R. § 70.6(a)(3)(ii)(B) and Rule 26.701(C)(2)(b)]

7. The permittee must submit reports of all required monitoring every six (6) months. If the permit establishes no other reporting period, the reporting period shall end on the last day of the month six months after the issuance of the initial Title V permit and every six months thereafter. The report is due on the first day of the second month after the end of the reporting period. The first report due after issuance of the initial Title V permit shall contain six months of data and each report thereafter shall contain 12 months of data. The report shall contain data for all monitoring requirements in effect during the reporting period. If a monitoring requirement is not in effect for the entire reporting period, only those months of data in which the monitoring requirement was in effect are required to be reported. The report must clearly identify all instances of deviations from permit requirements. A responsible official as defined in Rule 26.2 must certify all required reports. The permittee will send the reports electronically using https://eportal.adeq.state.ar.us or mail them to the address below:

   Division of Environmental Quality
   Office of Air Quality
   ATTN: Compliance Inspector Supervisor
   5301 Northshore Drive
   North Little Rock, AR 72118-5317

   [40 C.F.R. § 70.6(a)(3)(iii)(A) and Rule 26.701(C)(3)(a)]

8. The permittee shall report to the Division of Environmental Quality all deviations from permit requirements, including those attributable to upset conditions as defined in the permit.

   a. For all upset conditions (as defined in Rule 19.601), the permittee will make an initial report to the Division of Environmental Quality by the next business day after the discovery of the occurrence. The initial report may be made by telephone and shall include:

      i. The facility name and location;
      ii. The process unit or emission source deviating from the permit limit;
      iii. The permit limit, including the identification of pollutants, from which deviation occurs;
      iv. The date and time the deviation started;
      v. The duration of the deviation;

vi. The emissions during the deviation;
vii. The probable cause of such deviations;
viii. Any corrective actions or preventive measures taken or being taken to prevent such deviations in the future; and
ix. The name of the person submitting the report.

The permittee shall make a full report in writing to the Division of Environmental Quality within five (5) business days of discovery of the occurrence. The report must include, in addition to the information required by the initial report, a schedule of actions taken or planned to eliminate future occurrences and/or to minimize the amount the permit's limits were exceeded and to reduce the length of time the limits were exceeded. The permittee may submit a full report in writing (by facsimile, overnight courier, or other means) by the next business day after discovery of the occurrence, and the report will serve as both the initial report and full report.

b. For all deviations, the permittee shall report such events in semi-annual reporting and annual certifications required in this permit. This includes all upset conditions reported in 8a above. The semi-annual report must include all the information as required by the initial and full reports required in 8a.

[Rule 19.601, Rule 19.602, Rule 26.701(C)(3)(b), and 40 C.F.R. § 70.6(a)(3)(iii)(B)]

9. If any provision of the permit or the application thereof to any person or circumstance is held invalid, such invalidity will not affect other provisions or applications hereof which can be given effect without the invalid provision or application, and to this end, provisions of this Rule are declared to be separable and severable. [40 C.F.R. § 70.6(a)(5), Rule 26.701(E), and Ark. Code Ann. § 8-4-203 as referenced by Ark. Code Ann. §§ 8-4-304 and 8-4-311]

10. The permittee must comply with all conditions of this Part 70 permit. Any permit noncompliance with applicable requirements as defined in Rule 26 constitutes a violation of the Clean Air Act, as amended, 42 U.S.C. § 7401, *et seq.* and is grounds for enforcement action; for permit termination, revocation and reissuance, for permit modification; or for denial of a permit renewal application. [40 C.F.R. § 70.6(a)(6)(i) and Rule 26.701(F)(1)]

11. It shall not be a defense for a permittee in an enforcement action that it would have been necessary to halt or reduce the permitted activity to maintain compliance with the conditions of this permit. [40 C.F.R. § 70.6(a)(6)(ii) and Rule 26.701(F)(2)]

12. The Division of Environmental Quality may modify, revoke, reopen and reissue the permit or terminate the permit for cause. The filing of a request by the permittee for a permit modification, revocation and reissuance, termination, or of a notification of planned changes or anticipated noncompliance does not stay any permit condition. [40 C.F.R. § 70.6(a)(6)(iii) and Rule 26.701(F)(3)]

13. This permit does not convey any property rights of any sort, or any exclusive privilege. [40 C.F.R. § 70.6(a)(6)(iv) and Rule 26.701(F)(4)]

14. The permittee must furnish to the Director, within the time specified by the Director, any information that the Director may request in writing to determine whether cause exists for modifying, revoking and reissuing, or terminating the permit or to determine compliance with the permit. Upon request, the permittee must also furnish to the Director copies of records required by the permit. For information the permittee claims confidentiality, the Division of Environmental Quality may require the permittee to furnish such records directly to the Director along with a claim of confidentiality. [40 C.F.R. § 70.6(a)(6)(v) and Rule 26.701(F)(5)]

15. The permittee must pay all permit fees in accordance with the procedures established in Rule 9. [40 C.F.R. § 70.6(a)(7) and Rule 26.701(G)]

16. No permit revision shall be required, under any approved economic incentives, marketable permits, emissions trading and other similar programs or processes for changes provided for elsewhere in this permit. [40 C.F.R. § 70.6(a)(8) and Rule 26.701(H)]

17. If the permit allows different operating scenarios, the permittee shall, contemporaneously with making a change from one operating scenario to another, record in a log at the permitted facility a record of the operational scenario. [40 C.F.R. § 70.6(a)(9)(i) and Rule 26.701(I)(1)]

18. The Administrator and citizens may enforce under the Act all terms and conditions in this permit, including any provisions designed to limit a source's potential to emit, unless the Division of Environmental Quality specifically designates terms and conditions of the permit as being federally unenforceable under the Act or under any of its applicable requirements. [40 C.F.R. § 70.6(b) and Rule 26.702(A) and (B)]

19. Any document (including reports) required by this permit pursuant to 40 C.F.R. § 70 must contain a certification by a responsible official as defined in Rule 26.2. [40 C.F.R. § 70.6(c)(1) and Rule 26.703(A)]

20. The permittee must allow an authorized representative of the Division of Environmental Quality, upon presentation of credentials, to perform the following: [40 C.F.R. § 70.6(c)(2) and Rule 26.703(B)]

    a. Enter upon the permittee's premises where the permitted source is located or emissions related activity is conducted, or where records must be kept under the conditions of this permit;
    b. Have access to and copy, at reasonable times, any records required under the conditions of this permit;

c. Inspect at reasonable times any facilities, equipment (including monitoring and air pollution control equipment), practices, or operations regulated or required under this permit; and
d. As authorized by the Act, sample or monitor at reasonable times substances or parameters for assuring compliance with this permit or applicable requirements.

21. The permittee shall submit a compliance certification with the terms and conditions contained in the permit, including emission limitations, standards, or work practices. The permittee must submit the compliance certification annually. If the permit establishes no other reporting period, the reporting period shall end on the last day of the anniversary month of the initial Title V permit. The report is due on the first day of the second month after the end of the reporting period. The permittee must also submit the compliance certification to the Administrator as well as to the Division of Environmental Quality. All compliance certifications required by this permit must include the following: [40 C.F.R. § 70.6(c)(5) and Rule 26.703(E)(3)]

    a. The identification of each term or condition of the permit that is the basis of the certification;
    b. The compliance status;
    c. Whether compliance was continuous or intermittent;
    d. The method(s) used for determining the compliance status of the source, currently and over the reporting period established by the monitoring requirements of this permit; and
    e. Such other facts as the Division of Environmental Quality may require elsewhere in this permit or by § 114(a)(3) and § 504(b) of the Act.

22. Nothing in this permit will alter or affect the following: [Rule 26.704(C)]

    a. The provisions of Section 303 of the Act (emergency orders), including the authority of the Administrator under that section;
    b. The liability of the permittee for any violation of applicable requirements prior to or at the time of permit issuance;
    c. The applicable requirements of the acid rain program, consistent with § 408(a) of the Act; or
    d. The ability of EPA to obtain information from a source pursuant to § 114 of the Act.

23. This permit authorizes only those pollutant emitting activities addressed in this permit. [Ark. Code Ann. § 8-4-203 as referenced by Ark. Code Ann. §§ 8-4-304 and 8-4-311]

24. The permittee may request in writing and at least 15 days in advance of the deadline, an extension to any testing, compliance or other dates in this permit. No such extensions are authorized until the permittee receives written Division of Environmental Quality approval. The Division of Environmental Quality may grant such a request, at its discretion in the following circumstances:

a. Such an extension does not violate a federal requirement;
b. The permittee demonstrates the need for the extension; and
c. The permittee documents that all reasonable measures have been taken to meet the current deadline and documents reasons it cannot be met.

[Rule 18.314(A), Rule 19.416(A), Rule 26.1013(A), Ark. Code Ann. § 8-4-203 as referenced by Ark. Code Ann. §§ 8-4-304 and 8-4-311, and 40 C.F.R. § 52 Subpart E]

25. The permittee may request in writing and at least 30 days in advance, temporary emissions and/or testing that would otherwise exceed an emission rate, throughput requirement, or other limit in this permit. No such activities are authorized until the permittee receives written Division of Environmental Quality approval. Any such emissions shall be included in the facility's total emissions and reported as such. The Division of Environmental Quality may grant such a request, at its discretion under the following conditions:

a. Such a request does not violate a federal requirement;
b. Such a request is temporary in nature;
c. Such a request will not result in a condition of air pollution;
d. The request contains such information necessary for the Division of Environmental Quality to evaluate the request, including but not limited to, quantification of such emissions and the date/time such emission will occur;
e. Such a request will result in increased emissions less than five tons of any individual criteria pollutant, one ton of any single HAP and 2.5 tons of total HAPs; and
f. The permittee maintains records of the dates and results of such temporary emissions/testing.

[Rule 18.314(B), Rule 19.416(B), Rule 26.1013(B), Ark. Code Ann. § 8-4-203 as referenced by Ark. Code Ann. §§ 8-4-304 and 8-4-311, and 40 C.F.R. § 52 Subpart E]

26. The permittee may request in writing and at least 30 days in advance, an alternative to the specified monitoring in this permit. No such alternatives are authorized until the permittee receives written Division of Environmental Quality approval. The Division of Environmental Quality may grant such a request, at its discretion under the following conditions:

a. The request does not violate a federal requirement;
b. The request provides an equivalent or greater degree of actual monitoring to the current requirements; and
c. Any such request, if approved, is incorporated in the next permit modification application by the permittee.

[Rule 18.314(C), Rule 19.416(C), Rule 26.1013(C), Ark. Code Ann. § 8-4-203 as referenced by Ark. Code Ann. §§ 8-4-304 and 8-4-311, and 40 C.F.R. § 52 Subpart E]

27. Any credible evidence based on sampling, monitoring, and reporting may be used to determine violations of applicable emission limitations. [Rule 18.1001, Rule 19.701, Ark. Code Ann. § 8-4-203 as referenced by Ark. Code Ann. §§ 8-4-304 and 8-4-311, and 40 C.F.R. § 52 Subpart E]

Appendix A

40 C.F.R. Part 60 Subpart Dc

Standards of Performance for Small Industrial-Commercial-Institutional Steam Generating Units

Subpart Dc—Standards of Performance for Small Industrial-Commercial-Institutional Steam Generating Units

Contents

SOURCE: 72 FR 32759, June 13, 2007, unless otherwise noted.

Back to Top

§60.40c Applicability and delegation of authority.

(a) Except as provided in paragraphs (d), (e), (f), and (g) of this section, the affected facility to which this subpart applies is each steam generating unit for which construction, modification, or reconstruction is commenced after June 9, 1989 and that has a maximum design heat input capacity of 29 megawatts (MW) (100 million British thermal units per hour (MMBtu/h)) or less, but greater than or equal to 2.9 MW (10 MMBtu/h).

(b) In delegating implementation and enforcement authority to a State under section 111(c) of the Clean Air Act, §60.48c(a)(4) shall be retained by the Administrator and not transferred to a State.

(c) Steam generating units that meet the applicability requirements in paragraph (a) of this section are not subject to the sulfur dioxide (SO_2) or particulate matter (PM) emission limits, performance testing requirements, or monitoring requirements under this subpart (§§60.42c, 60.43c, 60.44c, 60.45c, 60.46c, or 60.47c) during periods of combustion research, as defined in §60.41c.

(d) Any temporary change to an existing steam generating unit for the purpose of conducting combustion research is not considered a modification under §60.14.

(e) Affected facilities (*i.e.* heat recovery steam generators and fuel heaters) that are associated with stationary combustion turbines and meet the applicability requirements of subpart KKKK of this part are not subject to this subpart. This subpart will continue to apply to all other heat recovery steam generators, fuel heaters, and other affected facilities that are capable of combusting more than or equal to 2.9 MW (10 MMBtu/h) heat input of fossil fuel but less than or equal to 29 MW (100 MMBtu/h) heat input of fossil fuel. If the heat recovery steam generator, fuel heater, or other affected facility is subject to this subpart, only emissions resulting from combustion of fuels in the steam generating unit are subject to this subpart. (The stationary combustion turbine emissions are subject to subpart GG or KKKK, as applicable, of this part.)

(f) Any affected facility that meets the applicability requirements of and is subject to subpart AAAA or subpart CCCC of this part is not subject to this subpart.

(g) Any facility that meets the applicability requirements and is subject to an EPA approved State or Federal section 111(d)/129 plan implementing subpart BBBB of this part is not subject to this subpart.

(h) Affected facilities that also meet the applicability requirements under subpart J or subpart Ja of this part are subject to the PM and NO_X standards under this subpart and the SO_2 standards under subpart J or subpart Ja of this part, as applicable.

(i) Temporary boilers are not subject to this subpart.

[72 FR 32759, June 13, 2007, as amended at 74 FR 5090, Jan. 28, 2009; 77 FR 9461, Feb. 16, 2012]

Back to Top

§60.41c Definitions.

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

Annual capacity factor means the ratio between the actual heat input to a steam generating unit from an individual fuel or combination of fuels during a period of 12 consecutive calendar months and the potential heat input to the steam generating unit from all fuels had the steam generating unit been operated for 8,760 hours during that 12-month period at the maximum design heat input capacity. In the case of steam generating units that are rented or leased, the actual heat input shall be determined based on the combined heat input from all operations of the affected facility during a period of 12 consecutive calendar months.

Coal means all solid fuels classified as anthracite, bituminous, subbituminous, or lignite by the American Society of Testing and Materials in ASTM D388 (incorporated by reference, see §60.17), coal refuse, and petroleum coke. Coal-derived synthetic fuels derived from coal for the purposes of creating useful heat, including but not limited to solvent refined coal, gasified coal not meeting the definition of natural gas, coal-oil mixtures, and coal-water mixtures, are also included in this definition for the purposes of this subpart.

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 (kJ/kg) (6,000 Btu per pound (Btu/lb) on a dry basis.

Combined cycle system means a system in which a separate source (such as a stationary gas turbine, internal combustion engine, or kiln) provides exhaust gas to a steam generating unit.

Combustion research means the experimental firing of any fuel or combination of fuels in a steam generating unit for the purpose of conducting research and development of more efficient combustion or more effective prevention or control of air pollutant emissions from combustion, provided that, during these periods of research and development, the heat generated is not used for any purpose other than preheating combustion air for use by that steam generating unit (*i.e.*, the heat generated is released to the atmosphere without being used for space heating, process heating, driving pumps, preheating combustion air for other units, generating electricity, or any other purpose).

Conventional technology means wet flue gas desulfurization technology, dry flue gas desulfurization technology, atmospheric fluidized bed combustion technology, and oil hydrodesulfurization technology.

Distillate oil means fuel oil that complies with the specifications for fuel oil numbers 1 or 2, as defined by the American Society for Testing and Materials in ASTM D396 (incorporated by reference, see §60.17), diesel fuel oil numbers 1 or 2, as defined by the American Society for Testing and Materials in ASTM D975 (incorporated by reference, see §60.17), kerosine, as defined by the American Society of Testing and Materials in ASTM D3699 (incorporated by reference, see §60.17), biodiesel as defined by the American Society of Testing and Materials in ASTM D6751 (incorporated by reference, see §60.17), or biodiesel blends as defined by the American Society of Testing and Materials in ASTM D7467 (incorporated by reference, see §60.17).

Dry flue gas desulfurization technology means a SO_2 control system that is located between the steam generating unit and the exhaust vent or stack, and that removes sulfur oxides from the combustion gases of the steam generating unit by contacting the combustion gases with an alkaline reagent and water, whether introduced separately or as a premixed slurry or solution and forming a dry powder material. This definition includes devices where the dry powder material is subsequently converted to another form. Alkaline reagents used in dry flue gas desulfurization systems include, but are not limited to, lime and sodium compounds.

Duct burner means a device that combusts fuel and that is placed in the exhaust duct from another source (such as a stationary gas turbine, internal combustion engine, kiln, etc.) to allow the firing of additional fuel to heat the exhaust gases before the exhaust gases enter a steam generating unit.

Emerging technology means any SO_2 control system that is not defined as a conventional technology under this section, and for which the owner or operator of the affected facility has received approval from the Administrator to operate as an emerging technology under §60.48c(a)(4).

Federally enforceable means all limitations and conditions that are enforceable by the Administrator, including the requirements of 40 CFR parts 60 and 61, requirements within any applicable State implementation plan, and any permit requirements established under 40 CFR 52.21 or under 40 CFR 51.18 and 51.24.

Fluidized bed combustion technology means a device wherein fuel is distributed onto a bed (or series of beds) of limestone aggregate (or other sorbent materials) for combustion; and these materials are forced upward in the device by the flow of combustion air and the gaseous products of combustion. Fluidized bed combustion technology includes, but is not limited to, bubbling bed units and circulating bed units.

Fuel pretreatment means a process that removes a portion of the sulfur in a fuel before combustion of the fuel in a steam generating unit.

Heat input means heat derived from combustion of fuel in a steam generating unit and does not include the heat derived from preheated combustion air, recirculated flue gases, or exhaust gases from other sources (such as stationary gas turbines, internal combustion engines, and kilns).

Heat transfer medium means any material that is used to transfer heat from one point to another point.

Maximum design heat input capacity means the ability of a steam generating unit to combust a stated maximum amount of fuel (or combination of fuels) on a steady state basis as determined by the physical design and characteristics of the steam generating unit.

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 (LP) gas, as defined by the American Society for Testing and Materials in ASTM D1835 (incorporated by reference, see §60.17); or

(3) A mixture of hydrocarbons that maintains a gaseous state at ISO conditions. Additionally, natural gas must either be composed of at least 70 percent methane by volume or have a gross calorific value between 34 and 43 megajoules (MJ) per dry standard cubic meter (910 and 1,150 Btu per dry standard cubic foot).

Noncontinental area means the State of Hawaii, the Virgin Islands, Guam, American Samoa, the Commonwealth of Puerto Rico, or the Northern Mariana Islands.

Oil means crude oil or petroleum, or a liquid fuel derived from crude oil or petroleum, including distillate oil and residual oil.

Potential sulfur dioxide emission rate means the theoretical SO_2 emissions (nanograms per joule (ng/J) or lb/MMBtu heat input) that would result from combusting fuel in an uncleaned state and without using emission control systems.

Process heater means a device that is primarily used to heat a material to initiate or promote a chemical reaction in which the material participates as a reactant or catalyst.

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 for Testing and Materials in ASTM D396 (incorporated by reference, see §60.17).

Steam generating unit means a device that combusts any fuel and produces steam or heats water or heats any heat transfer medium. This term includes any duct burner that combusts fuel and is part of a combined cycle system. This term does not include process heaters as defined in this subpart.

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

Temporary boiler means a steam generating unit that combusts natural gas or distillate oil with a potential SO_2emissions rate no greater than 26 ng/J (0.060 lb/MMBtu), and the unit 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 steam generating unit is not a temporary boiler if any one of the following conditions exists:

(1) The equipment is attached to a foundation.

(2) The steam generating unit or a replacement remains at a location for more than 180 consecutive days. 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 in an attempt to circumvent the residence time requirements of this definition.

Wet flue gas desulfurization technology means an SO_2 control system that is located between the steam generating unit and the exhaust vent or stack, and that removes sulfur oxides from the combustion gases of the steam generating unit by contacting the combustion gases with an alkaline slurry or solution and forming a liquid material. This definition includes devices where the liquid material is subsequently converted to another form. Alkaline reagents used in wet flue gas desulfurization systems include, but are not limited to, lime, limestone, and sodium compounds.

Wet scrubber system means any emission control device that mixes an aqueous stream or slurry with the exhaust gases from a steam generating unit to control emissions of PM or SO_2.

Wood means wood, wood residue, bark, or any derivative fuel or residue thereof, in any form, including but not limited to sawdust, sanderdust, wood chips, scraps, slabs, millings, shavings, and processed pellets made from wood or other forest residues.

[72 FR 32759, June 13, 2007, as amended at 74 FR 5090, Jan. 28, 2009; 77 FR 9461, Feb. 16, 2012]

Back to Top

§60.42c Standard for sulfur dioxide (SO_2).

(a) Except as provided in paragraphs (b), (c), and (e) of this section, on and after the date on which the performance test is completed or required to be completed under §60.8, whichever date comes first, the owner or operator of an affected facility that combusts only coal shall neither: cause to be discharged into the atmosphere from the affected facility any gases that contain SO_2 in excess of 87 ng/J (0.20 lb/MMBtu) heat input or 10 percent (0.10) of the potential SO_2 emission rate (90 percent reduction), nor cause to be discharged into the atmosphere from the affected facility any gases that contain SO_2 in excess of 520 ng/J (1.2 lb/MMBtu) heat input. If coal is combusted with other fuels, the affected facility shall neither: cause to be discharged into the atmosphere from the affected facility any gases that contain SO_2 in excess of 87 ng/J (0.20 lb/MMBtu) heat input or 10 percent (0.10) of the potential SO_2 emission rate (90 percent reduction), nor cause to be discharged into the atmosphere from the affected facility any gases that contain SO_2in excess of the emission limit is determined pursuant to paragraph (e)(2) of this section.

(b) Except as provided in paragraphs (c) and (e) of this section, on and after the date on which the performance test is completed or required to be completed under §60.8, whichever date comes first, the owner or operator of an affected facility that:

(1) Combusts only coal refuse alone in a fluidized bed combustion steam generating unit shall neither:

(i) Cause to be discharged into the atmosphere from that affected facility any gases that contain SO_2 in excess of 87 ng/J (0.20 lb/MMBtu) heat input or 20 percent (0.20) of the potential SO_2 emission rate (80 percent reduction); nor

(ii) Cause to be discharged into the atmosphere from that affected facility any gases that contain SO_2 in excess of SO_2 in excess of 520 ng/J (1.2 lb/MMBtu) heat input. If coal is fired with coal refuse, the affected facility subject to paragraph (a) of this section. If oil or any other fuel (except coal) is fired with coal refuse, the affected facility is subject to the 87 ng/J (0.20 lb/MMBtu) heat input SO_2 emissions limit or the 90 percent SO_2 reduction requirement specified in paragraph (a) of this section and the emission limit is determined pursuant to paragraph (e)(2) of this section.

(2) Combusts only coal and that uses an emerging technology for the control of SO_2 emissions shall neither:

(i) Cause to be discharged into the atmosphere from that affected facility any gases that contain SO_2 in excess of 50 percent (0.50) of the potential SO_2 emission rate (50 percent reduction); nor

(ii) Cause to be discharged into the atmosphere from that affected facility any gases that contain SO_2 in excess of 260 ng/J (0.60 lb/MMBtu) heat input. If coal is combusted with other fuels, the affected facility is subject to the 50 percent SO_2 reduction requirement specified in this paragraph and the emission limit determined pursuant to paragraph (e)(2) of this section.

(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 of an affected facility that combusts coal, alone or in combination with any other fuel, and is listed in paragraphs (c)(1), (2), (3), or (4) of this section shall cause to be discharged into the atmosphere from that affected facility any gases that contain SO_2 in excess of the emission limit determined pursuant to paragraph (e)(2) of this section. Percent reduction requirements are not applicable to affected facilities under paragraphs (c)(1), (2), (3), or (4).

(1) Affected facilities that have a heat input capacity of 22 MW (75 MMBtu/h) or less;

(2) Affected facilities that have an annual capacity for coal of 55 percent (0.55) or less and are subject to a federally enforceable requirement limiting operation of the affected facility to an annual capacity factor for coal of 55 percent (0.55) or less.

(3) Affected facilities located in a noncontinental area; or

(4) Affected facilities that combust coal in a duct burner as part of a combined cycle system where 30 percent (0.30) or less of the heat entering the steam generating unit is from combustion of coal in the duct burner and 70 percent (0.70) or more of the heat entering the steam generating unit is from exhaust gases entering the duct burner.

(d) On and after the date on which the initial performance test is completed or required to be completed under §60.8, whichever date comes first, no owner or operator of an affected facility that combusts oil shall cause to be discharged into the atmosphere from that affected facility any gases that contain SO_2 in excess of 215 ng/J (0.50 lb/MMBtu) heat input from oil; or, as an alternative, no owner or operator of an affected facility that combusts oil shall combust oil in the affected facility that contains greater than 0.5 weight percent sulfur. The percent reduction requirements are not applicable to affected facilities under this paragraph.

(e) On and after the date on which the initial performance test is completed or required to be completed under §60.8, whichever date comes first, no owner or operator of an affected facility that combusts coal, oil, or coal and oil with any other fuel shall cause to be discharged into the atmosphere from that affected facility any gases that contain SO_2 in excess of the following:

(1) The percent of potential SO_2 emission rate or numerical SO_2 emission rate required under paragraph (a) or (b)(2) of this section, as applicable, for any affected facility that

(i) Combusts coal in combination with any other fuel;

(ii) Has a heat input capacity greater than 22 MW (75 MMBtu/h); and

(iii) Has an annual capacity factor for coal greater than 55 percent (0.55); and

(2) The emission limit determined according to the following formula for any affected facility that combusts coal, oil, or coal and oil with any other fuel:

$$E_s = \frac{(K_a H_a + K_b H_b + K_c H_c)}{(H_a + H_b + H_c)}$$

View or download PDF

Where:

E_s = SO_2 emission limit, expressed in ng/J or lb/MMBtu heat input;

K_a = 520 ng/J (1.2 lb/MMBtu);

K_b = 260 ng/J (0.60 lb/MMBtu);

K_c = 215 ng/J (0.50 lb/MMBtu);

H_a = Heat input from the combustion of coal, except coal combusted in an affected facility subject to paragraph (b)(2) of this section, in Joules (J) [MMBtu];

H_b = Heat input from the combustion of coal in an affected facility subject to paragraph (b)(2) of this section, in J (MMBtu); and

H_c = Heat input from the combustion of oil, in J (MMBtu).

(f) Reduction in the potential SO_2 emission rate through fuel pretreatment is not credited toward the percent reduction requirement under paragraph (b)(2) of this section unless:

(1) Fuel pretreatment results in a 50 percent (0.50) or greater reduction in the potential SO_2 emission rate; and

(2) Emissions from the pretreated fuel (without either combustion or post-combustion SO_2 control) are equal to or less than the emission limits specified under paragraph (b)(2) of this section.

(g) Except as provided in paragraph (h) of this section, compliance with the percent reduction requirements, fuel oil sulfur limits, and emission limits of this section shall be determined on a 30-day rolling average basis.

(h) For affected facilities listed under paragraphs (h)(1), (2), (3), or (4) of this section, compliance with the emission limits or fuel oil sulfur limits under this section may be determined based on a certification from the fuel supplier, as described under §60.48c(f), as applicable.

(1) Distillate oil-fired affected facilities with heat input capacities between 2.9 and 29 MW (10 and 100 MMBtu/hr).

(2) Residual oil-fired affected facilities with heat input capacities between 2.9 and 8.7 MW (10 and 30 MMBtu/hr).

(3) Coal-fired affected facilities with heat input capacities between 2.9 and 8.7 MW (10 and 30 MMBtu/h).

(4) Other fuels-fired affected facilities with heat input capacities between 2.9 and 8.7 MW (10 and 30 MMBtu/h).

(i) The SO_2 emission limits, fuel oil sulfur limits, and percent reduction requirements under this section apply at all times, including periods of startup, shutdown, and malfunction.

(j) For affected facilities located in noncontinental areas and affected facilities complying with the percent reduction standard, only the heat input supplied to the affected facility from the combustion of coal and oil is counted under this section. No credit is provided for the heat input to the affected facility from wood or other fuels or for heat derived from exhaust gases from other sources, such as stationary gas turbines, internal combustion engines, and kilns.

[72 FR 32759, June 13, 2007, as amended at 74 FR 5090, Jan. 28, 2009; 77 FR 9462, Feb. 16, 2012]

Back to Top

§60.43c Standard for particulate matter (PM).

(a) On and after the date on which the initial performance test is completed or required to be completed under §60.8, whichever date comes first, no owner or operator of an affected facility that commenced construction, reconstruction, or modification on or before February 28, 2005, that combusts coal or combusts mixtures of coal with other fuels and has a heat input capacity of 8.7 MW (30 MMBtu/h) or greater, shall cause to be discharged into the atmosphere from that affected facility any gases that contain PM in excess of the following emission limits:

(1) 22 ng/J (0.051 lb/MMBtu) heat input if the affected facility combusts only coal, or combusts coal with other fuels and has an annual capacity factor for the other fuels of 10 percent (0.10) or less.

(2) 43 ng/J (0.10 lb/MMBtu) heat input if the affected facility combusts coal with other fuels, has an annual capacity factor for the other fuels greater than 10 percent (0.10), and is subject to a federally enforceable requirement limiting operation of the affected facility to an annual capacity factor greater than 10 percent (0.10) for fuels other than coal.

(b) On and after the date on which the initial performance test is completed or required to be completed under §60.8, whichever date comes first, no owner or operator of an affected facility that commenced construction, reconstruction, or modification on or before February 28, 2005, that combusts wood or combusts mixtures of wood with other fuels (except coal) and has a heat input capacity of 8.7 MW (30 MMBtu/h) or greater, shall cause to be discharged into the atmosphere from that affected facility any gases that contain PM in excess of the following emissions limits:

(1) 43 ng/J (0.10 lb/MMBtu) heat input if the affected facility has an annual capacity factor for wood greater than 30 percent (0.30); or

(2) 130 ng/J (0.30 lb/MMBtu) heat input if the affected facility has an annual capacity factor for wood of 30 percent (0.30) or less and is subject to a federally enforceable requirement limiting operation of the affected facility to an annual capacity factor for wood of 30 percent (0.30) or less.

(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 of an affected facility that combusts coal, wood, or oil and has a heat input capacity of 8.7 MW (30 MMBtu/h) or greater shall cause to be discharged into the atmosphere from that affected facility any gases that exhibit greater than 20 percent opacity (6-minute average), except for one 6-minute period per hour of not more than 27 percent opacity. Owners and operators of an affected facility that elect to install, calibrate, maintain, and operate a continuous emissions monitoring system (CEMS) for measuring PM emissions according to the requirements of this subpart and are subject to a federally enforceable PM limit of 0.030 lb/MMBtu or less are exempt from the opacity standard specified in this paragraph (c).

(d) The PM and opacity standards under this section apply at all times, except during periods of startup, shutdown, or malfunction.

(e)(1) On and after the date on which the initial performance test is completed or is required to be completed under §60.8, whichever date comes first, no owner or operator of an affected facility that commences construction, reconstruction, or modification after February 28, 2005, and that combusts coal, oil, wood, a mixture of these fuels, or a mixture of these fuels with any other fuels and has a heat input capacity of 8.7 MW (30 MMBtu/h) or greater shall cause to be discharged into the atmosphere from that affected facility any gases that contain PM in excess of 13 ng/J (0.030 lb/MMBtu) heat input, except as provided in paragraphs (e)(2), (e)(3), and (e)(4) of this section.

(2) As an alternative to meeting the requirements of paragraph (e)(1) of this section, the owner or operator of an affected facility for which modification commenced after February 28, 2005, may elect to meet the requirements of this paragraph. On and after the date on which the initial performance test is completed or required to be completed under §60.8, whichever date comes first, no owner or operator of an affected facility that commences modification after February 28, 2005 shall cause to be discharged into the atmosphere from that affected facility any gases that contain PM in excess of both:

(i) 22 ng/J (0.051 lb/MMBtu) heat input derived from the combustion of coal, oil, wood, a mixture of these fuels, or a mixture of these fuels with any other fuels; and

(ii) 0.2 percent of the combustion concentration (99.8 percent reduction) when combusting coal, oil, wood, a mixture of these fuels, or a mixture of these fuels with any other fuels.

(3) On and after the date on which the initial performance test is completed or is required to be completed under §60.8, whichever date comes first, no owner or operator of an affected facility that commences modification after February 28, 2005, and that combusts over 30 percent wood (by heat input) on an annual basis and has a heat input capacity of 8.7 MW (30 MMBtu/h) or greater shall cause to be discharged into the atmosphere from that affected facility any gases that contain PM in excess of 43 ng/J (0.10 lb/MMBtu) heat input.

(4) An owner or operator of an affected facility that commences construction, reconstruction, or modification after February 28, 2005, and that combusts only oil that contains no more than 0.50 weight percent sulfur or a mixture of 0.50 weight percent sulfur oil with other fuels not subject to a PM standard under §60.43c and not using a post-combustion technology (except a wet scrubber) to reduce PM or SO_2 emissions is not subject to the PM limit in this section.

[72 FR 32759, June 13, 2007, as amended at 74 FR 5091, Jan. 28, 2009; 77 FR 9462, Feb. 16, 2012]

Back to Top

§60.44c Compliance and performance test methods and procedures for sulfur dioxide.

(a) Except as provided in paragraphs (g) and (h) of this section and §60.8(b), performance tests required under §60.8 shall be conducted following the procedures specified in paragraphs (b), (c), (d), (e), and (f) of this section, as applicable. Section 60.8(f) does not apply to this section. The 30-day notice required in §60.8(d) applies only to the initial performance test unless otherwise specified by the Administrator.

(b) The initial performance test required under §60.8 shall be conducted over 30 consecutive operating days of the steam generating unit. Compliance with the percent reduction requirements and SO_2 emission limits under §60.42c shall be determined using a 30-day average. The first operating day included in the initial performance test shall be scheduled within 30 days after achieving the maximum production rate at which the affect facility will be operated, but not later than 180 days after the initial startup of the facility. The steam generating unit load during the 30-day period does not have to be the maximum design heat input capacity, but must be representative of future operating conditions.

(c) After the initial performance test required under paragraph (b) of this section and §60.8, compliance with the percent reduction requirements and SO_2 emission limits under §60.42c is based on the average percent reduction and the average SO_2 emission rates for 30 consecutive steam generating unit operating days. A separate performance test is completed at the end of each steam generating unit operating day, and a new 30-day average percent reduction and SO_2emission rate are calculated to show compliance with the standard.

(d) If only coal, only oil, or a mixture of coal and oil is combusted in an affected facility, the procedures in Method 19 of appendix A of this part are used to determine the hourly SO_2 emission rate (E_{ho}) and the 30-day average SO_2 emission rate (E_{ao}). The hourly averages used to compute the 30-day averages are obtained from the CEMS. Method 19 of appendix A of this part shall be used to calculate E_{ao} when using daily fuel sampling or Method 6B of appendix A of this part.

(e) If coal, oil, or coal and oil are combusted with other fuels:

(1) An adjusted E_{ho} ($E_{ho}o$) is used in Equation 19-19 of Method 19 of appendix A of this part to compute the adjusted E_{ao} ($E_{ao}o$). The $E_{ho}o$ is computed using the following formula:

$$E_{ho}o = \frac{E_{ho} - E_w(1 - X_k)}{X_k}$$

View or download PDF

Where:

$E_{ho}o$ = Adjusted E_{ho}, ng/J (lb/MMBtu);

E_{ho} = Hourly SO_2 emission rate, ng/J (lb/MMBtu);

E_w = SO_2 concentration in fuels other than coal and oil combusted in the affected facility, as determined by fuel sampling and analysis procedures in Method 9 of appendix A of this part, ng/J (lb/MMBtu). The value E_w for each fuel lot is used for each hourly average during the time that the lot is being combusted. The owner or operator does not have to measure E_w if the owner or operator elects to assume E_w = 0.

X_k = Fraction of the total heat input from fuel combustion derived from coal and oil, as determined by applicable procedures in Method 19 of appendix A of this part.

(2) The owner or operator of an affected facility that qualifies under the provisions of §60.42c(c) or (d) (where percent reduction is not required) does not have to measure the parameters E_w or X_k if the owner or operator of the affected facility elects to measure emission rates of the coal or oil using the fuel sampling and analysis procedures under Method 19 of appendix A of this part.

(f) Affected facilities subject to the percent reduction requirements under §60.42c(a) or (b) shall determine compliance with the SO_2 emission limits under §60.42c pursuant to paragraphs (d) or (e) of this section, and shall determine compliance with the percent reduction requirements using the following procedures:

(1) If only coal is combusted, the percent of potential SO_2 emission rate is computed using the following formula:

$$\%P_s = 100\left(1 - \frac{\%R_g}{100}\right)\left(1 - \frac{\%R_f}{100}\right)$$

View or download PDF

Where:

$\%P_s$ = Potential SO_2 emission rate, in percent;

$\%R_g$ = SO_2 removal efficiency of the control device as determined by Method 19 of appendix A of this part, in percent; and

$\%R_f$ = SO_2 removal efficiency of fuel pretreatment as determined by Method 19 of appendix A of this part, in percent.

(2) If coal, oil, or coal and oil are combusted with other fuels, the same procedures required in paragraph (f)(1) of this section are used, except as provided for in the following:

(i) To compute the $\%P_s$, an adjusted $\%R_g$ ($\%R_go$) is computed from $E_{ao}o$ from paragraph (e)(1) of this section and an adjusted average SO_2 inlet rate ($E_{ai}o$) using the following formula:

$$\%R_go = 100\left(1 - \frac{E_{ao}^{o}}{E_{ai}^{o}}\right)$$

View or download PDF

Where:

$\%R_go$ = Adjusted $\%R_g$, in percent;

$E_{ao}o$ = Adjusted E_{ao}, ng/J (lb/MMBtu); and

$E_{ai}o$ = Adjusted average SO_2 inlet rate, ng/J (lb/MMBtu).

(ii) To compute $E_{ai}o$, an adjusted hourly SO_2 inlet rate ($E_{hi}o$) is used. The $E_{hi}o$ is computed using the following formula:

$$E_{hi}o = \frac{E_{hi} - E_w(1 - X_1)}{X_1}$$

View or download PDF

Where:

$E_{hi}o$ = Adjusted E_{hi}, ng/J (lb/MMBtu);

E_{hi} = Hourly SO_2 inlet rate, ng/J (lb/MMBtu);

E_w = SO_2 concentration in fuels other than coal and oil combusted in the affected facility, as determined by fuel sampling and analysis procedures in Method 19 of appendix A of this part, ng/J (lb/MMBtu). The value E_w for each fuel lot is used for each hourly average during the time that the lot is being combusted. The owner or operator does not have to measure E_w if the owner or operator elects to assume E_w = 0; and

X_k = Fraction of the total heat input from fuel combustion derived from coal and oil, as determined by applicable procedures in Method 19 of appendix A of this part.

(g) For oil-fired affected facilities where the owner or operator seeks to demonstrate compliance with the fuel oil sulfur limits under §60.42c based on shipment fuel sampling, the initial performance test shall consist of sampling and analyzing the oil in the initial tank of oil to be fired in the steam generating unit to demonstrate that the oil contains 0.5 weight percent sulfur or less. Thereafter, the owner or operator of the affected facility shall sample the oil in the fuel tank after each new shipment of oil is received, as described under §60.46c(d)(2).

(h) For affected facilities subject to §60.42c(h)(1), (2), or (3) where the owner or operator seeks to demonstrate compliance with the SO_2 standards based on fuel supplier certification, the performance test shall consist of the certification from the fuel supplier, as described in §60.48c(f), as applicable.

(i) The owner or operator of an affected facility seeking to demonstrate compliance with the SO_2 standards under §60.42c(c)(2) shall demonstrate the maximum design heat input capacity of the steam generating unit by operating the steam generating unit at this capacity for 24 hours. This demonstration shall be made during the initial performance test, and a subsequent demonstration may be requested at any other time. If the demonstrated 24-hour average firing rate for the affected facility is less than the maximum design heat input capacity stated by the manufacturer of the affected facility, the demonstrated 24-hour average firing rate shall be used to determine the annual capacity factor for the affected facility; otherwise, the maximum design heat input capacity provided by the manufacturer shall be used.

(j) The owner or operator of an affected facility shall use all valid SO_2 emissions data in calculating $\%P_s$ and E_{ho} under paragraphs (d), (e), or (f) of this section, as applicable, whether or not the minimum emissions data requirements under §60.46c(f) are achieved. All valid emissions data, including valid data collected during periods of startup, shutdown, and malfunction, shall be used in calculating $\%P_s$ or E_{ho} pursuant to paragraphs (d), (e), or (f) of this section, as applicable.

[72 FR 32759, June 13, 2007, as amended at 74 FR 5091, Jan. 28, 2009]

Back to Top

§60.45c Compliance and performance test methods and procedures for particulate matter.

(a) The owner or operator of an affected facility subject to the PM and/or opacity standards under §60.43c shall conduct an initial performance test as required under §60.8, and shall conduct subsequent performance tests as requested by the Administrator, to determine compliance with the standards using the following procedures and reference methods, except as specified in paragraph (c) of this section.

(1) Method 1 of appendix A of this part shall be used to select the sampling site and the number of traverse sampling points.

(2) Method 3A or 3B of appendix A-2 of this part shall be used for gas analysis when applying Method 5 or 5B of appendix A-3 of this part or 17 of appendix A-6 of this part.

(3) Method 5, 5B, or 17 of appendix A of this part shall be used to measure the concentration of PM as follows:

(i) Method 5 of appendix A of this part may be used only at affected facilities without wet scrubber systems.

(ii) Method 17 of appendix A of this part may be used at affected facilities with or without wet scrubber systems provided the stack gas temperature does not exceed a temperature of 160 °C (320 °F). The procedures of Sections 8.1 and 11.1 of Method 5B of appendix A of this part may be used in Method 17 of appendix A of this part only if Method 17 of appendix A of this part is used in conjunction with a wet scrubber system. Method 17 of appendix A of this part shall not be used in conjunction with a wet scrubber system if the effluent is saturated or laden with water droplets.

(iii) Method 5B of appendix A of this part may be used in conjunction with a wet scrubber system.

(4) The sampling time for each run shall be at least 120 minutes and the minimum sampling volume shall be 1.7 dry standard cubic meters (dscm) [60 dry standard cubic feet (dscf)] except that smaller sampling times or volumes may be approved by the Administrator when necessitated by process variables or other factors.

(5) For Method 5 or 5B of appendix A of this part, the temperature of the sample gas in the probe and filter holder shall be monitored and maintained at 160 ±14 °C (320±25 °F).

(6) For determination of PM emissions, an oxygen (O_2) or carbon dioxide (CO_2) measurement shall be obtained simultaneously with each run of Method 5, 5B, or 17 of appendix A of this part by traversing the duct at the same sampling location.

(7) For each run using Method 5, 5B, or 17 of appendix A of this part, the emission rates expressed in ng/J (lb/MMBtu) heat input shall be determined using:

(i) The O_2 or CO_2 measurements and PM measurements obtained under this section, (ii) The dry basis F factor, and

(iii) The dry basis emission rate calculation procedure contained in Method 19 of appendix A of this part.

(8) Method 9 of appendix A-4 of this part shall be used for determining the opacity of stack emissions.

(b) The owner or operator of an affected facility seeking to demonstrate compliance with the PM standards under §60.43c(b)(2) shall demonstrate the maximum design heat input capacity of the steam generating unit by operating the steam generating unit at this capacity for 24 hours. This demonstration shall be made during the initial performance test, and a subsequent demonstration may be requested at any other time. If the demonstrated 24-hour average firing rate for the affected facility is less than the maximum design heat input capacity stated by the manufacturer of the affected facility, the demonstrated 24-hour average firing rate shall be used to determine the annual capacity factor for the affected facility; otherwise, the maximum design heat input capacity provided by the manufacturer shall be used.

(c) In place of PM testing with Method 5 or 5B of appendix A-3 of this part or Method 17 of appendix A-6 of this part, an owner or operator may elect to install, calibrate, maintain, and operate a CEMS for monitoring PM emissions discharged to the atmosphere and record the output of the system. The owner or operator of an affected facility who elects to continuously monitor PM emissions instead of conducting performance testing using Method 5 or 5B of appendix A-3 of this part or Method 17 of appendix A-6 of this part shall install, calibrate, maintain, and operate a CEMS and shall comply with the requirements specified in paragraphs (c)(1) through (c)(14) of this section.

(1) Notify the Administrator 1 month before starting use of the system.

(2) Notify the Administrator 1 month before stopping use of the system.

(3) The monitor shall be installed, evaluated, and operated in accordance with §60.13 of subpart A of this part.

(4) The initial performance evaluation shall be completed no later than 180 days after the date of initial startup of the affected facility, as specified under §60.8 of subpart A of this part or within 180 days of notification to the Administrator of use of CEMS if the owner or operator was previously determining compliance by Method 5, 5B, or 17 of appendix A of this part performance tests, whichever is later.

(5) The owner or operator of an affected facility shall conduct an initial performance test for PM emissions as required under §60.8 of subpart A of this part. Compliance with the PM emission limit shall be determined by using the CEMS specified in paragraph (d) of this section to measure PM and calculating a 24-hour block arithmetic average emission concentration using EPA Reference Method 19 of appendix A of this part, section 4.1.

(6) Compliance with the PM emission limit shall be determined based on the 24-hour daily (block) average of the hourly arithmetic average emission concentrations using CEMS outlet data.

(7) At a minimum, valid CEMS hourly averages shall be obtained as specified in paragraph (c)(7)(i) of this section for 75 percent of the total operating hours per 30-day rolling average.

(i) At least two data points per hour shall be used to calculate each 1-hour arithmetic average.

(ii) [Reserved]

(8) The 1-hour arithmetic averages required under paragraph (c)(7) of this section shall be expressed in ng/J or lb/MMBtu heat input and shall be used to calculate the boiler operating day daily arithmetic average emission concentrations. The 1-hour arithmetic averages shall be calculated using the data points required under §60.13(e)(2) of subpart A of this part.

(9) All valid CEMS data shall be used in calculating average emission concentrations even if the minimum CEMS data requirements of paragraph (c)(7) of this section are not met.

(10) The CEMS shall be operated according to Performance Specification 11 in appendix B of this part.

(11) During the correlation testing runs of the CEMS required by Performance Specification 11 in appendix B of this part, PM and O_2 (or CO_2) data shall be collected concurrently (or within a 30- to 60-minute period) by both the continuous emission monitors and performance tests conducted using the following test methods.

(i) For PM, Method 5 or 5B of appendix A-3 of this part or Method 17 of appendix A-6 of this part shall be used; and

(ii) For O2 (or CO_2), Method 3A or 3B of appendix A-2 of this part, as applicable shall be used.

(12) Quarterly accuracy determinations and daily calibration drift tests shall be performed in accordance with procedure 2 in appendix F of this part. Relative Response Audit's must be performed annually and Response Correlation Audits must be performed every 3 years.

(13) When PM emissions data are not obtained because of CEMS breakdowns, repairs, calibration checks, and zero and span adjustments, emissions data shall be obtained by using other monitoring systems as approved by the Administrator or EPA Reference Method 19 of appendix A of this part to

provide, as necessary, valid emissions data for a minimum of 75 percent of total operating hours on a 30-day rolling average.

(14) As of January 1, 2012, and within 90 days after the date of completing each performance test, as defined in §60.8, conducted to demonstrate compliance with this subpart, you must submit relative accuracy test audit (*i.e.,*reference method) data and performance test (*i.e.,* compliance test) data, except opacity data, electronically to EPA's Central Data Exchange (CDX) by using the Electronic Reporting Tool (ERT) (see *http://www.epa.gov/ttn/chief/ert/ert tool.html/*) or other compatible electronic spreadsheet. Only data collected using test methods compatible with ERT are subject to this requirement to be submitted electronically into EPA's WebFIRE database.

(d) The owner or operator of an affected facility seeking to demonstrate compliance under §60.43c(e)(4) shall follow the applicable procedures under §60.48c(f). For residual oil-fired affected facilities, fuel supplier certifications are only allowed for facilities with heat input capacities between 2.9 and 8.7 MW (10 to 30 MMBtu/h).

[72 FR 32759, June 13, 2007, as amended at 74 FR 5091, Jan. 28, 2009; 76 FR 3523, Jan. 20, 2011; 77 FR 9463, Feb. 16, 2012]

Back to Top

§60.46c Emission monitoring for sulfur dioxide.

(a) Except as provided in paragraphs (d) and (e) of this section, the owner or operator of an affected facility subject to the SO_2 emission limits under §60.42c shall install, calibrate, maintain, and operate a CEMS for measuring SO_2concentrations and either O_2 or CO_2 concentrations at the outlet of the SO_2 control device (or the outlet of the steam generating unit if no SO_2 control device is used), and shall record the output of the system. The owner or operator of an affected facility subject to the percent reduction requirements under §60.42c shall measure SO_2 concentrations and either O_2 or CO_2 concentrations at both the inlet and outlet of the SO_2 control device.

(b) The 1-hour average SO_2 emission rates measured by a CEMS shall be expressed in ng/J or lb/MMBtu heat input and shall be used to calculate the average emission rates under §60.42c. Each 1-hour average SO_2 emission rate must be based on at least 30 minutes of operation, and shall be calculated using the data points required under §60.13(h)(2). Hourly SO_2 emission rates are not calculated if the affected facility is operated less than 30 minutes in a 1-hour period and are not counted toward determination of a steam generating unit operating day.

(c) The procedures under §60.13 shall be followed for installation, evaluation, and operation of the CEMS.

(1) All CEMS shall be operated in accordance with the applicable procedures under Performance Specifications 1, 2, and 3 of appendix B of this part.

(2) Quarterly accuracy determinations and daily calibration drift tests shall be performed in accordance with Procedure 1 of appendix F of this part.

(3) For affected facilities subject to the percent reduction requirements under §60.42c, the span value of the SO_2CEMS at the inlet to the SO_2 control device shall be 125 percent of the maximum estimated hourly potential SO_2emission rate of the fuel combusted, and the span value of the SO_2 CEMS at the outlet from the SO_2 control device shall be 50 percent of the maximum estimated hourly potential SO_2 emission rate of the fuel combusted.

(4) For affected facilities that are not subject to the percent reduction requirements of §60.42c, the span value of the SO_2 CEMS at the outlet from the SO_2 control device (or outlet of the steam generating unit if no SO_2 control device is used) shall be 125 percent of the maximum estimated hourly potential SO_2 emission rate of the fuel combusted.

(d) As an alternative to operating a CEMS at the inlet to the SO_2 control device (or outlet of the steam generating unit if no SO_2 control device is used) as required under paragraph (a) of this section, an owner or operator may elect to determine the average SO_2 emission rate by sampling the fuel prior to combustion. As an alternative to operating a CEMS at the outlet from the SO_2 control device (or outlet of the steam generating unit if no SO_2 control device is used) as required under paragraph (a) of this section, an owner or operator may elect to determine the average SO_2 emission rate by using Method 6B of appendix A of this part. Fuel sampling shall be conducted pursuant to either paragraph (d)(1) or (d)(2) of this section. Method 6B of appendix A of this part shall be conducted pursuant to paragraph (d)(3) of this section.

(1) For affected facilities combusting coal or oil, coal or oil samples shall be collected daily in an as-fired condition at the inlet to the steam generating unit and analyzed for sulfur content and heat content according the Method 19 of appendix A of this part. Method 19 of appendix A of this part provides procedures for converting these measurements into the format to be used in calculating the average SO_2 input rate.

(2) As an alternative fuel sampling procedure for affected facilities combusting oil, oil samples may be collected from the fuel tank for each steam generating unit immediately after the fuel tank is filled and before any oil is combusted. The owner or operator of the affected facility shall analyze the oil sample to determine the sulfur content of the oil. If a partially empty fuel tank is refilled, a new sample and analysis of the fuel in the tank would be required upon filling. Results of the fuel analysis taken after each new shipment of oil is received shall be used as the daily value when calculating the 30-day rolling average until the next shipment is received. If the fuel analysis shows that the sulfur content in the fuel tank is greater than 0.5 weight percent sulfur, the owner or operator shall ensure that the sulfur content of subsequent oil shipments is low enough to cause the 30-day rolling average sulfur content to be 0.5 weight percent sulfur or less.

(3) Method 6B of appendix A of this part may be used in lieu of CEMS to measure SO_2 at the inlet or outlet of the SO_2 control system. An initial stratification test is required to verify the adequacy of the Method 6B of appendix A of this part sampling location. The stratification test shall consist of three paired runs of a suitable SO_2 and CO_2 measurement train operated at the candidate location and a second similar train operated according to the procedures in §3.2 and the applicable procedures in section 7 of Performance Specification 2 of appendix B of this part. Method 6B of appendix A of this part, Method 6A of appendix A of this part, or a combination of Methods 6 and 3 of appendix A of this part or Methods 6C and 3A of appendix A of this part are suitable measurement techniques. If Method 6B of appendix A of this part is used for the second train, sampling time and timer operation may be adjusted for the stratification test as long as an adequate sample volume is collected; however, both sampling trains are to be operated similarly. For the location to be adequate for Method 6B of appendix A of this part 24-hour tests, the mean of the absolute difference between the three paired runs must be less than 10 percent (0.10).

(e) The monitoring requirements of paragraphs (a) and (d) of this section shall not apply to affected facilities subject to §60.42c(h) (1), (2), or (3) where the owner or operator of the affected facility seeks to demonstrate compliance with the SO_2 standards based on fuel supplier certification, as described under §60.48c(f), as applicable.

(f) The owner or operator of an affected facility operating a CEMS pursuant to paragraph (a) of this section, or conducting as-fired fuel sampling pursuant to paragraph (d)(1) of this section, shall obtain emission data for at least 75 percent of the operating hours in at least 22 out of 30 successive steam generating unit operating days. If this minimum data requirement is not met with a single monitoring system, the owner or operator of the affected facility shall supplement the emission data with data collected with other monitoring systems as approved by the Administrator.

Back to Top

§60.47c Emission monitoring for particulate matter.

(a) Except as provided in paragraphs (c), (d), (e), and (f) of this section, the owner or operator of an affected facility combusting coal, oil, or wood that is subject to the opacity standards under §60.43c shall install, calibrate, maintain, and operate a continuous opacity monitoring system (COMS) for measuring the opacity of the emissions discharged to the atmosphere and record the output of the system. The owner or operator of an affected facility subject to an opacity standard in §60.43c(c) that is not required to use a COMS due to paragraphs (c), (d), (e), or (f) of this section that elects not to use a COMS shall conduct a performance test using Method 9 of appendix A-4 of this part and the procedures in §60.11 to demonstrate compliance with the applicable limit in §60.43c by April 29, 2011, within 45 days of stopping use of an existing COMS, or within 180 days after initial startup of the facility, whichever is later, and shall comply with either paragraphs (a)(1), (a)(2), or (a)(3) of this section. The observation period for Method 9 of appendix A-4 of this part performance tests may be reduced from 3 hours to 60 minutes if all 6-minute averages are less than 10 percent and all individual 15-second observations are less than or equal to 20 percent during the initial 60 minutes of observation.

(1) Except as provided in paragraph (a)(2) and (a)(3) of this section, the owner or operator shall conduct subsequent Method 9 of appendix A-4 of this part performance tests using the procedures in paragraph (a) of this section according to the applicable schedule in paragraphs (a)(1)(i) through (a)(1)(iv) of this section, as determined by the most recent Method 9 of appendix A-4 of this part performance test results.

(i) If no visible emissions are observed, a subsequent Method 9 of appendix A-4 of this part performance test must be completed within 12 calendar months from the date that the most recent performance test was conducted or within 45 days of the next day that fuel with an opacity standard is combusted, whichever is later;

(ii) If visible emissions are observed but the maximum 6-minute average opacity is less than or equal to 5 percent, a subsequent Method 9 of appendix A-4 of this part performance test must be completed within 6 calendar months from the date that the most recent performance test was conducted or within 45 days of the next day that fuel with an opacity standard is combusted, whichever is later;

(iii) If the maximum 6-minute average opacity is greater than 5 percent but less than or equal to 10 percent, a subsequent Method 9 of appendix A-4 of this part performance test must be completed within 3 calendar months from the date that the most recent performance test was conducted or within 45 days of the next day that fuel with an opacity standard is combusted, whichever is later; or

(iv) If the maximum 6-minute average opacity is greater than 10 percent, a subsequent Method 9 of appendix A-4 of this part performance test must be completed within 45 calendar days from the date that the most recent performance test was conducted.

(2) If the maximum 6-minute opacity is less than 10 percent during the most recent Method 9 of appendix A-4 of this part performance test, the owner or operator may, as an alternative to performing subsequent Method 9 of appendix A-4 of this part performance tests, elect to perform subsequent monitoring using Method 22 of appendix A-7 of this part according to the procedures specified in paragraphs (a)(2)(i) and (ii) of this section.

(i) The owner or operator shall conduct 10 minute observations (during normal operation) each operating day the affected facility fires fuel for which an opacity standard is applicable using Method 22 of appendix A-7 of this part and demonstrate that the sum of the occurrences of any visible emissions is not in excess of 5 percent of the observation period (*i.e.* , 30 seconds per 10 minute period). If the sum of the occurrence of any visible emissions is greater than 30 seconds during the initial 10 minute observation, immediately conduct a 30 minute observation. If the sum of the occurrence of visible emissions is greater than 5 percent of the observation period (*i.e.,* 90 seconds per 30 minute period), the owner or operator shall either document and adjust the operation of the facility and demonstrate within 24 hours that the sum of the occurrence of visible emissions is equal to or less than 5 percent during a 30 minute observation (*i.e.,* 90 seconds) or conduct a new Method 9 of appendix A-4 of this part performance test using the procedures in paragraph (a) of this section within 45 calendar days according to the requirements in §60.45c(a)(8).

(ii) If no visible emissions are observed for 10 operating days during which an opacity standard is applicable, observations can be reduced to once every 7 operating days during which an opacity standard is applicable. If any visible emissions are observed, daily observations shall be resumed.

(3) If the maximum 6-minute opacity is less than 10 percent during the most recent Method 9 of appendix A-4 of this part performance test, the owner or operator may, as an alternative to performing subsequent Method 9 of appendix A-4 performance tests, elect to perform subsequent monitoring using a digital opacity compliance system according to a site-specific monitoring plan approved by the Administrator. The observations shall be similar, but not necessarily identical, to the requirements in paragraph (a)(2) of this section. For reference purposes in preparing the monitoring plan, see OAQPS "Determination of Visible Emission Opacity from Stationary Sources Using Computer-Based Photographic Analysis Systems." This document is available from the U.S. Environmental Protection Agency (U.S. EPA); Office of Air Quality and Planning Standards; Sector Policies and Programs Division; Measurement Policy Group (D243-02), Research Triangle Park, NC 27711. This document is also available on the Technology Transfer Network (TTN) under Emission Measurement Center Preliminary Methods.

(b) All COMS shall be operated in accordance with the applicable procedures under Performance Specification 1 of appendix B of this part. The span value of the opacity COMS shall be between 60 and 80 percent.

(c) Owners and operators of an affected facilities that burn only distillate oil that contains no more than 0.5 weight percent sulfur and/or liquid or gaseous fuels with potential sulfur dioxide emission rates of 26 ng/J (0.060 lb/MMBtu) heat input or less and that do not use a post-combustion technology to reduce SO2 or PM emissions and that are subject to an opacity standard in §60.43c(c) are not required to operate a COMS if they follow the applicable procedures in §60.48c(f).

(d) Owners or operators complying with the PM emission limit by using a PM CEMS must calibrate, maintain, operate, and record the output of the system for PM emissions discharged to the atmosphere as specified in §60.45c(c). The CEMS specified in paragraph §60.45c(c) shall be operated and data recorded during all periods of operation of the affected facility except for CEMS breakdowns and repairs. Data is recorded during calibration checks, and zero and span adjustments.

(e) Owners and operators of an affected facility that is subject to an opacity standard in §60.43c(c) and that does not use post-combustion technology (except a wet scrubber) for reducing PM, SO_2, or carbon monoxide (CO) emissions, burns only gaseous fuels or fuel oils that contain less than or equal to 0.5 weight percent sulfur, and is operated such that emissions of CO discharged to the atmosphere from the affected facility are maintained at levels less than or equal to 0.15 lb/MMBtu on a boiler operating day average basis is not required to operate a COMS. Owners and operators of affected facilities electing to comply with this paragraph must demonstrate compliance according to the procedures specified in paragraphs (e)(1) through (4) of this section; or

(1) You must monitor CO emissions using a CEMS according to the procedures specified in paragraphs (e)(1)(i) through (iv) of this section.

(i) The CO CEMS must be installed, certified, maintained, and operated according to the provisions in §60.58b(i)(3) of subpart Eb of this part.

(ii) Each 1-hour CO emissions average is calculated using the data points generated by the CO CEMS expressed in parts per million by volume corrected to 3 percent oxygen (dry basis).

(iii) At a minimum, valid 1-hour CO emissions averages must be obtained for at least 90 percent of the operating hours on a 30-day rolling average basis. The 1-hour averages are calculated using the data points required in §60.13(h)(2).

(iv) Quarterly accuracy determinations and daily calibration drift tests for the CO CEMS must be performed in accordance with procedure 1 in appendix F of this part.

(2) You must calculate the 1-hour average CO emissions levels for each steam generating unit operating day by multiplying the average hourly CO output concentration measured by the CO CEMS times the corresponding average hourly flue gas flow rate and divided by the corresponding average hourly heat input to the affected source. The 24-hour average CO emission level is determined by calculating the arithmetic average of the hourly CO emission levels computed for each steam generating unit operating day.

(3) You must evaluate the preceding 24-hour average CO emission level each steam generating unit operating day excluding periods of affected source startup, shutdown, or malfunction. If the 24-hour average CO emission level is greater than 0.15 lb/MMBtu, you must initiate investigation of the relevant equipment and control systems within 24 hours of the first discovery of the high emission incident and, take the appropriate corrective action as soon as practicable to adjust control settings or repair equipment to reduce the 24-hour average CO emission level to 0.15 lb/MMBtu or less.

(4) You must record the CO measurements and calculations performed according to paragraph (e) of this section and any corrective actions taken. The record of corrective action taken must include the date and time during which the 24-hour average CO emission level was greater than 0.15 lb/MMBtu, and the date, time, and description of the corrective action.

(f) An owner or operator of an affected facility that is subject to an opacity standard in §60.43c(c) is not required to operate a COMS provided that the affected facility meets the conditions in either paragraphs (f)(1), (2), or (3) of this section.

(1) The affected facility uses a fabric filter (baghouse) as the primary PM control device and, the owner or operator operates a bag leak detection system to monitor the performance of the fabric filter according to the requirements in section §60.48Da of this part.

(2) The affected facility uses an ESP as the primary PM control device, and the owner or operator uses an ESP predictive model to monitor the performance of the ESP developed in accordance and operated according to the requirements in section §60.48Da of this part.

(3) The affected facility burns only gaseous fuels and/or fuel oils that contain no greater than 0.5 weight percent sulfur, and the owner or operator operates the unit according to a written site-specific monitoring plan approved by the permitting authority. This monitoring plan must include procedures and criteria for establishing and monitoring specific parameters for the affected facility indicative of compliance with the opacity standard. For testing performed as part of this site-specific monitoring plan, the permitting authority may require as an alternative to the notification and reporting requirements specified in §§60.8

and 60.11 that the owner or operator submit any deviations with the excess emissions report required under §60.48c(c).

[72 FR 32759, June 13, 2007, as amended at 74 FR 5091, Jan. 28, 2009; 76 FR 3523, Jan. 20, 2011; 77 FR 9463, Feb. 16, 2012]

Back to Top

§60.48c Reporting and recordkeeping requirements.

(a) The owner or operator of each affected facility shall submit notification of the date of construction or reconstruction and actual startup, as provided by §60.7 of this part. This notification shall include:

(1) The design heat input capacity of the affected facility and identification of fuels to be combusted in the affected facility.

(2) If applicable, a copy of any federally enforceable requirement that limits the annual capacity factor for any fuel or mixture of fuels under §60.42c, or §60.43c.

(3) The annual capacity factor at which the owner or operator anticipates operating the affected facility based on all fuels fired and based on each individual fuel fired.

(4) Notification if an emerging technology will be used for controlling SO_2 emissions. The Administrator will examine the description of the control device and will determine whether the technology qualifies as an emerging technology. In making this determination, the Administrator may require the owner or operator of the affected facility to submit additional information concerning the control device. The affected facility is subject to the provisions of §60.42c(a) or (b)(1), unless and until this determination is made by the Administrator.

(b) The owner or operator of each affected facility subject to the SO_2 emission limits of §60.42c, or the PM or opacity limits of §60.43c, shall submit to the Administrator the performance test data from the initial and any subsequent performance tests and, if applicable, the performance evaluation of the CEMS and/or COMS using the applicable performance specifications in appendix B of this part.

(c) In addition to the applicable requirements in §60.7, the owner or operator of an affected facility subject to the opacity limits in §60.43c(c) shall submit excess emission reports for any excess emissions from the affected facility that occur during the reporting period and maintain records according to the requirements specified in paragraphs (c)(1) through (3) of this section, as applicable to the visible emissions monitoring method used.

(1) For each performance test conducted using Method 9 of appendix A-4 of this part, the owner or operator shall keep the records including the information specified in paragraphs (c)(1)(i) through (iii) of this section.

(i) Dates and time intervals of all opacity observation periods;

(ii) Name, affiliation, and copy of current visible emission reading certification for each visible emission observer participating in the performance test; and

(iii) Copies of all visible emission observer opacity field data sheets;

(2) For each performance test conducted using Method 22 of appendix A-4 of this part, the owner or operator shall keep the records including the information specified in paragraphs (c)(2)(i) through (iv) of this section.

(i) Dates and time intervals of all visible emissions observation periods;

(ii) Name and affiliation for each visible emission observer participating in the performance test;

(iii) Copies of all visible emission observer opacity field data sheets; and

(iv) Documentation of any adjustments made and the time the adjustments were completed to the affected facility operation by the owner or operator to demonstrate compliance with the applicable monitoring requirements.

(3) For each digital opacity compliance system, the owner or operator shall maintain records and submit reports according to the requirements specified in the site-specific monitoring plan approved by the Administrator

(d) The owner or operator of each affected facility subject to the SO_2 emission limits, fuel oil sulfur limits, or percent reduction requirements under §60.42c shall submit reports to the Administrator.

(e) The owner or operator of each affected facility subject to the SO_2 emission limits, fuel oil sulfur limits, or percent reduction requirements under §60.42c shall keep records and submit reports as required under paragraph (d) of this section, including the following information, as applicable.

(1) Calendar dates covered in the reporting period.

(2) Each 30-day average SO_2 emission rate (ng/J or lb/MMBtu), or 30-day average sulfur content (weight percent), calculated during the reporting period, ending with the last 30-day period; reasons for any noncompliance with the emission standards; and a description of corrective actions taken.

(3) Each 30-day average percent of potential SO_2 emission rate calculated during the reporting period, ending with the last 30-day period; reasons for any noncompliance with the emission standards; and a description of the corrective actions taken.

(4) Identification of any steam generating unit operating days for which SO_2 or diluent (O_2 or CO_2) data have not been obtained by an approved method for at least 75 percent of the operating hours; justification for not obtaining sufficient data; and a description of corrective actions taken.

(5) Identification of any times when emissions data have been excluded from the calculation of average emission rates; justification for excluding data; and a description of corrective actions taken if data have been excluded for periods other than those during which coal or oil were not combusted in the steam generating unit.

(6) Identification of the F factor used in calculations, method of determination, and type of fuel combusted.

(7) Identification of whether averages have been obtained based on CEMS rather than manual sampling methods.

(8) If a CEMS is used, identification of any times when the pollutant concentration exceeded the full span of the CEMS.

(9) If a CEMS is used, description of any modifications to the CEMS that could affect the ability of the CEMS to comply with Performance Specifications 2 or 3 of appendix B of this part.

(10) If a CEMS is used, results of daily CEMS drift tests and quarterly accuracy assessments as required under appendix F, Procedure 1 of this part.

(11) If fuel supplier certification is used to demonstrate compliance, records of fuel supplier certification as described under paragraph (f)(1), (2), (3), or (4) of this section, as applicable. In addition to records of fuel supplier certifications, the report shall include a certified statement signed by the owner or operator of the affected facility that the records of fuel supplier certifications submitted represent all of the fuel combusted during the reporting period.

(f) Fuel supplier certification shall include the following information:

(1) For distillate oil:

(i) The name of the oil supplier;

(ii) A statement from the oil supplier that the oil complies with the specifications under the definition of distillate oil in §60.41c; and

(iii) The sulfur content or maximum sulfur content of the oil.

(2) For residual oil:

(i) The name of the oil supplier;

(ii) The location of the oil when the sample was drawn for analysis to determine the sulfur content of the oil, specifically including whether the oil was sampled as delivered to the affected facility, or whether the sample was drawn from oil in storage at the oil supplier's or oil refiner's facility, or other location;

(iii) The sulfur content of the oil from which the shipment came (or of the shipment itself); and

(iv) The method used to determine the sulfur content of the oil.

(3) For coal:

(i) The name of the coal supplier;

(ii) The location of the coal when the sample was collected for analysis to determine the properties of the coal, specifically including whether the coal was sampled as delivered to the affected facility or whether the sample was collected from coal in storage at the mine, at a coal preparation plant, at a coal supplier's facility, or at another location. The certification shall include the name of the coal mine (and coal seam), coal storage facility, or coal preparation plant (where the sample was collected);

(iii) The results of the analysis of the coal from which the shipment came (or of the shipment itself) including the sulfur content, moisture content, ash content, and heat content; and

(iv) The methods used to determine the properties of the coal.

(4) For other fuels:

(i) The name of the supplier of the fuel;

(ii) The potential sulfur emissions rate or maximum potential sulfur emissions rate of the fuel in ng/J heat input; and

(iii) The method used to determine the potential sulfur emissions rate of the fuel.

(g)(1) Except as provided under paragraphs (g)(2) and (g)(3) of this section, the owner or operator of each affected facility shall record and maintain records of the amount of each fuel combusted during each operating day.

(2) As an alternative to meeting the requirements of paragraph (g)(1) of this section, the owner or operator of an affected facility that combusts only natural gas, wood, fuels using fuel certification in §60.48c(f) to demonstrate compliance with the SO_2 standard, fuels not subject to an emissions standard (excluding opacity), or a mixture of these fuels may elect to record and maintain records of the amount of each fuel combusted during each calendar month.

(3) As an alternative to meeting the requirements of paragraph (g)(1) of this section, the owner or operator of an affected facility or multiple affected facilities located on a contiguous property unit where the only fuels combusted in any steam generating unit (including steam generating units not subject to this subpart) at that property are natural gas, wood, distillate oil meeting the most current requirements in §60.42C to use fuel certification to demonstrate compliance with the SO_2 standard, and/or fuels, excluding coal and residual oil, not subject to an emissions standard (excluding opacity) may elect to record and maintain records of the total amount of each steam generating unit fuel delivered to that property during each calendar month.

(h) The owner or operator of each affected facility subject to a federally enforceable requirement limiting the annual capacity factor for any fuel or mixture of fuels under §60.42c or §60.43c shall calculate the annual capacity factor individually for each fuel combusted. The annual capacity factor is determined on a 12-month rolling average basis with a new annual capacity factor calculated at the end of the calendar month.

(i) All records required under this section shall be maintained by the owner or operator of the affected facility for a period of two years following the date of such record.

(j) The reporting period for the reports required under this subpart is each six-month period. All reports shall be submitted to the Administrator and shall be postmarked by the 30th day following the end of the reporting period.

[72 FR 32759, June 13, 2007, as amended at 74 FR 5091, Jan. 28, 2009]

Appendix B

40 C.F.R. Part 60 Subpart AAa

Standards of Performance for Steel Plants: Electric Arc Furnaces and Argon-Oxygen Decarburization Vessels Constructed After August 17, 1983

Subpart AAa—Standards of Performance for Steel Plants: Electric Arc Furnaces and Argon-Oxygen Decarburization Vessels Constructed After August 17, 1983

Contents

SOURCE: 49 FR 43845, Oct. 31, 1984, unless otherwise noted.

Back to Top

§60.270a Applicability and designation of affected facility.

(a) The provisions of this subpart are applicable to the following affected facilities in steel plants that produce carbon, alloy, or specialty steels: electric arc furnaces, argon-oxygen decarburization vessels, and dust-handling systems.

(b) The provisions of this subpart apply to each affected facility identified in paragraph (a) of this section that commences construction, modification, or reconstruction after August 17, 1983.

Back to Top

§60.271a 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.

Argon-oxygen decarburization vessel (AOD vessel) means any closed-bottom, refractory-lined converter vessel with submerged tuyeres through which gaseous mixtures containing argon and oxygen or nitrogen may be blown into molten steel for further refining.

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

Capture system means the equipment (including ducts, hoods, fans, dampers, etc.) used to capture or transport particulate matter generated by an electric arc furnace or AOD vessel to the air pollution control device.

Charge means the addition of iron and steel scrap or other materials into the top of an electric arc furnace or the addition of molten steel or other materials into the top of an AOD vessel.

Control device means the air pollution control equipment used to remove particulate matter from the effluent gas stream generated by an electric arc furnace or AOD vessel.

Direct-shell evacuation control system (DEC system) means a system that maintains a negative pressure within the electric arc furnace above the slag or metal and ducts emissions to the control device.

Dust-handling system means equipment used to handle particulate matter collected by the control device for an electric arc furnace or AOD vessel subject to this subpart. For the purposes of this subpart, the dust-handling system shall consist of the control device dust hoppers, the dust-conveying equipment, any central dust storage equipment, the dust-treating equipment (e.g., pug mill, pelletizer), dust transfer equipment (from storage to truck), and any secondary control devices used with the dust transfer equipment.

Electric arc furnace (EAF) means a furnace that produces molten steel and heats the charge materials with electric arcs from carbon electrodes. For the purposes of this subpart, an EAF shall consist of the furnace shell and roof and the transformer. Furnaces that continuously feed direct-reduced iron ore pellets as the primary source of iron are not affected facilities within the scope of this definition.

Heat cycle means the period beginning when scrap is charged to an empty EAF and ending when the EAF tap is completed or beginning when molten steel is charged to an empty AOD vessel and ending when the AOD vessel tap is completed.

Meltdown and refining period means the time period commencing at the termination of the initial charging period and ending at the initiation of the tapping period, excluding any intermediate charging periods and times when power to the EAF is off.

Melting means that phase of steel production cycle during which the iron and steel scrap is heated to the molten state.

Negative-pressure fabric filter means a fabric filter with the fans on the downstream side of the filter bags.

Positive-pressure fabric filter means a fabric filter with the fans on the upstream side of the filter bags.

Refining means that phase of the steel production cycle during which undesirable elements are removed from the molten steel and alloys are added to reach the final metal chemistry.

Shop means the building which houses one or more EAF's or AOD vessels.

Shop opacity means the arithmetic average of 24 observations of the opacity of emissions from the shop taken in accordance with Method 9 of appendix A of this part.

Tap means the pouring of molten steel from an EAF or AOD vessel.

Tapping period means the time period commencing at the moment an EAF begins to pour molten steel and ending either three minutes after steel ceases to flow from an EAF, or six minutes after steel begins to flow, whichever is longer.

[49 FR 43845, Oct. 31, 1984, as amended at 64 FR 10110, Mar. 2, 1999; 70 FR 8532, Feb. 22, 2005]

Back to Top

§60.272a Standard for particulate matter.

(a) On and after the date of which the performance test required to be conducted by §60.8 is completed, no owner or operator subject to the provisions of this subpart shall cause to be discharged into the atmosphere from an EAF or an AOD vessel any gases which:

(1) Exit from a control device and contain particulate matter in excess of 12 mg/dscm (0.0052 gr/dscf);

(2) Exit from a control device and exhibit 3 percent opacity or greater; and

(3) Exit from a shop and, due solely to the operations of any affected EAF(s) or AOD vessel(s), exhibit 6 percent opacity or greater.

(b) On and after the date on which the performance test required to be conducted by §60.8 is completed, no owner or operator subject to the provisions of this subpart shall cause to be discharged into the atmosphere from the dust-handling system any gases that exhibit 10 percent opacity or greater.

Back to Top

§60.273a Emission monitoring.

(a) Except as provided under paragraphs (b) and (c) of this section, a continuous monitoring system for the measurement of the opacity of emissions discharged into the atmosphere from the control device(s) shall be installed, calibrated, maintained, and operated by the owner or operator subject to the provisions of this subpart.

(b) No continuous monitoring system shall be required on any control device serving the dust-handling system.

(c) A continuous monitoring system for the measurement of the opacity of emissions discharged into the atmosphere from the control device(s) is not required on any modular, multi-stack, negative-pressure or positive-pressure fabric filter if observations of the opacity of the visible emissions from the control device are performed by a certified visible emission observer; or on any single-stack fabric filter if visible emissions from the control device are performed by a certified visible emission observer and the owner installs and continuously operates a bag leak detection system according to paragraph (e) of this section. Visible emission observations shall be conducted at least once per day for at least three 6-minute periods when the furnace is operating in the melting and refining period. All visible emissions observations shall be conducted in accordance with Method 9. If visible emissions occur from more than one point, the opacity shall be recorded for any points where visible emissions are observed. Where it is possible to determine that a number of visible emission sites relate to only one incident of the visible emission, only one set of three 6-minute observations will be required. In that case, the Method 9 observations must be made for the site of highest opacity that directly relates to the cause (or location) of visible emissions observed during a single incident. Records shall be maintained of any 6-minute average that is in excess of the emission limit specified in §60.272a(a).

(d) A furnace static pressure monitoring device is not required on any EAF equipped with a DEC system if observations of shop opacity are performed by a certified visible emission observer as follows: Shop opacity observations shall be conducted at least once per day when the furnace is operating in the meltdown and refining period. Shop opacity shall be determined as the arithmetic average of 24 consecutive 15-second opacity observations of emissions from the shop taken in accordance with Method

9. Shop opacity shall be recorded for any point(s) where visible emissions are observed. Where it is possible to determine that a number of visible emission sites relate to only one incident of visible emissions, only one observation of shop opacity will be required. In this case, the shop opacity observations must be made for the site of highest opacity that directly relates to the cause (or location) of visible emissions observed during a single incident.

(e) A bag leak detection system must be installed and continuously operated on all single-stack fabric filters if the owner or operator elects not to install and operate a continuous opacity monitoring system as provided for under paragraph (c) of this section. In addition, the owner or operator shall meet the visible emissions observation requirements in paragraph (c) of this section. The bag leak detection system must meet the specifications and requirements of paragraphs (e)(1) through (8) of this section.

(1) The bag leak detection system must be certified by the manufacturer to be capable of detecting particulate matter emissions at concentrations of 1 milligram per actual cubic meter (0.00044 grains per actual cubic foot) or less.

(2) The bag leak detection system sensor must provide output of relative particulate matter loadings and the owner or operator shall continuously record the output from the bag leak detection system using electronic or other means (*e.g.,*using a strip chart recorder or a data logger.)

(3) The bag leak detection system must be equipped with an alarm system that will sound when an increase in relative particulate loading is detected over the alarm set point established according to paragraph (e)(4) of this section, and the alarm must be located such that it can be heard by the appropriate plant personnel.

(4) For each bag leak detection system required by paragraph (e) of this section, the owner or operator shall develop and submit to the Administrator or delegated authority, for approval, a site-specific monitoring plan that addresses the items identified in paragraphs (i) through (v) of this paragraph (e)(4). For each bag leak detection system that operates based on the triboelectric effect, the monitoring plan shall be consistent with the recommendations contained in the U.S. Environmental Protection Agency guidance document “Fabric Filter Bag Leak Detection Guidance” (EPA-454/R-98-015). The owner or operator shall operate and maintain the bag leak detection system according to the site-specific monitoring plan at all times. The plan shall describe the following:

(i) Installation of the bag leak detection system;

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

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

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

(v) How the bag leak detection system output shall be recorded and stored.

(5) The initial adjustment of the system shall, at a minimum, consist of establishing the baseline output by adjusting the sensitivity (range) and the averaging period of the device, and establishing the alarm set points and the alarm delay time (if applicable).

(6) Following initial adjustment, the owner or operator shall not adjust the averaging period, alarm set point, or alarm delay time without approval from the Administrator or delegated authority except as provided for in paragraphs (e)(6)(i) and (ii) of this section.

(i) Once per quarter, the owner or operator may adjust the sensitivity of the bag leak detection system to account for seasonal effects including temperature and humidity according to the procedures identified in the site-specific monitoring plan required under paragraphs (e)(4) of this section.

(ii) If opacities greater than zero percent are observed over four consecutive 15-second observations during the daily opacity observations required under paragraph (c) of this section and the alarm on the bag leak detection system does not sound, the owner or operator shall lower the alarm set point on the bag leak detection system to a point where the alarm would have sounded during the period when the opacity observations were made.

(7) For negative pressure, induced air baghouses, and positive pressure baghouses that are discharged to the atmosphere through a stack, the bag leak detection sensor must be installed downstream of the baghouse and upstream of any wet scrubber.

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

(f) For each bag leak detection system installed according to paragraph (e) of this section, the owner or operator shall initiate procedures to determine the cause of all alarms within 1 hour of an alarm. Except as provided for under paragraph (g) of this section, the cause of the alarm must be alleviated within 3 hours of the time the alarm occurred by taking whatever corrective action(s) are necessary. Corrective actions may include, but are not limited to, the following:

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

(2) Sealing off defective bags or filter media;

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

(4) Sealing off a defective baghouse compartment;

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

(6) Shutting down the process producing the particulate emissions.

(g) In approving the site-specific monitoring plan required in paragraph (e)(4) of this section, the Administrator or delegated authority may allow owners or operators more than 3 hours to alleviate specific conditions that cause an alarm if the owner or operator identifies the condition that could lead to an alarm in the monitoring plan, adequately explains why it is not feasible to alleviate the condition within 3 hours of the time the alarm occurred, and demonstrates that the requested additional time will ensure alleviation of the condition as expeditiously as practicable.

[49 FR 43845, Oct. 31, 1984, as amended at 54 FR 6672, Feb. 14, 1989; 64 FR 10111, Mar. 2, 1999; 70 FR 8532, Feb. 22, 2005]

Back to Top

§60.274a Monitoring of operations.

(a) The owner or operator subject to the provisions of this subpart shall maintain records of the following information:

(1) All data obtained under paragraph (b) of this section; and

(2) All monthly operational status inspections performed under paragraph (c) of this section.

(b) Except as provided under paragraph (e) of this section, the owner or operator subject to the provisions of this subpart shall check and record on a once-per-shift basis the furnace static pressure (if DEC system is in use, and a furnace static pressure gauge is installed according to paragraph (f) of this section) and either: check and record the control system fan motor amperes and damper position on a once-per-shift basis; install, calibrate, and maintain a monitoring device that continuously records the volumetric flow rate through each separately ducted hood; or install, calibrate, and maintain a monitoring device that continuously records the volumetric flow rate at the control device inlet and check and record damper positions on a once-per-shift basis. The monitoring device(s) may be installed in any appropriate location in the exhaust duct such that reproducible flow rate monitoring will result. The flow rate monitoring device(s) shall have an accuracy of ±10 percent over its normal operating range and shall be calibrated according to the manufacturer's instructions. The Administrator may require the owner or operator to demonstrate the accuracy of the monitoring device(s) relative to Methods 1 and 2 of appendix A of this part.

(c) When the owner or operator of an affected facility is required to demonstrate compliance with the standards under §60.272a(a)(3) and at any other time that the Administrator may require (under section 114 of the CAA, as amended) either: the control system fan motor amperes and all damper positions, the volumetric flow rate through each separately ducted hood, or the volumetric flow rate at the control device inlet and all damper positions shall be determined during all periods in which a hood is operated for the purpose of capturing emissions from the affected facility subject to paragraph (b) of this section. The owner or operator may petition the Administrator for reestablishment of these parameters whenever the owner or operator can demonstrate to the Administrator's satisfaction that the affected facility operating conditions upon which the parameters were previously established are no longer applicable. The values of these parameters as determined during the most recent demonstration of compliance shall be maintained at the appropriate level for each applicable period. Operation at other than baseline values may be subject to the requirements of §60.276a(c).

(d) Except as provided under paragraph (e) of this section, the owner or operator shall perform monthly operational status inspections of the equipment that is important to the performance of the total capture system (*i.e.*, pressure sensors, dampers, and damper switches). This inspection shall include observations of the physical appearance of the equipment (e.g., presence of holes in ductwork or hoods, flow constrictions caused by dents or accumulated dust in ductwork, and fan erosion). Any deficiencies shall be noted and proper maintenance performed.

(e) The owner or operator may petition the Administrator to approve any alternative to either the monitoring requirements specified in paragraph (b) of this section or the monthly operational status inspections specified in paragraph (d) of this section if the alternative will provide a continuous record of operation of each emission capture system.

(f) Except as provided for under §60.273a(d), if emissions during any phase of the heat time are controlled by the use of a DEC system, the owner or operator shall install, calibrate, and maintain a monitoring device that allows the pressure in the free space inside the EAF to be monitored. The pressure shall be recorded as 15-minute integrated averages. The monitoring device may be installed in any appropriate location in the EAF or DEC duct prior to the introduction of ambient air such that reproducible results will be obtained. The pressure monitoring device shall have an accuracy of ±5 mm of water gauge over its normal operating range and shall be calibrated according to the manufacturer's instructions.

(g) Except as provided for under §60.273a(d), when the owner or operator of an EAF controlled by a DEC is required to demonstrate compliance with the standard under §60.272a(a)(3), and at any other time the Administrator may require (under section 114 of the Clean Air Act, as amended), the pressure in the free space inside the furnace shall be determined during the meltdown and refining period(s) using the monitoring device required under paragraph (f) of this section. The owner or operator may petition the Administrator for reestablishment of the pressure whenever the owner or operator can demonstrate to the Administrator's satisfaction that the EAF operating conditions upon which the pressures were previously established are no longer applicable. The pressure determined during the most recent demonstration of compliance shall be maintained at all times when the EAF is operating in a meltdown and refining period. Operation at higher pressures may be considered by the Administrator to be unacceptable operation and maintenance of the affected facility.

(h) During any performance test required under §60.8, and for any report thereof required by §60.276a(f) of this subpart, or to determine compliance with §60.272a(a)(3) of this subpart, the owner or operator shall monitor the following information for all heats covered by the test:

(1) Charge weights and materials, and tap weights and materials;

(2) Heat times, including start and stop times, and a log of process operation, including periods of no operation during testing and the pressure inside an EAF when direct-shell evacuation control systems are used;

(3) Control device operation log; and

(4) Continuous opacity monitor or Method 9 data.

[49 FR 43845, Oct. 31, 1984, as amended at 64 FR 10111, Mar. 2, 1999; 65 FR 61758, Oct. 17, 2000; 70 FR 8533, Feb. 22, 2005]

Back to Top

§60.275a Test methods and procedures.

(a) During performance tests required in §60.8, the owner or operator shall not add gaseous diluents to the effluent gas stream after the fabric in any pressurized fabric filter collector, unless the amount of dilution is separately determined and considered in the determination of emissions.

(b) When emissions from any EAF(s) or AOD vessel(s) are combined with emissions from facilities not subject to the provisions of this subpart but controlled by a common capture system and control device, the owner or operator shall use either or both of the following procedures during a performance test (see also §60.276a(e)):

(1) Determine compliance using the combined emissions.

(2) Use a method that is acceptable to the Administrator and that compensates for the emissions from the facilities not subject to the provisions of this subpart.

(c) When emission from any EAF(s) or AOD vessel(s) are combined with emissions from facilities not subject to the provisions of this subpart, the owner or operator shall demonstrate compliance with §60.272(a)(3) based on emissions from only the affected facility(ies).

(d) In conducting the performance tests required in §60.8, the owner or operator shall use as reference methods and procedures the test methods in appendix A of this part or other methods and procedures as specified in this section, except as provided in §60.8(b).

(e) The owner or operator shall determine compliance with the particulate matter standards in §60.272a as follows:

(1) Method 5 shall be used for negative-pressure fabric filters and other types of control devices and Method 5D shall be used for positive-pressure fabric filters to determine the particulate matter concentration and volumetric flow rate of the effluent gas. The sampling time and sample volume for each run shall be at least 4 hours and 4.50 dscm (160 dscf) and, when a single EAF or AOD vessel is sampled, the sampling time shall include an integral number of heats.

(2) When more than one control device serves the EAF(s) being tested, the concentration of particulate matter shall be determined using the following equation:

$$c_{st} = \left[\sum_{i=1}^{n} \left(c_{si} Q_{sdi} \right) \right] / \sum_{i=1}^{n} Q_{sdi}$$

View or download PDF

where:

c_{st} = average concentration of particulate matter, mg/dscm (gr/dscf).

c_{si} = concentration of particulate matter from control device “i”, mg/dscm (gr/dscf).

n = total number of control devices tested.

Q_{sdi} = volumetric flow rate of stack gas from control device “i”, dscm/hr (dscf/hr).

(3) Method 9 and the procedures of §60.11 shall be used to determine opacity.

(4) To demonstrate compliance with §60.272a(a) (1), (2), and (3), the Method 9 test runs shall be conducted concurrently with the particulate matter test runs, unless inclement weather interferes.

(f) To comply with §60.274a (c), (f), (g), and (h), the owner or operator shall obtain the information required in these paragraphs during the particulate matter runs.

(g) Any control device subject to the provisions of the subpart shall be designed and constructed to allow measurement of emissions using applicable test methods and procedures.

(h) Where emissions from any EAF(s) or AOD vessel(s) are combined with emissions from facilities not subject to the provisions of this subpart but controlled by a common capture system and control device, the owner or operator may use any of the following procedures during a performance test:

(1) Base compliance on control of the combined emissions;

(2) Utilize a method acceptable to the Administrator that compensates for the emissions from the facilities not subject to the provisions of this subpart, or;

(3) Any combination of the criteria of paragraphs (h)(1) and (h)(2) of this section.

(i) Where emissions from any EAF(s) or AOD vessel(s) are combined with emissions from facilities not subject to the provisions of this subpart, determinations of compliance with §60.272a(a)(3) will only be based upon emissions originating from the affected facility(ies).

(j) Unless the presence of inclement weather makes concurrent testing infeasible, the owner or operator shall conduct concurrently the performance tests required under §60.8 to demonstrate compliance with §60.272a(a) (1), (2), and (3) of this subpart.

[49 FR 43845, Oct. 31, 1984, as amended at 54 FR 6673, Feb. 14, 1989; 54 FR 21344, May 17, 1989; 65 FR 61758, Oct. 17, 2000]

Back to Top

§60.276a Recordkeeping and reporting requirements.

(a) Records of the measurements required in §60.274a must be retained for at least 2 years following the date of the measurement.

(b) Each owner or operator shall submit a written report of exceedances of the control device opacity to the Administrator semi-annually. For the purposes of these reports, exceedances are defined as all 6-minute periods during which the average opacity is 3 percent or greater.

(c) Operation at a furnace static pressure that exceeds the value established under §60.274a(g) and either operation of control system fan motor amperes at values exceeding ±15 percent of the value established under §60.274a(c) or operation at flow rates lower than those established under §60.274a(c) may be considered by the Administrator to be unacceptable operation and maintenance of the affected facility. Operation at such values shall be reported to the Administrator semiannually.

(d) The requirements of this section remain in force until and unless EPA, in delegating enforcement authority to a State under section 111(c) of the Act, approves reporting requirements or an alternative means of compliance surveillance adopted by such State. In that event, affected sources within the State will be relieved of the obligation to comply with this section, provided that they comply with the requirements established by the State.

(e) When the owner or operator of an EAF or AOD is required to demonstrate compliance with the standard under §60.275 (b)(2) or a combination of (b)(1) and (b)(2) the owner or operator shall obtain approval from the Administrator of the procedure(s) that will be used to determine compliance. Notification of the procedure(s) to be used must be postmarked at least 30 days prior to the performance test.

(f) For the purpose of this subpart, the owner or operator shall conduct the demonstration of compliance with §60.272a(a) of this subpart and furnish the Administrator a written report of the results of the test. This report shall include the following information:

(1) Facility name and address;

(2) Plant representative;

(3) Make and model of process, control device, and continuous monitoring equipment;

(4) Flow diagram of process and emission capture equipment including other equipment or process(es) ducted to the same control device;

(5) Rated (design) capacity of process equipment;

(6) Those data required under §60.274a(h) of this subpart;

(i) List of charge and tap weights and materials;

(ii) Heat times and process log;

(iii) Control device operation log; and

(iv) Continuous opacity monitor or Method 9 data.

(7) Test dates and test times;

(8) Test company;

(9) Test company representative;

(10) Test observers from outside agency;

(11) Description of test methodology used, including any deviation from standard reference methods;

(12) Schematic of sampling location;

(13) Number of sampling points;

(14) Description of sampling equipment;

(15) Listing of sampling equipment calibrations and procedures;

(16) Field and laboratory data sheets;

(17) Description of sample recovery procedures;

(18) Sampling equipment leak check results;

(19) Description of quality assurance procedures;

(20) Description of analytical procedures;

(21) Notation of sample blank corrections; and

(22) Sample emission calculations.

(g) The owner or operator shall maintain records of all shop opacity observations made in accordance with §60.273a(d). All shop opacity observations in excess of the emission limit specified in §60.272a(a)(3) of this subpart shall indicate a period of excess emission, and shall be reported to the administrator semi-annually, according to §60.7(c).

(h) The owner or operator shall maintain the following records for each bag leak detection system required under §60.273a(e):

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

(2) Records of bag leak detection system adjustments, including the date and time of the adjustment, the initial bag leak detection system settings, and the final bag leak detection system settings; and

(3) An identification of the date and time of all bag leak detection system alarms, the time that procedures to determine the cause of the alarm were initiated, if procedures were initiated within 1 hour of the alarm, the cause of the alarm, an explanation of the actions taken, the date and time the cause of the alarm was alleviated, and if the alarm was alleviated within 3 hours of the alarm.

[49 FR 43845, Oct. 31, 1984, as amended at 54 FR 6673, Feb. 14, 1989; 64 FR 10111, Mar. 2, 1999; 65 FR 61758, Oct. 17, 2000; 70 FR 8533, Feb. 22, 2005]

Appendix C

40 C.F.R. Part 60 Subpart TT

Standards of Performance for Metal Coil Surface Coating

Subpart TT—Standards of Performance for Metal Coil Surface Coating

Contents

SOURCE: 47 FR 49612, Nov. 1, 1982, unless otherwise noted.

Back to Top

§60.460 Applicability and designation of affected facility.

(a) The provisions of this subpart apply to the following affected facilities in a metal coil surface coating operation: each prime coat operation, each finish coat operation, and each prime and finish coat operation combined when the finish coat is applied wet on wet over the prime coat and both coatings are cured simultaneously.

(b) This subpart applies to any facility identified in paragraph (a) of this section that commences construction, modification, or reconstruction after January 5, 1981.

Back to Top

§60.461 Definitions.

(a) All terms used in this subpart not defined below are given the same meaning as in the Act or in subpart A of this part.

Coating means any organic material that is applied to the surface of metal coil.

Coating application station means that portion of the metal coil surface coating operation where the coating is applied to the surface of the metal coil. Included as part of the coating application station is the flashoff area between the coating application station and the curing oven.

Curing oven means the device that uses heat or radiation to dry or cure the coating applied to the metal coil.

Finish coat operation means the coating application station, curing oven, and quench station used to apply and dry or cure the final coating(s) on the surface of the metal coil. Where only a single coating is applied to the metal coil, that coating is considered a finish coat.

Metal coil surface coating operation means the application system used to apply an organic coating to the surface of any continuous metal strip with thickness of 0.15 millimeter (mm) (0.006 in.) or more that is packaged in a roll or coil.

Prime coat operation means the coating application station, curing oven, and quench station used to apply and dry or cure the initial coating(s) on the surface of the metal coil.

Quench station means that portion of the metal coil surface coating operation where the coated metal coil is cooled, usually by a water spray, after baking or curing.

VOC content means the quantity, in kilograms per liter of coating solids, of volatile organic compounds (VOC's) in a coating.

(b) All symbols used in this subpart not defined below are given the same meaning as in the Act and in subpart A of this part.

C_a = the VOC concentration in each gas stream leaving the control device and entering the atmosphere (parts per million by volume, as carbon).

C_b = the VOC concentration in each gas stream entering the control device (parts per million by volume, as carbon).

C_f = the VOC concentration in each gas steam emitted directly to the atmosphere (parts per million by volume, as carbon).

D_c = density of each coating, as received (kilograms per liter).

D_d = density of each VOC-solvent added to coatings (kilograms per liter).

D_r = density of VOC-solvent recovered by an emission control device (kilograms per liter).

E= VOC destruction efficiency of the control device (fraction).

F= the proportion of total VOC's emitted by an affected facility that enters the control device (fraction).

G= volume-weighted average mass of VOC's in coatings consumed in a calendar month per unit volume of coating solids applied (kilograms per liter).

L_c = the volume of each coating consumed, as received (liters).

L_d = the volume of each VOC-solvent added to coatings (liters).

L_r = the volume of VOC-solvent recovered by an emission control device (liters).

L_s = the volume of coating solids consumed (liters).

M_d = the mass of VOC-solvent added to coatings (kilograms).

M_o = the mass of VOC's in coatings consumed, as received (kilograms).

M_r = the mass of VOC's recovered by an emission control device (kilograms).

N= the volume-weighted average mass of VOC emissions to the atmosphere per unit volume of coating solids applied (kilograms per liter).

Q_a = the volumetric flow rate of each gas stream leaving the control device and entering the atmosphere (dry standard cubic meters per hour).

Q_b = the volumetric flow rate of each gas stream entering the control device (dry standard cubic meters per hour).

Q_f = the volumetric flow rate of each gas steam emitted directly to the atmosphere (dry standard cubic meters per hour).

R= the overall VOC emission reduction achieved for an affected facility (fraction).

S= the calculated monthly allowable emission limit (kilograms of VOC per liter of coating solids applied).

V_s = the proportion of solids in each coating, as received (fraction by volume).

W_o = the proportion of VOC's in each coating, as received (fraction by weight).

Back to Top

§60.462 Standards for volatile organic compounds.

(a) On and after the date on which §60.8 requires a performance test to be completed, each owner or operator subject to this subpart shall not cause to be discharged into the atmosphere more than:

(1) 0.28 kilogram VOC per liter (kg VOC/*l*) of coating solids applied for each calendar month for each affected facility that does not use an emission control device(s); or

(2) 0.14 kg VOC/*l* of coating solids applied for each calendar month for each affected facility that continuously uses an emission control device(s) operated at the most recently demonstrated overall efficiency; or

(3) 10 percent of the VOC's applied for each calendar month (90 percent emission reduction) for each affected facility that continuously uses an emission control device(s) operated at the most recently demonstrated overall efficiency; or

(4) A value between 0.14 (or a 90-percent emission reduction) and 0.28 kg VOC/*l* of coating solids applied for each calendar month for each affected facility that intermittently uses an emission control device operated at the most recently demonstrated overall efficiency.

Back to Top

§60.463 Performance test and compliance provisions.

(a) Section 60.8(d) and (f) do not apply to the performance test.

(b) The owner or operator of an affected facility shall conduct an initial performance test as required under §60.8(a) and thereafter a performance test for each calendar month for each affected facility according to the procedures in this section.

(c) The owner or operator shall use the following procedures for determining monthly volume-weighted average emissions of VOC's in kg/*l* of coating solids applied.

(1) An owner or operator shall use the following procedures for each affected facility that does not use a capture system and control device to comply with the emission limit specified under §60.462(a)(1). The owner or operator shall determine the composition of the coatings by formulation data supplied by the manufacturer of the coating or by an analysisof each coating, as received, using Method 24. The Administrator may require the owner or operator who uses formulation data supplied by the manufacturer of the coatings to determine the VOC content of coatings using Method 24 or an equivalent or alternative method. The owner or operator shall determine the volume of coating and the mass of VOC-solvent added to coatings from company records on a monthly basis. If a common coating distribution system

serves more than one affected facility or serves both affected and existing facilities, the owner or operator shall estimate the volume of coating used at each affected facility by using the average dry weight of coating and the surface area coated by each affected and existing facility or by other procedures acceptable to the Administrator.

(i) Calculate the volume-weighted average of the total mass of VOC's consumed per unit volume of coating solids applied during each calendar month for each affected facility, except as provided under paragraph (c)(1)(iv) of this section. The weighted average of the total mass of VOC's used per unit volume of coating solids applied each calendar month is determined by the following procedures.

(A) Calculate the mass of VOC's used (Mo + Md) during each calendar month for each affected facility by the following equation:

$$M_o + M_d = \sum_{i=1}^{n} L_{ci} D_{ci} W_{oi} + \sum_{j=1}^{m} L_{dj} D_{dj} \qquad \text{Equation 1}$$

View or download PDF

($\Sigma L_{dj} D_{dj}$ will be 0 if no VOC solvent is added to the coatings, as received)

where

n is the number of different coatings used during the calendar month, and

m is the number of different VOC solvents added to coatings used during the calendar month.

(B) Calculate the total volume of coating solids used (L_s) in each calendar month for each affected facility by the following equation:

$$L_s = \sum_{i=1}^{n} V_{si} L_{ci} \qquad \text{Equation 2}$$

View or download PDF

Where:

n is the number of different coatings used during the calendar month.

(C) Calculate the volume-weighted average mass of VOC's used per unit volume of coating solids applied (G) during the calendar month for each affected facility by the following equation:

$$G = \frac{M_o + M_d}{L_s} \qquad \text{Equation 3}$$

View or download PDF

(ii) Calculate the volume-weighted average of VOC emissions to the atmosphere (N) during the calendar month for each affected facility by the following equation:

$$N = G \qquad \text{Equation 4}$$

View or download PDF

(iii) Where the volume-weighted average mass of VOC's discharged to the atmosphere per unit volume of coating solids applied (N) is equal to or less than 0.28 kg/*l*, the affected facility is in compliance.

(iv) If each individual coating used by an affected facility has a VOC content, as received, that is equal to or less than 0.28 kg/*l* of coating solids, the affected facility is in compliance provided no VOC's are added to the coatings during distribution or application.

(2) An owner or operator shall use the following procedures for each affected facility that continuously uses a capture system and a control device that destroys VOC's (e.g., incinerator) to comply with the emission limit specified under §60.462(a) (2) or (3).

(i) Determine the overall reduction efficiency (R) for the capture system and control device.

For the initial performance test, the overall reduction efficiency (R) shall be determined as prescribed in paragraphs (c)(2)(i) (A), (B), and (C) of this section. In subsequent months, the owner or operator may use the most recently determined overall reduction efficiency (R) for the performance test, providing control device and capture system operating conditions have not changed. The procedure in paragraphs (c)(2)(i) (A), (B), and (C) of this section, shall be repeated when directed by the Administrator or when the owner or operator elects to operate the control device or capture system at conditions different from the initial performance test.

(A) Determine the fraction (F) of total VOC's emitted by an affected facility that enters the control device using the following equation:

$$F = \frac{\sum_{i=1}^{l} C_{bi} Q_{bi}}{\sum_{i=1}^{l} C_{bi} Q_{bi} + \sum_{j=1}^{p} C_{fj} Q_{fj}}$$

View or download PDF

Equation 5

Where:

l is the number of gas streams entering the control device, and

p is the number of gas streams emitted directly to the atmosphere.

(B) Determine the destruction efficiency of the control device (E) using values of the volumetric flow rate of each of the gas streams and the VOC content (as carbon) of each of the gas streams in and out of the device by the following equation:

$$E = \frac{\sum_{i=1}^{n} Q_{bi} C_{bi} - \sum_{j=1}^{m} Q_{aj} C_{aj}}{\sum_{i=1}^{n} Q_{bi} C_{bi}}$$

View or download PDF

Equation 6

Where:

n is the number of gas streams entering the control device, and

m is the number of gas streams leaving the control device and entering the atmosphere.

The owner or operator of the affected facility shall construct the VOC emission reduction system so that all volumetric flow rates and total VOC emissions can be accurately determined by the applicable test methods and procedures specified in §60.466. The owner or operator of the affected facility shall construct a temporary enclosure around the coating applicator and flashoff area during the performance test for the purpose of evaluating the capture efficiency of the system. The enclosure must be maintained at a negative pressure to ensure that all VOC emissions are measurable. If a permanent enclosure exists in the affected facility prior to the performance test and the Administrator is satisfied that the enclosure is adequately containing VOC emissions, no additional enclosure is required for the performance test.

(C) Determine overall reduction efficiency (R) using the following equation:

$$R=EF \qquad \text{Equation 7}$$

View or download PDF

If the overall reduction efficiency (R) is equal to or greater than 0.90, the affected facility is in compliance and no further computations are necessary. If the overall reduction efficiency (R) is less than 0.90, the average total VOC emissions to the atmosphere per unit volume of coating solids applied (N) shall be computed as follows.

(ii) Calculate the volume-weighted average of the total mass of VOC's per unit volume of coating solids applied (G) during each calendar month for each affected facility using equations in paragraphs (c)(1)(i) (A), (B), and (C) of this section.

(iii) Calculate the volume-weighted average of VOC emissions to the atmosphere (N) during each calendar month by the following equation:

$$N=G(1-R) \qquad \text{Equation 8}$$

View or download PDF

(iv) If the volume-weighted average mass of VOC's emitted to the atmosphere for each calendar month (N) is less than or equal to 0.14 kg/*l* of coating solids applied, the affected facility is in compliance. Each monthly calculation is a performance test.

(3) An owner or operator shall use the following procedure for each affected facility that uses a control device that recovers the VOC's (e.g., carbon adsorber) to comply with the applicable emission limit specified under §60.462(a) (2) or (3).

(i) Calculate the total mass of VOC's consumed (M_o + M_d) during each calendar month for each affected facility using equation (1).

(ii) Calculate the total mass of VOC's recovered (M_r) during each calendar month using the following equation:

$$M_r = L_r D_r \qquad \text{Equation 9}$$

View or download PDF

(iii) Calculate the overall reduction efficiency of the control device (R) for each calendar month for each affected facility using the following equation:

$$R=\frac{M_r}{M_o+M_d} \qquad \textit{Equation } 10$$

View or download PDF

If the overall reduction efficiency (R) is equal to or greater than 0.90, the affected facility is in compliance and no further computations are necessary. If the overall reduction efficiency (R) is less than 0.90, the average total VOC emissions to the atmosphere per unit volume of coating solids applied (N) must be computed as follows.

(iv) Calculate the total volume of coating solids consumed (L_s) and the volume-weighted average of the total mass of VOC's per unit volume of coating solids applied (G) during each calendar month for each affected facility using equations in paragraphs (c)(1)(i) (B) and (C) of this section.

(v) Calculate the volume-weighted average mass of VOC's emitted to the atmosphere (N) for each calendar month for each affected facility using equation (8).

(vi) If the weighted average mass of VOC's emitted to the atmosphere for each calendar month (N) is less than or equal to 0.14 kg/*l* of coating solids applied, the affected facility is in compliance. Each monthly calculation is a performance test.

(4) An owner or operator shall use the following procedures for each affected facility that intermittently uses a capture system and a control device to comply with the emission limit specified in §60.462(a)(4).

(i) Calculate the total volume of coating solids applied without the control device in operation (L_{sn}) during each calendar month for each affected facility using the following equation:

$$L_{sn}=\sum_{i-1}^{n} V_{si} L_{ci} \qquad \textit{Equation } 11$$

View or download PDF

Where:

n is the number of coatings used during the calendar month without the control device in operation.

(ii) Calculate the total volume of coating solids applied with the control device in operation (L_{sc}) during each calendar month for each affected facility using the following equation:

$$L_{sc}=\sum_{i-1}^{n} V_{si} L_{ci} \qquad \textit{Equation } 12$$

View or download PDF

Where:

n is the number of coatings used during the calendar month with the control device in operation.

(iii) Calculate the mass of VOC's used without the control device in operation (M_{on} + M_{dn}) during each calendar month for each affected facility using the following equation:

$$M_{on} + M_{dn} + \sum_{i=1}^{n} L_{ci} D_{ci} W_{oi} + \sum_{j=1}^{m} L_{dj} D_{dj} \quad \textit{Equation } 13$$

View or download PDF

Where:

n is the number of different coatings used without the control device in operation during the calendar month, and

m is the number of different VOC-solvents added to coatings used without the control device in operation during the calendar month.

(iv) Calculate the volume-weighted average of the total mass of VOC's consumed per unit volume of coating solids applied without the control device in operation (G_n) during each calendar month for each affected facility using the following equation:

$$G_n = \frac{M_{on} + M_{dn}}{L_{sn}} \quad \textit{Equation } 14$$

View or download PDF

(v) Calculate the mass of VOC's used with the control device in operation (M_{oc} + M_{dc}) during each calendar month for each affected facility using the following equation:

$$M_{oc} + M_{dc} = \sum_{i=1}^{n} L_{ci} D_{ci} W_{oi} + \sum_{i=1}^{m} L_{dj} D_{dj} \quad \textit{Equation } 15$$

View or download PDF

Where:

n is the number of different coatings used with the control device in operation during the calendar month, and

m is the number of different VOC-solvents added to coatings used with the control device in operation during the calendar month.

(vi) Calculate the volume-weighted average of the total mass of VOC's used per unit volume of coating solids applied with the control device in operation (G_c) during each calendar month for each affected facility using the following equation:

$$G = \frac{M_{oc} + M_{dc}}{L_{sn}} \quad \textit{Equation } 16$$

View or download PDF

(vii) Determine the overall reduction efficiency (R) for the capture system and control device using the procedures in paragraphs (c)(2)(i) (A), (B), and (C) or paragraphs (c)(3) (i), (ii), and (iii) of this section, whichever is applicable.

(viii) Calculate the volume-weighted average of VOC emissions to the atmosphere (N) during each calendar month for each affected facility using the following equation:

$$N = \frac{G_n L_{sn} + G_c L_{sc}(1-R)}{L_{sn} + L_{sc}} \qquad \textit{Equation } 17$$

View or download PDF

Equation 17

(ix) Calculate the emission limit(s) for each calendar month for each affected facility using the following equation:

$$S = \frac{0.28\, L_{sn} + 0.1\, G_c L_{sc}}{L_{ns} + L_{sc}}$$

View or download PDF

or

$$\frac{0.28\, L_{sn} + 0.14\, L_{sc}}{L_{sn} + L_{sc}} \qquad \textit{Equation } 18$$

View or download PDF

whichever is greater.

(x) If the volume-weighted average mass of VOC's emitted to the atmosphere for each calendar month (N) is less than or equal to the calculated emission limit (S) for the calendar month, the affected facility is in compliance. Each monthly calculation is a performance test.

[47 FR 49612, Nov. 1, 1982; 48 FR 1056, Jan. 10, 1983, as amended at 65 FR 61761, Oct. 17, 2000]

Back to Top

§60.464 Monitoring of emissions and operations.

(a) Where compliance with the numerical limit specified in §60.462(a) (1) or (2) is achieved through the use of low VOC-content coatings without the use of emission control devices or through the use of higher VOC-content coatings in conjunction with emission control devices, the owner or operator shall compute and record the average VOC content of coatings applied during each calendar month for each affected facility, according to the equations provided in §60.463.

(b) Where compliance with the limit specified in §60.462(a)(4) is achieved through the intermittent use of emission control devices, the owner or operator shall compute and record for each affected facility the average VOC content of coatings applied during each calendar month according to the equations provided in §60.463.

(c) If thermal incineration is used, each owner or operator subject to the provisions of this subpart shall install, calibrate, operate, and maintain a device that continuously records the combustion temperature of any effluent gases incinerated to achieve compliance with §60.462(a)(2), (3), or (4). This device shall have an accuracy of ±2.5 °C. or ±0.75 percent of the temperature being measured expressed in degrees Celsius, whichever is greater. Each owner or operator shall also record all periods (during actual coating operations) in excess of 3 hours during which the average temperature in any thermal incinerator used to control emissions from an affected facility remains more than 28 °C (50 °F) below the temperature at which compliance with §60.462(a)(2), (3), or (4) was demonstrated during the most recent measurement of incinerator efficiency required by §60.8. The records required by §60.7 shall identify each such occurrence and its duration. If catalytic incineration is used, the owner or operator shall install, calibrate, operate, and maintain a device to monitor and record continuously the gas temperature both upstream and downstream of the incinerator catalyst bed. This device shall have an accuracy of ±2.5 °C. or ±0.75 percent of the temperature being measured expressed in degrees Celsius, whichever is greater. During coating operations, the owner or operator shall record all periods in excess of 3 hours where the average difference between the temperature upstream and downstream of the incinerator catalyst bed remains below 80 percent of the temperature difference at which compliance was demonstrated during the most recent measurement of incinerator efficiency or when the inlet temperature falls more than 28 °C (50 °F) below the temperature at which compliance with §60.462(a)(2), (3), or (4) was demonstrated during the most recent measurement of incinerator efficiency required by §60.8. The records required by §60.7 shall identify each such occurrence and its duration.

[47 FR 49612, Nov. 1, 1982; 48 FR 1056, Jan. 10, 1983, as amended at 65 FR 61761, Oct. 17, 2000]

Back to Top

§60.465 Reporting and recordkeeping requirements.

(a) Where compliance with the numerical limit specified in §60.462(a) (1), (2), or (4) is achieved through the use of low VOC-content coatings without emission control devices or through the use of higher VOC-content coatings in conjunction with emission control devices, each owner or operator subject to the provisions of this subpart shall include in the initial compliance report required by §60.8 the weighted average of the VOC content of coatings used during a period of one calendar month for each affected facility. Where compliance with §60.462(a)(4) is achieved through the intermittent use of a control device, reports shall include separate values of the weighted average VOC content of coatings used with and without the control device in operation.

(b) Where compliance with §60.462(a)(2), (3), or (4) is achieved through the use of an emission control device that destroys VOC's, each owner or operator subject to the provisions of this subpart shall include the following data in the initial compliance report required by §60.8:

(1) The overall VOC destruction rate used to attain compliance with §60.462(a)(2), (3), or (4) and the calculated emission limit used to attain compliance with §60.462(a)(4); and

(2) The combustion temperature of the thermal incinerator or the gas temperature, both upstream and downstream of the incinerator catalyst bed, used to attain compliance with §60.462(a)(2), (3), or (4).

(c) Following the initial performance test, the owner or operator of an affected facility shall identify, record, and submit a written report to the Administrator every calendar quarter of each instance in which the volume-weighted average of the local mass of VOC's emitted to the atmosphere per volume of applied coating solids (N) is greater than the limit specified under §60.462. If no such instances have occurred during a particular quarter, a report stating this shall be submitted to the Administrator semiannually.

(d) The owner or operator of each affected facility shall also submit reports at the frequency specified in §60.7(c) when the incinerator temperature drops as defined under §60.464(c). If no such periods occur, the owner or operator shall state this in the report.

(e) Each owner or operator subject to the provisions of this subpart shall maintain at the source, for a period of at least 2 years, records of all data and calculations used to determine monthly VOC emissions from each affected facility and to determine the monthly emission limit, where applicable. Where compliance is achieved through the use of thermal incineration, each owner or operator shall maintain, at the source, daily records of the incinerator combustion temperature. If catalytic incineration is used, the owner or operator shall maintain at the source daily records of the gas temperature, both upstream and downstream of the incinerator catalyst bed.

[47 FR 49612, Nov. 1, 1982, as amended at 55 FR 51383, Dec. 13, 1990; 56 FR 20497, May 3, 1991; 65 FR 61761, Oct. 17, 2000]

Back to Top

§60.466 Test methods and procedures.

(a) The reference methods in appendix A to this part, except as provided under §60.8(b), shall be used to determine compliance with §60.462 as follows:

(1) Method 24, or data provided by the formulator of the coating, shall be used for determining the VOC content of each coating as applied to the surface of the metal coil. In the event of a dispute, Method 24 shall be the reference method. When VOC content of waterborne coatings, determined by Method 24, is used to determine compliance of affected facilities, the results of the Method 24 analysis shall be adjusted as described in Section 12.6 of Method 24;

(2) Method 25, both for measuring the VOC concentration in each gas stream entering and leaving the control device on each stack equipped with an emission control device and for measuring the VOC concentration in each gas stream emitted directly to the atmosphere;

(3) Method 1 for sample and velocity traverses;

(4) Method 2 for velocity and volumetric flow rate;

(5) Method 3 for gas analysis; and

(6) Method 4 for stack gas moisture.

(b) For Method 24, the coating sample must be at least a 1-liter sample taken at a point where the sample will be representative of the coating as applied to the surface of the metal coil.

(c) For Method 25, the sampling time for each of three runs is to be at least 60 minutes, and the minimum sampling volume is to be at least 0.003 dscm (0.11 dscf); however, shorter sampling times or smaller volumes, when necessitated by process variables or other factors, may be approved by the Administrator.

(d) The Administrator will approve testing of representative stacks on a case-by-case basis if the owner or operator can demonstrate to the satisfaction of the Administrator that testing of representative stacks yields results comparable to those that would be obtained by testing all stacks.

[47 FR 49612, Nov. 1, 1982, as amended at 51 FR 22938, June 24, 1986; 65 FR 61761, Oct. 17, 2000]

Appendix D

40 C.F.R. Part 60 Subpart IIII

Standards of Performance for Stationary Compression Ignition Internal Combustion Engines

Title 40: Protection of Environment
PART 60—STANDARDS OF PERFORMANCE FOR NEW STATIONARY SOURCES

Subpart IIII—Standards of Performance for Stationary Compression Ignition Internal Combustion Engines

Contents

SOURCE: 71 FR 39172, July 11, 2006, unless otherwise noted.

Back to Top

WHAT THIS SUBPART COVERS

Back to Top

§60.4200 Am I subject to this subpart?

(a) The provisions of this subpart are applicable to manufacturers, owners, and operators of stationary compression ignition (CI) internal combustion engines (ICE) and other persons as specified in paragraphs (a)(1) through (4) of this section. For the purposes of this subpart, the date that construction commences is the date the engine is ordered by the owner or operator.

(1) Manufacturers of stationary CI ICE with a displacement of less than 30 liters per cylinder where the model year is:

(i) 2007 or later, for engines that are not fire pump engines;

(ii) The model year listed in Table 3 to this subpart or later model year, for fire pump engines.

(2) Owners and operators of stationary CI ICE that commence construction after July 11, 2005, where the stationary CI ICE are:

(i) Manufactured after April 1, 2006, and are not fire pump engines, or

(ii) Manufactured as a certified National Fire Protection Association (NFPA) fire pump engine after July 1, 2006.

(3) Owners and operators of any stationary CI ICE that are modified or reconstructed after July 11, 2005 and any person that modifies or reconstructs any stationary CI ICE after July 11, 2005.

(4) The provisions of §60.4208 of this subpart are applicable to all owners and operators of stationary CI ICE that commence construction after July 11, 2005.

(b) The provisions of this subpart are not applicable to stationary CI ICE being tested at a stationary CI ICE test cell/stand.

(c) If you are an owner or operator of an area source subject to this subpart, you are exempt from the obligation to obtain a permit under 40 CFR part 70 or 40 CFR part 71, provided you are not required to obtain a permit under 40 CFR 70.3(a) or 40 CFR 71.3(a) for a reason other than your status as an area source under this subpart. Notwithstanding the previous sentence, you must continue to comply with the provisions of this subpart applicable to area sources.

(d) Stationary CI ICE may be eligible for exemption from the requirements of this subpart as described in 40 CFR part 1068, subpart C (or the exemptions described in 40 CFR part 89, subpart J and 40 CFR part 94, subpart J, for engines that would need to be certified to standards in those parts), except that owners and operators, as well as manufacturers, may be eligible to request an exemption for national security.

(e) Owners and operators of facilities with CI ICE that are acting as temporary replacement units and that are located at a stationary source for less than 1 year and that have been properly certified as meeting the standards that would be applicable to such engine under the appropriate nonroad engine provisions, are not required to meet any other provisions under this subpart with regard to such engines.

[71 FR 39172, July 11, 2006, as amended at 76 FR 37967, June 28, 2011]

Back to Top

EMISSION STANDARDS FOR MANUFACTURERS

Back to Top

§60.4201 What emission standards must I meet for non-emergency engines if I am a stationary CI internal combustion engine manufacturer?

(a) Stationary CI internal combustion engine manufacturers must certify their 2007 model year and later non-emergency stationary CI ICE with a maximum engine power less than or equal to 2,237 kilowatt (KW) (3,000 horsepower (HP)) and a displacement of less than 10 liters per cylinder to the certification emission standards for new nonroad CI engines in 40 CFR 89.112, 40 CFR 89.113, 40 CFR 1039.101, 40 CFR 1039.102, 40 CFR 1039.104, 40 CFR 1039.105, 40 CFR 1039.107, and 40 CFR 1039.115, as applicable, for all pollutants, for the same model year and maximum engine power.

(b) Stationary CI internal combustion engine manufacturers must certify their 2007 through 2010 model year non-emergency stationary CI ICE with a maximum engine power greater than 2,237 KW (3,000 HP) and a displacement of less than 10 liters per cylinder to the emission standards in table 1 to this subpart, for all pollutants, for the same maximum engine power.

(c) Stationary CI internal combustion engine manufacturers must certify their 2011 model year and later non-emergency stationary CI ICE with a maximum engine power greater than 2,237 KW (3,000 HP) and a displacement of less than 10 liters per cylinder to the certification emission standards for new nonroad CI engines in 40 CFR 1039.101, 40 CFR 1039.102, 40 CFR 1039.104, 40 CFR 1039.105, 40 CFR 1039.107, and 40 CFR 1039.115, as applicable, for all pollutants, for the same maximum engine power.

(d) Stationary CI internal combustion engine manufacturers must certify the following non-emergency stationary CI ICE to the certification emission standards for new marine CI engines in 40 CFR 94.8, as applicable, for all pollutants, for the same displacement and maximum engine power:

(1) Their 2007 model year through 2012 non-emergency stationary CI ICE with a displacement of greater than or equal to 10 liters per cylinder and less than 30 liters per cylinder;

(2) Their 2013 model year non-emergency stationary CI ICE with a maximum engine power greater than or equal to 3,700 KW (4,958 HP) and a displacement of greater than or equal to 10 liters per cylinder and less than 15 liters per cylinder; and

(3) Their 2013 model year non-emergency stationary CI ICE with a displacement of greater than or equal to 15 liters per cylinder and less than 30 liters per cylinder.

(e) Stationary CI internal combustion engine manufacturers must certify the following non-emergency stationary CI ICE to the certification emission standards and other requirements for new marine CI engines in 40 CFR 1042.101, 40 CFR 1042.107, 40 CFR 1042.110, 40 CFR 1042.115, 40 CFR 1042.120, and 40 CFR 1042.145, as applicable, for all pollutants, for the same displacement and maximum engine power:

(1) Their 2013 model year non-emergency stationary CI ICE with a maximum engine power less than 3,700 KW (4,958 HP) and a displacement of greater than or equal to 10 liters per cylinder and less than 15 liters per cylinder; and

(2) Their 2014 model year and later non-emergency stationary CI ICE with a displacement of greater than or equal to 10 liters per cylinder and less than 30 liters per cylinder.

(f) Notwithstanding the requirements in paragraphs (a) through (c) of this section, stationary non-emergency CI ICE identified in paragraphs (a) and (c) may be certified to the provisions of 40 CFR part 94 or, if Table 1 to 40 CFR 1042.1 identifies 40 CFR part 1042 as being applicable, 40 CFR part 1042, if the engines will be used solely in either or both of the following locations:

(1) Areas of Alaska not accessible by the Federal Aid Highway System (FAHS); and

(2) Marine offshore installations.

(g) Notwithstanding the requirements in paragraphs (a) through (f) of this section, stationary CI internal combustion engine manufacturers are not required to certify reconstructed engines; however manufacturers may elect to do so. The reconstructed engine must be certified to the emission standards specified in paragraphs (a) through (e) of this section that are applicable to the model year, maximum engine power, and displacement of the reconstructed stationary CI ICE.

[71 FR 39172, July 11, 2006, as amended at 76 FR 37967, June 28, 2011]

Back to Top

§60.4202 What emission standards must I meet for emergency engines if I am a stationary CI internal combustion engine manufacturer?

(a) Stationary CI internal combustion engine manufacturers must certify their 2007 model year and later emergency stationary CI ICE with a maximum engine power less than or equal to 2,237 KW (3,000 HP) and a displacement of less than 10 liters per cylinder that are not fire pump engines to the emission standards specified in paragraphs (a)(1) through (2) of this section.

(1) For engines with a maximum engine power less than 37 KW (50 HP):

(i) The certification emission standards for new nonroad CI engines for the same model year and maximum engine power in 40 CFR 89.112 and 40 CFR 89.113 for all pollutants for model year 2007 engines, and

(ii) The certification emission standards for new nonroad CI engines in 40 CFR 1039.104, 40 CFR 1039.105, 40 CFR 1039.107, 40 CFR 1039.115, and table 2 to this subpart, for 2008 model year and later engines.

(2) For engines with a maximum engine power greater than or equal to 37 KW (50 HP), the certification emission standards for new nonroad CI engines for the same model year and maximum engine power in 40 CFR 89.112 and 40 CFR 89.113 for all pollutants beginning in model year 2007.

(b) Stationary CI internal combustion engine manufacturers must certify their 2007 model year and later emergency stationary CI ICE with a maximum engine power greater than 2,237 KW (3,000 HP) and a displacement of less than 10 liters per cylinder that are not fire pump engines to the emission standards specified in paragraphs (b)(1) through (2) of this section.

(1) For 2007 through 2010 model years, the emission standards in table 1 to this subpart, for all pollutants, for the same maximum engine power.

(2) For 2011 model year and later, the certification emission standards for new nonroad CI engines for engines of the same model year and maximum engine power in 40 CFR 89.112 and 40 CFR 89.113 for all pollutants.

(c) [Reserved]

(d) Beginning with the model years in table 3 to this subpart, stationary CI internal combustion engine manufacturers must certify their fire pump stationary CI ICE to the emission standards in table 4 to this subpart, for all pollutants, for the same model year and NFPA nameplate power.

(e) Stationary CI internal combustion engine manufacturers must certify the following emergency stationary CI ICE that are not fire pump engines to the certification emission standards for new marine CI engines in 40 CFR 94.8, as applicable, for all pollutants, for the same displacement and maximum engine power:

(1) Their 2007 model year through 2012 emergency stationary CI ICE with a displacement of greater than or equal to 10 liters per cylinder and less than 30 liters per cylinder;

(2) Their 2013 model year and later emergency stationary CI ICE with a maximum engine power greater than or equal to 3,700 KW (4,958 HP) and a displacement of greater than or equal to 10 liters per cylinder and less than 15 liters per cylinder;

(3) Their 2013 model year emergency stationary CI ICE with a displacement of greater than or equal to 15 liters per cylinder and less than 30 liters per cylinder; and

(4) Their 2014 model year and later emergency stationary CI ICE with a maximum engine power greater than or equal to 2,000 KW (2,682 HP) and a displacement of greater than or equal to 15 liters per cylinder and less than 30 liters per cylinder.

(f) Stationary CI internal combustion engine manufacturers must certify the following emergency stationary CI ICE to the certification emission standards and other requirements applicable to Tier 3 new marine CI engines in 40 CFR 1042.101, 40 CFR 1042.107, 40 CFR 1042.115, 40 CFR 1042.120, and 40 CFR 1042.145, for all pollutants, for the same displacement and maximum engine power:

(1) Their 2013 model year and later emergency stationary CI ICE with a maximum engine power less than 3,700 KW (4,958 HP) and a displacement of greater than or equal to 10 liters per cylinder and less than 15 liters per cylinder; and

(2) Their 2014 model year and later emergency stationary CI ICE with a maximum engine power less than 2,000 KW (2,682 HP) and a displacement of greater than or equal to 15 liters per cylinder and less than 30 liters per cylinder.

(g) Notwithstanding the requirements in paragraphs (a) through (d) of this section, stationary emergency CI internal combustion engines identified in paragraphs (a) and (c) may be certified to the provisions of 40 CFR part 94 or, if Table 2 to 40 CFR 1042.101 identifies Tier 3 standards as being applicable, the requirements applicable to Tier 3 engines in 40 CFR part 1042, if the engines will be used solely in either or both of the following locations:

(1) Areas of Alaska not accessible by the FAHS; and

(2) Marine offshore installations.

(h) Notwithstanding the requirements in paragraphs (a) through (f) of this section, stationary CI internal combustion engine manufacturers are not required to certify reconstructed engines; however manufacturers may elect to do so. The reconstructed engine must be certified to the emission standards specified in paragraphs (a) through (f) of this section that are applicable to the model year, maximum engine power and displacement of the reconstructed emergency stationary CI ICE.

[71 FR 39172, July 11, 2006, as amended at 76 FR 37968, June 28, 2011]

Back to Top

§60.4203 How long must my engines meet the emission standards if I am a manufacturer of stationary CI internal combustion engines?

Engines manufactured by stationary CI internal combustion engine manufacturers must meet the emission standards as required in §§60.4201 and 60.4202 during the certified emissions life of the engines.

[76 FR 37968, June 28, 2011]

Back to Top

EMISSION STANDARDS FOR OWNERS AND OPERATORS

Back to Top

§60.4204 What emission standards must I meet for non-emergency engines if I am an owner or operator of a stationary CI internal combustion engine?

(a) Owners and operators of pre-2007 model year non-emergency stationary CI ICE with a displacement of less than 10 liters per cylinder must comply with the emission standards in table 1 to this subpart. Owners and operators of pre-2007 model year non-emergency stationary CI ICE with a displacement of greater than or equal to 10 liters per cylinder and less than 30 liters per cylinder must comply with the emission standards in 40 CFR 94.8(a)(1).

(b) Owners and operators of 2007 model year and later non-emergency stationary CI ICE with a displacement of less than 30 liters per cylinder must comply with the emission standards for new CI engines in §60.4201 for their 2007 model year and later stationary CI ICE, as applicable.

(c) Owners and operators of non-emergency stationary CI engines with a displacement of greater than or equal to 30 liters per cylinder must meet the following requirements:

(1) For engines installed prior to January 1, 2012, limit the emissions of NO_x in the stationary CI internal combustion engine exhaust to the following:

(i) 17.0 grams per kilowatt-hour (g/KW-hr) (12.7 grams per horsepower-hr (g/HP-hr)) when maximum engine speed is less than 130 revolutions per minute (rpm);

(ii) $45 \cdot n^{-0.2}$ g/KW-hr ($34 \cdot n^{-0.2}$ g/HP-hr) when maximum engine speed is 130 or more but less than 2,000 rpm, where n is maximum engine speed; and

(iii) 9.8 g/KW-hr (7.3 g/HP-hr) when maximum engine speed is 2,000 rpm or more.

(2) For engines installed on or after January 1, 2012 and before January 1, 2016, limit the emissions of NO_x in the stationary CI internal combustion engine exhaust to the following:

(i) 14.4 g/KW-hr (10.7 g/HP-hr) when maximum engine speed is less than 130 rpm;

(ii) $44 \cdot n^{-0.23}$ g/KW-hr ($33 \cdot n^{-0.23}$ g/HP-hr) when maximum engine speed is greater than or equal to 130 but less than 2,000 rpm and where n is maximum engine speed; and

(iii) 7.7 g/KW-hr (5.7 g/HP-hr) when maximum engine speed is greater than or equal to 2,000 rpm.

(3) For engines installed on or after January 1, 2016, limit the emissions of NO_x in the stationary CI internal combustion engine exhaust to the following:

(i) 3.4 g/KW-hr (2.5 g/HP-hr) when maximum engine speed is less than 130 rpm;

(ii) $9.0 \cdot n^{-0.20}$ g/KW-hr ($6.7 \cdot n^{-0.20}$ g/HP-hr) where n (maximum engine speed) is 130 or more but less than 2,000 rpm; and

(iii) 2.0 g/KW-hr (1.5 g/HP-hr) where maximum engine speed is greater than or equal to 2,000 rpm.

(4) Reduce particulate matter (PM) emissions by 60 percent or more, or limit the emissions of PM in the stationary CI internal combustion engine exhaust to 0.15 g/KW-hr (0.11 g/HP-hr).

(d) Owners and operators of non-emergency stationary CI ICE with a displacement of less than 30 liters per cylinder who conduct performance tests in-use must meet the not-to-exceed (NTE) standards as indicated in §60.4212.

(e) Owners and operators of any modified or reconstructed non-emergency stationary CI ICE subject to this subpart must meet the emission standards applicable to the model year, maximum engine power, and displacement of the modified or reconstructed non-emergency stationary CI ICE that are specified in paragraphs (a) through (d) of this section.

[71 FR 39172, July 11, 2006, as amended at 76 FR 37968, June 28, 2011]

Back to Top

§60.4205 What emission standards must I meet for emergency engines if I am an owner or operator of a stationary CI internal combustion engine?

(a) Owners and operators of pre-2007 model year emergency stationary CI ICE with a displacement of less than 10 liters per cylinder that are not fire pump engines must comply with the emission standards in Table 1 to this subpart. Owners and operators of pre-2007 model year emergency stationary CI ICE with a displacement of greater than or equal to 10 liters per cylinder and less than 30 liters per cylinder that are not fire pump engines must comply with the emission standards in 40 CFR 94.8(a)(1).

(b) Owners and operators of 2007 model year and later emergency stationary CI ICE with a displacement of less than 30 liters per cylinder that are not fire pump engines must comply with the emission standards for new nonroad CI engines in §60.4202, for all pollutants, for the same model year and maximum engine power for their 2007 model year and later emergency stationary CI ICE.

(c) Owners and operators of fire pump engines with a displacement of less than 30 liters per cylinder must comply with the emission standards in table 4 to this subpart, for all pollutants.

(d) Owners and operators of emergency stationary CI engines with a displacement of greater than or equal to 30 liters per cylinder must meet the requirements in this section.

(1) For engines installed prior to January 1, 2012, limit the emissions of NO_x in the stationary CI internal combustion engine exhaust to the following:

(i) 17.0 g/KW-hr (12.7 g/HP-hr) when maximum engine speed is less than 130 rpm;

(ii) $45 \cdot n^{-0.2}$ g/KW-hr ($34 \cdot n^{-0.2}$ g/HP-hr) when maximum engine speed is 130 or more but less than 2,000 rpm, where n is maximum engine speed; and

(iii) 9.8 g/kW-hr (7.3 g/HP-hr) when maximum engine speed is 2,000 rpm or more.

(2) For engines installed on or after January 1, 2012, limit the emissions of NO_x in the stationary CI internal combustion engine exhaust to the following:

(i) 14.4 g/KW-hr (10.7 g/HP-hr) when maximum engine speed is less than 130 rpm;

(ii) $44 \cdot n^{-0.23}$ g/KW-hr ($33 \cdot n^{-0.23}$ g/HP-hr) when maximum engine speed is greater than or equal to 130 but less than 2,000 rpm and where n is maximum engine speed; and

(iii) 7.7 g/KW-hr (5.7 g/HP-hr) when maximum engine speed is greater than or equal to 2,000 rpm.

(3) Limit the emissions of PM in the stationary CI internal combustion engine exhaust to 0.40 g/KW-hr (0.30 g/HP-hr).

(e) Owners and operators of emergency stationary CI ICE with a displacement of less than 30 liters per cylinder who conduct performance tests in-use must meet the NTE standards as indicated in §60.4212.

(f) Owners and operators of any modified or reconstructed emergency stationary CI ICE subject to this subpart must meet the emission standards applicable to the model year, maximum engine power, and displacement of the modified or reconstructed CI ICE that are specified in paragraphs (a) through (e) of this section.

[71 FR 39172, July 11, 2006, as amended at 76 FR 37969, June 28, 2011]

Back to Top

§60.4206 How long must I meet the emission standards if I am an owner or operator of a stationary CI internal combustion engine?

Owners and operators of stationary CI ICE must operate and maintain stationary CI ICE that achieve the emission standards as required in §§60.4204 and 60.4205 over the entire life of the engine.

[76 FR 37969, June 28, 2011]

Back to Top

FUEL REQUIREMENTS FOR OWNERS AND OPERATORS

Back to Top

§60.4207 What fuel requirements must I meet if I am an owner or operator of a stationary CI internal combustion engine subject to this subpart?

(a) Beginning October 1, 2007, owners and operators of stationary CI ICE subject to this subpart that use diesel fuel must use diesel fuel that meets the requirements of 40 CFR 80.510(a).

(b) Beginning October 1, 2010, owners and operators of stationary CI ICE subject to this subpart with a displacement of less than 30 liters per cylinder that use diesel fuel must use diesel fuel that meets the requirements of 40 CFR 80.510(b) for nonroad diesel fuel, except that any existing diesel fuel purchased (or otherwise obtained) prior to October 1, 2010, may be used until depleted.

(c) [Reserved]

(d) Beginning June 1, 2012, owners and operators of stationary CI ICE subject to this subpart with a displacement of greater than or equal to 30 liters per cylinder are no longer subject to the requirements of paragraph (a) of this section, and must use fuel that meets a maximum per-gallon sulfur content of 1,000 parts per million (ppm).

(e) Stationary CI ICE that have a national security exemption under §60.4200(d) are also exempt from the fuel requirements in this section.

[71 FR 39172, July 11, 2006, as amended at 76 FR 37969, June 28, 2011; 78 FR 6695, Jan. 30, 2013]

Back to Top

OTHER REQUIREMENTS FOR OWNERS AND OPERATORS

Back to Top

§60.4208 What is the deadline for importing or installing stationary CI ICE produced in previous model years?

(a) After December 31, 2008, owners and operators may not install stationary CI ICE (excluding fire pump engines) that do not meet the applicable requirements for 2007 model year engines.

(b) After December 31, 2009, owners and operators may not install stationary CI ICE with a maximum engine power of less than 19 KW (25 HP) (excluding fire pump engines) that do not meet the applicable requirements for 2008 model year engines.

(c) After December 31, 2014, owners and operators may not install non-emergency stationary CI ICE with a maximum engine power of greater than or equal to 19 KW (25 HP) and less than 56 KW (75 HP) that do not meet the applicable requirements for 2013 model year non-emergency engines.

(d) After December 31, 2013, owners and operators may not install non-emergency stationary CI ICE with a maximum engine power of greater than or equal to 56 KW (75 HP) and less than 130 KW (175 HP) that do not meet the applicable requirements for 2012 model year non-emergency engines.

(e) After December 31, 2012, owners and operators may not install non-emergency stationary CI ICE with a maximum engine power of greater than or equal to 130 KW (175 HP), including those above 560 KW (750 HP), that do not meet the applicable requirements for 2011 model year non-emergency engines.

(f) After December 31, 2016, owners and operators may not install non-emergency stationary CI ICE with a maximum engine power of greater than or equal to 560 KW (750 HP) that do not meet the applicable requirements for 2015 model year non-emergency engines.

(g) After December 31, 2018, owners and operators may not install non-emergency stationary CI ICE with a maximum engine power greater than or equal to 600 KW (804 HP) and less than 2,000 KW (2,680 HP) and a displacement of greater than or equal to 10 liters per cylinder and less than 30 liters per cylinder that do not meet the applicable requirements for 2017 model year non-emergency engines.

(h) In addition to the requirements specified in §§60.4201, 60.4202, 60.4204, and 60.4205, it is prohibited to import stationary CI ICE with a displacement of less than 30 liters per cylinder that do not meet the applicable requirements specified in paragraphs (a) through (g) of this section after the dates specified in paragraphs (a) through (g) of this section.

(i) The requirements of this section do not apply to owners or operators of stationary CI ICE that have been modified, reconstructed, and do not apply to engines that were removed from one existing location and reinstalled at a new location.

[71 FR 39172, July 11, 2006, as amended at 76 FR 37969, June 28, 2011]

Back to Top

§60.4209 What are the monitoring requirements if I am an owner or operator of a stationary CI internal combustion engine?

If you are an owner or operator, you must meet the monitoring requirements of this section. In addition, you must also meet the monitoring requirements specified in §60.4211.

(a) If you are an owner or operator of an emergency stationary CI internal combustion engine that does not meet the standards applicable to non-emergency engines, you must install a non-resettable hour meter prior to startup of the engine.

(b) If you are an owner or operator of a stationary CI internal combustion engine equipped with a diesel particulate filter to comply with the emission standards in §60.4204, the diesel particulate filter must be installed with a backpressure monitor that notifies the owner or operator when the high backpressure limit of the engine is approached.

[71 FR 39172, July 11, 2006, as amended at 76 FR 37969, June 28, 2011]

Back to Top

COMPLIANCE REQUIREMENTS

Back to Top

§60.4210 What are my compliance requirements if I am a stationary CI internal combustion engine manufacturer?

(a) Stationary CI internal combustion engine manufacturers must certify their stationary CI ICE with a displacement of less than 10 liters per cylinder to the emission standards specified in §60.4201(a) through (c) and §60.4202(a), (b) and (d) using the certification procedures required in 40 CFR part 89, subpart B, or 40 CFR part 1039, subpart C, as applicable, and must test their engines as specified in those parts. For the purposes of this subpart, engines certified to the standards in table 1 to this subpart shall be subject to the same requirements as engines certified to the standards in 40 CFR part 89. For the purposes of this subpart, engines certified to the standards in table 4 to this subpart shall be subject to the same requirements as engines certified to the standards in 40 CFR part 89, except that engines with NFPA nameplate power of less than 37 KW (50 HP) certified to model year 2011 or later standards shall be subject to the same requirements as engines certified to the standards in 40 CFR part 1039.

(b) Stationary CI internal combustion engine manufacturers must certify their stationary CI ICE with a displacement of greater than or equal to 10 liters per cylinder and less than 30 liters per cylinder to the emission standards specified in §60.4201(d) and (e) and §60.4202(e) and (f) using the certification procedures required in 40 CFR part 94, subpart C, or 40 CFR part 1042, subpart C, as applicable, and must test their engines as specified in 40 CFR part 94 or 1042, as applicable.

(c) Stationary CI internal combustion engine manufacturers must meet the requirements of 40 CFR 1039.120, 1039.125, 1039.130, and 1039.135, and 40 CFR part 1068 for engines that are certified to the emission standards in 40 CFR part 1039. Stationary CI internal combustion engine manufacturers must meet the corresponding provisions of 40 CFR part 89, 40 CFR part 94 or 40 CFR part 1042 for engines that would be covered by that part if they were nonroad (including marine) engines. Labels on such engines must refer to stationary engines, rather than or in addition to nonroad or marine engines, as appropriate. Stationary CI internal combustion engine manufacturers must label their engines according to paragraphs (c)(1) through (3) of this section.

(1) Stationary CI internal combustion engines manufactured from January 1, 2006 to March 31, 2006 (January 1, 2006 to June 30, 2006 for fire pump engines), other than those that are part of certified engine families under the nonroad CI engine regulations, must be labeled according to 40 CFR 1039.20.

(2) Stationary CI internal combustion engines manufactured from April 1, 2006 to December 31, 2006 (or, for fire pump engines, July 1, 2006 to December 31 of the year preceding the year listed in table 3 to this subpart) must be labeled according to paragraphs (c)(2)(i) through (iii) of this section:

(i) Stationary CI internal combustion engines that are part of certified engine families under the nonroad regulations must meet the labeling requirements for nonroad CI engines, but do not have to meet the labeling requirements in 40 CFR 1039.20.

(ii) Stationary CI internal combustion engines that meet Tier 1 requirements (or requirements for fire pumps) under this subpart, but do not meet the requirements applicable to nonroad CI engines must be labeled according to 40 CFR 1039.20. The engine manufacturer may add language to the label clarifying that the engine meets Tier 1 requirements (or requirements for fire pumps) of this subpart.

(iii) Stationary CI internal combustion engines manufactured after April 1, 2006 that do not meet Tier 1 requirements of this subpart, or fire pumps engines manufactured after July 1, 2006 that do not meet the requirements for fire pumps under this subpart, may not be used in the U.S. If any such engines are manufactured in the U.S. after April 1, 2006 (July 1, 2006 for fire pump engines), they must be exported or must be brought into compliance with the appropriate standards prior to initial operation. The export provisions of 40 CFR 1068.230 would apply to engines for export and the manufacturers must label such engines according to 40 CFR 1068.230.

(3) Stationary CI internal combustion engines manufactured after January 1, 2007 (for fire pump engines, after January 1 of the year listed in table 3 to this subpart, as applicable) must be labeled according to paragraphs (c)(3)(i) through (iii) of this section.

(i) Stationary CI internal combustion engines that meet the requirements of this subpart and the corresponding requirements for nonroad (including marine) engines of the same model year and HP must be labeled according to the provisions in 40 CFR parts 89, 94, 1039 or 1042, as appropriate.

(ii) Stationary CI internal combustion engines that meet the requirements of this subpart, but are not certified to the standards applicable to nonroad (including marine) engines of the same model year and HP must be labeled according to the provisions in 40 CFR parts 89, 94, 1039 or 1042, as appropriate, but the words “stationary” must be included instead of “nonroad” or “marine” on the label. In addition, such engines must be labeled according to 40 CFR 1039.20.

(iii) Stationary CI internal combustion engines that do not meet the requirements of this subpart must be labeled according to 40 CFR 1068.230 and must be exported under the provisions of 40 CFR 1068.230.

(d) An engine manufacturer certifying an engine family or families to standards under this subpart that are identical to standards applicable under 40 CFR parts 89, 94, 1039 or 1042 for that model year may certify any such family that contains both nonroad (including marine) and stationary engines as a single engine family and/or may include any such family containing stationary engines in the averaging, banking and trading provisions applicable for such engines under those parts.

(e) Manufacturers of engine families discussed in paragraph (d) of this section may meet the labeling requirements referred to in paragraph (c) of this section for stationary CI ICE by either adding a separate label containing the information required in paragraph (c) of this section or by adding the words “and stationary” after the word “nonroad” or “marine,” as appropriate, to the label.

(f) Starting with the model years shown in table 5 to this subpart, stationary CI internal combustion engine manufacturers must add a permanent label stating that the engine is for stationary emergency use only to each new emergency stationary CI internal combustion engine greater than or equal to 19 KW (25 HP) that meets all the emission standards for emergency engines in §60.4202 but does not meet all the emission standards for non-emergency engines in §60.4201. The label must be added according to the labeling requirements specified in 40 CFR 1039.135(b). Engine manufacturers must specify in the owner's manual that operation of emergency engines is limited to emergency operations and required maintenance and testing.

(g) Manufacturers of fire pump engines may use the test cycle in table 6 to this subpart for testing fire pump engines and may test at the NFPA certified nameplate HP, provided that the engine is labeled as “Fire Pump Applications Only”.

(h) Engine manufacturers, including importers, may introduce into commerce uncertified engines or engines certified to earlier standards that were manufactured before the new or changed standards took effect until inventories are depleted, as long as such engines are part of normal inventory. For example, if the engine manufacturers' normal industry practice is to keep on hand a one-month supply of engines based on its projected sales, and a new tier of standards starts to apply for the 2009 model year, the engine manufacturer may manufacture engines based on the normal inventory requirements late in the 2008 model year, and sell those engines for installation. The engine manufacturer may not circumvent the provisions of §60.4201 or §60.4202 by stockpiling engines that are built before new or changed standards take effect. Stockpiling of such engines beyond normal industry practice is a violation of this subpart.

(i) The replacement engine provisions of 40 CFR 89.1003(b)(7), 40 CFR 94.1103(b)(3), 40 CFR 94.1103(b)(4) and 40 CFR 1068.240 are applicable to stationary CI engines replacing existing equipment that is less than 15 years old.

[71 FR 39172, July 11, 2006, as amended at 76 FR 37969, June 28, 2011]

Back to Top

§60.4211 What are my compliance requirements if I am an owner or operator of a stationary CI internal combustion engine?

(a) If you are an owner or operator and must comply with the emission standards specified in this subpart, you must do all of the following, except as permitted under paragraph (g) of this section:

(1) Operate and maintain the stationary CI internal combustion engine and control device according to the manufacturer's emission-related written instructions;

(2) Change only those emission-related settings that are permitted by the manufacturer; and

(3) Meet the requirements of 40 CFR parts 89, 94 and/or 1068, as they apply to you.

(b) If you are an owner or operator of a pre-2007 model year stationary CI internal combustion engine and must comply with the emission standards specified in §§60.4204(a) or 60.4205(a), or if you are an owner or operator of a CI fire pump engine that is manufactured prior to the model years in table 3 to this subpart and must comply with the emission standards specified in §60.4205(c), you must demonstrate compliance according to one of the methods specified in paragraphs (b)(1) through (5) of this section.

(1) Purchasing an engine certified according to 40 CFR part 89 or 40 CFR part 94, as applicable, for the same model year and maximum engine power. The engine must be installed and configured according to the manufacturer's specifications.

(2) Keeping records of performance test results for each pollutant for a test conducted on a similar engine. The test must have been conducted using the same methods specified in this subpart and these methods must have been followed correctly.

(3) Keeping records of engine manufacturer data indicating compliance with the standards.

(4) Keeping records of control device vendor data indicating compliance with the standards.

(5) Conducting an initial performance test to demonstrate compliance with the emission standards according to the requirements specified in §60.4212, as applicable.

(c) If you are an owner or operator of a 2007 model year and later stationary CI internal combustion engine and must comply with the emission standards specified in §60.4204(b) or §60.4205(b), or if you are an owner or operator of a CI fire pump engine that is manufactured during or after the model year that applies to your fire pump engine power rating in table 3 to this subpart and must comply with the emission standards specified in §60.4205(c), you must comply by purchasing an engine certified to the emission standards in §60.4204(b), or §60.4205(b) or (c), as applicable, for the same model year and maximum (or in the case of fire pumps, NFPA nameplate) engine power. The engine must be installed and configured according to the manufacturer's emission-related specifications, except as permitted in paragraph (g) of this section.

(d) If you are an owner or operator and must comply with the emission standards specified in §60.4204(c) or §60.4205(d), you must demonstrate compliance according to the requirements specified in paragraphs (d)(1) through (3) of this section.

(1) Conducting an initial performance test to demonstrate initial compliance with the emission standards as specified in §60.4213.

(2) Establishing operating parameters to be monitored continuously to ensure the stationary internal combustion engine continues to meet the emission standards. The owner or operator must petition the Administrator for approval of operating parameters to be monitored continuously. The petition must include the information described in paragraphs (d)(2)(i) through (v) of this section.

(i) Identification of the specific parameters you propose to monitor continuously;

(ii) A discussion of the relationship between these parameters and NO_x and PM emissions, identifying how the emissions of these pollutants change with changes in these parameters, and how limitations on these parameters will serve to limit NO_x and PM emissions;

(iii) A discussion of how you will establish the upper and/or lower values for these parameters which will establish the limits on these parameters in the operating limitations;

(iv) A discussion identifying the methods and the instruments you will use to monitor these parameters, as well as the relative accuracy and precision of these methods and instruments; and

(v) A discussion identifying the frequency and methods for recalibrating the instruments you will use for monitoring these parameters.

(3) For non-emergency engines with a displacement of greater than or equal to 30 liters per cylinder, conducting annual performance tests to demonstrate continuous compliance with the emission standards as specified in §60.4213.

(e) If you are an owner or operator of a modified or reconstructed stationary CI internal combustion engine and must comply with the emission standards specified in §60.4204(e) or §60.4205(f), you must demonstrate compliance according to one of the methods specified in paragraphs (e)(1) or (2) of this section.

(1) Purchasing, or otherwise owning or operating, an engine certified to the emission standards in §60.4204(e) or §60.4205(f), as applicable.

(2) Conducting a performance test to demonstrate initial compliance with the emission standards according to the requirements specified in §60.4212 or §60.4213, as appropriate. The test must be conducted within 60 days after the engine commences operation after the modification or reconstruction.

(f) If you own or operate an emergency stationary ICE, you must operate the emergency stationary ICE according to the requirements in paragraphs (f)(1) through (3) of this section. In order for the engine to be considered an emergency stationary ICE under this subpart, any operation other than emergency operation, maintenance and testing, emergency demand response, and operation in non-emergency situations for 50 hours per year, as described in paragraphs (f)(1) through (3) of this section, is prohibited. If you do not operate the engine according to the requirements in paragraphs (f)(1) through (3) of this section, the engine will not be considered an emergency engine under this subpart and must meet all requirements for non-emergency engines.

(1) There is no time limit on the use of emergency stationary ICE in emergency situations.

(2) You may operate your emergency stationary ICE for any combination of the purposes specified in paragraphs (f)(2)(i) through (iii) of this section for a maximum of 100 hours per calendar year. Any operation for non-emergency situations as allowed by paragraph (f)(3) of this section counts as part of the 100 hours per calendar year allowed by this paragraph (f)(2).

(i) Emergency stationary ICE may be operated for maintenance checks and readiness testing, provided that the tests are recommended by federal, state or local government, the manufacturer, the vendor, the regional transmission organization or equivalent balancing authority and transmission operator, or the insurance company associated with the engine. The owner or operator may petition the Administrator for approval of additional hours to be used for maintenance checks and readiness testing, but a petition is not required if the owner or operator maintains records indicating that federal, state, or local standards require maintenance and testing of emergency ICE beyond 100 hours per calendar year.

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

(iii) Emergency stationary ICE may be operated for periods where there is a deviation of voltage or frequency of 5 percent or greater below standard voltage or frequency.

(3) Emergency stationary ICE may be operated for up to 50 hours per calendar year in non-emergency situations. The 50 hours of operation in non-emergency situations are counted as part of the 100 hours per calendar year for maintenance and testing and emergency demand response provided in paragraph (f)(2) of this section. Except as provided in paragraph (f)(3)(i) of this section, the 50 hours per calendar year for non-emergency situations cannot be used for peak shaving or non-emergency demand

response, or to generate income for a facility to an electric grid or otherwise supply power as part of a financial arrangement with another entity.

(i) The 50 hours per year for non-emergency situations can be used to supply power as part of a financial arrangement with another entity if all of the following conditions are met:

(A) The engine is dispatched by the local balancing authority or local transmission and distribution system operator;

(B) The dispatch is intended to mitigate local transmission and/or distribution limitations so as to avert potential voltage collapse or line overloads that could lead to the interruption of power supply in a local area or region.

(C) The dispatch follows reliability, emergency operation or similar protocols that follow specific NERC, regional, state, public utility commission or local standards or guidelines.

(D) The power is provided only to the facility itself or to support the local transmission and distribution system.

(E) The owner or operator identifies and records the entity that dispatches the engine and the specific NERC, regional, state, public utility commission or local standards or guidelines that are being followed for dispatching the engine. The local balancing authority or local transmission and distribution system operator may keep these records on behalf of the engine owner or operator.

(ii) [Reserved]

(g) If you do not install, configure, operate, and maintain your engine and control device according to the manufacturer's emission-related written instructions, or you change emission-related settings in a way that is not permitted by the manufacturer, you must demonstrate compliance as follows:

(1) If you are an owner or operator of a stationary CI internal combustion engine with maximum engine power less than 100 HP, you must keep a maintenance plan and records of conducted maintenance to demonstrate compliance and must, to the extent practicable, maintain and operate the engine in a manner consistent with good air pollution control practice for minimizing emissions. In addition, if you do not install and configure the engine and control device according to the manufacturer's emission-related written instructions, or you change the emission-related settings in a way that is not permitted by the manufacturer, you must conduct an initial performance test to demonstrate compliance with the applicable emission standards within 1 year of such action.

(2) If you are an owner or operator of a stationary CI internal combustion engine greater than or equal to 100 HP and less than or equal to 500 HP, you must keep a maintenance plan and records of conducted maintenance and must, to the extent practicable, maintain and operate the engine in a manner consistent with good air pollution control practice for minimizing emissions. In addition, you must conduct an initial performance test to demonstrate compliance with the applicable emission standards within 1 year of startup, or within 1 year after an engine and control device is no longer installed, configured, operated, and maintained in accordance with the manufacturer's emission-related written instructions, or within 1 year after you change emission-related settings in a way that is not permitted by the manufacturer.

(3) If you are an owner or operator of a stationary CI internal combustion engine greater than 500 HP, you must keep a maintenance plan and records of conducted maintenance and must, to the extent practicable, maintain and operate the engine in a manner consistent with good air pollution control practice for minimizing emissions. In addition, you must conduct an initial performance test to

demonstrate compliance with the applicable emission standards within 1 year of startup, or within 1 year after an engine and control device is no longer installed, configured, operated, and maintained in accordance with the manufacturer's emission-related written instructions, or within 1 year after you change emission-related settings in a way that is not permitted by the manufacturer. You must conduct subsequent performance testing every 8,760 hours of engine operation or 3 years, whichever comes first, thereafter to demonstrate compliance with the applicable emission standards.

[71 FR 39172, July 11, 2006, as amended at 76 FR 37970, June 28, 2011; 78 FR 6695, Jan. 30, 2013]

Back to Top

Testing Requirements for Owners and Operators

Back to Top

§60.4212 What test methods and other procedures must I use if I am an owner or operator of a stationary CI internal combustion engine with a displacement of less than 30 liters per cylinder?

Owners and operators of stationary CI ICE with a displacement of less than 30 liters per cylinder who conduct performance tests pursuant to this subpart must do so according to paragraphs (a) through (e) of this section.

(a) The performance test must be conducted according to the in-use testing procedures in 40 CFR part 1039, subpart F, for stationary CI ICE with a displacement of less than 10 liters per cylinder, and according to 40 CFR part 1042, subpart F, for stationary CI ICE with a displacement of greater than or equal to 10 liters per cylinder and less than 30 liters per cylinder.

(b) Exhaust emissions from stationary CI ICE that are complying with the emission standards for new CI engines in 40 CFR part 1039 must not exceed the not-to-exceed (NTE) standards for the same model year and maximum engine power as required in 40 CFR 1039.101(e) and 40 CFR 1039.102(g)(1), except as specified in 40 CFR 1039.104(d). This requirement starts when NTE requirements take effect for nonroad diesel engines under 40 CFR part 1039.

(c) Exhaust emissions from stationary CI ICE that are complying with the emission standards for new CI engines in 40 CFR 89.112 or 40 CFR 94.8, as applicable, must not exceed the NTE numerical requirements, rounded to the same number of decimal places as the applicable standard in 40 CFR 89.112 or 40 CFR 94.8, as applicable, determined from the following equation:

$$\text{NTE requirement for each pollutant} = (1.25) \times (\text{STD}) \qquad \text{(Eq. 1)}$$

View or download PDF

Where:

STD = The standard specified for that pollutant in 40 CFR 89.112 or 40 CFR 94.8, as applicable.

Alternatively, stationary CI ICE that are complying with the emission standards for new CI engines in 40 CFR 89.112 or 40 CFR 94.8 may follow the testing procedures specified in §60.4213 of this subpart, as appropriate.

(d) Exhaust emissions from stationary CI ICE that are complying with the emission standards for pre-2007 model year engines in §60.4204(a), §60.4205(a), or §60.4205(c) must not exceed the NTE numerical requirements, rounded to the same number of decimal places as the applicable standard in §60.4204(a), §60.4205(a), or §60.4205(c), determined from the equation in paragraph (c) of this section.

Where:

STD = The standard specified for that pollutant in §60.4204(a), §60.4205(a), or §60.4205(c).

Alternatively, stationary CI ICE that are complying with the emission standards for pre-2007 model year engines in §60.4204(a), §60.4205(a), or §60.4205(c) may follow the testing procedures specified in §60.4213, as appropriate.

(e) Exhaust emissions from stationary CI ICE that are complying with the emission standards for new CI engines in 40 CFR part 1042 must not exceed the NTE standards for the same model year and maximum engine power as required in 40 CFR 1042.101(c).

[71 FR 39172, July 11, 2006, as amended at 76 FR 37971, June 28, 2011]

Back to Top

§60.4213 What test methods and other procedures must I use if I am an owner or operator of a stationary CI internal combustion engine with a displacement of greater than or equal to 30 liters per cylinder?

Owners and operators of stationary CI ICE with a displacement of greater than or equal to 30 liters per cylinder must conduct performance tests according to paragraphs (a) through (f) of this section.

(a) Each performance test must be conducted according to the requirements in §60.8 and under the specific conditions that this subpart specifies in table 7. The test must be conducted within 10 percent of 100 percent peak (or the highest achievable) load.

(b) You may not conduct performance tests during periods of startup, shutdown, or malfunction, as specified in §60.8(c).

(c) You must conduct three separate test runs for each performance test required in this section, as specified in §60.8(f). Each test run must last at least 1 hour.

(d) To determine compliance with the percent reduction requirement, you must follow the requirements as specified in paragraphs (d)(1) through (3) of this section.

(1) You must use Equation 2 of this section to determine compliance with the percent reduction requirement:

$$\frac{C_i - C_o}{C_i} \times 100 = R \qquad \text{(Eq. 2)}$$

View or download PDF

Where:

C_i = concentration of NO_X or PM at the control device inlet,

C_o = concentration of NO_x or PM at the control device outlet, and

R = percent reduction of NO_x or PM emissions.

(2) You must normalize the NO_x or PM concentrations at the inlet and outlet of the control device to a dry basis and to 15 percent oxygen (O_2) using Equation 3 of this section, or an equivalent percent carbon dioxide (CO_2) using the procedures described in paragraph (d)(3) of this section.

$$C_{adj} = C_d \frac{5.9}{20.9 - \% O_2} \qquad \text{(Eq. 3)}$$

View or download PDF

Where:

C_{adj} = Calculated NO_x or PM concentration adjusted to 15 percent O_2.

C_d = Measured concentration of NO_x or PM, uncorrected.

5.9 = 20.9 percent O_2−15 percent O_2, the defined O_2 correction value, percent.

$\%O_2$ = Measured O_2 concentration, dry basis, percent.

(3) If pollutant concentrations are to be corrected to 15 percent O_2 and CO_2 concentration is measured in lieu of O_2concentration measurement, a CO_2 correction factor is needed. Calculate the CO_2 correction factor as described in paragraphs (d)(3)(i) through (iii) of this section.

(i) Calculate the fuel-specific F_o value for the fuel burned during the test using values obtained from Method 19, Section 5.2, and the following equation:

$$F_o = \frac{0.209_{F_d}}{F_c} \qquad \text{(Eq. 4)}$$

View or download PDF

Where:

F_o = Fuel factor based on the ratio of O_2 volume to the ultimate CO_2 volume produced by the fuel at zero percent excess air.

0.209 = Fraction of air that is O_2, percent/100.

F_d = Ratio of the volume of dry effluent gas to the gross calorific value of the fuel from Method 19, dsm^3/J ($dscf/10^6$ Btu).

F_c = Ratio of the volume of CO_2 produced to the gross calorific value of the fuel from Method 19, dsm^3/J ($dscf/10^6$ Btu).

(ii) Calculate the CO_2 correction factor for correcting measurement data to 15 percent O_2, as follows:

$$X_{CO_2} = \frac{5.9}{F_o} \qquad \text{(Eq. 5)}$$

View or download PDF

Where:

X_{CO2} = CO_2 correction factor, percent.

5.9 = 20.9 percent O_2−15 percent O_2, the defined O_2 correction value, percent.

(iii) Calculate the NO_x and PM gas concentrations adjusted to 15 percent O_2 using CO_2 as follows:

$$C_{adj} = C_d \frac{X_{CO_2}}{\%CO_2} \qquad \text{(Eq. 6)}$$

View or download PDF

Where:

C_{adj} = Calculated NO_x or PM concentration adjusted to 15 percent O_2.

C_d = Measured concentration of NO_x or PM, uncorrected.

$\%CO_2$ = Measured CO_2 concentration, dry basis, percent.

(e) To determine compliance with the NO_x mass per unit output emission limitation, convert the concentration of NO_xin the engine exhaust using Equation 7 of this section:

$$ER = \frac{C_d \times 1.912 \times 10^{-3} \times Q \times T}{\text{KW-hour}} \qquad \text{(Eq. 7)}$$

View or download PDF

Where:

ER = Emission rate in grams per KW-hour.

C_d = Measured NO_x concentration in ppm.

$1.912x10^{-3}$ = Conversion constant for ppm NO_x to grams per standard cubic meter at 25 degrees Celsius.

Q = Stack gas volumetric flow rate, in standard cubic meter per hour.

T = Time of test run, in hours.

KW-hour = Brake work of the engine, in KW-hour.

(f) To determine compliance with the PM mass per unit output emission limitation, convert the concentration of PM in the engine exhaust using Equation 8 of this section:

$$ER = \frac{C_{adj} \times Q \times T}{\text{KW-hour}} \qquad \text{(Eq. 8)}$$

View or download PDF

Where:

ER = Emission rate in grams per KW-hour.

C_{adj} = Calculated PM concentration in grams per standard cubic meter.

Q = Stack gas volumetric flow rate, in standard cubic meter per hour.

T = Time of test run, in hours.

KW-hour = Energy output of the engine, in KW.

[71 FR 39172, July 11, 2006, as amended at 76 FR 37971, June 28, 2011]

Back to Top

NOTIFICATION, REPORTS, AND RECORDS FOR OWNERS AND OPERATORS

Back to Top

§60.4214 What are my notification, reporting, and recordkeeping requirements if I am an owner or operator of a stationary CI internal combustion engine?

(a) Owners and operators of non-emergency stationary CI ICE that are greater than 2,237 KW (3,000 HP), or have a displacement of greater than or equal to 10 liters per cylinder, or are pre-2007 model year engines that are greater than 130 KW (175 HP) and not certified, must meet the requirements of paragraphs (a)(1) and (2) of this section.

(1) Submit an initial notification as required in §60.7(a)(1). The notification must include the information in paragraphs (a)(1)(i) through (v) of this section.

(i) Name and address of the owner or operator;

(ii) The address of the affected source;

(iii) Engine information including make, model, engine family, serial number, model year, maximum engine power, and engine displacement;

(iv) Emission control equipment; and

(v) Fuel used.

(2) Keep records of the information in paragraphs (a)(2)(i) through (iv) of this section.

(i) All notifications submitted to comply with this subpart and all documentation supporting any notification.

(ii) Maintenance conducted on the engine.

(iii) If the stationary CI internal combustion is a certified engine, documentation from the manufacturer that the engine is certified to meet the emission standards.

(iv) If the stationary CI internal combustion is not a certified engine, documentation that the engine meets the emission standards.

(b) If the stationary CI internal combustion engine is an emergency stationary internal combustion engine, the owner or operator is not required to submit an initial notification. Starting with the model years in table 5 to this subpart, if the emergency engine does not meet the standards applicable to non-emergency engines in the applicable model year, the owner or operator must keep records of the operation of the engine in emergency and non-emergency service that are recorded through the non-resettable hour meter. The owner must record the time of operation of the engine and the reason the engine was in operation during that time.

(c) If the stationary CI internal combustion engine is equipped with a diesel particulate filter, the owner or operator must keep records of any corrective action taken after the backpressure monitor has notified the owner or operator that the high backpressure limit of the engine is approached.

(d) If you own or operate an emergency stationary CI ICE with a maximum engine power more than 100 HP that operates or is contractually obligated to be available for more than 15 hours per calendar year for the purposes specified in §60.4211(f)(2)(ii) and (iii) or that operates for the purposes specified in §60.4211(f)(3)(i), you must submit an annual report according to the requirements in paragraphs (d)(1) through (3) of this section.

(1) The report must contain the following information:

(i) Company name and address where the engine is located.

(ii) Date of the report and beginning and ending dates of the reporting period.

(iii) Engine site rating and model year.

(iv) Latitude and longitude of the engine in decimal degrees reported to the fifth decimal place.

(v) Hours operated for the purposes specified in §60.4211(f)(2)(ii) and (iii), including the date, start time, and end time for engine operation for the purposes specified in §60.4211(f)(2)(ii) and (iii).

(vi) Number of hours the engine is contractually obligated to be available for the purposes specified in §60.4211(f)(2)(ii) and (iii).

(vii) Hours spent for operation for the purposes specified in §60.4211(f)(3)(i), including the date, start time, and end time for engine operation for the purposes specified in §60.4211(f)(3)(i). The report must also identify the entity that dispatched the engine and the situation that necessitated the dispatch of the engine.

(2) The first annual report must cover the calendar year 2015 and must be submitted no later than March 31, 2016. Subsequent annual reports for each calendar year must be submitted no later than March 31 of the following calendar year.

(3) The annual report must be submitted electronically using the subpart specific reporting form in the Compliance and Emissions Data Reporting Interface (CEDRI) that is accessed through 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 written report must be submitted to the Administrator at the appropriate address listed in §60.4.

[71 FR 39172, July 11, 2006, as amended at 78 FR 6696, Jan. 30, 2013]

Back to Top

SPECIAL REQUIREMENTS

Back to Top

§60.4215 What requirements must I meet for engines used in Guam, American Samoa, or the Commonwealth of the Northern Mariana Islands?

(a) Stationary CI ICE with a displacement of less than 30 liters per cylinder that are used in Guam, American Samoa, or the Commonwealth of the Northern Mariana Islands are required to meet the applicable emission standards in §§60.4202 and 60.4205.

(b) Stationary CI ICE that are used in Guam, American Samoa, or the Commonwealth of the Northern Mariana Islands are not required to meet the fuel requirements in §60.4207.

(c) Stationary CI ICE with a displacement of greater than or equal to 30 liters per cylinder that are used in Guam, American Samoa, or the Commonwealth of the Northern Mariana Islands are required to meet the following emission standards:

(1) For engines installed prior to January 1, 2012, limit the emissions of NO_x in the stationary CI internal combustion engine exhaust to the following:

(i) 17.0 g/KW-hr (12.7 g/HP-hr) when maximum engine speed is less than 130 rpm;

(ii) $45 \cdot n^{-0.2}$ g/KW-hr ($34 \cdot n^{-0.2}$ g/HP-hr) when maximum engine speed is 130 or more but less than 2,000 rpm, where n is maximum engine speed; and

(iii) 9.8 g/KW-hr (7.3 g/HP-hr) when maximum engine speed is 2,000 rpm or more.

(2) For engines installed on or after January 1, 2012, limit the emissions of NO_x in the stationary CI internal combustion engine exhaust to the following:

(i) 14.4 g/KW-hr (10.7 g/HP-hr) when maximum engine speed is less than 130 rpm;

(ii) $44 \cdot n^{-0.23}$ g/KW-hr ($33 \cdot n^{-0.23}$ g/HP-hr) when maximum engine speed is greater than or equal to 130 but less than 2,000 rpm and where n is maximum engine speed; and

(iii) 7.7 g/KW-hr (5.7 g/HP-hr) when maximum engine speed is greater than or equal to 2,000 rpm.

(3) Limit the emissions of PM in the stationary CI internal combustion engine exhaust to 0.40 g/KW-hr (0.30 g/HP-hr).

[71 FR 39172, July 11, 2006, as amended at 76 FR 37971, June 28, 2011]

Back to Top

§60.4216 What requirements must I meet for engines used in Alaska?

(a) Prior to December 1, 2010, owners and operators of stationary CI ICE with a displacement of less than 30 liters per cylinder located in areas of Alaska not accessible by the FAHS should refer to 40 CFR part 69 to determine the diesel fuel requirements applicable to such engines.

(b) Except as indicated in paragraph (c) of this section, manufacturers, owners and operators of stationary CI ICE with a displacement of less than 10 liters per cylinder located in areas of Alaska not accessible by the FAHS may meet the requirements of this subpart by manufacturing and installing engines meeting the requirements of 40 CFR parts 94 or 1042, as appropriate, rather than the otherwise applicable requirements of 40 CFR parts 89 and 1039, as indicated in sections §§60.4201(f) and 60.4202(g) of this subpart.

(c) Manufacturers, owners and operators of stationary CI ICE that are located in areas of Alaska not accessible by the FAHS may choose to meet the applicable emission standards for emergency engines in §§60.4202 and 60.4205, and not those for non-emergency engines in §60.4201 and §60.4204, except that for 2014 model year and later non-emergency CI ICE, the owner or operator of any such engine that was not certified as meeting Tier 4 PM standards, must meet the applicable requirements for PM in §§60.4201 and 60.4204 or install a PM emission control device that achieves PM emission reductions of 85 percent, or 60 percent for engines with a displacement of greater than or equal to 30 liters per cylinder, compared to engine-out emissions.

(d) The provisions of §60.4207 do not apply to owners and operators of pre-2014 model year stationary CI ICE subject to this subpart that are located in areas of Alaska not accessible by the FAHS.

(e) The provisions of §60.4208(a) do not apply to owners and operators of stationary CI ICE subject to this subpart that are located in areas of Alaska not accessible by the FAHS until after December 31, 2009.

(f) The provisions of this section and §60.4207 do not prevent owners and operators of stationary CI ICE subject to this subpart that are located in areas of Alaska not accessible by the FAHS from using fuels mixed with used lubricating oil, in volumes of up to 1.75 percent of the total fuel. The sulfur content of the used lubricating oil must be less than 200 parts per million. The used lubricating oil must meet the on-specification levels and properties for used oil in 40 CFR 279.11.

[76 FR 37971, June 28, 2011]

Back to Top

§60.4217 What emission standards must I meet if I am an owner or operator of a stationary internal combustion engine using special fuels?

Owners and operators of stationary CI ICE that do not use diesel fuel may petition the Administrator for approval of alternative emission standards, if they can demonstrate that they use a fuel that is not the fuel on which the manufacturer of the engine certified the engine and that the engine cannot meet the applicable standards required in §60.4204 or §60.4205 using such fuels and that use of such fuel is appropriate and reasonably necessary, considering cost, energy, technical feasibility, human health and environmental, and other factors, for the operation of the engine.

[76 FR 37972, June 28, 2011]

Back to Top

General Provisions

Back to Top

§60.4218 What parts of the General Provisions apply to me?

Table 8 to this subpart shows which parts of the General Provisions in §§60.1 through 60.19 apply to you.

Back to Top

§60.4219 What definitions apply to this subpart?

As used in this subpart, all terms not defined herein shall have the meaning given them in the CAA and in subpart A of this part.

Certified emissions life means the period during which the engine is designed to properly function in terms of reliability and fuel consumption, without being remanufactured, specified as a number of hours of operation or calendar years, whichever comes first. The values for certified emissions life for stationary CI ICE with a displacement of less than 10 liters per cylinder are given in 40 CFR 1039.101(g). The values for certified emissions life for stationary CI ICE with a displacement of greater than or equal to 10 liters per cylinder and less than 30 liters per cylinder are given in 40 CFR 94.9(a).

Combustion turbine means all equipment, including but not limited to the turbine, the fuel, air, lubrication and exhaust gas systems, control systems (except emissions control equipment), and any ancillary components and sub-components comprising any simple cycle combustion turbine, any regenerative/recuperative cycle combustion turbine, the combustion turbine portion of any cogeneration cycle combustion system, or the combustion turbine portion of any combined cycle steam/electric generating system.

Compression ignition means relating to a type of stationary internal combustion engine that is not a spark ignition engine.

Date of manufacture means one of the following things:

(1) For freshly manufactured engines and modified engines, date of manufacture means the date the engine is originally produced.

(2) For reconstructed engines, date of manufacture means the date the engine was originally produced, except as specified in paragraph (3) of this definition.

(3) Reconstructed engines are assigned a new date of manufacture if the fixed capital cost of the new and refurbished components exceeds 75 percent of the fixed capital cost of a comparable entirely new facility. An engine that is produced from a previously used engine block does not retain the date of manufacture of the engine in which the engine block was previously used if the engine is produced using all new components except for the engine block. In these cases, the date of manufacture is the date of reconstruction or the date the new engine is produced.

Diesel fuel means any liquid obtained from the distillation of petroleum with a boiling point of approximately 150 to 360 degrees Celsius. One commonly used form is number 2 distillate oil.

Diesel particulate filter means an emission control technology that reduces PM emissions by trapping the particles in a flow filter substrate and periodically removes the collected particles by either physical action or by oxidizing (burning off) the particles in a process called regeneration.

Emergency stationary internal combustion engine means any stationary reciprocating internal combustion engine that meets all of the criteria in paragraphs (1) through (3) of this definition. All emergency stationary ICE must comply with the requirements specified in §60.4211(f) in order to be considered emergency stationary ICE. If the engine does not comply with the requirements specified in §60.4211(f), then it is not considered to be an emergency stationary ICE under this subpart.

(1) The stationary ICE is operated to provide electrical power or mechanical work during an emergency situation. Examples include stationary ICE used to produce power for critical networks or equipment (including power supplied to portions of a facility) when electric power from the local utility (or the normal power source, if the facility runs on its own power production) is interrupted, or stationary ICE used to pump water in the case of fire or flood, etc.

(2) The stationary ICE is operated under limited circumstances for situations not included in paragraph (1) of this definition, as specified in §60.4211(f).

(3) The stationary ICE operates as part of a financial arrangement with another entity in situations not included in paragraph (1) of this definition only as allowed in §60.4211(f)(2)(ii) or (iii) and §60.4211(f)(3)(i).

Engine manufacturer means the manufacturer of the engine. See the definition of “manufacturer” in this section.

Fire pump engine means an emergency stationary internal combustion engine certified to NFPA requirements that is used to provide power to pump water for fire suppression or protection.

Freshly manufactured engine means an engine that has not been placed into service. An engine becomes freshly manufactured when it is originally produced.

Installed means the engine is placed and secured at the location where it is intended to be operated.

Manufacturer has the meaning given in section 216(1) of the Act. In general, this term includes any person who manufactures a stationary engine for sale in the United States or otherwise introduces a new stationary engine into commerce in the United States. This includes importers who import stationary engines for sale or resale.

Maximum engine power means maximum engine power as defined in 40 CFR 1039.801.

Model year means the calendar year in which an engine is manufactured (see “date of manufacture”), except as follows:

(1) Model year means the annual new model production period of the engine manufacturer in which an engine is manufactured (see “date of manufacture”), if the annual new model production period is different than the calendar year and includes January 1 of the calendar year for which the model year is named. It may not begin before January 2 of the previous calendar year and it must end by December 31 of the named calendar year.

(2) For an engine that is converted to a stationary engine after being placed into service as a nonroad or other non-stationary engine, model year means the calendar year or new model production period in which the engine was manufactured (see “date of manufacture”).

Other internal combustion engine means any internal combustion engine, except combustion turbines, which is not a reciprocating internal combustion engine or rotary internal combustion engine.

Reciprocating internal combustion engine means any internal combustion engine which uses reciprocating motion to convert heat energy into mechanical work.

Rotary internal combustion engine means any internal combustion engine which uses rotary motion to convert heat energy into mechanical work.

Spark ignition means relating to a gasoline, natural gas, or liquefied petroleum gas fueled engine or any other type of engine with a spark plug (or other sparking device) and with operating characteristics significantly similar to the theoretical Otto combustion cycle. Spark ignition engines usually use a throttle to regulate intake air flow to control power during normal operation. Dual-fuel engines in which a liquid fuel (typically diesel fuel) is used for CI and gaseous fuel (typically natural gas) is used as the primary fuel at an annual average ratio of less than 2 parts diesel fuel to 100 parts total fuel on an energy equivalent basis are spark ignition engines.

Stationary internal combustion engine means any internal combustion engine, except combustion turbines, that converts heat energy into mechanical work and is not mobile. Stationary ICE differ from mobile ICE in that a stationary internal combustion engine is not a nonroad engine as defined at 40 CFR 1068.30 (excluding paragraph (2)(ii) of that definition), and is not used to propel a motor vehicle, aircraft, or a vehicle used solely for competition. Stationary ICE include reciprocating ICE, rotary ICE, and other ICE, except combustion turbines.

Subpart means 40 CFR part 60, subpart IIII.

[71 FR 39172, July 11, 2006, as amended at 76 FR 37972, June 28, 2011; 78 FR 6696, Jan. 30, 2013]

Back to Top

Table 1 to Subpart IIII of Part 60—Emission Standards for Stationary Pre-2007 Model Year Engines With a Displacement of <10 Liters per Cylinder and 2007-2010 Model Year Engines >2,237 KW (3,000 HP) and With a Displacement of <10 Liters per Cylinder

[As stated in §§60.4201(b), 60.4202(b), 60.4204(a), and 60.4205(a), you must comply with the following emission standards]

Maximum engine power	Emission standards for stationary pre-2007 model year engines with a displacement of <10 liters per cylinder and 2007-2010 model year engines >2,237 KW (3,000 HP) and with a displacement of <10 liters per cylinder in g/KW-hr (g/HP-hr)				
	$NMHC + NO_x$	HC	NO_x	CO	PM
KW<8 (HP<11)	10.5 (7.8)			8.0 (6.0)	1.0 (0.75)
8≤KW<19 (11≤HP<25)	9.5 (7.1)			6.6 (4.9)	0.80 (0.60)
19≤KW<37 (25≤HP<50)	9.5 (7.1)			5.5 (4.1)	0.80 (0.60)
37≤KW<56 (50≤HP<75)			9.2 (6.9)		
56≤KW<75 (75≤HP<100)			9.2 (6.9)		
75≤KW<130 (100≤HP<175)			9.2 (6.9)		
130≤KW<225		1.3 (1.0)	9.2 (6.9)	11.4 (8.5)	0.54 (0.40)

(175≤HP<300)					
225≤KW<450 (300≤HP<600)		1.3 (1.0)	9.2 (6.9)	11.4 (8.5)	0.54 (0.40)
450≤KW≤560 (600≤HP≤750)		1.3 (1.0)	9.2 (6.9)	11.4 (8.5)	0.54 (0.40)
KW>560 (HP>750)		1.3 (1.0)	9.2 (6.9)	11.4 (8.5)	0.54 (0.40)

Back to Top

Table 2 to Subpart IIII of Part 60—Emission Standards for 2008 Model Year and Later Emergency Stationary CI ICE <37 KW (50 HP) With a Displacement of <10 Liters per Cylinder

[As stated in §60.4202(a)(1), you must comply with the following emission standards]

Engine power	Emission standards for 2008 model year and later emergency stationary CI ICE <37 KW (50 HP) with a displacement of <10 liters per cylinder in g/KW-hr (g/HP-hr)			
	Model year(s)	NO_x + NMHC	CO	PM
KW<8 (HP<11)	2008 +	7.5 (5.6)	8.0 (6.0)	0.40 (0.30)
8≤KW<19 (11≤HP<25)	2008 +	7.5 (5.6)	6.6 (4.9)	0.40 (0.30)
19≤KW<37 (25≤HP<50)	2008 +	7.5 (5.6)	5.5 (4.1)	0.30 (0.22)

Back to Top

Table 3 to Subpart IIII of Part 60—Certification Requirements for Stationary Fire Pump Engines

As stated in §60.4202(d), you must certify new stationary fire pump engines beginning with the following model years:

Engine power	Starting model year engine manufacturers must certify new stationary fire pump engines according to §60.4202(d)[1]
KW<75 (HP<100)	2011

75≤KW<130 (100≤HP<175)	2010
130≤KW≤560 (175≤HP≤750)	2009
KW>560 (HP>750)	2008

[1]Manufacturers of fire pump stationary CI ICE with a maximum engine power greater than or equal to 37 kW (50 HP) and less than 450 KW (600 HP) and a rated speed of greater than 2,650 revolutions per minute (rpm) are not required to certify such engines until three model years following the model year indicated in this Table 3 for engines in the applicable engine power category.

[71 FR 39172, July 11, 2006, as amended at 76 FR 37972, June 28, 2011]

Back to Top

Table 4 to Subpart IIII of Part 60—Emission Standards for Stationary Fire Pump Engines

[As stated in §§60.4202(d) and 60.4205(c), you must comply with the following emission standards for stationary fire pump engines]

Maximum engine power	Model year(s)	NMHC + NO_x	CO	PM
KW<8 (HP<11)	2010 and earlier	10.5 (7.8)	8.0 (6.0)	1.0 (0.75)
	2011 +	7.5 (5.6)		0.40 (0.30)
8≤KW<19 (11≤HP<25)	2010 and earlier	9.5 (7.1)	6.6 (4.9)	0.80 (0.60)
	2011 +	7.5 (5.6)		0.40 (0.30)
19≤KW<37 (25≤HP<50)	2010 and earlier	9.5 (7.1)	5.5 (4.1)	0.80 (0.60)
	2011 +	7.5 (5.6)		0.30 (0.22)
37≤KW<56 (50≤HP<75)	2010 and earlier	10.5 (7.8)	5.0 (3.7)	0.80 (0.60)
	2011 + [1]	4.7 (3.5)		0.40 (0.30)
56≤KW<75 (75≤HP<100)	2010 and earlier	10.5 (7.8)	5.0 (3.7)	0.80 (0.60)
	2011 + [1]	4.7 (3.5)		0.40 (0.30)
75≤KW<130 (100≤HP<175)	2009 and earlier	10.5 (7.8)	5.0 (3.7)	0.80 (0.60)
	2010 + [2]	4.0 (3.0)		0.30 (0.22)
130≤KW<225 (175≤HP<300)	2008 and earlier	10.5 (7.8)	3.5 (2.6)	0.54 (0.40)
	2009 + [3]	4.0 (3.0)		0.20 (0.15)
225≤KW<450 (300≤HP<600)	2008 and earlier	10.5 (7.8)	3.5 (2.6)	0.54 (0.40)

	2009 + [3]	4.0 (3.0)		0.20 (0.15)
450≤KW≤560 (600≤HP≤750)	2008 and earlier	10.5 (7.8)	3.5 (2.6)	0.54 (0.40)
	2009 +	4.0 (3.0)		0.20 (0.15)
KW>560 (HP>750)	2007 and earlier	10.5 (7.8)	3.5 (2.6)	0.54 (0.40)
	2008 +	6.4 (4.8)		0.20 (0.15)

[1]For model years 2011-2013, manufacturers, owners and operators of fire pump stationary CI ICE in this engine power category with a rated speed of greater than 2,650 revolutions per minute (rpm) may comply with the emission limitations for 2010 model year engines.

[2]For model years 2010-2012, manufacturers, owners and operators of fire pump stationary CI ICE in this engine power category with a rated speed of greater than 2,650 rpm may comply with the emission limitations for 2009 model year engines.

[3]In model years 2009-2011, manufacturers of fire pump stationary CI ICE in this engine power category with a rated speed of greater than 2,650 rpm may comply with the emission limitations for 2008 model year engines.

Back to Top

Table 5 to Subpart IIII of Part 60—Labeling and Recordkeeping Requirements for New Stationary Emergency Engines

[You must comply with the labeling requirements in §60.4210(f) and the recordkeeping requirements in §60.4214(b) for new emergency stationary CI ICE beginning in the following model years:]

Engine power	Starting model year
19≤KW<56 (25≤HP<75)	2013
56≤KW<130 (75≤HP<175)	2012
KW≥130 (HP≥175)	2011

Back to Top

Table 6 to Subpart IIII of Part 60—Optional 3-Mode Test Cycle for Stationary Fire Pump Engines

[As stated in §60.4210(g), manufacturers of fire pump engines may use the following test cycle for testing fire pump engines:]

Mode No.	Engine speed[1]	Torque (percent)[2]	Weighting factors
1	Rated	100	0.30
2	Rated	75	0.50

3	Rated	50	0.20

[1]Engine speed: ±2 percent of point.

[2]Torque: NFPA certified nameplate HP for 100 percent point. All points should be ±2 percent of engine percent load value.

Back to Top

Table 7 to Subpart IIII of Part 60—Requirements for Performance Tests for Stationary CI ICE With a Displacement of ≥30 Liters per Cylinder

As stated in §60.4213, you must comply with the following requirements for performance tests for stationary CI ICE with a displacement of ≥30 liters per cylinder:

Each	Complying with the requirement to	You must	Using	According to the following requirements
1. Stationary CI internal combustion engine with a displacement of ≥ 30 liters per cylinder	a. Reduce NO_x emissions by 90 percent or more;	i. Select the sampling port location and number/location of traverse points at the inlet and outlet of the control device;		(a) For NO_x, O_2, and moisture measurement, ducts ≤6 inches in diameter may be sampled at a single point located at the duct centroid and ducts >6 and ≤12 inches in diameter may be sampled at 3 traverse points located at 16.7, 50.0, and 83.3% of the measurement line ('3-point long line'). If the duct is >12 inches in diameter *and* the sampling port location meets the two and half-diameter criterion of Section 11.1.1 of Method 1 of 40 CFR part 60, appendix A-1, the duct may be sampled at '3-point long line'; otherwise, conduct the stratification testing and select sampling points according to Section 8.1.2 of Method 7E of 40 CFR part 60, appendix A-4.

		ii. Measure O_2 at the inlet and outlet of the control device;	(1) Method 3, 3A, or 3B of 40 CFR part 60, appendix A-2	(b) Measurements to determine O_2 concentration must be made at the same time as the measurements for NO_x concentration.
		iii. If necessary, measure moisture content at the inlet and outlet of the control device; and	(2) Method 4 of 40 CFR part 60, appendix A-3, Method 320 of 40 CFR part 63, appendix A, or ASTM D 6348-03 (incorporated by reference, see §60.17)	(c) Measurements to determine moisture content must be made at the same time as the measurements for NO_x concentration.
		iv. Measure NO_x at the inlet and outlet of the control device.	(3) Method 7E of 40 CFR part 60, appendix A-4, Method 320 of 40 CFR part 63, appendix A, or ASTM D 6348-03 (incorporated by reference, see §60.17)	(d) NO_x concentration must be at 15 percent O_2, dry basis. Results of this test consist of the average of the three 1-hour or longer runs.
	b. Limit the concentration of NO_x in the stationary CI internal combustion engine exhaust.	i. Select the sampling port location and number/location of traverse points at the exhaust of the stationary internal combustion engine;		(a) For NO_x, O_2, and moisture measurement, ducts ≤6 inches in diameter may be sampled at a single point located at the duct centroid and ducts >6 and ≤12 inches in diameter may be sampled at 3 traverse points located at 16.7, 50.0, and 83.3% of the measurement line ('3-point long line'). If the duct is >12 inches in diameter *and* the sampling port location meets the two and half-diameter criterion of Section 11.1.1

				of Method 1 of 40 CFR part 60, appendix A-1, the duct may be sampled at '3-point long line'; otherwise, conduct the stratification testing and select sampling points according to Section 8.1.2 of Method 7E of 40 CFR part 60, appendix A-4.
		ii. Determine the O_2concentration of the stationary internal combustion engine exhaust at the sampling port location;	(1) Method 3, 3A, or 3B of 40 CFR part 60, appendix A-2	(b) Measurements to determine O_2 concentration must be made at the same time as the measurement for NO_xconcentration.
		iii. If necessary, measure moisture content of the stationary internal combustion engine exhaust at the sampling port location; and	(2) Method 4 of 40 CFR part 60, appendix A-3, Method 320 of 40 CFR part 63, appendix A, or ASTM D 6348-03 (incorporated by reference, see §60.17)	(c) Measurements to determine moisture content must be made at the same time as the measurement for NO_xconcentration.
		iv. Measure NO_x at the exhaust of the stationary internal combustion engine; if using a control device, the sampling site must be located at the outlet of the control device.	(3) Method 7E of 40 CFR part 60, Appendix A-4, Method 320 of 40 CFR part 63, appendix A, or ASTM D 6348-03 (incorporated by reference, see §60.17)	(d) NO_x concentration must be at 15 percent O_2, dry basis. Results of this test consist of the average of the three 1-hour or longer runs.
	c. Reduce PM emissions by 60 percent or more	i. Select the sampling port location and the number of traverse points;	(1) Method 1 or 1A of 40 CFR part 60, appendix A-1	(a) Sampling sites must be located at the inlet and outlet of the control device.

		ii. Measure O_2 at the inlet and outlet of the control device;	(2) Method 3, 3A, or 3B of 40 CFR part 60, appendix A-2	(b) Measurements to determine O_2 concentration must be made at the same time as the measurements for PM concentration.
		iii. If necessary, measure moisture content at the inlet and outlet of the control device; and	(3) Method 4 of 40 CFR part 60, appendix A-3	(c) Measurements to determine and moisture content must be made at the same time as the measurements for PM concentration.
		iv. Measure PM at the inlet and outlet of the control device.	(4) Method 5 of 40 CFR part 60, appendix A-3	(d) PM concentration must be at 15 percent O_2, dry basis. Results of this test consist of the average of the three 1-hour or longer runs.
	d. Limit the concentration of PM in the stationary CI internal combustion engine exhaust	i. Select the sampling port location and the number of traverse points;	(1) Method 1 or 1A of 40 CFR part 60, appendix A-1	(a) If using a control device, the sampling site must be located at the outlet of the control device.
		ii. Determine the O_2 concentration of the stationary internal combustion engine exhaust at the sampling port location;	(2) Method 3, 3A, or 3B of 40 CFR part 60, appendix A-2	(b) Measurements to determine O_2 concentration must be made at the same time as the measurements for PM concentration.
		iii. If necessary, measure moisture content of the stationary internal combustion engine exhaust at the sampling port location; and	(3) Method 4 of 40 CFR part 60, appendix A-3	(c) Measurements to determine moisture content must be made at the same time as the measurements for PM concentration.
		iv. Measure PM at the exhaust of the stationary internal	(4) Method 5 of 40 CFR part 60, appendix A-3	(d) PM concentration must be at 15 percent O_2, dry basis. Results of this test

		combustion engine.		consist of the average of the three 1-hour or longer runs.

[79 FR 11251, Feb. 27, 2014]

Back to Top

Table 8 to Subpart IIII of Part 60—Applicability of General Provisions to Subpart IIII

[As stated in §60.4218, you must comply with the following applicable General Provisions:]

General Provisions citation	Subject of citation	Applies to subpart	Explanation
§60.1	General applicability of the General Provisions	Yes	
§60.2	Definitions	Yes	Additional terms defined in §60.4219.
§60.3	Units and abbreviations	Yes	
§60.4	Address	Yes	
§60.5	Determination of construction or modification	Yes	
§60.6	Review of plans	Yes	
§60.7	Notification and Recordkeeping	Yes	Except that §60.7 only applies as specified in §60.4214(a).
§60.8	Performance tests	Yes	Except that §60.8 only applies to stationary CI ICE with a displacement of (≥30 liters per cylinder and engines that are not certified.
§60.9	Availability of information	Yes	
§60.10	State Authority	Yes	
§60.11	Compliance with standards and maintenance requirements	No	Requirements are specified in subpart IIII.
§60.12	Circumvention	Yes	
§60.13	Monitoring requirements	Yes	Except that §60.13 only applies to stationary CI ICE with a displacement of (≥30 liters per cylinder.

§60.14	Modification	Yes	
§60.15	Reconstruction	Yes	
§60.16	Priority list	Yes	
§60.17	Incorporations by reference	Yes	
§60.18	General control device requirements	No	
§60.19	General notification and reporting requirements	Yes	

Back to Top

Appendix E

40 C.F.R. Part 63 Subpart ZZZZ

National Emission Standards for Hazardous Air Pollutants for Stationary Reciprocating

Title 40: Protection of Environment
PART 63—NATIONAL EMISSION STANDARDS FOR HAZARDOUS AIR POLLUTANTS FOR SOURCE CATEGORIES (CONTINUED)

Subpart ZZZZ—National Emissions Standards for Hazardous Air Pollutants for Stationary Reciprocating Internal Combustion Engines

Contents

SOURCE: 69 FR 33506, June 15, 2004, unless otherwise noted.

Back to Top

WHAT THIS SUBPART COVERS

Back to Top

§63.6580 What is the purpose of subpart ZZZZ?

Subpart ZZZZ establishes national emission limitations and operating limitations for hazardous air pollutants (HAP) emitted from stationary reciprocating internal combustion engines (RICE) located at major and area sources of HAP emissions. This subpart also establishes requirements to demonstrate initial and continuous compliance with the emission limitations and operating limitations.

[73 FR 3603, Jan. 18, 2008]

Back to Top

§63.6585 Am I subject to this subpart?

You are subject to this subpart if you own or operate a stationary RICE at a major or area source of HAP emissions, except if the stationary RICE is being tested at a stationary RICE test cell/stand.

(a) A stationary RICE is any internal combustion engine which uses reciprocating motion to convert heat energy into mechanical work and which is not mobile. Stationary RICE differ from mobile RICE in that a stationary RICE is not a non-road engine as defined at 40 CFR 1068.30, and is not used to propel a motor vehicle or a vehicle used solely for competition.

(b) A major source of HAP emissions is a plant site that emits or has the potential to emit any single HAP at a rate of 10 tons (9.07 megagrams) or more per year or any combination of HAP at a rate of 25 tons (22.68 megagrams) or more per year, except that for oil and gas production facilities, a major source of HAP emissions is determined for each surface site.

(c) An area source of HAP emissions is a source that is not a major source.

(d) If you are an owner or operator of an area source subject to this subpart, your status as an entity subject to a standard or other requirements under this subpart does not subject you to the obligation to obtain a permit under 40 CFR part 70 or 71, provided you are not required to obtain a permit under 40 CFR 70.3(a) or 40 CFR 71.3(a) for a reason other than your status as an area source under this subpart. Notwithstanding the previous sentence, you must continue to comply with the provisions of this subpart as applicable.

(e) If you are an owner or operator of a stationary RICE used for national security purposes, you may be eligible to request an exemption from the requirements of this subpart as described in 40 CFR part 1068, subpart C.

(f) The emergency stationary RICE listed in paragraphs (f)(1) through (3) of this section are not subject to this subpart. The stationary RICE must meet the definition of an emergency stationary RICE in §63.6675, which includes operating according to the provisions specified in §63.6640(f).

(1) Existing residential emergency stationary RICE located at an area source of HAP emissions that do not operate or are not contractually obligated to be available for more than 15 hours per calendar year for the purposes specified in §63.6640(f)(2)(ii) and (iii) and that do not operate for the purpose specified in §63.6640(f)(4)(ii).

(2) Existing commercial emergency stationary RICE located at an area source of HAP emissions that do not operate or are not contractually obligated to be available for more than 15 hours per calendar year for the purposes specified in §63.6640(f)(2)(ii) and (iii) and that do not operate for the purpose specified in §63.6640(f)(4)(ii).

(3) Existing institutional emergency stationary RICE located at an area source of HAP emissions that do not operate or are not contractually obligated to be available for more than 15 hours per calendar year for the purposes specified in §63.6640(f)(2)(ii) and (iii) and that do not operate for the purpose specified in §63.6640(f)(4)(ii).

[69 FR 33506, June 15, 2004, as amended at 73 FR 3603, Jan. 18, 2008; 78 FR 6700, Jan. 30, 2013]

Back to Top

§63.6590 What parts of my plant does this subpart cover?

This subpart applies to each affected source.

(a) *Affected source.* An affected source is any existing, new, or reconstructed stationary RICE located at a major or area source of HAP emissions, excluding stationary RICE being tested at a stationary RICE test cell/stand.

(1) *Existing stationary RICE.*

(i) For stationary RICE with a site rating of more than 500 brake horsepower (HP) located at a major source of HAP emissions, a stationary RICE is existing if you commenced construction or reconstruction of the stationary RICE before December 19, 2002.

(ii) For stationary RICE with a site rating of less than or equal to 500 brake HP located at a major source of HAP emissions, a stationary RICE is existing if you commenced construction or reconstruction of the stationary RICE before June 12, 2006.

(iii) For stationary RICE located at an area source of HAP emissions, a stationary RICE is existing if you commenced construction or reconstruction of the stationary RICE before June 12, 2006.

(iv) A change in ownership of an existing stationary RICE does not make that stationary RICE a new or reconstructed stationary RICE.

(2) *New stationary RICE.* (i) A stationary RICE with a site rating of more than 500 brake HP located at a major source of HAP emissions is new if you commenced construction of the stationary RICE on or after December 19, 2002.

(ii) A stationary RICE with a site rating of equal to or less than 500 brake HP located at a major source of HAP emissions is new if you commenced construction of the stationary RICE on or after June 12, 2006.

(iii) A stationary RICE located at an area source of HAP emissions is new if you commenced construction of the stationary RICE on or after June 12, 2006.

(3) *Reconstructed stationary RICE.* (i) A stationary RICE with a site rating of more than 500 brake HP located at a major source of HAP emissions is reconstructed if you meet the definition of reconstruction in §63.2 and reconstruction is commenced on or after December 19, 2002.

(ii) A stationary RICE with a site rating of equal to or less than 500 brake HP located at a major source of HAP emissions is reconstructed if you meet the definition of reconstruction in §63.2 and reconstruction is commenced on or after June 12, 2006.

(iii) A stationary RICE located at an area source of HAP emissions is reconstructed if you meet the definition of reconstruction in §63.2 and reconstruction is commenced on or after June 12, 2006.

(b) *Stationary RICE subject to limited requirements.* (1) An affected source which meets either of the criteria in paragraphs (b)(1)(i) through (ii) of this section does not have to meet the requirements of this subpart and of subpart A of this part except for the initial notification requirements of §63.6645(f).

(i) The stationary RICE is a new or reconstructed emergency stationary RICE with a site rating of more than 500 brake HP located at a major source of HAP emissions that does not operate or is not contractually obligated to be available for more than 15 hours per calendar year for the purposes specified in §63.6640(f)(2)(ii) and (iii).

(ii) The stationary RICE is a new or reconstructed limited use stationary RICE with a site rating of more than 500 brake HP located at a major source of HAP emissions.

(2) A new or reconstructed stationary RICE with a site rating of more than 500 brake HP located at a major source of HAP emissions which combusts landfill or digester gas equivalent to 10 percent or more of the gross heat input on an annual basis must meet the initial notification requirements of §63.6645(f) and the requirements of §§63.6625(c), 63.6650(g), and 63.6655(c). These stationary RICE do not have to meet the emission limitations and operating limitations of this subpart.

(3) The following stationary RICE do not have to meet the requirements of this subpart and of subpart A of this part, including initial notification requirements:

(i) Existing spark ignition 2 stroke lean burn (2SLB) stationary RICE with a site rating of more than 500 brake HP located at a major source of HAP emissions;

(ii) Existing spark ignition 4 stroke lean burn (4SLB) stationary RICE with a site rating of more than 500 brake HP located at a major source of HAP emissions;

(iii) Existing emergency stationary RICE with a site rating of more than 500 brake HP located at a major source of HAP emissions that does not operate or is not contractually obligated to be available for more than 15 hours per calendar year for the purposes specified in §63.6640(f)(2)(ii) and (iii).

(iv) Existing limited use stationary RICE with a site rating of more than 500 brake HP located at a major source of HAP emissions;

(v) Existing stationary RICE with a site rating of more than 500 brake HP located at a major source of HAP emissions that combusts landfill gas or digester gas equivalent to 10 percent or more of the gross heat input on an annual basis;

(c) *Stationary RICE subject to Regulations under 40 CFR Part 60.* An affected source that meets any of the criteria in paragraphs (c)(1) through (7) of this section must meet the requirements of this part by meeting the requirements of 40 CFR part 60 subpart IIII, for compression ignition engines or 40 CFR part 60 subpart JJJJ, for spark ignition engines. No further requirements apply for such engines under this part.

(1) A new or reconstructed stationary RICE located at an area source;

(2) A new or reconstructed 2SLB stationary RICE with a site rating of less than or equal to 500 brake HP located at a major source of HAP emissions;

(3) A new or reconstructed 4SLB stationary RICE with a site rating of less than 250 brake HP located at a major source of HAP emissions;

(4) A new or reconstructed spark ignition 4 stroke rich burn (4SRB) stationary RICE with a site rating of less than or equal to 500 brake HP located at a major source of HAP emissions;

(5) A new or reconstructed stationary RICE with a site rating of less than or equal to 500 brake HP located at a major source of HAP emissions which combusts landfill or digester gas equivalent to 10 percent or more of the gross heat input on an annual basis;

(6) A new or reconstructed emergency or limited use stationary RICE with a site rating of less than or equal to 500 brake HP located at a major source of HAP emissions;

(7) A new or reconstructed compression ignition (CI) stationary RICE with a site rating of less than or equal to 500 brake HP located at a major source of HAP emissions.

[69 FR 33506, June 15, 2004, as amended at 73 FR 3604, Jan. 18, 2008; 75 FR 9674, Mar. 3, 2010; 75 FR 37733, June 30, 2010; 75 FR 51588, Aug. 20, 2010; 78 FR 6700, Jan. 30, 2013]

Back to Top

§63.6595 When do I have to comply with this subpart?

(a) *Affected sources.* (1) If you have an existing stationary RICE, excluding existing non-emergency CI stationary RICE, with a site rating of more than 500 brake HP located at a major source of HAP emissions, you must comply with the applicable emission limitations, operating limitations and other requirements no later than June 15, 2007. If you have an existing non-emergency CI stationary RICE with a site rating of more than 500 brake HP located at a major source of HAP emissions, an existing stationary CI RICE with a site rating of less than or equal to 500 brake HP located at a major source of HAP emissions, or an existing stationary CI RICE located at an area source of HAP emissions, you must comply with the applicable emission limitations, operating limitations, and other requirements no later than May 3, 2013. If you have an existing stationary SI RICE with a site rating of less than or equal to 500 brake HP located at a major source of HAP emissions, or an existing stationary SI RICE located at an area source of HAP emissions, you must comply with the applicable emission limitations, operating limitations, and other requirements no later than October 19, 2013.

(2) If you start up your new or reconstructed stationary RICE with a site rating of more than 500 brake HP located at a major source of HAP emissions before August 16, 2004, you must comply with the applicable emission limitations and operating limitations in this subpart no later than August 16, 2004.

(3) If you start up your new or reconstructed stationary RICE with a site rating of more than 500 brake HP located at a major source of HAP emissions after August 16, 2004, you must comply with the applicable emission limitations and operating limitations in this subpart upon startup of your affected source.

(4) If you start up your new or reconstructed stationary RICE with a site rating of less than or equal to 500 brake HP located at a major source of HAP emissions before January 18, 2008, you must comply with the applicable emission limitations and operating limitations in this subpart no later than January 18, 2008.

(5) If you start up your new or reconstructed stationary RICE with a site rating of less than or equal to 500 brake HP located at a major source of HAP emissions after January 18, 2008, you must comply with the applicable emission limitations and operating limitations in this subpart upon startup of your affected source.

(6) If you start up your new or reconstructed stationary RICE located at an area source of HAP emissions before January 18, 2008, you must comply with the applicable emission limitations and operating limitations in this subpart no later than January 18, 2008.

(7) If you start up your new or reconstructed stationary RICE located at an area source of HAP emissions after January 18, 2008, you must comply with the applicable emission limitations and operating limitations in this subpart upon startup of your affected source.

(b) *Area sources that become major sources.* If you have an area source that increases its emissions or its potential to emit such that it becomes a major source of HAP, the compliance dates in paragraphs (b)(1) and (2) of this section apply to you.

(1) Any stationary RICE for which construction or reconstruction is commenced after the date when your area source becomes a major source of HAP must be in compliance with this subpart upon startup of your affected source.

(2) Any stationary RICE for which construction or reconstruction is commenced before your area source becomes a major source of HAP must be in compliance with the provisions of this subpart that are applicable to RICE located at major sources within 3 years after your area source becomes a major source of HAP.

(c) If you own or operate an affected source, you must meet the applicable notification requirements in §63.6645 and in 40 CFR part 63, subpart A.

[69 FR 33506, June 15, 2004, as amended at 73 FR 3604, Jan. 18, 2008; 75 FR 9675, Mar. 3, 2010; 75 FR 51589, Aug. 20, 2010; 78 FR 6701, Jan. 30, 2013]

Back to Top

EMISSION AND OPERATING LIMITATIONS

Back to Top

§63.6600 What emission limitations and operating limitations must I meet if I own or operate a stationary RICE with a site rating of more than 500 brake HP located at a major source of HAP emissions?

Compliance with the numerical emission limitations established in this subpart is based on the results of testing the average of three 1-hour runs using the testing requirements and procedures in §63.6620 and Table 4 to this subpart.

(a) If you own or operate an existing, new, or reconstructed spark ignition 4SRB stationary RICE with a site rating of more than 500 brake HP located at a major source of HAP emissions, you must comply with the emission limitations in Table 1a to this subpart and the operating limitations in Table 1b to this subpart which apply to you.

(b) If you own or operate a new or reconstructed 2SLB stationary RICE with a site rating of more than 500 brake HP located at major source of HAP emissions, a new or reconstructed 4SLB stationary RICE with a site rating of more than 500 brake HP located at major source of HAP emissions, or a new or reconstructed CI stationary RICE with a site rating of more than 500 brake HP located at a major source of HAP emissions, you must comply with the emission limitations in Table 2a to this subpart and the operating limitations in Table 2b to this subpart which apply to you.

(c) If you own or operate any of the following stationary RICE with a site rating of more than 500 brake HP located at a major source of HAP emissions, you do not need to comply with the emission limitations in Tables 1a, 2a, 2c, and 2d to this subpart or operating limitations in Tables 1b and 2b to this subpart: an existing 2SLB stationary RICE; an existing 4SLB stationary RICE; a stationary RICE that combusts landfill gas or digester gas equivalent to 10 percent or more of the gross heat input on an annual basis; an emergency stationary RICE; or a limited use stationary RICE.

(d) If you own or operate an existing non-emergency stationary CI RICE with a site rating of more than 500 brake HP located at a major source of HAP emissions, you must comply with the emission limitations in Table 2c to this subpart and the operating limitations in Table 2b to this subpart which apply to you.

[73 FR 3605, Jan. 18, 2008, as amended at 75 FR 9675, Mar. 3, 2010]

Back to Top

§63.6601 What emission limitations must I meet if I own or operate a new or reconstructed 4SLB stationary RICE with a site rating of greater than or equal to 250 brake HP and less than or equal to 500 brake HP located at a major source of HAP emissions?

Compliance with the numerical emission limitations established in this subpart is based on the results of testing the average of three 1-hour runs using the testing requirements and procedures in §63.6620 and Table 4 to this subpart. If you own or operate a new or reconstructed 4SLB stationary RICE with a site rating of greater than or equal to 250 and less than or equal to 500 brake HP located at major source of HAP emissions manufactured on or after January 1, 2008, you must comply with the emission limitations in Table 2a to this subpart and the operating limitations in Table 2b to this subpart which apply to you.

[73 FR 3605, Jan. 18, 2008, as amended at 75 FR 9675, Mar. 3, 2010; 75 FR 51589, Aug. 20, 2010]

Back to Top

§63.6602 What emission limitations and other requirements must I meet if I own or operate an existing stationary RICE with a site rating of equal to or less than 500 brake HP located at a major source of HAP emissions?

If you own or operate an existing stationary RICE with a site rating of equal to or less than 500 brake HP located at a major source of HAP emissions, you must comply with the emission limitations and other requirements in Table 2c to this subpart which apply to you. Compliance with the numerical emission limitations established in this subpart is based on the results of testing the average of three 1-hour runs using the testing requirements and procedures in §63.6620 and Table 4 to this subpart.

[78 FR 6701, Jan. 30, 2013]

Back to Top

§63.6603 What emission limitations, operating limitations, and other requirements must I meet if I own or operate an existing stationary RICE located at an area source of HAP emissions?

Compliance with the numerical emission limitations established in this subpart is based on the results of testing the average of three 1-hour runs using the testing requirements and procedures in §63.6620 and Table 4 to this subpart.

(a) If you own or operate an existing stationary RICE located at an area source of HAP emissions, you must comply with the requirements in Table 2d to this subpart and the operating limitations in Table 2b to this subpart that apply to you.

(b) If you own or operate an existing stationary non-emergency CI RICE with a site rating of more than 300 HP located at an area source of HAP that meets either paragraph (b)(1) or (2) of this section, you do not have to meet the numerical CO emission limitations specified in Table 2d of this subpart. Existing stationary non-emergency CI RICE with a site rating of more than 300 HP located at an area source of HAP that meet either paragraph (b)(1) or (2) of this section must meet the management practices that are shown for stationary non-emergency CI RICE with a site rating of less than or equal to 300 HP in Table 2d of this subpart.

(1) The area source is located in an area of Alaska that is not accessible by the Federal Aid Highway System (FAHS).

(2) The stationary RICE is located at an area source that meets paragraphs (b)(2)(i), (ii), and (iii) of this section.

(i) The only connection to the FAHS is through the Alaska Marine Highway System (AMHS), or the stationary RICE operation is within an isolated grid in Alaska that is not connected to the statewide electrical grid referred to as the Alaska Railbelt Grid.

(ii) At least 10 percent of the power generated by the stationary RICE on an annual basis is used for residential purposes.

(iii) The generating capacity of the area source is less than 12 megawatts, or the stationary RICE is used exclusively for backup power for renewable energy.

(c) If you own or operate an existing stationary non-emergency CI RICE with a site rating of more than 300 HP located on an offshore vessel that is an area source of HAP and is a nonroad vehicle that is an Outer Continental Shelf (OCS) source as defined in 40 CFR 55.2, you do not have to meet the numerical CO emission limitations specified in Table 2d of this subpart. You must meet all of the following management practices:

(1) Change oil every 1,000 hours of operation or annually, whichever comes first. Sources have the option to utilize an oil analysis program as described in §63.6625(i) in order to extend the specified oil change requirement.

(2) Inspect and clean air filters every 750 hours of operation or annually, whichever comes first, and replace as necessary.

(3) Inspect fuel filters and belts, if installed, every 750 hours of operation or annually, whichever comes first, and replace as necessary.

(4) Inspect all flexible hoses every 1,000 hours of operation or annually, whichever comes first, and replace as necessary.

(d) If you own or operate an existing non-emergency CI RICE with a site rating of more than 300 HP located at an area source of HAP emissions that is certified to the Tier 1 or Tier 2 emission standards in Table 1 of 40 CFR 89.112 and that is subject to an enforceable state or local standard that requires the engine to be replaced no later than June 1, 2018, you may until January 1, 2015, or 12 years after the installation date of the engine (whichever is later), but not later than June 1, 2018, choose to comply with the management practices that are shown for stationary non-emergency CI RICE with a site rating of less than or equal to 300 HP in Table 2d of this subpart instead of the applicable emission limitations in Table 2d, operating limitations in Table 2b, and crankcase ventilation system requirements in §63.6625(g). You must comply with the emission limitations in Table 2d and operating limitations in Table 2b that apply for non-emergency CI RICE with a site rating of more than 300 HP located at an area source of HAP emissions by January 1, 2015, or 12 years after the installation date of the engine (whichever is later), but not later than June 1, 2018. You must also comply with the crankcase ventilation system requirements in §63.6625(g) by January 1, 2015, or 12 years after the installation date of the engine (whichever is later), but not later than June 1, 2018.

(e) If you own or operate an existing non-emergency CI RICE with a site rating of more than 300 HP located at an area source of HAP emissions that is certified to the Tier 3 (Tier 2 for engines above 560 kilowatt (kW)) emission standards in Table 1 of 40 CFR 89.112, you may comply with the requirements under this part by meeting the requirements for Tier 3 engines (Tier 2 for engines above 560 kW) in 40 CFR part 60 subpart IIII instead of the emission limitations and other requirements that would otherwise apply under this part for existing non-emergency CI RICE with a site rating of more than 300 HP located at an area source of HAP emissions.

(f) An existing non-emergency SI 4SLB and 4SRB stationary RICE with a site rating of more than 500 HP located at area sources of HAP must meet the definition of remote stationary RICE in §63.6675 on the initial compliance date for the engine, October 19, 2013, in order to be considered a remote stationary RICE under this subpart. Owners and operators of existing non-emergency SI 4SLB and 4SRB stationary RICE with a site rating of more than 500 HP located at area sources of HAP that meet the definition of remote stationary RICE in §63.6675 of this subpart as of October 19, 2013 must evaluate the status of their stationary RICE every 12 months. Owners and operators must keep records of the initial and annual evaluation of the status of the engine. If the evaluation indicates that the stationary RICE no longer meets the definition of remote stationary RICE in §63.6675 of this subpart, the owner or operator must comply with all of the requirements for existing non-emergency SI 4SLB and 4SRB stationary RICE with a site rating of more than 500 HP located at area sources of HAP that are not remote stationary RICE within 1 year of the evaluation.

[75 FR 9675, Mar. 3, 2010, as amended at 75 FR 51589, Aug. 20, 2010; 76 FR 12866, Mar. 9, 2011; 78 FR 6701, Jan. 30, 2013]

Back to Top

§63.6604 What fuel requirements must I meet if I own or operate a stationary CI RICE?

(a) If you own or operate an existing non-emergency, non-black start CI stationary RICE with a site rating of more than 300 brake HP with a displacement of less than 30 liters per cylinder that uses diesel fuel, you must use diesel fuel that meets the requirements in 40 CFR 80.510(b) for nonroad diesel fuel.

(b) Beginning January 1, 2015, if you own or operate an existing emergency CI stationary RICE with a site rating of more than 100 brake HP and a displacement of less than 30 liters per cylinder that uses diesel fuel and operates or is contractually obligated to be available for more than 15 hours per calendar year for the purposes specified in §63.6640(f)(2)(ii) and (iii) or that operates for the purpose specified in §63.6640(f)(4)(ii), you must use diesel fuel that meets the requirements in 40 CFR 80.510(b) for nonroad diesel fuel, except that any existing diesel fuel purchased (or otherwise obtained) prior to January 1, 2015, may be used until depleted.

(c) Beginning January 1, 2015, if you own or operate a new emergency CI stationary RICE with a site rating of more than 500 brake HP and a displacement of less than 30 liters per cylinder located at a major source of HAP that uses diesel fuel and operates or is contractually obligated to be available for more than 15 hours per calendar year for the purposes specified in §63.6640(f)(2)(ii) and (iii), you must use diesel fuel that meets the requirements in 40 CFR 80.510(b) for nonroad diesel fuel, except that any existing diesel fuel purchased (or otherwise obtained) prior to January 1, 2015, may be used until depleted.

(d) Existing CI stationary RICE located in Guam, American Samoa, the Commonwealth of the Northern Mariana Islands, at area sources in areas of Alaska that meet either §63.6603(b)(1) or §63.6603(b)(2), or are on offshore vessels that meet §63.6603(c) are exempt from the requirements of this section.

[78 FR 6702, Jan. 30, 2013]

Back to Top

GENERAL COMPLIANCE REQUIREMENTS

Back to Top

§63.6605 What are my general requirements for complying with this subpart?

(a) You must be in compliance with the emission limitations, operating limitations, and other requirements in this subpart that apply to you at all times.

(b) At all times you must operate and maintain any affected source, including associated air pollution control equipment and monitoring equipment, in a manner consistent with safety and good air pollution control practices for minimizing emissions. The general duty to minimize emissions does not require you to make any further efforts to reduce emissions if levels required by this standard have been achieved. Determination of whether such operation 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, review of operation and maintenance procedures, review of operation and maintenance records, and inspection of the source.

[75 FR 9675, Mar. 3, 2010, as amended at 78 FR 6702, Jan. 30, 2013]

Back to Top

TESTING AND INITIAL COMPLIANCE REQUIREMENTS

Back to Top

§63.6610 By what date must I conduct the initial performance tests or other initial compliance demonstrations if I own or operate a stationary RICE with a site rating of more than 500 brake HP located at a major source of HAP emissions?

If you own or operate a stationary RICE with a site rating of more than 500 brake HP located at a major source of HAP emissions you are subject to the requirements of this section.

(a) You must conduct the initial performance test or other initial compliance demonstrations in Table 4 to this subpart that apply to you within 180 days after the compliance date that is specified for your stationary RICE in §63.6595 and according to the provisions in §63.7(a)(2).

(b) If you commenced construction or reconstruction between December 19, 2002 and June 15, 2004 and own or operate stationary RICE with a site rating of more than 500 brake HP located at a major source of HAP emissions, you must demonstrate initial compliance with either the proposed emission limitations or the promulgated emission limitations no later than February 10, 2005 or no later than 180 days after startup of the source, whichever is later, according to §63.7(a)(2)(ix).

(c) If you commenced construction or reconstruction between December 19, 2002 and June 15, 2004 and own or operate stationary RICE with a site rating of more than 500 brake HP located at a major source of HAP emissions, and you chose to comply with the proposed emission limitations when demonstrating initial compliance, you must conduct a second performance test to demonstrate compliance with the promulgated emission limitations by December 13, 2007 or after startup of the source, whichever is later, according to §63.7(a)(2)(ix).

(d) An owner or operator is not required to conduct an initial performance test on units for which a performance test has been previously conducted, but the test must meet all of the conditions described in paragraphs (d)(1) through (5) of this section.

(1) The test must have been conducted using the same methods specified in this subpart, and these methods must have been followed correctly.

(2) The test must not be older than 2 years.

(3) The test must be reviewed and accepted by the Administrator.

(4) Either no process or equipment changes must have been made since the test was performed, or the owner or operator must be able to demonstrate that the results of the performance test, with or without adjustments, reliably demonstrate compliance despite process or equipment changes.

(5) The test must be conducted at any load condition within plus or minus 10 percent of 100 percent load.

[69 FR 33506, June 15, 2004, as amended at 73 FR 3605, Jan. 18, 2008]

Back to Top

§63.6611 By what date must I conduct the initial performance tests or other initial compliance demonstrations if I own or operate a new or reconstructed 4SLB SI stationary RICE with a site rating of greater than or equal to 250 and less than or equal to 500 brake HP located at a major source of HAP emissions?

If you own or operate a new or reconstructed 4SLB stationary RICE with a site rating of greater than or equal to 250 and less than or equal to 500 brake HP located at a major source of HAP emissions, you must conduct an initial performance test within 240 days after the compliance date that is specified for your stationary RICE in §63.6595 and according to the provisions specified in Table 4 to this subpart, as appropriate.

[73 FR 3605, Jan. 18, 2008, as amended at 75 FR 51589, Aug. 20, 2010]

Back to Top

§63.6612 By what date must I conduct the initial performance tests or other initial compliance demonstrations if I own or operate an existing stationary RICE with a site rating of less than or equal to 500 brake HP located at a major source of HAP emissions or an existing stationary RICE located at an area source of HAP emissions?

If you own or operate an existing stationary RICE with a site rating of less than or equal to 500 brake HP located at a major source of HAP emissions or an existing stationary RICE located at an area source of HAP emissions you are subject to the requirements of this section.

(a) You must conduct any initial performance test or other initial compliance demonstration according to Tables 4 and 5 to this subpart that apply to you within 180 days after the compliance date that is specified for your stationary RICE in §63.6595 and according to the provisions in §63.7(a)(2).

(b) An owner or operator is not required to conduct an initial performance test on a unit for which a performance test has been previously conducted, but the test must meet all of the conditions described in paragraphs (b)(1) through (4) of this section.

(1) The test must have been conducted using the same methods specified in this subpart, and these methods must have been followed correctly.

(2) The test must not be older than 2 years.

(3) The test must be reviewed and accepted by the Administrator.

(4) Either no process or equipment changes must have been made since the test was performed, or the owner or operator must be able to demonstrate that the results of the performance test, with or without adjustments, reliably demonstrate compliance despite process or equipment changes.

[75 FR 9676, Mar. 3, 2010, as amended at 75 FR 51589, Aug. 20, 2010]

Back to Top

§63.6615 When must I conduct subsequent performance tests?

If you must comply with the emission limitations and operating limitations, you must conduct subsequent performance tests as specified in Table 3 of this subpart.

Back to Top

§63.6620 What performance tests and other procedures must I use?

(a) You must conduct each performance test in Tables 3 and 4 of this subpart that applies to you.

(b) Each performance test must be conducted according to the requirements that this subpart specifies in Table 4 to this subpart. If you own or operate a non-operational stationary RICE that is subject to performance testing, you do not need to start up the engine solely to conduct the performance test. Owners and operators of a non-operational engine can conduct the performance test when the engine is started up again. The test must be conducted at any load condition within plus or minus 10 percent of 100 percent load for the stationary RICE listed in paragraphs (b)(1) through (4) of this section.

(1) Non-emergency 4SRB stationary RICE with a site rating of greater than 500 brake HP located at a major source of HAP emissions.

(2) New non-emergency 4SLB stationary RICE with a site rating of greater than or equal to 250 brake HP located at a major source of HAP emissions.

(3) New non-emergency 2SLB stationary RICE with a site rating of greater than 500 brake HP located at a major source of HAP emissions.

(4) New non-emergency CI stationary RICE with a site rating of greater than 500 brake HP located at a major source of HAP emissions.

(c) [Reserved]

(d) You must conduct three separate test runs for each performance test required in this section, as specified in §63.7(e)(3). Each test run must last at least 1 hour, unless otherwise specified in this subpart.

(e)(1) You must use Equation 1 of this section to determine compliance with the percent reduction requirement:

$$\frac{C_i - C_o}{C_i} \times 100 = R \quad (Eq.\ 1)$$

View or download PDF

Where:

C_i = concentration of carbon monoxide (CO), total hydrocarbons (THC), or formaldehyde at the control device inlet,

C_o = concentration of CO, THC, or formaldehyde at the control device outlet, and

R = percent reduction of CO, THC, or formaldehyde emissions.

(2) You must normalize the CO, THC, or formaldehyde concentrations at the inlet and outlet of the control device to a dry basis and to 15 percent oxygen, or an equivalent percent carbon dioxide (CO_2). If pollutant concentrations are to be corrected to 15 percent oxygen and CO_2 concentration is measured in lieu of oxygen concentration measurement, a CO_2 correction factor is needed. Calculate the CO_2 correction factor as described in paragraphs (e)(2)(i) through (iii) of this section.

(i) Calculate the fuel-specific F_o value for the fuel burned during the test using values obtained from Method 19, Section 5.2, and the following equation:

$$F_o = \frac{0.209\ F_d}{F_c} \quad (Eq.\ 2)$$

View or download PDF

Where:

F_o = Fuel factor based on the ratio of oxygen volume to the ultimate CO_2 volume produced by the fuel at zero percent excess air.

0.209 = Fraction of air that is oxygen, percent/100.

F_d = Ratio of the volume of dry effluent gas to the gross calorific value of the fuel from Method 19, dsm^3/J ($dscf/10^6$ Btu).

F_c = Ratio of the volume of CO_2 produced to the gross calorific value of the fuel from Method 19, dsm^3/J ($dscf/10^6$ Btu)

(ii) Calculate the CO_2 correction factor for correcting measurement data to 15 percent O_2, as follows:

$$X_{CO2} = \frac{5.9}{F_o} \quad (Eq.\ 3)$$

View or download PDF

Where:

X_{CO2} = CO_2 correction factor, percent.

5.9 = 20.9 percent O_2—15 percent O_2, the defined O_2 correction value, percent.

(iii) Calculate the CO, THC, and formaldehyde gas concentrations adjusted to 15 percent O_2 using CO_2 as follows:

$$C_{adj} = C_d \frac{X_{CO2}}{\%CO_2} \quad (Eq.\ 4)$$

View or download PDF

Where:

C_{adj} = Calculated concentration of CO, THC, or formaldehyde adjusted to 15 percent O_2.

C_d = Measured concentration of CO, THC, or formaldehyde, uncorrected.

X_{CO2} = CO_2 correction factor, percent.

$\%CO_2$ = Measured CO_2 concentration measured, dry basis, percent.

(f) If you comply with the emission limitation to reduce CO and you are not using an oxidation catalyst, if you comply with the emission limitation to reduce formaldehyde and you are not using NSCR, or if you comply with the emission limitation to limit the concentration of formaldehyde in the stationary RICE exhaust and you are not using an oxidation catalyst or NSCR, you must petition the Administrator for operating limitations to be established during the initial performance test and continuously monitored thereafter; or for approval of no operating limitations. You must not conduct the initial performance test until after the petition has been approved by the Administrator.

(g) If you petition the Administrator for approval of operating limitations, your petition must include the information described in paragraphs (g)(1) through (5) of this section.

(1) Identification of the specific parameters you propose to use as operating limitations;

(2) A discussion of the relationship between these parameters and HAP emissions, identifying how HAP emissions change with changes in these parameters, and how limitations on these parameters will serve to limit HAP emissions;

(3) A discussion of how you will establish the upper and/or lower values for these parameters which will establish the limits on these parameters in the operating limitations;

(4) A discussion identifying the methods you will use to measure and the instruments you will use to monitor these parameters, as well as the relative accuracy and precision of these methods and instruments; and

(5) A discussion identifying the frequency and methods for recalibrating the instruments you will use for monitoring these parameters.

(h) If you petition the Administrator for approval of no operating limitations, your petition must include the information described in paragraphs (h)(1) through (7) of this section.

(1) Identification of the parameters associated with operation of the stationary RICE and any emission control device which could change intentionally (*e.g.,* operator adjustment, automatic controller adjustment, etc.) or unintentionally (*e.g.,*wear and tear, error, etc.) on a routine basis or over time;

(2) A discussion of the relationship, if any, between changes in the parameters and changes in HAP emissions;

(3) For the parameters which could change in such a way as to increase HAP emissions, a discussion of whether establishing limitations on the parameters would serve to limit HAP emissions;

(4) For the parameters which could change in such a way as to increase HAP emissions, a discussion of how you could establish upper and/or lower values for the parameters which would establish limits on the parameters in operating limitations;

(5) For the parameters, a discussion identifying the methods you could use to measure them and the instruments you could use to monitor them, as well as the relative accuracy and precision of the methods and instruments;

(6) For the parameters, a discussion identifying the frequency and methods for recalibrating the instruments you could use to monitor them; and

(7) A discussion of why, from your point of view, it is infeasible or unreasonable to adopt the parameters as operating limitations.

(i) The engine percent load during a performance test must be determined by documenting the calculations, assumptions, and measurement devices used to measure or estimate the percent load in a specific application. A written report of the average percent load determination must be included in the notification of compliance status. The following information must be included in the written report: the engine model number, the engine manufacturer, the year of purchase, the manufacturer's site-rated brake horsepower, the ambient temperature, pressure, and humidity during the performance test, and all assumptions that were made to estimate or calculate percent load during the performance test must be clearly explained. If measurement devices such as flow meters, kilowatt meters, beta analyzers, stain gauges, etc. are used, the model number of the measurement device, and an estimate of its accurate in percentage of true value must be provided.

[69 FR 33506, June 15, 2004, as amended at 75 FR 9676, Mar. 3, 2010; 78 FR 6702, Jan. 30, 2013]

Back to Top

§63.6625 What are my monitoring, installation, collection, operation, and maintenance requirements?

(a) If you elect to install a CEMS as specified in Table 5 of this subpart, you must install, operate, and maintain a CEMS to monitor CO and either O_2 or CO_2 according to the requirements in paragraphs (a)(1) through (4) of this section. If you are meeting a requirement to reduce CO emissions, the CEMS must be installed at both the inlet and outlet of the control device. If you are meeting a requirement to limit the concentration of CO, the CEMS must be installed at the outlet of the control device.

(1) Each CEMS must be installed, operated, and maintained according to the applicable performance specifications of 40 CFR part 60, appendix B.

(2) You must conduct an initial performance evaluation and an annual relative accuracy test audit (RATA) of each CEMS according to the requirements in §63.8 and according to the applicable performance specifications of 40 CFR part 60, appendix B as well as daily and periodic data quality checks in accordance with 40 CFR part 60, appendix F, procedure 1.

(3) As specified in §63.8(c)(4)(ii), each CEMS must complete a minimum of one cycle of operation (sampling, analyzing, and data recording) for each successive 15-minute period. You must have at least two data points, with each representing a different 15-minute period, to have a valid hour of data.

(4) The CEMS data must be reduced as specified in §63.8(g)(2) and recorded in parts per million or parts per billion (as appropriate for the applicable limitation) at 15 percent oxygen or the equivalent CO_2 concentration.

(b) If you are required to install a continuous parameter monitoring system (CPMS) as specified in Table 5 of this subpart, you must install, operate, and maintain each CPMS according to the requirements in paragraphs (b)(1) through (6) of this section. For an affected source that is complying with the emission limitations and operating limitations on March 9, 2011, the requirements in paragraph (b) of this section are applicable September 6, 2011.

(1) You must prepare a site-specific monitoring plan that addresses the monitoring system design, data collection, and the quality assurance and quality control elements outlined in paragraphs (b)(1)(i) through (v) of this section and in §63.8(d). As specified in §63.8(f)(4), you may request approval of monitoring system quality assurance and quality control procedures alternative to those specified in paragraphs (b)(1) through (5) of this section in your site-specific monitoring plan.

(i) The performance criteria and design specifications for the monitoring system equipment, including the sample interface, detector signal analyzer, and data acquisition and calculations;

(ii) Sampling interface (*e.g.,* thermocouple) location such that the monitoring system will provide representative measurements;

(iii) Equipment performance evaluations, system accuracy audits, or other audit procedures;

(iv) Ongoing operation and maintenance procedures in accordance with provisions in §63.8(c)(1)(ii) and (c)(3); and

(v) Ongoing reporting and recordkeeping procedures in accordance with provisions in §63.10(c), (e)(1), and (e)(2)(i).

(2) You must install, operate, and maintain each CPMS in continuous operation according to the procedures in your site-specific monitoring plan.

(3) The CPMS must collect data at least once every 15 minutes (see also §63.6635).

(4) For a CPMS for measuring temperature range, the temperature sensor must have a minimum tolerance of 2.8 degrees Celsius (5 degrees Fahrenheit) or 1 percent of the measurement range, whichever is larger.

(5) You must conduct the CPMS equipment performance evaluation, system accuracy audits, or other audit procedures specified in your site-specific monitoring plan at least annually.

(6) You must conduct a performance evaluation of each CPMS in accordance with your site-specific monitoring plan.

(c) If you are operating a new or reconstructed stationary RICE which fires landfill gas or digester gas equivalent to 10 percent or more of the gross heat input on an annual basis, you must monitor and record your fuel usage daily with separate fuel meters to measure the volumetric flow rate of each fuel. In addition, you must operate your stationary RICE in a manner which reasonably minimizes HAP emissions.

(d) If you are operating a new or reconstructed emergency 4SLB stationary RICE with a site rating of greater than or equal to 250 and less than or equal to 500 brake HP located at a major source of HAP emissions, you must install a non-resettable hour meter prior to the startup of the engine.

(e) If you own or operate any of the following stationary RICE, you must operate and maintain the stationary RICE and after-treatment control device (if any) according to the manufacturer's emission-related written instructions or develop your own maintenance plan which must provide to the extent practicable for the maintenance and operation of the engine in a manner consistent with good air pollution control practice for minimizing emissions:

(1) An existing stationary RICE with a site rating of less than 100 HP located at a major source of HAP emissions;

(2) An existing emergency or black start stationary RICE with a site rating of less than or equal to 500 HP located at a major source of HAP emissions;

(3) An existing emergency or black start stationary RICE located at an area source of HAP emissions;

(4) An existing non-emergency, non-black start stationary CI RICE with a site rating less than or equal to 300 HP located at an area source of HAP emissions;

(5) An existing non-emergency, non-black start 2SLB stationary RICE located at an area source of HAP emissions;

(6) An existing non-emergency, non-black start stationary RICE located at an area source of HAP emissions which combusts landfill or digester gas equivalent to 10 percent or more of the gross heat input on an annual basis.

(7) An existing non-emergency, non-black start 4SLB stationary RICE with a site rating less than or equal to 500 HP located at an area source of HAP emissions;

(8) An existing non-emergency, non-black start 4SRB stationary RICE with a site rating less than or equal to 500 HP located at an area source of HAP emissions;

(9) An existing, non-emergency, non-black start 4SLB stationary RICE with a site rating greater than 500 HP located at an area source of HAP emissions that is operated 24 hours or less per calendar year; and

(10) An existing, non-emergency, non-black start 4SRB stationary RICE with a site rating greater than 500 HP located at an area source of HAP emissions that is operated 24 hours or less per calendar year.

(f) If you own or operate an existing emergency stationary RICE with a site rating of less than or equal to 500 brake HP located at a major source of HAP emissions or an existing emergency stationary RICE located at an area source of HAP emissions, you must install a non-resettable hour meter if one is not already installed.

(g) If you own or operate an existing non-emergency, non-black start CI engine greater than or equal to 300 HP that is not equipped with a closed crankcase ventilation system, you must comply with either paragraph (g)(1) or paragraph (2) of this section. Owners and operators must follow the manufacturer's specified maintenance requirements for operating and maintaining the open or closed crankcase ventilation systems and replacing the crankcase filters, or can request the Administrator to approve different maintenance requirements that are as protective as manufacturer requirements. Existing CI engines located at area sources in areas of Alaska that meet either §63.6603(b)(1) or §63.6603(b)(2) do not have to meet the requirements of this paragraph (g). Existing CI engines located on offshore vessels that meet §63.6603(c) do not have to meet the requirements of this paragraph (g).

(1) Install a closed crankcase ventilation system that prevents crankcase emissions from being emitted to the atmosphere, or

(2) Install an open crankcase filtration emission control system that reduces emissions from the crankcase by filtering the exhaust stream to remove oil mist, particulates and metals.

(h) If you operate a new, reconstructed, or existing stationary engine, you must minimize the engine's time spent at idle during startup and minimize the engine's startup time to a period needed for appropriate and safe loading of the engine, not to exceed 30 minutes, after which time the emission standards applicable to all times other than startup in Tables 1a, 2a, 2c, and 2d to this subpart apply.

(i) If you own or operate a stationary CI engine that is subject to the work, operation or management practices in items 1 or 2 of Table 2c to this subpart or in items 1 or 4 of Table 2d to this subpart, you have the option of utilizing an oil analysis program in order to extend the specified oil change requirement in Tables 2c and 2d to this subpart. The oil analysis must be performed at the same frequency specified for changing the oil in Table 2c or 2d to this subpart. The analysis program must at a minimum analyze the following three parameters: Total Base Number, viscosity, and percent water content. The condemning limits for these parameters are as follows: Total Base Number is less than 30 percent of the Total Base Number of the oil when new; viscosity of the oil has changed by more than 20 percent from the viscosity of the oil when new; or percent water content (by volume) is greater than 0.5. If all of these condemning limits are not exceeded, the engine owner or operator is not required to change the oil. If any of the limits are exceeded, the engine owner or operator must change the oil within 2 business days of receiving the results of the analysis; if the engine is not in operation when the results of the analysis are received, the engine owner or operator must change the oil within 2 business days or before commencing operation, whichever is later. The owner or operator must keep records of the parameters that are analyzed as part of the program, the results of the analysis, and the oil changes for the engine. The analysis program must be part of the maintenance plan for the engine.

(j) If you own or operate a stationary SI engine that is subject to the work, operation or management practices in items 6, 7, or 8 of Table 2c to this subpart or in items 5, 6, 7, 9, or 11 of Table 2d to this subpart, you have the option of utilizing an oil analysis program in order to extend the specified oil change requirement in Tables 2c and 2d to this subpart. The oil analysis must be performed at the same frequency specified for changing the oil in Table 2c or 2d to this subpart. The analysis program must at a minimum analyze the following three parameters: Total Acid Number, viscosity, and percent water content. The condemning limits for these parameters are as follows: Total Acid Number increases by more than 3.0 milligrams of potassium hydroxide (KOH) per gram from Total Acid Number of the oil when new; viscosity of the oil has changed by more than 20 percent from the viscosity of the oil when new; or percent water content (by volume) is greater than 0.5. If all of these condemning limits are not exceeded, the engine owner or operator is not required to change the oil. If any of the limits are exceeded, the engine owner or operator must change the oil within 2 business days of receiving the results of the analysis; if the engine is not in operation when the results of the analysis are received, the engine owner or operator must change the oil within 2 business days or before commencing operation, whichever is later. The owner or operator must keep records of the parameters that are analyzed as part of the program, the results of the analysis, and the oil changes for the engine. The analysis program must be part of the maintenance plan for the engine.

[69 FR 33506, June 15, 2004, as amended at 73 FR 3606, Jan. 18, 2008; 75 FR 9676, Mar. 3, 2010; 75 FR 51589, Aug. 20, 2010; 76 FR 12866, Mar. 9, 2011; 78 FR 6703, Jan. 30, 2013]

Back to Top

§63.6630 How do I demonstrate initial compliance with the emission limitations, operating limitations, and other requirements?

(a) You must demonstrate initial compliance with each emission limitation, operating limitation, and other requirement that applies to you according to Table 5 of this subpart.

(b) During the initial performance test, you must establish each operating limitation in Tables 1b and 2b of this subpart that applies to you.

(c) You must submit the Notification of Compliance Status containing the results of the initial compliance demonstration according to the requirements in §63.6645.

(d) Non-emergency 4SRB stationary RICE complying with the requirement to reduce formaldehyde emissions by 76 percent or more can demonstrate initial compliance with the formaldehyde emission limit by testing for THC instead of formaldehyde. The testing must be conducted according to the requirements in Table 4 of this subpart. The average reduction of emissions of THC determined from the performance test must be equal to or greater than 30 percent.

(e) The initial compliance demonstration required for existing non-emergency 4SLB and 4SRB stationary RICE with a site rating of more than 500 HP located at an area source of HAP that are not remote stationary RICE and that are operated more than 24 hours per calendar year must be conducted according to the following requirements:

(1) The compliance demonstration must consist of at least three test runs.

(2) Each test run must be of at least 15 minute duration, except that each test conducted using the method in appendix A to this subpart must consist of at least one measurement cycle and include at least 2 minutes of test data phase measurement.

(3) If you are demonstrating compliance with the CO concentration or CO percent reduction requirement, you must measure CO emissions using one of the CO measurement methods specified in Table 4 of this subpart, or using appendix A to this subpart.

(4) If you are demonstrating compliance with the THC percent reduction requirement, you must measure THC emissions using Method 25A, reported as propane, of 40 CFR part 60, appendix A.

(5) You must measure O_2 using one of the O_2 measurement methods specified in Table 4 of this subpart. Measurements to determine O_2 concentration must be made at the same time as the measurements for CO or THC concentration.

(6) If you are demonstrating compliance with the CO or THC percent reduction requirement, you must measure CO or THC emissions and O_2 emissions simultaneously at the inlet and outlet of the control device.

[69 FR 33506, June 15, 2004, as amended at 78 FR 6704, Jan. 30, 2013]

Back to Top

CONTINUOUS COMPLIANCE REQUIREMENTS

Back to Top

§63.6635 How do I monitor and collect data to demonstrate continuous compliance?

(a) If you must comply with emission and operating limitations, you must monitor and collect data according to this section.

(b) Except for monitor malfunctions, associated repairs, required performance evaluations, and required quality assurance or control activities, you must monitor continuously at all times that the stationary RICE is operating. 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.

(c) You may not use data recorded during monitoring malfunctions, associated repairs, and required quality assurance or control activities in data averages and calculations used to report emission or operating levels. You must, however, use all the valid data collected during all other periods.

[69 FR 33506, June 15, 2004, as amended at 76 FR 12867, Mar. 9, 2011]

Back to Top

§63.6640 How do I demonstrate continuous compliance with the emission limitations, operating limitations, and other requirements?

(a) You must demonstrate continuous compliance with each emission limitation, operating limitation, and other requirements in Tables 1a and 1b, Tables 2a and 2b, Table 2c, and Table 2d to this subpart that apply to you according to methods specified in Table 6 to this subpart.

(b) You must report each instance in which you did not meet each emission limitation or operating limitation in Tables 1a and 1b, Tables 2a and 2b, Table 2c, and Table 2d to this subpart that apply to you. These instances are deviations from the emission and operating limitations in this subpart. These deviations must be reported according to the requirements in §63.6650. If you change your catalyst, you must reestablish the values of the operating parameters measured during the initial performance test. When you reestablish the values of your operating parameters, you must also conduct a performance test to demonstrate that you are meeting the required emission limitation applicable to your stationary RICE.

(c) The annual compliance demonstration required for existing non-emergency 4SLB and 4SRB stationary RICE with a site rating of more than 500 HP located at an area source of HAP that are not remote stationary RICE and that are operated more than 24 hours per calendar year must be conducted according to the following requirements:

(1) The compliance demonstration must consist of at least one test run.

(2) Each test run must be of at least 15 minute duration, except that each test conducted using the method in appendix A to this subpart must consist of at least one measurement cycle and include at least 2 minutes of test data phase measurement.

(3) If you are demonstrating compliance with the CO concentration or CO percent reduction requirement, you must measure CO emissions using one of the CO measurement methods specified in Table 4 of this subpart, or using appendix A to this subpart.

(4) If you are demonstrating compliance with the THC percent reduction requirement, you must measure THC emissions using Method 25A, reported as propane, of 40 CFR part 60, appendix A.

(5) You must measure O_2 using one of the O_2 measurement methods specified in Table 4 of this subpart. Measurements to determine O_2 concentration must be made at the same time as the measurements for CO or THC concentration.

(6) If you are demonstrating compliance with the CO or THC percent reduction requirement, you must measure CO or THC emissions and O_2 emissions simultaneously at the inlet and outlet of the control device.

(7) If the results of the annual compliance demonstration show that the emissions exceed the levels specified in Table 6 of this subpart, the stationary RICE must be shut down as soon as safely possible, and appropriate corrective action must be taken (e.g., repairs, catalyst cleaning, catalyst replacement). The stationary RICE must be retested within 7 days of being restarted and the emissions must meet the levels specified in Table 6 of this subpart. If the retest shows that the emissions continue to exceed the specified levels, the stationary RICE must again be shut down as soon as safely possible, and the stationary RICE may not operate, except for purposes of startup and testing, until the owner/operator demonstrates through testing that the emissions do not exceed the levels specified in Table 6 of this subpart.

(d) For new, reconstructed, and rebuilt stationary RICE, deviations from the emission or operating limitations that occur during the first 200 hours of operation from engine startup (engine burn-in period) are not violations. Rebuilt stationary RICE means a stationary RICE that has been rebuilt as that term is defined in 40 CFR 94.11(a).

(e) You must also report each instance in which you did not meet the requirements in Table 8 to this subpart that apply to you. If you own or operate a new or reconstructed stationary RICE with a site rating of less than or equal to 500 brake HP located at a major source of HAP emissions (except new or reconstructed 4SLB engines greater than or equal to 250 and less than or equal to 500 brake HP), a new or reconstructed stationary RICE located at an area source of HAP emissions, or any of the following RICE with a site rating of more than 500 brake HP located at a major source of HAP emissions, you do not need to comply with the requirements in Table 8 to this subpart: An existing 2SLB stationary RICE, an existing 4SLB stationary RICE, an existing emergency stationary RICE, an existing limited use stationary RICE, or an existing stationary RICE which fires landfill gas or digester gas equivalent to 10 percent or more of the gross heat input on an annual basis. If you own or operate any of the following RICE with a site rating of more than 500 brake HP located at a major source of HAP emissions, you do not need to comply with the requirements in Table 8 to this subpart, except for the initial notification requirements: a new or reconstructed stationary RICE that combusts landfill gas or digester gas equivalent to 10 percent or more of the gross heat input on an annual basis, a new or reconstructed emergency stationary RICE, or a new or reconstructed limited use stationary RICE.

(f) If you own or operate an emergency stationary RICE, you must operate the emergency stationary RICE according to the requirements in paragraphs (f)(1) through (4) of this section. In order for the engine to be considered an emergency stationary RICE under this subpart, any operation other than emergency operation, maintenance and testing, emergency demand response, and operation in non-emergency situations for 50 hours per year, as described in paragraphs (f)(1) through (4) of this section, is prohibited. If you do not operate the engine according to the requirements in paragraphs (f)(1) through (4) of this section, the engine will not be considered an emergency engine under this subpart and must meet all requirements for non-emergency engines.

(1) There is no time limit on the use of emergency stationary RICE in emergency situations.

(2) You may operate your emergency stationary RICE for any combination of the purposes specified in paragraphs (f)(2)(i) through (iii) of this section for a maximum of 100 hours per calendar year. Any operation for non-emergency situations as allowed by paragraphs (f)(3) and (4) of this section counts as part of the 100 hours per calendar year allowed by this paragraph (f)(2).

(i) Emergency stationary RICE may be operated for maintenance checks and readiness testing, provided that the tests are recommended by federal, state or local government, the manufacturer, the vendor, the regional transmission organization or equivalent balancing authority and transmission operator, or the insurance company associated with the engine. The owner or operator may petition the Administrator for approval of additional hours to be used for maintenance checks and readiness testing, but a petition is not required if the owner or operator maintains records indicating that federal, state, or local standards require maintenance and testing of emergency RICE beyond 100 hours per calendar year.

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

(iii) Emergency stationary RICE may be operated for periods where there is a deviation of voltage or frequency of 5 percent or greater below standard voltage or frequency.

(3) Emergency stationary RICE located at major sources of HAP may be operated for up to 50 hours per calendar year in non-emergency situations. The 50 hours of operation in non-emergency situations are counted as part of the 100 hours per calendar year for maintenance and testing and emergency demand response provided in paragraph (f)(2) of this section. The 50 hours per year for non-emergency situations cannot be used for peak shaving or non-emergency demand response, or to generate income for a facility to supply power to an electric grid or otherwise supply power as part of a financial arrangement with another entity.

(4) Emergency stationary RICE located at area sources of HAP may be operated for up to 50 hours per calendar year in non-emergency situations. The 50 hours of operation in non-emergency situations are counted as part of the 100 hours per calendar year for maintenance and testing and emergency demand response provided in paragraph (f)(2) of this section. Except as provided in paragraphs (f)(4)(i) and (ii) of this section, the 50 hours per year for non-emergency situations cannot be used for peak shaving or non-emergency demand response, or to generate income for a facility to an electric grid or otherwise supply power as part of a financial arrangement with another entity.

(i) Prior to May 3, 2014, the 50 hours per year for non-emergency situations can be used for peak shaving or non-emergency demand response to generate income for a facility, or to otherwise supply power as part of a financial arrangement with another entity if the engine is operated as part of a peak shaving (load management program) with the local distribution system operator and the power is provided only to the facility itself or to support the local distribution system.

(ii) The 50 hours per year for non-emergency situations can be used to supply power as part of a financial arrangement with another entity if all of the following conditions are met:

(A) The engine is dispatched by the local balancing authority or local transmission and distribution system operator.

(B) The dispatch is intended to mitigate local transmission and/or distribution limitations so as to avert potential voltage collapse or line overloads that could lead to the interruption of power supply in a local area or region.

(C) The dispatch follows reliability, emergency operation or similar protocols that follow specific NERC, regional, state, public utility commission or local standards or guidelines.

(D) The power is provided only to the facility itself or to support the local transmission and distribution system.

(E) The owner or operator identifies and records the entity that dispatches the engine and the specific NERC, regional, state, public utility commission or local standards or guidelines that are being followed for dispatching the engine. The local balancing authority or local transmission and distribution system operator may keep these records on behalf of the engine owner or operator.

[69 FR 33506, June 15, 2004, as amended at 71 FR 20467, Apr. 20, 2006; 73 FR 3606, Jan. 18, 2008; 75 FR 9676, Mar. 3, 2010; 75 FR 51591, Aug. 20, 2010; 78 FR 6704, Jan. 30, 2013]

Back to Top

Notifications, Reports, and Records

Back to Top

§63.6645 What notifications must I submit and when?

(a) You must submit all of the notifications in §§63.7(b) and (c), 63.8(e), (f)(4) and (f)(6), 63.9(b) through (e), and (g) and (h) that apply to you by the dates specified if you own or operate any of the following;

(1) An existing stationary RICE with a site rating of less than or equal to 500 brake HP located at a major source of HAP emissions.

(2) An existing stationary RICE located at an area source of HAP emissions.

(3) A stationary RICE with a site rating of more than 500 brake HP located at a major source of HAP emissions.

(4) A new or reconstructed 4SLB stationary RICE with a site rating of greater than or equal to 250 HP located at a major source of HAP emissions.

(5) This requirement does not apply if you own or operate an existing stationary RICE less than 100 HP, an existing stationary emergency RICE, or an existing stationary RICE that is not subject to any numerical emission standards.

(b) As specified in §63.9(b)(2), if you start up your stationary RICE with a site rating of more than 500 brake HP located at a major source of HAP emissions before the effective date of this subpart, you must submit an Initial Notification not later than December 13, 2004.

(c) If you start up your new or reconstructed stationary RICE with a site rating of more than 500 brake HP located at a major source of HAP emissions on or after August 16, 2004, you must submit an Initial Notification not later than 120 days after you become subject to this subpart.

(d) As specified in §63.9(b)(2), if you start up your stationary RICE with a site rating of equal to or less than 500 brake HP located at a major source of HAP emissions before the effective date of this subpart and you are required to submit an initial notification, you must submit an Initial Notification not later than July 16, 2008.

(e) If you start up your new or reconstructed stationary RICE with a site rating of equal to or less than 500 brake HP located at a major source of HAP emissions on or after March 18, 2008 and you are required to submit an initial notification, you must submit an Initial Notification not later than 120 days after you become subject to this subpart.

(f) If you are required to submit an Initial Notification but are otherwise not affected by the requirements of this subpart, in accordance with §63.6590(b), your notification should include the information in §63.9(b)(2)(i) through (v), and a statement that your stationary RICE has no additional requirements and explain the basis of the exclusion (for example, that it operates exclusively as an emergency stationary RICE if it has a site rating of more than 500 brake HP located at a major source of HAP emissions).

(g) 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 as required in §63.7(b)(1).

(h) If you are required to conduct a performance test or other initial compliance demonstration as specified in Tables 4 and 5 to this subpart, you must submit a Notification of Compliance Status according to §63.9(h)(2)(ii).

(1) For each initial compliance demonstration required in Table 5 to this subpart that does not include a performance test, you must submit the Notification of Compliance Status before the close of business on the 30th day following the completion of the initial compliance demonstration.

(2) For each initial compliance demonstration required in Table 5 to this subpart that includes a performance test conducted according to the requirements in Table 3 to this subpart, you must submit the Notification of Compliance Status, including the performance test results, before the close of business on the 60th day following the completion of the performance test according to §63.10(d)(2).

(i) If you own or operate an existing non-emergency CI RICE with a site rating of more than 300 HP located at an area source of HAP emissions that is certified to the Tier 1 or Tier 2 emission standards in Table 1 of 40 CFR 89.112 and subject to an enforceable state or local standard requiring engine replacement and you intend to meet management practices rather than emission limits, as specified in §63.6603(d), you must submit a notification by March 3, 2013, stating that you intend to use the provision in §63.6603(d) and identifying the state or local regulation that the engine is subject to.

[73 FR 3606, Jan. 18, 2008, as amended at 75 FR 9677, Mar. 3, 2010; 75 FR 51591, Aug. 20, 2010; 78 FR 6705, Jan. 30, 2013]

Back to Top

§63.6650 What reports must I submit and when?

(a) You must submit each report in Table 7 of this subpart that applies to you.

(b) Unless the Administrator has approved a different schedule for submission of reports under §63.10(a), you must submit each report by the date in Table 7 of this subpart and according to the requirements in paragraphs (b)(1) through (b)(9) of this section.

(1) For semiannual Compliance reports, the first Compliance report must cover the period beginning on the compliance date that is specified for your affected source in §63.6595 and ending on June 30 or December 31, whichever date is the first date following the end of the first calendar half after the compliance date that is specified for your source in §63.6595.

(2) For semiannual Compliance reports, the first Compliance report must be postmarked or delivered no later than July 31 or January 31, whichever date follows the end of the first calendar half after the compliance date that is specified for your affected source in §63.6595.

(3) For semiannual Compliance reports, each subsequent Compliance report must cover the semiannual reporting period from January 1 through June 30 or the semiannual reporting period from July 1 through December 31.

(4) For semiannual Compliance reports, each subsequent Compliance report must be postmarked or delivered no later than July 31 or January 31, whichever date is the first date following the end of the semiannual reporting period.

(5) For each stationary RICE that is subject to permitting regulations pursuant to 40 CFR part 70 or 71, and if the permitting authority has established dates for submitting semiannual reports pursuant to 40 CFR 70.6(a)(3)(iii)(A) or 40 CFR 71.6 (a)(3)(iii)(A), you may submit the first and subsequent Compliance reports according to the dates the permitting authority has established instead of according to the dates in paragraphs (b)(1) through (b)(4) of this section.

(6) For annual Compliance reports, the first Compliance report must cover the period beginning on the compliance date that is specified for your affected source in §63.6595 and ending on December 31.

(7) For annual Compliance reports, the first Compliance report must be postmarked or delivered no later than January 31 following the end of the first calendar year after the compliance date that is specified for your affected source in §63.6595.

(8) For annual Compliance reports, each subsequent Compliance report must cover the annual reporting period from January 1 through December 31.

(9) For annual Compliance reports, each subsequent Compliance report must be postmarked or delivered no later than January 31.

(c) The Compliance report must contain the information in paragraphs (c)(1) through (6) of this section.

(1) Company name and address.

(2) Statement by a responsible official, with that official's name, title, and signature, certifying the accuracy of the content of the report.

(3) Date of report and beginning and ending dates of the reporting period.

(4) If you had a malfunction during the reporting period, the compliance report must include the number, duration, and a brief description for each type of malfunction which occurred during the reporting period and which caused or may have caused any applicable emission limitation to be exceeded. The report must also include a description of actions taken by an owner or operator during a malfunction of an affected source to minimize emissions in accordance with §63.6605(b), including actions taken to correct a malfunction.

(5) If there are no deviations from any emission or operating limitations that apply to you, a statement that there were no deviations from the emission or operating limitations during the reporting period.

(6) If there were no periods during which the continuous monitoring system (CMS), including CEMS and CPMS, was out-of-control, as specified in §63.8(c)(7), a statement that there were no periods during which the CMS was out-of-control during the reporting period.

(d) For each deviation from an emission or operating limitation that occurs for a stationary RICE where you are not using a CMS to comply with the emission or operating limitations in this subpart, the Compliance report must contain the information in paragraphs (c)(1) through (4) of this section and the information in paragraphs (d)(1) and (2) of this section.

(1) The total operating time of the stationary RICE at which the deviation occurred during the reporting period.

(2) Information on the number, duration, and cause of deviations (including unknown cause, if applicable), as applicable, and the corrective action taken.

(e) For each deviation from an emission or operating limitation occurring for a stationary RICE where you are using a CMS to comply with the emission and operating limitations in this subpart, you must include information in paragraphs (c)(1) through (4) and (e)(1) through (12) of this section.

(1) The date and time that each malfunction started and stopped.

(2) The date, time, and duration 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, and whether each deviation occurred during a period of malfunction or during another period.

(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 breakdown 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 downtime during the reporting period, and the total duration of CMS downtime as a percent of the total operating time of the stationary RICE at which the CMS downtime occurred during that reporting period.

(8) An identification of each parameter and pollutant (CO or formaldehyde) that was monitored at the stationary RICE.

(9) A brief description of the stationary RICE.

(10) A brief description of the CMS.

(11) The date of the latest CMS certification or audit.

(12) A description of any changes in CMS, processes, or controls since the last reporting period.

(f) Each affected source that has obtained a title V operating permit pursuant to 40 CFR part 70 or 71 must report all deviations as defined in this subpart in the semiannual monitoring report required by 40 CFR 70.6 (a)(3)(iii)(A) or 40 CFR 71.6(a)(3)(iii)(A). If an affected source submits a Compliance report pursuant to Table 7 of this subpart along with, or as part of, the semiannual monitoring report required by 40 CFR 70.6(a)(3)(iii)(A) or 40 CFR 71.6(a)(3)(iii)(A), and the Compliance report includes all required information concerning deviations from any emission or operating limitation in this subpart, submission of the Compliance report shall be deemed to satisfy any obligation to report the same deviations in the semiannual monitoring report. However, submission of a Compliance report shall not otherwise affect any obligation the affected source may have to report deviations from permit requirements to the permit authority.

(g) If you are operating as a new or reconstructed stationary RICE which fires landfill gas or digester gas equivalent to 10 percent or more of the gross heat input on an annual basis, you must submit an annual report according to Table 7 of this subpart by the date specified unless the Administrator has approved a different schedule, according to the information described in paragraphs (b)(1) through (b)(5) of this section. You must report the data specified in (g)(1) through (g)(3) of this section.

(1) Fuel flow rate of each fuel and the heating values that were used in your calculations. You must also demonstrate that the percentage of heat input provided by landfill gas or digester gas is equivalent to 10 percent or more of the total fuel consumption on an annual basis.

(2) The operating limits provided in your federally enforceable permit, and any deviations from these limits.

(3) Any problems or errors suspected with the meters.

(h) If you own or operate an emergency stationary RICE with a site rating of more than 100 brake HP that operates or is contractually obligated to be available for more than 15 hours per calendar year for the purposes specified in §63.6640(f)(2)(ii) and (iii) or that operates for the purpose specified in §63.6640(f)(4)(ii), you must submit an annual report according to the requirements in paragraphs (h)(1) through (3) of this section.

(1) The report must contain the following information:

(i) Company name and address where the engine is located.

(ii) Date of the report and beginning and ending dates of the reporting period.

(iii) Engine site rating and model year.

(iv) Latitude and longitude of the engine in decimal degrees reported to the fifth decimal place.

(v) Hours operated for the purposes specified in §63.6640(f)(2)(ii) and (iii), including the date, start time, and end time for engine operation for the purposes specified in §63.6640(f)(2)(ii) and (iii).

(vi) Number of hours the engine is contractually obligated to be available for the purposes specified in §63.6640(f)(2)(ii) and (iii).

(vii) Hours spent for operation for the purpose specified in §63.6640(f)(4)(ii), including the date, start time, and end time for engine operation for the purposes specified in §63.6640(f)(4)(ii). The report must also identify the entity that dispatched the engine and the situation that necessitated the dispatch of the engine.

(viii) If there were no deviations from the fuel requirements in §63.6604 that apply to the engine (if any), a statement that there were no deviations from the fuel requirements during the reporting period.

(ix) If there were deviations from the fuel requirements in §63.6604 that apply to the engine (if any), information on the number, duration, and cause of deviations, and the corrective action taken.

(2) The first annual report must cover the calendar year 2015 and must be submitted no later than March 31, 2016. Subsequent annual reports for each calendar year must be submitted no later than March 31 of the following calendar year.

(3) The annual report must be submitted electronically using the subpart specific reporting form in the Compliance and Emissions Data Reporting Interface (CEDRI) that is accessed through 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 written report must be submitted to the Administrator at the appropriate address listed in §63.13.

[69 FR 33506, June 15, 2004, as amended at 75 FR 9677, Mar. 3, 2010; 78 FR 6705, Jan. 30, 2013]

Back to Top

§63.6655 What records must I keep?

(a) If you must comply with the emission and operating limitations, you must keep the records described in paragraphs (a)(1) through (a)(5), (b)(1) through (b)(3) and (c) 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 that you submitted, according to the requirement in §63.10(b)(2)(xiv).

(2) Records of the occurrence and duration of each malfunction of operation (*i.e.,* process equipment) or the air pollution control and monitoring equipment.

(3) Records of performance tests and performance evaluations as required in §63.10(b)(2)(viii).

(4) Records of all required maintenance performed on the air pollution control and monitoring equipment.

(5) Records of actions taken during periods of malfunction to minimize emissions in accordance with §63.6605(b), including corrective actions to restore malfunctioning process and air pollution control and monitoring equipment to its normal or usual manner of operation.

(b) For each CEMS or CPMS, you must keep the records listed in paragraphs (b)(1) through (3) of this section.

(1) Records described in §63.10(b)(2)(vi) through (xi).

(2) Previous (*i.e.,* superseded) versions of the performance evaluation plan as required in §63.8(d)(3).

(3) Requests for alternatives to the relative accuracy test for CEMS or CPMS as required in §63.8(f)(6)(i), if applicable.

(c) If you are operating a new or reconstructed stationary RICE which fires landfill gas or digester gas equivalent to 10 percent or more of the gross heat input on an annual basis, you must keep the records of your daily fuel usage monitors.

(d) You must keep the records required in Table 6 of this subpart to show continuous compliance with each emission or operating limitation that applies to you.

(e) You must keep records of the maintenance conducted on the stationary RICE in order to demonstrate that you operated and maintained the stationary RICE and after-treatment control device (if any) according to your own maintenance plan if you own or operate any of the following stationary RICE;

(1) An existing stationary RICE with a site rating of less than 100 brake HP located at a major source of HAP emissions.

(2) An existing stationary emergency RICE.

(3) An existing stationary RICE located at an area source of HAP emissions subject to management practices as shown in Table 2d to this subpart.

(f) If you own or operate any of the stationary RICE in paragraphs (f)(1) through (2) of this section, you must keep records of the hours of operation of the engine that is recorded through the non-resettable hour meter. The owner or operator must document how many hours are spent for emergency operation, including what classified the operation as emergency and how many hours are spent for non-emergency operation. If the engine is used for the purposes specified in §63.6640(f)(2)(ii) or (iii) or §63.6640(f)(4)(ii), the owner or operator must keep records of the notification of the emergency situation, and the date, start time, and end time of engine operation for these purposes.

(1) An existing emergency stationary RICE with a site rating of less than or equal to 500 brake HP located at a major source of HAP emissions that does not meet the standards applicable to non-emergency engines.

(2) An existing emergency stationary RICE located at an area source of HAP emissions that does not meet the standards applicable to non-emergency engines.

[69 FR 33506, June 15, 2004, as amended at 75 FR 9678, Mar. 3, 2010; 75 FR 51592, Aug. 20, 2010; 78 FR 6706, Jan. 30, 2013]

Back to Top

§63.6660 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 readily accessible in hard copy or electronic form for at least 5 years after the date of each occurrence, measurement, maintenance, corrective action, report, or record, according to §63.10(b)(1).

[69 FR 33506, June 15, 2004, as amended at 75 FR 9678, Mar. 3, 2010]

Back to Top

OTHER REQUIREMENTS AND INFORMATION

Back to Top

§63.6665 What parts of the General Provisions apply to me?

Table 8 to this subpart shows which parts of the General Provisions in §§63.1 through 63.15 apply to you. If you own or operate a new or reconstructed stationary RICE with a site rating of less than or equal to 500 brake HP located at a major source of HAP emissions (except new or reconstructed 4SLB engines greater than or equal to 250 and less than or equal to 500 brake HP), a new or reconstructed stationary RICE located at an area source of HAP emissions, or any of the following RICE with a site rating of more than 500 brake HP located at a major source of HAP emissions, you do not need to comply with any of the requirements of the General Provisions specified in Table 8: An existing 2SLB stationary RICE, an existing 4SLB stationary RICE, an existing stationary RICE that combusts landfill or digester gas equivalent to 10 percent or more of the gross heat input on an annual basis, an existing emergency stationary RICE, or an existing limited use stationary RICE. If you own or operate any of the following RICE with a site rating of more than 500 brake HP located at a major source of HAP emissions, you do not need to comply with the requirements in the General Provisions specified in Table 8 except for the initial notification requirements: A new stationary RICE that combusts landfill gas or digester gas equivalent to 10 percent or more of the gross heat input on an annual basis, a new emergency stationary RICE, or a new limited use stationary RICE.

[75 FR 9678, Mar. 3, 2010]

Back to Top

§63.6670 Who implements and enforces this subpart?

(a) This subpart is implemented and enforced by the U.S. EPA, or a delegated authority such as your State, local, or tribal agency. If the U.S. EPA Administrator has delegated authority to your State, local, or tribal agency, then that agency (as well as the U.S. EPA) has the authority to implement and enforce this subpart. You should contact your U.S. EPA Regional Office to find out whether 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 contained in paragraph (c) of this section are retained by the Administrator of the U.S. EPA and are not transferred to the State, local, or tribal agency.

(c) The authorities that will not be delegated to State, local, or tribal agencies are:

(1) Approval of alternatives to the non-opacity emission limitations and operating limitations in §63.6600 under §63.6(g).

(2) Approval of major alternatives to test methods under §63.7(e)(2)(ii) and (f) and as defined in §63.90.

(3) Approval of major alternatives to monitoring under §63.8(f) and as defined in §63.90.

(4) Approval of major alternatives to recordkeeping and reporting under §63.10(f) and as defined in §63.90.

(5) Approval of a performance test which was conducted prior to the effective date of the rule, as specified in §63.6610(b).

Back to Top

§63.6675 What definitions apply to this subpart?

Terms used in this subpart are defined in the Clean Air Act (CAA); in 40 CFR 63.2, the General Provisions of this part; and in this section as follows:

Alaska Railbelt Grid means the service areas of the six regulated public utilities that extend from Fairbanks to Anchorage and the Kenai Peninsula. These utilities are Golden Valley Electric Association; Chugach Electric Association; Matanuska Electric Association; Homer Electric Association; Anchorage Municipal Light & Power; and the City of Seward Electric System.

Area source means any stationary source of HAP that is not a major source as defined in part 63.

Associated equipment as used in this subpart and as referred to in section 112(n)(4) of the CAA, means equipment associated with an oil or natural gas exploration or production well, and includes all equipment from the well bore to the point of custody transfer, except glycol dehydration units, storage vessels with potential for flash emissions, combustion turbines, and stationary RICE.

Backup power for renewable energy means an engine that provides backup power to a facility that generates electricity from renewable energy resources, as that term is defined in Alaska Statute 42.45.045(l)(5) (incorporated by reference, see §63.14).

Black start engine means an engine whose only purpose is to start up a combustion turbine.

CAA means the Clean Air Act (42 U.S.C. 7401 *et seq.,* as amended by Public Law 101-549, 104 Stat. 2399).

Commercial emergency stationary RICE means an emergency stationary RICE used in commercial establishments such as office buildings, hotels, stores, telecommunications facilities, restaurants, financial institutions such as banks, doctor's offices, and sports and performing arts facilities.

Compression ignition means relating to a type of stationary internal combustion engine that is not a spark ignition engine.

Custody transfer means the transfer of hydrocarbon liquids or natural gas: After processing and/or treatment in the producing operations, or from storage vessels or automatic transfer facilities or other such equipment, including product loading racks, to pipelines or any other forms of transportation. For the purposes of this subpart, the point at which such liquids or natural gas enters a natural gas processing plant is a point of custody transfer.

Deviation means any instance in which an affected source subject to this subpart, or an owner or operator of such a source:

(1) Fails to meet any requirement or obligation established by this subpart, including but not limited to any emission limitation or operating limitation;

(2) 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; or

(3) Fails to meet any emission limitation or operating limitation in this subpart during malfunction, regardless or whether or not such failure is permitted by this subpart.

(4) Fails to satisfy the general duty to minimize emissions established by §63.6(e)(1)(i).

Diesel engine means any stationary RICE in which a high boiling point liquid fuel injected into the combustion chamber ignites when the air charge has been compressed to a temperature sufficiently high for auto-ignition. This process is also known as compression ignition.

Diesel fuel means any liquid obtained from the distillation of petroleum with a boiling point of approximately 150 to 360 degrees Celsius. One commonly used form is fuel oil number 2. Diesel fuel also includes any non-distillate fuel with comparable physical and chemical properties (*e.g.* biodiesel) that is suitable for use in compression ignition engines.

Digester gas means any gaseous by-product of wastewater treatment typically formed through the anaerobic decomposition of organic waste materials and composed principally of methane and CO_2.

Dual-fuel engine means any stationary RICE in which a liquid fuel (typically diesel fuel) is used for compression ignition and gaseous fuel (typically natural gas) is used as the primary fuel.

Emergency stationary RICE means any stationary reciprocating internal combustion engine that meets all of the criteria in paragraphs (1) through (3) of this definition. All emergency stationary RICE must comply with the requirements specified in §63.6640(f) in order to be considered emergency stationary RICE. If the engine does not comply with the requirements specified in §63.6640(f), then it is not considered to be an emergency stationary RICE under this subpart.

(1) The stationary RICE is operated to provide electrical power or mechanical work during an emergency situation. Examples include stationary RICE used to produce power for critical networks or equipment (including power supplied to portions of a facility) when electric power from the local utility (or the normal power source, if the facility runs on its own power production) is interrupted, or stationary RICE used to pump water in the case of fire or flood, etc.

(2) The stationary RICE is operated under limited circumstances for situations not included in paragraph (1) of this definition, as specified in §63.6640(f).

(3) The stationary RICE operates as part of a financial arrangement with another entity in situations not included in paragraph (1) of this definition only as allowed in §63.6640(f)(2)(ii) or (iii) and §63.6640(f)(4)(i) or (ii).

Engine startup means the time from initial start until applied load and engine and associated equipment reaches steady state or normal operation. For stationary engine with catalytic controls, engine startup means the time from initial start until applied load and engine and associated equipment, including the catalyst, reaches steady state or normal operation.

Four-stroke engine means any type of engine which completes the power cycle in two crankshaft revolutions, with intake and compression strokes in the first revolution and power and exhaust strokes in the second revolution.

Gaseous fuel means a material used for combustion which is in the gaseous state at standard atmospheric temperature and pressure conditions.

Gasoline means any fuel sold in any State for use in motor vehicles and motor vehicle engines, or nonroad or stationary engines, and commonly or commercially known or sold as gasoline.

Glycol dehydration unit means a device in which a liquid glycol (including, but not limited to, ethylene glycol, diethylene glycol, or triethylene glycol) absorbent directly contacts a natural gas stream and absorbs water in a contact tower or absorption column (absorber). The glycol contacts and absorbs water vapor and other gas stream constituents from the natural gas and becomes “rich” glycol. This glycol is then regenerated in the glycol dehydration unit reboiler. The “lean” glycol is then recycled.

Hazardous air pollutants (HAP) means any air pollutants listed in or pursuant to section 112(b) of the CAA.

Institutional emergency stationary RICE means an emergency stationary RICE used in institutional establishments such as medical centers, nursing homes, research centers, institutions of higher education, correctional facilities, elementary and secondary schools, libraries, religious establishments, police stations, and fire stations.

ISO standard day conditions means 288 degrees Kelvin (15 degrees Celsius), 60 percent relative humidity and 101.3 kilopascals pressure.

Landfill gas means a gaseous by-product of the land application of municipal refuse typically formed through the anaerobic decomposition of waste materials and composed principally of methane and CO_2.

Lean burn engine means any two-stroke or four-stroke spark ignited engine that does not meet the definition of a rich burn engine.

Limited use stationary RICE means any stationary RICE that operates less than 100 hours per year.

Liquefied petroleum gas means any liquefied hydrocarbon gas obtained as a by-product in petroleum refining of natural gas production.

Liquid fuel means any fuel in liquid form at standard temperature and pressure, including but not limited to diesel, residual/crude oil, kerosene/naphtha (jet fuel), and gasoline.

Major Source, 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) For oil and gas production facilities, emissions from processes, operations, or equipment that are not part of the same oil and gas production facility, as defined in §63.1271 of subpart HHH of this part, shall not be aggregated;

(3) For production field facilities, only HAP emissions from glycol dehydration units, storage vessel with the potential for flash emissions, combustion turbines and reciprocating internal combustion engines shall be aggregated for a major source determination; and

(4) Emissions from processes, operations, and equipment that are not part of the same natural gas transmission and storage facility, as defined in §63.1271 of subpart HHH of this part, shall not be aggregated.

Malfunction means any sudden, infrequent, and not reasonably preventable failure of air pollution control equipment, process equipment, or a process to operate in a normal or usual manner which causes, or has the potential to cause, the emission limitations in an applicable standard to be exceeded. Failures that are caused in part by poor maintenance or careless operation are not malfunctions.

Natural gas means 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. Natural gas may be field or pipeline quality.

Non-selective catalytic reduction (NSCR) means an add-on catalytic nitrogen oxides (NO_x) control device for rich burn engines that, in a two-step reaction, promotes the conversion of excess oxygen, NO_x, CO, and volatile organic compounds (VOC) into CO_2, nitrogen, and water.

Oil and gas production facility as used in this subpart means any grouping of equipment where hydrocarbon liquids are processed, upgraded (*i.e.,* remove impurities or other constituents to meet contract specifications), or stored prior to the point of custody transfer; or where natural gas is processed, upgraded, or stored prior to entering the natural gas transmission and storage source category. For purposes of a major source determination, facility (including a building, structure, or installation) means oil and natural gas production and processing equipment that is located within the boundaries of an individual surface site as defined in this section. Equipment that is part of a facility will typically be located within close proximity to other equipment located at the same facility. Pieces of production equipment or groupings of equipment located on different oil and gas leases, mineral fee tracts, lease tracts, subsurface or surface unit areas, surface fee tracts, surface lease tracts, or separate surface sites, whether or not connected by a road, waterway, power line or pipeline, shall not be considered part of the same facility. Examples of facilities in the oil and natural gas production source category include, but are not limited to, well sites, satellite tank batteries, central tank batteries, a compressor station that transports natural gas to a natural gas processing plant, and natural gas processing plants.

Oxidation catalyst means an add-on catalytic control device that controls CO and VOC by oxidation.

Peaking unit or engine means any standby engine intended for use during periods of high demand that are not emergencies.

Percent load means the fractional power of an engine compared to its maximum manufacturer's design capacity at engine site conditions. Percent load may range between 0 percent to above 100 percent.

Potential to emit means the maximum capacity of a stationary source to emit a pollutant under its physical and operational design. Any physical or operational limitation on the capacity of the stationary source to emit a pollutant, including air pollution control equipment and restrictions on hours of operation or on the type or amount of material combusted, stored, or processed, shall be treated as part of its design if the limitation or the effect it would have on emissions is federally enforceable. For oil and natural gas production facilities subject to subpart HH of this part, the potential to emit provisions in §63.760(a) may be used. For natural gas transmission and storage facilities subject to subpart HHH of this part, the maximum annual facility gas throughput for storage facilities may be determined according to §63.1270(a)(1) and the maximum annual throughput for transmission facilities may be determined according to §63.1270(a)(2).

Production field facility means those oil and gas production facilities located prior to the point of custody transfer.

Production well means any hole drilled in the earth from which crude oil, condensate, or field natural gas is extracted.

Propane means a colorless gas derived from petroleum and natural gas, with the molecular structure C_3H_8.

Remote stationary RICE means stationary RICE meeting any of the following criteria:

(1) Stationary RICE located in an offshore area that is beyond the line of ordinary low water along that portion of the coast of the United States that is in direct contact with the open seas and beyond the line marking the seaward limit of inland waters.

(2) Stationary RICE located on a pipeline segment that meets both of the criteria in paragraphs (2)(i) and (ii) of this definition.

(i) A pipeline segment with 10 or fewer buildings intended for human occupancy and no buildings with four or more stories within 220 yards (200 meters) on either side of the centerline of any continuous 1-mile (1.6 kilometers) length of pipeline. Each separate dwelling unit in a multiple dwelling unit building is counted as a separate building intended for human occupancy.

(ii) The pipeline segment does not lie within 100 yards (91 meters) of either a building or a small, well-defined outside area (such as a playground, recreation area, outdoor theater, or other place of public assembly) that is occupied by 20 or more persons on at least 5 days a week for 10 weeks in any 12-month period. The days and weeks need not be consecutive. The building or area is considered occupied for a full day if it is occupied for any portion of the day.

(iii) For purposes of this paragraph (2), the term pipeline segment means all parts of those physical facilities through which gas moves in transportation, including but not limited to pipe, valves, and other appurtenance attached to pipe, compressor units, metering stations, regulator stations, delivery stations, holders, and fabricated assemblies. Stationary RICE located within 50 yards (46 meters) of the pipeline segment providing power for equipment on a pipeline segment are part of the pipeline segment. Transportation of gas means the gathering, transmission, or distribution of gas by pipeline, or the storage of gas. A building is intended for human occupancy if its primary use is for a purpose involving the presence of humans.

(3) Stationary RICE that are not located on gas pipelines and that have 5 or fewer buildings intended for human occupancy and no buildings with four or more stories within a 0.25 mile radius around the engine. A building is intended for human occupancy if its primary use is for a purpose involving the presence of humans.

Residential emergency stationary RICE means an emergency stationary RICE used in residential establishments such as homes or apartment buildings.

Responsible official means responsible official as defined in 40 CFR 70.2.

Rich burn engine means any four-stroke spark ignited engine where the manufacturer's recommended operating air/fuel ratio divided by the stoichiometric air/fuel ratio at full load conditions is less than or equal to 1.1. Engines originally manufactured as rich burn engines, but modified prior to December 19, 2002 with passive emission control technology for NO_x (such as pre-combustion chambers) will be considered lean burn engines. Also, existing engines where there are no manufacturer's recommendations regarding air/fuel ratio will be considered a rich burn engine if the excess oxygen content of the exhaust at full load conditions is less than or equal to 2 percent.

Site-rated HP means the maximum manufacturer's design capacity at engine site conditions.

Spark ignition means relating to either: A gasoline-fueled engine; or any other type of engine with a spark plug (or other sparking device) and with operating characteristics significantly similar to the theoretical Otto combustion cycle. Spark ignition engines usually use a throttle to regulate intake air flow to control power during normal operation. Dual-fuel engines in which a liquid fuel (typically diesel fuel) is used for CI and gaseous fuel (typically natural gas) is used as the primary fuel at an annual average ratio of less than 2 parts diesel fuel to 100 parts total fuel on an energy equivalent basis are spark ignition engines.

Stationary reciprocating internal combustion engine (RICE) means any reciprocating internal combustion engine which uses reciprocating motion to convert heat energy into mechanical work and which is not mobile. Stationary RICE differ from mobile RICE in that a stationary RICE is not a non-road engine as defined at 40 CFR 1068.30, and is not used to propel a motor vehicle or a vehicle used solely for competition.

Stationary RICE test cell/stand means an engine test cell/stand, as defined in subpart PPPPP of this part, that tests stationary RICE.

Stoichiometric means the theoretical air-to-fuel ratio required for complete combustion.

Storage vessel with the potential for flash emissions means any storage vessel that contains a hydrocarbon liquid with a stock tank gas-to-oil ratio equal to or greater than 0.31 cubic meters per liter and an American Petroleum Institute gravity equal to or greater than 40 degrees and an actual annual average hydrocarbon liquid throughput equal to or greater than 79,500 liters per day. Flash emissions occur when dissolved hydrocarbons in the fluid evolve from solution when the fluid pressure is reduced.

Subpart means 40 CFR part 63, subpart ZZZZ.

Surface site means any combination of one or more graded pad sites, gravel pad sites, foundations, platforms, or the immediate physical location upon which equipment is physically affixed.

Two-stroke engine means a type of engine which completes the power cycle in single crankshaft revolution by combining the intake and compression operations into one stroke and the power and exhaust operations into a second stroke. This system requires auxiliary scavenging and inherently runs lean of stoichiometric.

[69 FR 33506, June 15, 2004, as amended at 71 FR 20467, Apr. 20, 2006; 73 FR 3607, Jan. 18, 2008; 75 FR 9679, Mar. 3, 2010; 75 FR 51592, Aug. 20, 2010; 76 FR 12867, Mar. 9, 2011; 78 FR 6706, Jan. 30, 2013]

Back to Top

Table 1a to Subpart ZZZZ of Part 63—Emission Limitations for Existing, New, and Reconstructed Spark Ignition, 4SRB Stationary RICE >500 HP Located at a Major Source of HAP Emissions

As stated in §§63.6600 and 63.6640, you must comply with the following emission limitations at 100 percent load plus or minus 10 percent for existing, new and reconstructed 4SRB stationary RICE >500 HP located at a major source of HAP emissions:

For each . . .	You must meet the following emission limitation, except during periods of startup . . .	During periods of startup you must . . .

1. 4SRB stationary RICE	a. Reduce formaldehyde emissions by 76 percent or more. If you commenced construction or reconstruction between December 19, 2002 and June 15, 2004, you may reduce formaldehyde emissions by 75 percent or more until June 15, 2007 or	Minimize the engine's time spent at idle and minimize the engine's startup time at startup to a period needed for appropriate and safe loading of the engine, not to exceed 30 minutes, after which time the non-startup emission limitations apply.[1]
	b. Limit the concentration of formaldehyde in the stationary RICE exhaust to 350 ppbvd or less at 15 percent O_2	

[1] Sources can petition the Administrator pursuant to the requirements of 40 CFR 63.6(g) for alternative work practices.

[75 FR 9679, Mar. 3, 2010, as amended at 75 FR 51592, Aug. 20, 2010]

Back to Top

Table 1b to Subpart ZZZZ of Part 63—Operating Limitations for Existing, New, and Reconstructed SI 4SRB Stationary RICE >500 HP Located at a Major Source of HAP Emissions

As stated in §§63.6600, 63.6603, 63.6630 and 63.6640, you must comply with the following operating limitations for existing, new and reconstructed 4SRB stationary RICE >500 HP located at a major source of HAP emissions:

For each . . .	You must meet the following operating limitation, except during periods of startup . . .
1. existing, new and reconstructed 4SRB stationary RICE >500 HP located at a major source of HAP emissions complying with the requirement to reduce formaldehyde emissions by 76 percent or more (or by 75 percent or more, if applicable) and using NSCR; or existing, new and reconstructed 4SRB stationary RICE >500 HP located at a major source of HAP emissions complying with the requirement to limit the concentration of formaldehyde in the stationary RICE exhaust to 350 ppbvd or less at 15 percent O_2 and using NSCR;	a. maintain your catalyst so that the pressure drop across the catalyst does not change by more than 2 inches of water at 100 percent load plus or minus 10 percent from the pressure drop across the catalyst measured during the initial performance test; and b. maintain the temperature of your stationary RICE exhaust so that the catalyst inlet temperature is greater than or equal to 750 °F and less than or equal to 1250 °F.[1]
2. existing, new and reconstructed 4SRB stationary RICE >500 HP located at a major source of HAP emissions complying with the requirement to reduce formaldehyde emissions by 76 percent or more (or by 75 percent or more,	Comply with any operating limitations approved by the Administrator.

if applicable) and not using NSCR; or	
existing, new and reconstructed 4SRB stationary RICE >500 HP located at a major source of HAP emissions complying with the requirement to limit the concentration of formaldehyde in the stationary RICE exhaust to 350 ppbvd or less at 15 percent O_2 and not using NSCR.	

[1]Sources can petition the Administrator pursuant to the requirements of 40 CFR 63.8(f) for a different temperature range.

[78 FR 6706, Jan. 30, 2013]

Back to Top

Table 2a to Subpart ZZZZ of Part 63—Emission Limitations for New and Reconstructed 2SLB and Compression Ignition Stationary RICE >500 HP and New and Reconstructed 4SLB Stationary RICE ≥250 HP Located at a Major Source of HAP Emissions

As stated in §§63.6600 and 63.6640, you must comply with the following emission limitations for new and reconstructed lean burn and new and reconstructed compression ignition stationary RICE at 100 percent load plus or minus 10 percent:

For each . . .	You must meet the following emission limitation, except during periods of startup . . .	During periods of startup you must . . .
1. 2SLB stationary RICE	a. Reduce CO emissions by 58 percent or more; or b. Limit concentration of formaldehyde in the stationary RICE exhaust to 12 ppmvd or less at 15 percent O_2. If you commenced construction or reconstruction between December 19, 2002 and June 15, 2004, you may limit concentration of formaldehyde to 17 ppmvd or less at 15 percent O_2 until June 15, 2007	Minimize the engine's time spent at idle and minimize the engine's startup time at startup to a period needed for appropriate and safe loading of the engine, not to exceed 30 minutes, after which time the non-startup emission limitations apply.[1]
2. 4SLB stationary RICE	a. Reduce CO emissions by 93 percent or more; or	
	b. Limit concentration of formaldehyde in the stationary RICE exhaust to 14 ppmvd or less at 15 percent O_2	
3. CI stationary RICE	a. Reduce CO emissions by 70 percent or more; or	

	b. Limit concentration of formaldehyde in the stationary RICE exhaust to 580 ppbvd or less at 15 percent O_2	

[1]Sources can petition the Administrator pursuant to the requirements of 40 CFR 63.6(g) for alternative work practices.

[75 FR 9680, Mar. 3, 2010]

Back to Top

Table 2b to Subpart ZZZZ of Part 63—Operating Limitations for New and Reconstructed 2SLB and CI Stationary RICE >500 HP Located at a Major Source of HAP Emissions, New and Reconstructed 4SLB Stationary RICE ≥250 HP Located at a Major Source of HAP Emissions, Existing CI Stationary RICE >500 HP

As stated in §§63.6600, 63.6601, 63.6603, 63.6630, and 63.6640, you must comply with the following operating limitations for new and reconstructed 2SLB and CI stationary RICE >500 HP located at a major source of HAP emissions; new and reconstructed 4SLB stationary RICE ≥250 HP located at a major source of HAP emissions; and existing CI stationary RICE >500 HP:

For each . . .	You must meet the following operating limitation, except during periods of startup . . .
1. New and reconstructed 2SLB and CI stationary RICE >500 HP located at a major source of HAP emissions and new and reconstructed 4SLB stationary RICE ≥250 HP located at a major source of HAP emissions complying with the requirement to reduce CO emissions and using an oxidation catalyst; and New and reconstructed 2SLB and CI stationary RICE >500 HP located at a major source of HAP emissions and new and reconstructed 4SLB stationary RICE ≥250 HP located at a major source of HAP emissions complying with the requirement to limit the concentration of formaldehyde in the stationary RICE exhaust and using an oxidation catalyst.	a. maintain your catalyst so that the pressure drop across the catalyst does not change by more than 2 inches of water at 100 percent load plus or minus 10 percent from the pressure drop across the catalyst that was measured during the initial performance test; and b. maintain the temperature of your stationary RICE exhaust so that the catalyst inlet temperature is greater than or equal to 450 °F and less than or equal to 1350 °F.[1]
2. Existing CI stationary RICE >500 HP complying with the requirement to limit or reduce the concentration of CO in the stationary RICE exhaust and using an oxidation catalyst	a. maintain your catalyst so that the pressure drop across the catalyst does not change by more than 2 inches of water from the pressure drop across the catalyst that was measured during the initial performance test; and

	b. maintain the temperature of your stationary RICE exhaust so that the catalyst inlet temperature is greater than or equal to 450 °F and less than or equal to 1350 °F.[1]
3. New and reconstructed 2SLB and CI stationary RICE >500 HP located at a major source of HAP emissions and new and reconstructed 4SLB stationary RICE ≥250 HP located at a major source of HAP emissions complying with the requirement to reduce CO emissions and not using an oxidation catalyst; and	Comply with any operating limitations approved by the Administrator.
New and reconstructed 2SLB and CI stationary RICE >500 HP located at a major source of HAP emissions and new and reconstructed 4SLB stationary RICE ≥250 HP located at a major source of HAP emissions complying with the requirement to limit the concentration of formaldehyde in the stationary RICE exhaust and not using an oxidation catalyst; and	
existing CI stationary RICE >500 HP complying with the requirement to limit or reduce the concentration of CO in the stationary RICE exhaust and not using an oxidation catalyst.	

[1]Sources can petition the Administrator pursuant to the requirements of 40 CFR 63.8(f) for a different temperature range.

[78 FR 6707, Jan. 30, 2013]

Back to Top

Table 2c to Subpart ZZZZ of Part 63—Requirements for Existing Compression Ignition Stationary RICE Located at a Major Source of HAP Emissions and Existing Spark Ignition Stationary RICE ≤500 HP Located at a Major Source of HAP Emissions

As stated in §§63.6600, 63.6602, and 63.6640, you must comply with the following requirements for existing compression ignition stationary RICE located at a major source of HAP emissions and existing spark ignition stationary RICE ≤500 HP located at a major source of HAP emissions:

For each . . .	You must meet the following requirement, except during periods of startup . . .	During periods of startup you must . . .
1. Emergency stationary CI RICE and black start stationary	a. Change oil and filter every 500 hours of	Minimize the engine's time spent at idle and minimize the engine's

CI RICE[1]	operation or annually, whichever comes first.[2] b. Inspect air cleaner every 1,000 hours of operation or annually, whichever comes first, and replace as necessary; c. Inspect all hoses and belts every 500 hours of operation or annually, whichever comes first, and replace as necessary.[3]	startup time at startup to a period needed for appropriate and safe loading of the engine, not to exceed 30 minutes, after which time the non-startup emission limitations apply.[3]
2. Non-Emergency, non-black start stationary CI RICE <100 HP	a. Change oil and filter every 1,000 hours of operation or annually, whichever comes first.[2] b. Inspect air cleaner every 1,000 hours of operation or annually, whichever comes first, and replace as necessary; c. Inspect all hoses and belts every 500 hours of operation or annually, whichever comes first, and replace as necessary.[3]	
3. Non-Emergency, non-black start CI stationary RICE 100≤HP≤300 HP	Limit concentration of CO in the stationary RICE exhaust to 230 ppmvd or less at 15 percent O_2.	
4. Non-Emergency, non-black start CI stationary RICE 300<HP≤500	a. Limit concentration of CO in the stationary RICE exhaust to 49 ppmvd or less at 15 percent O_2; or b. Reduce CO emissions by 70 percent or more.	
5. Non-Emergency, non-black start stationary CI RICE >500 HP	a. Limit concentration of CO in the stationary RICE exhaust to 23 ppmvd or less at 15 percent O_2; or b. Reduce CO emissions	

	by 70 percent or more.	
6. Emergency stationary SI RICE and black start stationary SI RICE.[1]	a. Change oil and filter every 500 hours of operation or annually, whichever comes first;[2] b. Inspect spark plugs every 1,000 hours of operation or annually, whichever comes first, and replace as necessary; c. Inspect all hoses and belts every 500 hours of operation or annually, whichever comes first, and replace as necessary.[3]	
7. Non-Emergency, non-black start stationary SI RICE <100 HP that are not 2SLB stationary RICE	a. Change oil and filter every 1,440 hours of operation or annually, whichever comes first;[2] b. Inspect spark plugs every 1,440 hours of operation or annually, whichever comes first, and replace as necessary;	
	c. Inspect all hoses and belts every 1,440 hours of operation or annually, whichever comes first, and replace as necessary.[3]	
8. Non-Emergency, non-black start 2SLB stationary SI RICE <100 HP	a. Change oil and filter every 4,320 hours of operation or annually, whichever comes first;[2] b. Inspect spark plugs every 4,320 hours of operation or annually, whichever comes first, and replace as necessary;	
	c. Inspect all hoses and belts every 4,320 hours of operation or annually, whichever comes first, and replace as necessary.[3]	

9. Non-emergency, non-black start 2SLB stationary RICE 100≤HP≤500	Limit concentration of CO in the stationary RICE exhaust to 225 ppmvd or less at 15 percent O_2.	
10. Non-emergency, non-black start 4SLB stationary RICE 100≤HP≤500	Limit concentration of CO in the stationary RICE exhaust to 47 ppmvd or less at 15 percent O_2.	
11. Non-emergency, non-black start 4SRB stationary RICE 100≤HP≤500	Limit concentration of formaldehyde in the stationary RICE exhaust to 10.3 ppmvd or less at 15 percent O_2.	
12. Non-emergency, non-black start stationary RICE 100≤HP≤500 which combusts landfill or digester gas equivalent to 10 percent or more of the gross heat input on an annual basis	Limit concentration of CO in the stationary RICE exhaust to 177 ppmvd or less at 15 percent O_2.	

[1]If an emergency engine is operating during an emergency and it is not possible to shut down the engine in order to perform the work practice requirements on the schedule required in Table 2c of this subpart, or if performing the work practice on the required schedule would otherwise pose an unacceptable risk under federal, state, or local law, the work practice can be delayed until the emergency is over or the unacceptable risk under federal, state, or local law has abated. The work practice should be performed as soon as practicable after the emergency has ended or the unacceptable risk under federal, state, or local law has abated. Sources must report any failure to perform the work practice on the schedule required and the federal, state or local law under which the risk was deemed unacceptable.

[2]Sources have the option to utilize an oil analysis program as described in §63.6625(i) or (j) in order to extend the specified oil change requirement in Table 2c of this subpart.

[3]Sources can petition the Administrator pursuant to the requirements of 40 CFR 63.6(g) for alternative work practices.

[78 FR 6708, Jan. 30, 2013, as amended at 78 FR 14457, Mar. 6, 2013]

Back to Top

Table 2d to Subpart ZZZZ of Part 63—Requirements for Existing Stationary RICE Located at Area Sources of HAP Emissions

As stated in §§63.6603 and 63.6640, you must comply with the following requirements for existing stationary RICE located at area sources of HAP emissions:

For each . . .	You must meet the following requirement, except during periods of startup . . .	During periods of startup you must . . .
1. Non-Emergency, non-black start CI stationary RICE ≤300 HP	a. Change oil and filter every 1,000 hours of operation or annually, whichever comes first;[1] b. Inspect air cleaner every 1,000 hours of operation or annually, whichever comes first, and replace as necessary; c. Inspect all hoses and belts every 500 hours of operation or annually, whichever comes first, and replace as necessary.	Minimize the engine's time spent at idle and minimize the engine's startup time at startup to a period needed for appropriate and safe loading of the engine, not to exceed 30 minutes, after which time the non-startup emission limitations apply.
2. Non-Emergency, non-black start CI stationary RICE 300<HP≤500	a. Limit concentration of CO in the stationary RICE exhaust to 49 ppmvd at 15 percent O_2; or	
	b. Reduce CO emissions by 70 percent or more.	
3. Non-Emergency, non-black start CI stationary RICE >500 HP	a. Limit concentration of CO in the stationary RICE exhaust to 23 ppmvd at 15 percent O_2; or	
	b. Reduce CO emissions by 70 percent or more.	
4. Emergency stationary CI RICE and black start stationary CI RICE.[2]	a. Change oil and filter every 500 hours of operation or annually, whichever comes first;[1]	
	b. Inspect air cleaner	

	every 1,000 hours of operation or annually, whichever comes first, and replace as necessary; and	
	c. Inspect all hoses and belts every 500 hours of operation or annually, whichever comes first, and replace as necessary.	
5. Emergency stationary SI RICE; black start stationary SI RICE; non-emergency, non-black start 4SLB stationary RICE >500 HP that operate 24 hours or less per calendar year; non-emergency, non-black start 4SRB stationary RICE >500 HP that operate 24 hours or less per calendar year.[2]	a. Change oil and filter every 500 hours of operation or annually, whichever comes first;[1]; b. Inspect spark plugs every 1,000 hours of operation or annually, whichever comes first, and replace as necessary; and c. Inspect all hoses and belts every 500 hours of operation or annually, whichever comes first, and replace as necessary.	
6. Non-emergency, non-black start 2SLB stationary RICE	a. Change oil and filter every 4,320 hours of operation or annually, whichever comes first;[1]	
	b. Inspect spark plugs every 4,320 hours of operation or annually, whichever comes first, and replace as necessary; and	
	c. Inspect all hoses and belts every 4,320 hours of operation or annually, whichever comes first, and replace	

	as necessary.	
7. Non-emergency, non-black start 4SLB stationary RICE ≤500 HP	a. Change oil and filter every 1,440 hours of operation or annually, whichever comes first;[1]	
	b. Inspect spark plugs every 1,440 hours of operation or annually, whichever comes first, and replace as necessary; and	
	c. Inspect all hoses and belts every 1,440 hours of operation or annually, whichever comes first, and replace as necessary.	
8. Non-emergency, non-black start 4SLB remote stationary RICE >500 HP	a. Change oil and filter every 2,160 hours of operation or annually, whichever comes first;[1]	
	b. Inspect spark plugs every 2,160 hours of operation or annually, whichever comes first, and replace as necessary; and	
	c. Inspect all hoses and belts every 2,160 hours of operation or annually, whichever comes first, and replace as necessary.	
9. Non-emergency, non-black start 4SLB stationary RICE >500 HP that are not remote stationary RICE and that operate more than 24 hours per calendar year	Install an oxidation catalyst to reduce HAP emissions from the stationary RICE.	
10. Non-emergency, non-black start 4SRB stationary RICE ≤500 HP	a. Change oil and filter every 1,440 hours of operation or annually, whichever comes first;[1]	

	b. Inspect spark plugs every 1,440 hours of operation or annually, whichever comes first, and replace as necessary; and	
	c. Inspect all hoses and belts every 1,440 hours of operation or annually, whichever comes first, and replace as necessary.	
11. Non-emergency, non-black start 4SRB remote stationary RICE >500 HP	a. Change oil and filter every 2,160 hours of operation or annually, whichever comes first;[1]	
	b. Inspect spark plugs every 2,160 hours of operation or annually, whichever comes first, and replace as necessary; and	
	c. Inspect all hoses and belts every 2,160 hours of operation or annually, whichever comes first, and replace as necessary.	
12. Non-emergency, non-black start 4SRB stationary RICE >500 HP that are not remote stationary RICE and that operate more than 24 hours per calendar year	Install NSCR to reduce HAP emissions from the stationary RICE.	
13. Non-emergency, non-black start stationary RICE which combusts landfill or digester gas equivalent to 10 percent or more of the gross heat input on an annual basis	a. Change oil and filter every 1,440 hours of operation or annually, whichever comes first;[1] b. Inspect spark plugs every 1,440 hours of operation or annually, whichever comes first, and replace as necessary; and	

	c. Inspect all hoses and belts every 1,440 hours of operation or annually, whichever comes first, and replace as necessary.	

[1]Sources have the option to utilize an oil analysis program as described in §63.6625(i) or (j) in order to extend the specified oil change requirement in Table 2d of this subpart.

[2]If an emergency engine is operating during an emergency and it is not possible to shut down the engine in order to perform the management practice requirements on the schedule required in Table 2d of this subpart, or if performing the management practice on the required schedule would otherwise pose an unacceptable risk under federal, state, or local law, the management practice can be delayed until the emergency is over or the unacceptable risk under federal, state, or local law has abated. The management practice should be performed as soon as practicable after the emergency has ended or the unacceptable risk under federal, state, or local law has abated. Sources must report any failure to perform the management practice on the schedule required and the federal, state or local law under which the risk was deemed unacceptable.

[78 FR 6709, Jan. 30, 2013]

Back to Top

Table 3 to Subpart ZZZZ of Part 63—Subsequent Performance Tests

As stated in §§63.6615 and 63.6620, you must comply with the following subsequent performance test requirements:

For each . . .	Complying with the requirement to . . .	You must . . .
1. New or reconstructed 2SLB stationary RICE >500 HP located at major sources; new or reconstructed 4SLB stationary RICE ≥250 HP located at major sources; and new or reconstructed CI stationary RICE >500 HP located at major sources	Reduce CO emissions and not using a CEMS	Conduct subsequent performance tests semiannually.[1]
2. 4SRB stationary RICE ≥5,000 HP located at major sources	Reduce formaldehyde emissions	Conduct subsequent performance tests semiannually.[1]
3. Stationary RICE >500 HP located at major sources and new or reconstructed 4SLB stationary RICE 250≤HP≤500 located at major sources	Limit the concentration of formaldehyde in the stationary RICE exhaust	Conduct subsequent performance tests semiannually.[1]
4. Existing non-emergency, non-black start CI	Limit or reduce CO	Conduct subsequent

stationary RICE >500 HP that are not limited use stationary RICE	emissions and not using a CEMS	performance tests every 8,760 hours or 3 years, whichever comes first.
5. Existing non-emergency, non-black start CI stationary RICE >500 HP that are limited use stationary RICE	Limit or reduce CO emissions and not using a CEMS	Conduct subsequent performance tests every 8,760 hours or 5 years, whichever comes first.

[1]After you have demonstrated compliance for two consecutive tests, you may reduce the frequency of subsequent performance tests to annually. If the results of any subsequent annual performance test indicate the stationary RICE is not in compliance with the CO or formaldehyde emission limitation, or you deviate from any of your operating limitations, you must resume semiannual performance tests.

[78 FR 6711, Jan. 30, 2013]

Back to Top

Table 4 to Subpart ZZZZ of Part 63—Requirements for Performance Tests

As stated in §§63.6610, 63.6611, 63.6620, and 63.6640, you must comply with the following requirements for performance tests for stationary RICE:

For each . . .	Complying with the requirement to . . .	You must . . .	Using . . .	According to the following requirements . . .
1. 2SLB, 4SLB, and CI stationary RICE	a. reduce CO emissions	i. Select the sampling port location and the number/location of traverse points at the inlet and outlet of the control device; and		(a) For CO and O_2 measurement, ducts ≤6 inches in diameter may be sampled at a single point located at the duct centroid and ducts >6 and ≤12 inches in diameter may be sampled at 3 traverse points located at 16.7, 50.0, and 83.3% of the measurement line (`3-point long line'). If the duct is >12 inches in diameter *and* the sampling port location meets the two and half-diameter criterion of Section 11.1.1 of Method 1 of 40 CFR part 60, appendix A-1, the duct may be sampled at

				`3-point long line'; otherwise, conduct the stratification testing and select sampling points according to Section 8.1.2 of Method 7E of 40 CFR part 60, appendix A-4.
		ii. Measure the O_2 at the inlet and outlet of the control device; and	(1) Method 3 or 3A or 3B of 40 CFR part 60, appendix A-2, or ASTM Method D6522-00 (Reapproved 2005)[ac] (heated probe not necessary)	(b) Measurements to determine O_2 must be made at the same time as the measurements for CO concentration.
		iii. Measure the CO at the inlet and the outlet of the control device	(1) ASTM D6522-00 (Reapproved 2005)[abc] (heated probe not necessary) or Method 10 of 40 CFR part 60, appendix A-4	(c) The CO concentration must be at 15 percent O_2, dry basis.
2. 4SRB stationary RICE	a. reduce formaldehyde emissions	i. Select the sampling port location and the number/location of traverse points at the inlet and outlet of the control device; and		(a) For formaldehyde, O_2, and moisture measurement, ducts ≤6 inches in diameter may be sampled at a single point located at the duct centroid and ducts >6 and ≤12 inches in diameter may be sampled at 3 traverse points located at 16.7, 50.0, and 83.3% of the measurement line (`3-point long line'). If the duct is >12 inches in diameter *and* the sampling port location meets the two and half-diameter criterion of Section 11.1.1 of Method 1 of 40 CFR part 60, appendix A, the duct may be sampled at `3-point long line';

				otherwise, conduct the stratification testing and select sampling points according to Section 8.1.2 of Method 7E of 40 CFR part 60, appendix A.
		ii. Measure O_2 at the inlet and outlet of the control device; and	(1) Method 3 or 3A or 3B of 40 CFR part 60, appendix A-2, or ASTM Method D6522-00 (Reapproved 2005)[a] (heated probe not necessary)	(a) Measurements to determine O_2 concentration must be made at the same time as the measurements for formaldehyde or THC concentration.
		iii. Measure moisture content at the inlet and outlet of the control device; and	(1) Method 4 of 40 CFR part 60, appendix A-3, or Method 320 of 40 CFR part 63, appendix A, or ASTM D 6348-03[a]	(a) Measurements to determine moisture content must be made at the same time and location as the measurements for formaldehyde or THC concentration.
		iv. If demonstrating compliance with the formaldehyde percent reduction requirement, measure formalde-hyde at the inlet and the outlet of the control device	(1) Method 320 or 323 of 40 CFR part 63, appendix A; or ASTM D6348-03[a], provided in ASTM D6348-03 Annex A5 (Analyte Spiking Technique), the percent R must be greater than or equal to 70 and less than or equal to 130	(a) Formaldehyde concentration must be at 15 percent O_2, dry basis. Results of this test consist of the average of the three 1-hour or longer runs.
		v. If demonstrating compliance with the THC percent reduction requirement, measure THC at the inlet and the outlet of the control device	(1) Method 25A, reported as propane, of 40 CFR part 60, appendix A-7	(a) THC concentration must be at 15 percent O_2, dry basis. Results of this test consist of the average of the three 1-hour or longer runs.
3.	a. limit the	i. Select the		(a) For formaldehyde,

Stationary RICE	concentra-tion of formalde-hyde or CO in the stationary RICE exhaust	sampling port location and the number/location of traverse points at the exhaust of the stationary RICE; and		CO, O_2, and moisture measurement, ducts ≤6 inches in diameter may be sampled at a single point located at the duct centroid and ducts >6 and ≤12 inches in diameter may be sampled at 3 traverse points located at 16.7, 50.0, and 83.3% of the measurement line (`3-point long line'). If the duct is >12 inches in diameter *and* the sampling port location meets the two and half-diameter criterion of Section 11.1.1 of Method 1 of 40 CFR part 60, appendix A, the duct may be sampled at `3-point long line'; otherwise, conduct the stratification testing and select sampling points according to Section 8.1.2 of Method 7E of 40 CFR part 60, appendix A. If using a control device, the sampling site must be located at the outlet of the control device.
		ii. Determine the O_2concentration of the stationary RICE exhaust at the sampling port location; and	(1) Method 3 or 3A or 3B of 40 CFR part 60, appendix A-2, or ASTM Method D6522-00 (Reapproved 2005)[a] (heated probe not necessary)	(a) Measurements to determine O_2 concentration must be made at the same time and location as the measurements for formaldehyde or CO concentration.
		iii. Measure moisture content of the station-ary RICE exhaust at the sampling port location; and	(1) Method 4 of 40 CFR part 60, appendix A-3, or Method 320 of 40 CFR part 63, appendix A, or	(a) Measurements to determine moisture content must be made at the same time and location as the measurements for

			ASTM D 6348-03[a]	formaldehyde or CO concentration.
		iv. Measure formalde-hyde at the exhaust of the station-ary RICE; or	(1) Method 320 or 323 of 40 CFR part 63, appendix A; or ASTM D6348-03[a], provided in ASTM D6348-03 Annex A5 (Analyte Spiking Technique), the percent R must be greater than or equal to 70 and less than or equal to 130	(a) Formaldehyde concentration must be at 15 percent O_2, dry basis. Results of this test consist of the average of the three 1-hour or longer runs.
		v. measure CO at the exhaust of the station-ary RICE	(1) Method 10 of 40 CFR part 60, appendix A-4, ASTM Method D6522-00 (2005)[ac], Method 320 of 40 CFR part 63, appendix A, or ASTM D6348-03[a]	(a) CO concentration must be at 15 percent O_2, dry basis. Results of this test consist of the average of the three 1-hour or longer runs.

[a]You may also use Methods 3A and 10 as options to ASTM-D6522-00 (2005). You may obtain a copy of ASTM-D6522-00 (2005) from at least one of the following addresses: American Society for Testing and Materials, 100 Barr Harbor Drive, West Conshohocken, PA 19428-2959, or University Microfilms International, 300 North Zeeb Road, Ann Arbor, MI 48106.

[b]You may obtain a copy of ASTM-D6348-03 from at least one of the following addresses: American Society for Testing and Materials, 100 Barr Harbor Drive, West Conshohocken, PA 19428-2959, or University Microfilms International, 300 North Zeeb Road, Ann Arbor, MI 48106.

[79 FR 11290, Feb. 27, 2014]

Back to Top

Table 5 to Subpart ZZZZ of Part 63—Initial Compliance With Emission Limitations, Operating Limitations, and Other Requirements

As stated in §§63.6612, 63.6625 and 63.6630, you must initially comply with the emission and operating limitations as required by the following:

For each . . .	Complying with the requirement to . . .	You have demonstrated initial compliance if . . .
1. New or reconstructed non-	a. Reduce CO	i. The average reduction of emissions

emergency 2SLB stationary RICE >500 HP located at a major source of HAP, new or reconstructed non-emergency 4SLB stationary RICE ≥250 HP located at a major source of HAP, non-emergency stationary CI RICE >500 HP located at a major source of HAP, and existing non-emergency stationary CI RICE >500 HP located at an area source of HAP	emissions and using oxidation catalyst, and using a CPMS	of CO determined from the initial performance test achieves the required CO percent reduction; and ii. You have installed a CPMS to continuously monitor catalyst inlet temperature according to the requirements in §63.6625(b); and iii. You have recorded the catalyst pressure drop and catalyst inlet temperature during the initial performance test.
2. Non-emergency stationary CI RICE >500 HP located at a major source of HAP, and existing non-emergency stationary CI RICE >500 HP located at an area source of HAP	a. Limit the concentration of CO, using oxidation catalyst, and using a CPMS	i. The average CO concentration determined from the initial performance test is less than or equal to the CO emission limitation; and
		ii. You have installed a CPMS to continuously monitor catalyst inlet temperature according to the requirements in §63.6625(b); and
		iii. You have recorded the catalyst pressure drop and catalyst inlet temperature during the initial performance test.
3. New or reconstructed non-emergency 2SLB stationary RICE >500 HP located at a major source of HAP, new or reconstructed non-emergency 4SLB stationary RICE ≥250 HP located at a major source of HAP, non-emergency stationary CI RICE >500 HP located at a major source of HAP, and existing non-emergency stationary CI RICE >500 HP located at an area source of HAP	a. Reduce CO emissions and not using oxidation catalyst	i. The average reduction of emissions of CO determined from the initial performance test achieves the required CO percent reduction; and ii. You have installed a CPMS to continuously monitor operating parameters approved by the Administrator (if any) according to the requirements in §63.6625(b); and iii. You have recorded the approved operating parameters (if any) during the initial performance test.
4. Non-emergency stationary CI RICE >500 HP located at a major source of HAP, and existing non-emergency stationary CI RICE >500 HP located at an area source of HAP	a. Limit the concentration of CO, and not using oxidation catalyst	i. The average CO concentration determined from the initial performance test is less than or equal to the CO emission limitation; and ii. You have installed a CPMS to continuously monitor operating parameters approved by the

		Administrator (if any) according to the requirements in §63.6625(b); and
		iii. You have recorded the approved operating parameters (if any) during the initial performance test.
5. New or reconstructed non-emergency 2SLB stationary RICE >500 HP located at a major source of HAP, new or reconstructed non-emergency 4SLB stationary RICE ≥250 HP located at a major source of HAP, non-emergency stationary CI RICE >500 HP located at a major source of HAP, and existing non-emergency stationary CI RICE >500 HP located at an area source of HAP	a. Reduce CO emissions, and using a CEMS	i. You have installed a CEMS to continuously monitor CO and either O_2 or CO_2 at both the inlet and outlet of the oxidation catalyst according to the requirements in §63.6625(a); and ii. You have conducted a performance evaluation of your CEMS using PS 3 and 4A of 40 CFR part 60, appendix B; and
		iii. The average reduction of CO calculated using §63.6620 equals or exceeds the required percent reduction. The initial test comprises the first 4-hour period after successful validation of the CEMS. Compliance is based on the average percent reduction achieved during the 4-hour period.
6. Non-emergency stationary CI RICE >500 HP located at a major source of HAP, and existing non-emergency stationary CI RICE >500 HP located at an area source of HAP	a. Limit the concentration of CO, and using a CEMS	i. You have installed a CEMS to continuously monitor CO and either O_2 or CO_2 at the outlet of the oxidation catalyst according to the requirements in §63.6625(a); and
		ii. You have conducted a performance evaluation of your CEMS using PS 3 and 4A of 40 CFR part 60, appendix B; and
		iii. The average concentration of CO calculated using §63.6620 is less than or equal to the CO emission limitation. The initial test comprises the first 4-hour period after successful validation of the CEMS. Compliance is based on the average concentration measured during the 4-hour period.

7. Non-emergency 4SRB stationary RICE >500 HP located at a major source of HAP	a. Reduce formaldehyde emissions and using NSCR	i. The average reduction of emissions of formaldehyde determined from the initial performance test is equal to or greater than the required formaldehyde percent reduction, or the average reduction of emissions of THC determined from the initial performance test is equal to or greater than 30 percent; and
		ii. You have installed a CPMS to continuously monitor catalyst inlet temperature according to the requirements in §63.6625(b); and
		iii. You have recorded the catalyst pressure drop and catalyst inlet temperature during the initial performance test.
8. Non-emergency 4SRB stationary RICE >500 HP located at a major source of HAP	a. Reduce formaldehyde emissions and not using NSCR	i. The average reduction of emissions of formaldehyde determined from the initial performance test is equal to or greater than the required formaldehyde percent reduction or the average reduction of emissions of THC determined from the initial performance test is equal to or greater than 30 percent; and
		ii. You have installed a CPMS to continuously monitor operating parameters approved by the Administrator (if any) according to the requirements in §63.6625(b); and
		iii. You have recorded the approved operating parameters (if any) during the initial performance test.
9. New or reconstructed non-emergency stationary RICE >500 HP located at a major source of HAP, new or reconstructed non-emergency 4SLB stationary RICE 250≤HP≤500 located at a major source of HAP, and existing non-emergency 4SRB stationary RICE >500 HP located at a major source of HAP	a. Limit the concentration of formaldehyde in the stationary RICE exhaust and using oxidation catalyst or NSCR	i. The average formaldehyde concentration, corrected to 15 percent O_2, dry basis, from the three test runs is less than or equal to the formaldehyde emission limitation; and ii. You have installed a CPMS to continuously monitor catalyst inlet temperature according to the

		requirements in §63.6625(b); and
		iii. You have recorded the catalyst pressure drop and catalyst inlet temperature during the initial performance test.
10. New or reconstructed non-emergency stationary RICE >500 HP located at a major source of HAP, new or reconstructed non-emergency 4SLB stationary RICE 250≤HP≤500 located at a major source of HAP, and existing non-emergency 4SRB stationary RICE >500 HP located at a major source of HAP	a. Limit the concentration of formaldehyde in the stationary RICE exhaust and not using oxidation catalyst or NSCR	i. The average formaldehyde concentration, corrected to 15 percent O_2, dry basis, from the three test runs is less than or equal to the formaldehyde emission limitation; and ii. You have installed a CPMS to continuously monitor operating parameters approved by the Administrator (if any) according to the requirements in §63.6625(b); and
		iii. You have recorded the approved operating parameters (if any) during the initial performance test.
11. Existing non-emergency stationary RICE 100≤HP≤500 located at a major source of HAP, and existing non-emergency stationary CI RICE 300<HP≤500 located at an area source of HAP	a. Reduce CO emissions	i. The average reduction of emissions of CO or formaldehyde, as applicable determined from the initial performance test is equal to or greater than the required CO or formaldehyde, as applicable, percent reduction.
12. Existing non-emergency stationary RICE 100≤HP≤500 located at a major source of HAP, and existing non-emergency stationary CI RICE 300<HP≤500 located at an area source of HAP	a. Limit the concentration of formaldehyde or CO in the stationary RICE exhaust	i. The average formaldehyde or CO concentration, as applicable, corrected to 15 percent O_2, dry basis, from the three test runs is less than or equal to the formaldehyde or CO emission limitation, as applicable.
13. Existing non-emergency 4SLB stationary RICE >500 HP located at an area source of HAP that are not remote stationary RICE and that are operated more than 24 hours per calendar year	a. Install an oxidation catalyst	i. You have conducted an initial compliance demonstration as specified in §63.6630(e) to show that the average reduction of emissions of CO is 93 percent or more, or the average CO concentration is less than or equal to 47 ppmvd at 15 percent O_2;
		ii. You have installed a CPMS to continuously monitor catalyst inlet

		temperature according to the requirements in §63.6625(b), or you have installed equipment to automatically shut down the engine if the catalyst inlet temperature exceeds 1350 °F.
14. Existing non-emergency 4SRB stationary RICE >500 HP located at an area source of HAP that are not remote stationary RICE and that are operated more than 24 hours per calendar year	a. Install NSCR	i. You have conducted an initial compliance demonstration as specified in §63.6630(e) to show that the average reduction of emissions of CO is 75 percent or more, the average CO concentration is less than or equal to 270 ppmvd at 15 percent O_2, or the average reduction of emissions of THC is 30 percent or more;
		ii. You have installed a CPMS to continuously monitor catalyst inlet temperature according to the requirements in §63.6625(b), or you have installed equipment to automatically shut down the engine if the catalyst inlet temperature exceeds 1250 °F.

[78 FR 6712, Jan. 30, 2013]

Back to Top

Table 6 to Subpart ZZZZ of Part 63—Continuous Compliance With Emission Limitations, and Other Requirements

As stated in §63.6640, you must continuously comply with the emissions and operating limitations and work or management practices as required by the following:

For each . . .	Complying with the requirement to . . .	You must demonstrate continuous compliance by . . .
1. New or reconstructed non-emergency 2SLB stationary RICE >500 HP located at a major source of HAP, new or reconstructed non-emergency 4SLB stationary RICE ≥250 HP located at a major source of HAP, and new or reconstructed non-emergency CI stationary RICE	a. Reduce CO emissions and using an oxidation catalyst, and using a CPMS	i. Conducting semiannual performance tests for CO to demonstrate that the required CO percent reduction is achieved[a]; and ii. Collecting the catalyst inlet temperature data according to §63.6625(b); and iii. Reducing these data to 4-hour

>500 HP located at a major source of HAP		rolling averages; and
		iv. Maintaining the 4-hour rolling averages within the operating limitations for the catalyst inlet temperature; and
		v. Measuring the pressure drop across the catalyst once per month and demonstrating that the pressure drop across the catalyst is within the operating limitation established during the performance test.
2. New or reconstructed non-emergency 2SLB stationary RICE >500 HP located at a major source of HAP, new or reconstructed non-emergency 4SLB stationary RICE ≥250 HP located at a major source of HAP, and new or reconstructed non-emergency CI stationary RICE >500 HP located at a major source of HAP	a. Reduce CO emissions and not using an oxidation catalyst, and using a CPMS	i. Conducting semiannual performance tests for CO to demonstrate that the required CO percent reduction is achieved[a]; and ii. Collecting the approved operating parameter (if any) data according to §63.6625(b); and iii. Reducing these data to 4-hour rolling averages; and
		iv. Maintaining the 4-hour rolling averages within the operating limitations for the operating parameters established during the performance test.
3. New or reconstructed non-emergency 2SLB stationary RICE >500 HP located at a major source of HAP, new or reconstructed non-emergency 4SLB stationary RICE ≥250 HP located at a major source of HAP, new or reconstructed non-emergency stationary CI RICE >500 HP located at a major source of HAP, and existing non-emergency stationary CI RICE >500 HP	a. Reduce CO emissions or limit the concentration of CO in the stationary RICE exhaust, and using a CEMS	i. Collecting the monitoring data according to §63.6625(a), reducing the measurements to 1-hour averages, calculating the percent reduction or concentration of CO emissions according to §63.6620; and ii. Demonstrating that the catalyst achieves the required percent reduction of CO emissions over the 4-hour averaging period, or that the emission remain at or below the CO concentration limit; and
		iii. Conducting an annual RATA of your CEMS using PS 3 and 4A of 40 CFR part 60, appendix B, as well as

		daily and periodic data quality checks in accordance with 40 CFR part 60, appendix F, procedure 1.
4. Non-emergency 4SRB stationary RICE >500 HP located at a major source of HAP	a. Reduce formaldehyde emissions and using NSCR	i. Collecting the catalyst inlet temperature data according to §63.6625(b); and
		ii. Reducing these data to 4-hour rolling averages; and
		iii. Maintaining the 4-hour rolling averages within the operating limitations for the catalyst inlet temperature; and
		iv. Measuring the pressure drop across the catalyst once per month and demonstrating that the pressure drop across the catalyst is within the operating limitation established during the performance test.
5. Non-emergency 4SRB stationary RICE >500 HP located at a major source of HAP	a. Reduce formaldehyde emissions and not using NSCR	i. Collecting the approved operating parameter (if any) data according to §63.6625(b); and
		ii. Reducing these data to 4-hour rolling averages; and
		iii. Maintaining the 4-hour rolling averages within the operating limitations for the operating parameters established during the performance test.
6. Non-emergency 4SRB stationary RICE with a brake HP ≥5,000 located at a major source of HAP	a. Reduce formaldehyde emissions	Conducting semiannual performance tests for formaldehyde to demonstrate that the required formaldehyde percent reduction is achieved, or to demonstrate that the average reduction of emissions of THC determined from the performance test is equal to or greater than 30 percent.[a]
7. New or reconstructed non-emergency stationary RICE >500	a. Limit the concentration of	i. Conducting semiannual performance tests for formaldehyde

HP located at a major source of HAP and new or reconstructed non-emergency 4SLB stationary RICE 250≤HP≤500 located at a major source of HAP	formaldehyde in the stationary RICE exhaust and using oxidation catalyst or NSCR	to demonstrate that your emissions remain at or below the formaldehyde concentration limit[a]; and ii. Collecting the catalyst inlet temperature data according to §63.6625(b); and
		iii. Reducing these data to 4-hour rolling averages; and
		iv. Maintaining the 4-hour rolling averages within the operating limitations for the catalyst inlet temperature; and
		v. Measuring the pressure drop across the catalyst once per month and demonstrating that the pressure drop across the catalyst is within the operating limitation established during the performance test.
8. New or reconstructed non-emergency stationary RICE >500 HP located at a major source of HAP and new or reconstructed non-emergency 4SLB stationary RICE 250≤HP≤500 located at a major source of HAP	a. Limit the concentration of formaldehyde in the stationary RICE exhaust and not using oxidation catalyst or NSCR	i. Conducting semiannual performance tests for formaldehyde to demonstrate that your emissions remain at or below the formaldehyde concentration limit[a]; and ii. Collecting the approved operating parameter (if any) data according to §63.6625(b); and
		iii. Reducing these data to 4-hour rolling averages; and
		iv. Maintaining the 4-hour rolling averages within the operating limitations for the operating parameters established during the performance test.
9. Existing emergency and black start stationary RICE ≤500 HP located at a major source of HAP, existing non-emergency stationary RICE <100 HP located at a major source of HAP, existing emergency and black start stationary RICE located at an area source of HAP, existing non-emergency stationary	a. Work or Management practices	i. Operating and maintaining the stationary RICE according to the manufacturer's emission-related operation and maintenance instructions; or ii. Develop and follow your own maintenance plan which must provide to the extent practicable for the maintenance and operation of the

CI RICE ≤300 HP located at an area source of HAP, existing non-emergency 2SLB stationary RICE located at an area source of HAP, existing non-emergency stationary SI RICE located at an area source of HAP which combusts landfill or digester gas equivalent to 10 percent or more of the gross heat input on an annual basis, existing non-emergency 4SLB and 4SRB stationary RICE ≤500 HP located at an area source of HAP, existing non-emergency 4SLB and 4SRB stationary RICE >500 HP located at an area source of HAP that operate 24 hours or less per calendar year, and existing non-emergency 4SLB and 4SRB stationary RICE >500 HP located at an area source of HAP that are remote stationary RICE		engine in a manner consistent with good air pollution control practice for minimizing emissions.
10. Existing stationary CI RICE >500 HP that are not limited use stationary RICE	a. Reduce CO emissions, or limit the concentration of CO in the stationary RICE exhaust, and using oxidation catalyst	i. Conducting performance tests every 8,760 hours or 3 years, whichever comes first, for CO or formaldehyde, as appropriate, to demonstrate that the required CO or formaldehyde, as appropriate, percent reduction is achieved or that your emissions remain at or below the CO or formaldehyde concentration limit; and
		ii. Collecting the catalyst inlet temperature data according to §63.6625(b); and
		iii. Reducing these data to 4-hour rolling averages; and
		iv. Maintaining the 4-hour rolling averages within the operating limitations for the catalyst inlet temperature; and
		v. Measuring the pressure drop across the catalyst once per month and demonstrating that the pressure

		drop across the catalyst is within the operating limitation established during the performance test.
11. Existing stationary CI RICE >500 HP that are not limited use stationary RICE	a. Reduce CO emissions, or limit the concentration of CO in the stationary RICE exhaust, and not using oxidation catalyst	i. Conducting performance tests every 8,760 hours or 3 years, whichever comes first, for CO or formaldehyde, as appropriate, to demonstrate that the required CO or formaldehyde, as appropriate, percent reduction is achieved or that your emissions remain at or below the CO or formaldehyde concentration limit; and
		ii. Collecting the approved operating parameter (if any) data according to §63.6625(b); and
		iii. Reducing these data to 4-hour rolling averages; and
		iv. Maintaining the 4-hour rolling averages within the operating limitations for the operating parameters established during the performance test.
12. Existing limited use CI stationary RICE >500 HP	a. Reduce CO emissions or limit the concentration of CO in the stationary RICE exhaust, and using an oxidation catalyst	i. Conducting performance tests every 8,760 hours or 5 years, whichever comes first, for CO or formaldehyde, as appropriate, to demonstrate that the required CO or formaldehyde, as appropriate, percent reduction is achieved or that your emissions remain at or below the CO or formaldehyde concentration limit; and
		ii. Collecting the catalyst inlet temperature data according to §63.6625(b); and
		iii. Reducing these data to 4-hour rolling averages; and
		iv. Maintaining the 4-hour rolling averages within the operating limitations for the catalyst inlet temperature; and

		v. Measuring the pressure drop across the catalyst once per month and demonstrating that the pressure drop across the catalyst is within the operating limitation established during the performance test.
13. Existing limited use CI stationary RICE >500 HP	a. Reduce CO emissions or limit the concentration of CO in the stationary RICE exhaust, and not using an oxidation catalyst	i. Conducting performance tests every 8,760 hours or 5 years, whichever comes first, for CO or formaldehyde, as appropriate, to demonstrate that the required CO or formaldehyde, as appropriate, percent reduction is achieved or that your emissions remain at or below the CO or formaldehyde concentration limit; and
		ii. Collecting the approved operating parameter (if any) data according to §63.6625(b); and
		iii. Reducing these data to 4-hour rolling averages; and
		iv. Maintaining the 4-hour rolling averages within the operating limitations for the operating parameters established during the performance test.
14. Existing non-emergency 4SLB stationary RICE >500 HP located at an area source of HAP that are not remote stationary RICE and that are operated more than 24 hours per calendar year	a. Install an oxidation catalyst	i. Conducting annual compliance demonstrations as specified in §63.6640(c) to show that the average reduction of emissions of CO is 93 percent or more, or the average CO concentration is less than or equal to 47 ppmvd at 15 percent O_2; and either ii. Collecting the catalyst inlet temperature data according to §63.6625(b), reducing these data to 4-hour rolling averages; and maintaining the 4-hour rolling averages within the limitation of greater than 450 °F and less than or equal to 1350 °F for the catalyst inlet temperature; or

		iii. Immediately shutting down the engine if the catalyst inlet temperature exceeds 1350 °F.
15. Existing non-emergency 4SRB stationary RICE >500 HP located at an area source of HAP that are not remote stationary RICE and that are operated more than 24 hours per calendar year	a. Install NSCR	i. Conducting annual compliance demonstrations as specified in §63.6640(c) to show that the average reduction of emissions of CO is 75 percent or more, the average CO concentration is less than or equal to 270 ppmvd at 15 percent O_2, or the average reduction of emissions of THC is 30 percent or more; and either ii. Collecting the catalyst inlet temperature data according to §63.6625(b), reducing these data to 4-hour rolling averages; and maintaining the 4-hour rolling averages within the limitation of greater than or equal to 750 °F and less than or equal to 1250 °F for the catalyst inlet temperature; or iii. Immediately shutting down the engine if the catalyst inlet temperature exceeds 1250 °F.

[a]After you have demonstrated compliance for two consecutive tests, you may reduce the frequency of subsequent performance tests to annually. If the results of any subsequent annual performance test indicate the stationary RICE is not in compliance with the CO or formaldehyde emission limitation, or you deviate from any of your operating limitations, you must resume semiannual performance tests.

[78 FR 6715, Jan. 30, 2013]

Back to Top

Table 7 to Subpart ZZZZ of Part 63—Requirements for Reports

As stated in §63.6650, you must comply with the following requirements for reports:

For each . . .	You must submit a . . .	The report must contain . . .	You must submit the report . . .
1. Existing non-emergency, non-black start stationary RICE 100≤HP≤500 located at	Compliance report	a. If there are no deviations from any emission limitations or operating	i. Semiannually according to the requirements in

a major source of HAP; existing non-emergency, non-black start stationary CI RICE >500 HP located at a major source of HAP; existing non-emergency 4SRB stationary RICE >500 HP located at a major source of HAP; existing non-emergency, non-black start stationary CI RICE >300 HP located at an area source of HAP; new or reconstructed non-emergency stationary RICE >500 HP located at a major source of HAP; and new or reconstructed non-emergency 4SLB stationary RICE 250≤HP≤500 located at a major source of HAP		limitations that apply to you, a statement that there were no deviations from the emission limitations or operating limitations during the reporting period. If there were no periods during which the CMS, including CEMS and CPMS, was out-of-control, as specified in §63.8(c)(7), a statement that there were not periods during which the CMS was out-of-control during the reporting period; or	§63.6650(b)(1)-(5) for engines that are not limited use stationary RICE subject to numerical emission limitations; and ii. Annually according to the requirements in §63.6650(b)(6)-(9) for engines that are limited use stationary RICE subject to numerical emission limitations.
		b. If you had a deviation from any emission limitation or operating limitation during the reporting period, the information in §63.6650(d). If there were periods during which the CMS, including CEMS and CPMS, was out-of-control, as specified in §63.8(c)(7), the information in §63.6650(e); or	i. Semiannually according to the requirements in §63.6650(b).
		c. If you had a malfunction during the reporting period, the information in §63.6650(c)(4).	i. Semiannually according to the requirements in §63.6650(b).
2. New or reconstructed non-emergency stationary RICE that combusts landfill gas or digester gas equivalent to 10 percent or more of the gross heat input on an annual basis	Report	a. The fuel flow rate of each fuel and the heating values that were used in your calculations, and you must demonstrate that the percentage of heat input provided by landfill gas or digester gas, is equivalent to 10 percent or more of the	i. Annually, according to the requirements in §63.6650.

		gross heat input on an annual basis; and	
		b. The operating limits provided in your federally enforceable permit, and any deviations from these limits; and	i. See item 2.a.i.
		c. Any problems or errors suspected with the meters.	i. See item 2.a.i.
3. Existing non-emergency, non-black start 4SLB and 4SRB stationary RICE >500 HP located at an area source of HAP that are not remote stationary RICE and that operate more than 24 hours per calendar year	Compliance report	a. The results of the annual compliance demonstration, if conducted during the reporting period.	i. Semiannually according to the requirements in §63.6650(b)(1)-(5).
4. Emergency stationary RICE that operate or are contractually obligated to be available for more than 15 hours per year for the purposes specified in §63.6640(f)(2)(ii) and (iii) or that operate for the purposes specified in §63.6640(f)(4)(ii)	Report	a. The information in §63.6650(h)(1)	i. annually according to the requirements in §63.6650(h)(2)-(3).

[78 FR 6719, Jan. 30, 2013]

Back to Top

Table 8 to Subpart ZZZZ of Part 63—Applicability of General Provisions to Subpart ZZZZ.

As stated in §63.6665, you must comply with the following applicable general provisions.

General provisions citation	Subject of citation	Applies to subpart	Explanation
§63.1	General applicability of the General Provisions	Yes.	
§63.2	Definitions	Yes	Additional terms defined in §63.6675.

§63.3	Units and abbreviations	Yes.	
§63.4	Prohibited activities and circumvention	Yes.	
§63.5	Construction and reconstruction	Yes.	
§63.6(a)	Applicability	Yes.	
§63.6(b)(1)-(4)	Compliance dates for new and reconstructed sources	Yes.	
§63.6(b)(5)	Notification	Yes.	
§63.6(b)(6)	[Reserved]		
§63.6(b)(7)	Compliance dates for new and reconstructed area sources that become major sources	Yes.	
§63.6(c)(1)-(2)	Compliance dates for existing sources	Yes.	
§63.6(c)(3)-(4)	[Reserved]		
§63.6(c)(5)	Compliance dates for existing area sources that become major sources	Yes.	
§63.6(d)	[Reserved]		
§63.6(e)	Operation and maintenance	No.	
§63.6(f)(1)	Applicability of standards	No.	
§63.6(f)(2)	Methods for determining compliance	Yes.	
§63.6(f)(3)	Finding of compliance	Yes.	
§63.6(g)(1)-(3)	Use of alternate standard	Yes.	
§63.6(h)	Opacity and visible emission standards	No	Subpart ZZZZ does not contain opacity or visible emission standards.
§63.6(i)	Compliance extension procedures and criteria	Yes.	
§63.6(j)	Presidential compliance exemption	Yes.	
§63.7(a)(1)-(2)	Performance test dates	Yes	Subpart ZZZZ contains performance test dates at

			§§63.6610, 63.6611, and 63.6612.
§63.7(a)(3)	CAA section 114 authority	Yes.	
§63.7(b)(1)	Notification of performance test	Yes	Except that §63.7(b)(1) only applies as specified in §63.6645.
§63.7(b)(2)	Notification of rescheduling	Yes	Except that §63.7(b)(2) only applies as specified in §63.6645.
§63.7(c)	Quality assurance/test plan	Yes	Except that §63.7(c) only applies as specified in §63.6645.
§63.7(d)	Testing facilities	Yes.	
§63.7(e)(1)	Conditions for conducting performance tests	No.	Subpart ZZZZ specifies conditions for conducting performance tests at §63.6620.
§63.7(e)(2)	Conduct of performance tests and reduction of data	Yes	Subpart ZZZZ specifies test methods at §63.6620.
§63.7(e)(3)	Test run duration	Yes.	
§63.7(e)(4)	Administrator may require other testing under section 114 of the CAA	Yes.	
§63.7(f)	Alternative test method provisions	Yes.	
§63.7(g)	Performance test data analysis, recordkeeping, and reporting	Yes.	
§63.7(h)	Waiver of tests	Yes.	
§63.8(a)(1)	Applicability of monitoring requirements	Yes	Subpart ZZZZ contains specific requirements for monitoring at §63.6625.
§63.8(a)(2)	Performance specifications	Yes.	
§63.8(a)(3)	[Reserved]		
§63.8(a)(4)	Monitoring for control devices	No.	
§63.8(b)(1)	Monitoring	Yes.	
§63.8(b)(2)-(3)	Multiple effluents and multiple	Yes.	

	monitoring systems		
§63.8(c)(1)	Monitoring system operation and maintenance	Yes.	
§63.8(c)(1)(i)	Routine and predictable SSM	No	
§63.8(c)(1)(ii)	SSM not in Startup Shutdown Malfunction Plan	Yes.	
§63.8(c)(1)(iii)	Compliance with operation and maintenance requirements	No	
§63.8(c)(2)-(3)	Monitoring system installation	Yes.	
§63.8(c)(4)	Continuous monitoring system (CMS) requirements	Yes	Except that subpart ZZZZ does not require Continuous Opacity Monitoring System (COMS).
§63.8(c)(5)	COMS minimum procedures	No	Subpart ZZZZ does not require COMS.
§63.8(c)(6)-(8)	CMS requirements	Yes	Except that subpart ZZZZ does not require COMS.
§63.8(d)	CMS quality control	Yes.	
§63.8(e)	CMS performance evaluation	Yes	Except for §63.8(e)(5)(ii), which applies to COMS.
		Except that §63.8(e) only applies as specified in §63.6645.	
§63.8(f)(1)-(5)	Alternative monitoring method	Yes	Except that §63.8(f)(4) only applies as specified in §63.6645.
§63.8(f)(6)	Alternative to relative accuracy test	Yes	Except that §63.8(f)(6) only applies as specified in §63.6645.
§63.8(g)	Data reduction	Yes	Except that provisions for COMS are not applicable. Averaging periods for demonstrating compliance are specified at §§63.6635 and 63.6640.
§63.9(a)	Applicability and State	Yes.	

	delegation of notification requirements		
§63.9(b)(1)-(5)	Initial notifications	Yes	Except that §63.9(b)(3) is reserved.
		Except that §63.9(b) only applies as specified in §63.6645.	
§63.9(c)	Request for compliance extension	Yes	Except that §63.9(c) only applies as specified in §63.6645.
§63.9(d)	Notification of special compliance requirements for new sources	Yes	Except that §63.9(d) only applies as specified in §63.6645.
§63.9(e)	Notification of performance test	Yes	Except that §63.9(e) only applies as specified in §63.6645.
§63.9(f)	Notification of visible emission (VE)/opacity test	No	Subpart ZZZZ does not contain opacity or VE standards.
§63.9(g)(1)	Notification of performance evaluation	Yes	Except that §63.9(g) only applies as specified in §63.6645.
§63.9(g)(2)	Notification of use of COMS data	No	Subpart ZZZZ does not contain opacity or VE standards.
§63.9(g)(3)	Notification that criterion for alternative to RATA is exceeded	Yes	If alternative is in use.
		Except that §63.9(g) only applies as specified in §63.6645.	
§63.9(h)(1)-(6)	Notification of compliance status	Yes	Except that notifications for sources using a CEMS are due 30 days after completion of performance evaluations. §63.9(h)(4) is reserved.

			Except that §63.9(h) only applies as specified in §63.6645.
§63.9(i)	Adjustment of submittal deadlines	Yes.	
§63.9(j)	Change in previous information	Yes.	
§63.10(a)	Administrative provisions for recordkeeping/reporting	Yes.	
§63.10(b)(1)	Record retention	Yes	Except that the most recent 2 years of data do not have to be retained on site.
§63.10(b)(2)(i)-(v)	Records related to SSM	No.	
§63.10(b)(2)(vi)-(xi)	Records	Yes.	
§63.10(b)(2)(xii)	Record when under waiver	Yes.	
§63.10(b)(2)(xiii)	Records when using alternative to RATA	Yes	For CO standard if using RATA alternative.
§63.10(b)(2)(xiv)	Records of supporting documentation	Yes.	
§63.10(b)(3)	Records of applicability determination	Yes.	
§63.10(c)	Additional records for sources using CEMS	Yes	Except that §63.10(c)(2)-(4) and (9) are reserved.
§63.10(d)(1)	General reporting requirements	Yes.	
§63.10(d)(2)	Report of performance test results	Yes.	
§63.10(d)(3)	Reporting opacity or VE observations	No	Subpart ZZZZ does not contain opacity or VE standards.
§63.10(d)(4)	Progress reports	Yes.	
§63.10(d)(5)	Startup, shutdown, and malfunction reports	No.	
§63.10(e)(1) and (2)(i)	Additional CMS Reports	Yes.	

§63.10(e)(2)(ii)	COMS-related report	No	Subpart ZZZZ does not require COMS.
§63.10(e)(3)	Excess emission and parameter exceedances reports	Yes.	Except that §63.10(e)(3)(i)(C) is reserved.
§63.10(e)(4)	Reporting COMS data	No	Subpart ZZZZ does not require COMS.
§63.10(f)	Waiver for recordkeeping/reporting	Yes.	
§63.11	Flares	No.	
§63.12	State authority and delegations	Yes.	
§63.13	Addresses	Yes.	
§63.14	Incorporation by reference	Yes.	
§63.15	Availability of information	Yes.	

[75 FR 9688, Mar. 3, 2010, as amended at 78 FR 6720, Jan. 30, 2013]

Back to Top

Appendix A to Subpart ZZZZ of Part 63—Protocol for Using an Electrochemical Analyzer to Determine Oxygen and Carbon Monoxide Concentrations From Certain Engines

1.0 SCOPE AND APPLICATION. WHAT IS THIS PROTOCOL?

This protocol is a procedure for using portable electrochemical (EC) cells for measuring carbon monoxide (CO) and oxygen (O_2) concentrations in controlled and uncontrolled emissions from existing stationary 4-stroke lean burn and 4-stroke rich burn reciprocating internal combustion engines as specified in the applicable rule.

1.1 Analytes. What does this protocol determine?

This protocol measures the engine exhaust gas concentrations of carbon monoxide (CO) and oxygen (O_2).

Analyte	CAS No.	Sensitivity
Carbon monoxide (CO)	630-08-0	Minimum detectable limit should be 2 percent of the nominal range or 1 ppm, whichever is less restrictive.
Oxygen (O_2)	*7782-44-7*	

1.2 Applicability. When is this protocol acceptable?

This protocol is applicable to 40 CFR part 63, subpart ZZZZ. Because of inherent cross sensitivities of EC cells, you must not apply this protocol to other emissions sources without specific instruction to that effect.

1.3 Data Quality Objectives. How good must my collected data be?

Refer to Section 13 to verify and document acceptable analyzer performance.

1.4 Range. What is the targeted analytical range for this protocol?

The measurement system and EC cell design(s) conforming to this protocol will determine the analytical range for each gas component. The nominal ranges are defined by choosing up-scale calibration gas concentrations near the maximum anticipated flue gas concentrations for CO and O_2, or no more than twice the permitted CO level.

1.5 Sensitivity. What minimum detectable limit will this protocol yield for a particular gas component?

The minimum detectable limit depends on the nominal range and resolution of the specific EC cell used, and the signal to noise ratio of the measurement system. The minimum detectable limit should be 2 percent of the nominal range or 1 ppm, whichever is less restrictive.

2.0 SUMMARY OF PROTOCOL

In this protocol, a gas sample is extracted from an engine exhaust system and then conveyed to a portable EC analyzer for measurement of CO and O_2 gas concentrations. This method provides measurement system performance specifications and sampling protocols to ensure reliable data. You may use additions to, or modifications of vendor supplied measurement systems (e.g., heated or unheated sample lines, thermocouples, flow meters, selective gas scrubbers, etc.) to meet the design specifications of this protocol. Do not make changes to the measurement system from the as-verified configuration (Section 3.12).

3.0 DEFINITIONS

3.1 Measurement System. The total equipment required for the measurement of CO and O_2 concentrations. The measurement system consists of the following major subsystems:

3.1.1 Data Recorder. A strip chart recorder, computer or digital recorder for logging measurement data from the analyzer output. You may record measurement data from the digital data display manually or electronically.

3.1.2 Electrochemical (EC) Cell. A device, similar to a fuel cell, used to sense the presence of a specific analyte and generate an electrical current output proportional to the analyte concentration.

3.1.3 Interference Gas Scrubber. A device used to remove or neutralize chemical compounds that may interfere with the selective operation of an EC cell.

3.1.4 Moisture Removal System. Any device used to reduce the concentration of moisture in the sample stream so as to protect the EC cells from the damaging effects of condensation and to minimize errors in measurements caused by the scrubbing of soluble gases.

3.1.5 Sample Interface. The portion of the system used for one or more of the following: sample acquisition; sample transport; sample conditioning or protection of the EC cell from any degrading effects of the engine exhaust effluent; removal of particulate matter and condensed moisture.

3.2 Nominal Range. The range of analyte concentrations over which each EC cell is operated (normally 25 percent to 150 percent of up-scale calibration gas value). Several nominal ranges can be used for any given cell so long as the calibration and repeatability checks for that range remain within specifications.

3.3 Calibration Gas. A vendor certified concentration of a specific analyte in an appropriate balance gas.

3.4 Zero Calibration Error. The analyte concentration output exhibited by the EC cell in response to zero-level calibration gas.

3.5 Up-Scale Calibration Error. The mean of the difference between the analyte concentration exhibited by the EC cell and the certified concentration of the up-scale calibration gas.

3.6 Interference Check. A procedure for quantifying analytical interference from components in the engine exhaust gas other than the targeted analytes.

3.7 Repeatability Check. A protocol for demonstrating that an EC cell operated over a given nominal analyte concentration range provides a stable and consistent response and is not significantly affected by repeated exposure to that gas.

3.8 Sample Flow Rate. The flow rate of the gas sample as it passes through the EC cell. In some situations, EC cells can experience drift with changes in flow rate. The flow rate must be monitored and documented during all phases of a sampling run.

3.9 Sampling Run. A timed three-phase event whereby an EC cell's response rises and plateaus in a sample conditioning phase, remains relatively constant during a measurement data phase, then declines during a refresh phase. The sample conditioning phase exposes the EC cell to the gas sample for a length of time sufficient to reach a constant response. The measurement data phase is the time interval during which gas sample measurements can be made that meet the acceptance criteria of this protocol. The refresh phase then purges the EC cells with CO-free air. The refresh phase replenishes requisite O_2 and moisture in the electrolyte reserve and provides a mechanism to de-gas or desorb any interference gas scrubbers or filters so as to enable a stable CO EC cell response. There are four primary types of sampling runs: pre- sampling calibrations; stack gas sampling; post-sampling calibration checks; and measurement system repeatability checks. Stack gas sampling runs can be chained together for extended evaluations, providing all other procedural specifications are met.

3.10 Sampling Day. A time not to exceed twelve hours from the time of the pre-sampling calibration to the post-sampling calibration check. During this time, stack gas sampling runs can be repeated without repeated recalibrations, providing all other sampling specifications have been met.

3.11 Pre-Sampling Calibration/Post-Sampling Calibration Check. The protocols executed at the beginning and end of each sampling day to bracket measurement readings with controlled performance checks.

3.12 Performance-Established Configuration. The EC cell and sampling system configuration that existed at the time that it initially met the performance requirements of this protocol.

4.0 INTERFERENCES.

When present in sufficient concentrations, NO and NO_2 are two gas species that have been reported to interfere with CO concentration measurements. In the likelihood of this occurrence, it is the protocol user's responsibility to employ and properly maintain an appropriate CO EC cell filter or scrubber for removal of these gases, as described in Section 6.2.12.

5.0 SAFETY. [RESERVED]

6.0 EQUIPMENT AND SUPPLIES.

6.1 What equipment do I need for the measurement system?

The system must maintain the gas sample at conditions that will prevent moisture condensation in the sample transport lines, both before and as the sample gas contacts the EC cells. The essential components of the measurement system are described below.

6.2 Measurement System Components.

6.2.1 Sample Probe. A single extraction-point probe constructed of glass, stainless steel or other non-reactive material, and of length sufficient to reach any designated sampling point. The sample probe must be designed to prevent plugging due to condensation or particulate matter.

6.2.2 Sample Line. Non-reactive tubing to transport the effluent from the sample probe to the EC cell.

6.2.3 Calibration Assembly (optional). A three-way valve assembly or equivalent to introduce calibration gases at ambient pressure at the exit end of the sample probe during calibration checks. The assembly must be designed such that only stack gas or calibration gas flows in the sample line and all gases flow through any gas path filters.

6.2.4 Particulate Filter (optional). Filters before the inlet of the EC cell to prevent accumulation of particulate material in the measurement system and extend the useful life of the components. All filters must be fabricated of materials that are non-reactive to the gas mixtures being sampled.

6.2.5 Sample Pump. A leak-free pump to provide undiluted sample gas to the system at a flow rate sufficient to minimize the response time of the measurement system. If located upstream of the EC cells, the pump must be constructed of a material that is non-reactive to the gas mixtures being sampled.

6.2.8 Sample Flow Rate Monitoring. An adjustable rotameter or equivalent device used to adjust and maintain the sample flow rate through the analyzer as prescribed.

6.2.9 Sample Gas Manifold (optional). A manifold to divert a portion of the sample gas stream to the analyzer and the remainder to a by-pass discharge vent. The sample gas manifold may also include provisions for introducing calibration gases directly to the analyzer. The manifold must be constructed of a material that is non-reactive to the gas mixtures being sampled.

6.2.10 EC cell. A device containing one or more EC cells to determine the CO and O_2 concentrations in the sample gas stream. The EC cell(s) must meet the applicable performance specifications of Section 13 of this protocol.

6.2.11 Data Recorder. A strip chart recorder, computer or digital recorder to make a record of analyzer output data. The data recorder resolution (i.e., readability) must be no greater than 1 ppm for CO; 0.1 percent for O_2; and one degree (either °C or °F) for temperature. Alternatively, you may use a digital or analog meter having the same resolution to observe and manually record the analyzer responses.

6.2.12 Interference Gas Filter or Scrubber. A device to remove interfering compounds upstream of the CO EC cell. Specific interference gas filters or scrubbers used in the performance-established configuration of the analyzer must continue to be used. Such a filter or scrubber must have a means to determine when the removal agent is exhausted. Periodically replace or replenish it in accordance with the manufacturer's recommendations.

7.0 Reagents and Standards. What calibration gases are needed?

7.1 Calibration Gases. CO calibration gases for the EC cell must be CO in nitrogen or CO in a mixture of nitrogen and O_2. Use CO calibration gases with labeled concentration values certified by the manufacturer to be within ±5 percent of the label value. Dry ambient air (20.9 percent O_2) is acceptable for calibration of the O_2 cell. If needed, any lower percentage O_2 calibration gas must be a mixture of O_2 in nitrogen.

7.1.1 Up-Scale CO Calibration Gas Concentration. Choose one or more up-scale gas concentrations such that the average of the stack gas measurements for each stack gas sampling run are between 25 and 150 percent of those concentrations. Alternatively, choose an up-scale gas that does not exceed twice the concentration of the applicable outlet standard. If a measured gas value exceeds 150 percent of the up-scale CO calibration gas value at any time during the stack gas sampling run, the run must be discarded and repeated.

7.1.2 Up-Scale O_2 Calibration Gas Concentration.

Select an O_2 gas concentration such that the difference between the gas concentration and the average stack gas measurement or reading for each sample run is less than 15 percent O_2. When the average exhaust gas O_2 readings are above 6 percent, you may use dry ambient air (20.9 percent O_2) for the up-scale O_2 calibration gas.

7.1.3 Zero Gas. Use an inert gas that contains less than 0.25 percent of the up-scale CO calibration gas concentration. You may use dry air that is free from ambient CO and other combustion gas products (e.g., CO_2).

8.0 Sample Collection and Analysis

8.1 Selection of Sampling Sites.

8.1.1 Control Device Inlet. Select a sampling site sufficiently downstream of the engine so that the combustion gases should be well mixed. Use a single sampling extraction point near the center of the duct (e.g., within the 10 percent centroidal area), unless instructed otherwise.

8.1.2 Exhaust Gas Outlet. Select a sampling site located at least two stack diameters downstream of any disturbance (e.g., turbocharger exhaust, crossover junction or recirculation take-off) and at least one-half stack diameter upstream of the gas discharge to the atmosphere. Use a single sampling extraction point near the center of the duct (e.g., within the 10 percent centroidal area), unless instructed otherwise.

8.2 Stack Gas Collection and Analysis. Prior to the first stack gas sampling run, conduct that the pre-sampling calibration in accordance with Section 10.1. Use Figure 1 to record all data. Zero the analyzer with zero gas. Confirm and record that the scrubber media color is correct and not exhausted. Then position the probe at the sampling point and begin the sampling run at the same flow rate used during the up-scale calibration. Record the start time. Record all EC cell output responses and the flow rate during the “sample conditioning phase” once per minute until constant readings are obtained. Then begin the “measurement data phase” and record readings every 15 seconds for at least two minutes (or eight readings), or as otherwise required to achieve two continuous minutes of data that meet the specification given in Section 13.1. Finally, perform the “refresh phase” by introducing dry air, free from CO and other combustion gases, until several minute-to-minute readings of consistent value have been obtained. For each run use the “measurement data phase” readings to calculate the average stack gas CO and O_2 concentrations.

8.3 EC Cell Rate. Maintain the EC cell sample flow rate so that it does not vary by more than ±10 percent throughout the pre-sampling calibration, stack gas sampling and post-sampling calibration check. Alternatively, the EC cell sample flow rate can be maintained within a tolerance range that does not affect the gas concentration readings by more than ±3 percent, as instructed by the EC cell manufacturer.

9.0 QUALITY CONTROL (RESERVED)

10.0 CALIBRATION AND STANDARDIZATION

10.1 Pre-Sampling Calibration. Conduct the following protocol once for each nominal range to be used on each EC cell before performing a stack gas sampling run on each field sampling day. Repeat the calibration if you replace an EC cell before completing all of the sampling runs. There is no prescribed order for calibration of the EC cells; however, each cell must complete the measurement data phase during calibration. Assemble the measurement system by following the manufacturer's recommended protocols including for preparing and preconditioning the EC cell. Assure the measurement system has no leaks and verify the gas scrubbing agent is not depleted. Use Figure 1 to record all data.

10.1.1 Zero Calibration. For both the O_2 and CO cells, introduce zero gas to the measurement system (e.g., at the calibration assembly) and record the concentration reading every minute until readings are constant for at least two consecutive minutes. Include the time and sample flow rate. Repeat the steps in this section at least once to verify the zero calibration for each component gas.

10.1.2 Zero Calibration Tolerance. For each zero gas introduction, the zero level output must be less than or equal to ±3 percent of the up-scale gas value or ±1 ppm, whichever is less restrictive, for the CO channel and less than or equal to ±0.3 percent O_2 for the O_2 channel.

10.1.3 Up-Scale Calibration. Individually introduce each calibration gas to the measurement system (e.g., at the calibration assembly) and record the start time. Record all EC cell output responses and the flow rate during this “sample conditioning phase” once per minute until readings are constant for at least two minutes. Then begin the “measurement data phase” and record readings every 15 seconds for a total of two minutes, or as otherwise required. Finally, perform the “refresh phase” by introducing dry air, free from CO and other combustion gases, until readings are constant for at least two consecutive minutes. Then repeat the steps in this section at least once to verify the calibration for each component gas. Introduce all gases to flow through the entire sample handling system (i.e., at the exit end of the sampling probe or the calibration assembly).

10.1.4 Up-Scale Calibration Error. The mean of the difference of the “measurement data phase” readings from the reported standard gas value must be less than or equal to ±5 percent or ±1 ppm for CO or ±0.5 percent O_2, whichever is less restrictive, respectively. The maximum allowable deviation from the mean measured value of any single “measurement data phase” reading must be less than or equal to ±2 percent or ±1 ppm for CO or ±0.5 percent O_2, whichever is less restrictive, respectively.

10.2 Post-Sampling Calibration Check. Conduct a stack gas post-sampling calibration check after the stack gas sampling run or set of runs and within 12 hours of the initial calibration. Conduct up-scale and zero calibration checks using the protocol in Section 10.1. Make no changes to the sampling system or EC cell calibration until all post-sampling calibration checks have been recorded. If either the zero or up-scale calibration error exceeds the respective specification in Sections 10.1.2 and 10.1.4 then all measurement data collected since the previous successful calibrations are invalid and re-calibration and re-sampling are required. If the sampling system is disassembled or the EC cell calibration is adjusted, repeat the calibration check before conducting the next analyzer sampling run.

11.0 Analytical Procedure

The analytical procedure is fully discussed in Section 8.

12.0 Calculations and Data Analysis

Determine the CO and O_2 concentrations for each stack gas sampling run by calculating the mean gas concentrations of the data recorded during the “measurement data phase”.

13.0 Protocol Performance

Use the following protocols to verify consistent analyzer performance during each field sampling day.

13.1 Measurement Data Phase Performance Check. Calculate the mean of the readings from the “measurement data phase”. The maximum allowable deviation from the mean for each of the individual readings is ±2 percent, or ±1 ppm, whichever is less restrictive. Record the mean value and maximum deviation for each gas monitored. Data must conform to Section 10.1.4. The EC cell flow rate must conform to the specification in Section 8.3.

Example: A measurement data phase is invalid if the maximum deviation of any single reading comprising that mean is greater than ±2 percent *or* ±1 ppm (the default criteria). For example, if the mean = 30 ppm, single readings of below 29 ppm and above 31 ppm are disallowed).

13.2 Interference Check. Before the initial use of the EC cell and interference gas scrubber in the field, and semi-annually thereafter, challenge the interference gas scrubber with NO and NO_2 gas standards that are generally recognized as representative of diesel-fueled engine NO and NO_2 emission values. Record the responses displayed by the CO EC cell and other pertinent data on Figure 1 or a similar form.

13.2.1 Interference Response. The combined NO and NO_2 interference response should be less than or equal to ±5 percent of the up-scale CO calibration gas concentration.

13.3 Repeatability Check. Conduct the following check once for each nominal range that is to be used on the CO EC cell within 5 days prior to each field sampling program. If a field sampling program lasts longer than 5 days, repeat this check every 5 days. Immediately repeat the check if the EC cell is replaced or if the EC cell is exposed to gas concentrations greater than 150 percent of the highest up-scale gas concentration.

13.3.1 Repeatability Check Procedure. Perform a complete EC cell sampling run (all three phases) by introducing the CO calibration gas to the measurement system and record the response. Follow Section 10.1.3. Use Figure 1 to record all data. Repeat the run three times for a total of four complete runs. During the four repeatability check runs, do not adjust the system except where necessary to achieve the correct calibration gas flow rate at the analyzer.

13.3.2 Repeatability Check Calculations. Determine the highest and lowest average “measurement data phase” CO concentrations from the four repeatability check runs and record the results on Figure 1 or a similar form. The absolute value of the difference between the maximum and minimum average values recorded must not vary more than ±3 percent or ±1 ppm of the up-scale gas value, whichever is less restrictive.

14.0 POLLUTION PREVENTION (RESERVED)

15.0 WASTE MANAGEMENT (RESERVED)

16.0 ALTERNATIVE PROCEDURES (RESERVED)

17.0 REFERENCES

(1) “Development of an Electrochemical Cell Emission Analyzer Test Protocol”, Topical Report, Phil Juneau, Emission Monitoring, Inc., July 1997.

(2) “Determination of Nitrogen Oxides, Carbon Monoxide, and Oxygen Emissions from Natural Gas-Fired Engines, Boilers, and Process Heaters Using Portable Analyzers”, EMC Conditional Test Protocol 30 (CTM-30), Gas Research Institute Protocol GRI-96/0008, Revision 7, October 13, 1997.

(3) “ICAC Test Protocol for Periodic Monitoring”, EMC Conditional Test Protocol 34 (CTM-034), The Institute of Clean Air Companies, September 8, 1999.

(4) “Code of Federal Regulations”, Protection of Environment, 40 CFR, Part 60, Appendix A, Methods 1-4; 10.

TABLE 1: APPENDIX A—SAMPLING RUN DATA.

Facility___________ Engine I.D.___________ Date_______											
Run Type:	(_)			(_)				(_)		(_)	
(X)	Pre-Sample Calibration			Stack Gas Sample				Post-Sample Cal. Check		Repeatability Check	
Run #	1	1	2	2	3	3	4	4	Time	Scrub. OK	Flow- Rate
Gas	O_2	CO	O_2	CO	O_2	CO	O_2	CO			
Sample Cond. Phase											
″											
″											
″											
″											
Measurement Data Phase											
″											

″											
″											
″											
″											
″											
″											
″											
″											
″											
Mean											
Refresh Phase											
″											
″											
″											
″											

[78 FR 6721, Jan. 30, 2013]

Appendix F

40 C.F.R. Part 63 Subpart YYYYY

National Emission Standards for Hazardous Air Pollutants for Area Sources: Electric Arc Furnace Steelmaking Facilities

Title 40: Protection of Environment
PART 63—NATIONAL EMISSION STANDARDS FOR HAZARDOUS AIR POLLUTANTS FOR SOURCE CATEGORIES (CONTINUED)

Subpart YYYYY—National Emission Standards for Hazardous Air Pollutants for Area Sources: Electric Arc Furnace Steelmaking Facilities

Contents

SOURCE: 72 FR 74111, Dec. 28, 2007, unless otherwise noted.

Back to Top

APPLICABILITY AND COMPLIANCE DATES

Back to Top

§63.10680 Am I subject to this subpart?

(a) You are subject to this subpart if you own or operate an electric arc furnace (EAF) steelmaking facility that is an area source of hazardous air pollutant (HAP) emissions.

(b) This subpart applies to each new or existing affected source. The affected source is each EAF steelmaking facility.

(1) An affected source is existing if you commenced construction or reconstruction of the affected source on or before September 20, 2007.

(2) An affected source is new if you commenced construction or reconstruction of the affected source after September 20, 2007.

(c) This subpart does not apply to research and development facilities, as defined in section 112(c)(7) of the Clean Air Act (CAA).

(d) If you own or operate an area source subject to this subpart, you must have or obtain a permit under 40 CFR part 70 or 40 CFR part 71.

Back to Top

§63.10681 What are my compliance dates?

(a) Except as provided in paragraph (b) of this section, if you own or operate an existing affected source, you must achieve compliance with the applicable provisions of this subpart by no later than June 30, 2008.

(b) If you own or operate an existing affected source, you must achieve compliance with opacity limit in §63.10686(b)(2) or (c)(2) by no later than December 28, 2010 if you demonstrate to the satisfaction of the permitting authority that additional time is needed to install or modify emission control equipment.

(c) If you start up a new affected source on or before December 28, 2007, you must achieve compliance with the applicable provisions of this subpart by no later than December 28, 2007.

(d) If you start up a new affected source after December 28, 2007, you must achieve compliance with the applicable provisions of this subpart upon startup of your affected source.

Back to Top

Standards and Compliance Requirements

Back to Top

§63.10685 What are the requirements for the control of contaminants from scrap?

(a) *Chlorinated plastics, lead, and free organic liquids.* For metallic scrap utilized in the EAF at your facility, you must comply with the requirements in either paragraph (a)(1) or (2) of this section. You may have certain scrap at your facility subject to paragraph (a)(1) of this section and other scrap subject to paragraph (a)(2) of this section provided the scrap remains segregated until charge make-up.

(1) *Pollution prevention plan.* For the production of steel other than leaded steel, you must prepare and implement a pollution prevention plan for metallic scrap selection and inspection to minimize the amount of chlorinated plastics, lead, and free organic liquids that is charged to the furnace. For the production of leaded steel, you must prepare and implement a pollution prevention plan for scrap selection and inspection to minimize the amount of chlorinated plastics and free organic liquids in the scrap that is charged to the furnace. You must submit the scrap pollution prevention plan to the permitting authority for approval. You must operate according to the plan as submitted during the review and approval process, operate according to the approved plan at all times after approval, and address any deficiency identified by the permitting authority within 60 days following disapproval of a plan. You may request approval to revise the plan and may operate according to the revised plan unless and until the revision is disapproved by the permitting authority. You must keep a copy of the plan onsite, and you must provide training on the plan's requirements to all plant personnel with materials acquisition or inspection duties. Each plan must include the information in paragraphs (a)(1)(i) through (iii) of this section:

(i) Specifications that scrap materials must be depleted (to the extent practicable) of undrained used oil filters, chlorinated plastics, and free organic liquids at the time of charging to the furnace.

(ii) A requirement in your scrap specifications for removal (to the extent practicable) of lead-containing components (such as batteries, battery cables, and wheel weights) from the scrap, except for scrap used to produce leaded steel.

(iii) Procedures for determining if the requirements and specifications in paragraph (a)(1) of this section are met (such as visual inspection or periodic audits of scrap providers) and procedures for taking corrective actions with vendors whose shipments are not within specifications.

(iv) The requirements of paragraph (a)(1) of this section do not apply to the routine recycling of baghouse bags or other internal process or maintenance materials in the furnace. These exempted materials must be identified in the pollution prevention plan.

(2) *Restricted metallic scrap.* For the production of steel other than leaded steel, you must not charge to a furnace metallic scrap that contains scrap from motor vehicle bodies, engine blocks, oil filters, oily turnings, machine shop borings, transformers or capacitors containing polychlorinated biphenyls, lead-containing components, chlorinated plastics, or free organic liquids. For the production of leaded steel, you must not charge to the furnace metallic scrap that contains scrap from motor vehicle bodies, engine blocks, oil filters, oily turnings, machine shop borings, transformers or capacitors containing polychlorinated biphenyls, chlorinated plastics, or free organic liquids. This restriction does not apply to any post-consumer engine blocks, post-consumer oil filters, or oily turnings that are processed or cleaned to the extent practicable such that the materials do not include lead components, chlorinated plastics, or free organic liquids. This restriction does not apply to motor vehicle scrap that is charged to recover the chromium or nickel content if you meet the requirements in paragraph (b)(3) of this section.

(b) *Mercury requirements.* For scrap containing motor vehicle scrap, you must procure the scrap pursuant to one of the compliance options in paragraphs (b)(1), (2), or (3) of this section for each scrap provider, contract, or shipment. For scrap that does not contain motor vehicle scrap, you must procure the scrap pursuant to the requirements in paragraph (b)(4) of this section for each scrap provider, contract, or shipment. You may have one scrap provider, contract, or shipment subject to one compliance provision and others subject to another compliance provision.

(1) *Site-specific plan for mercury switches.* You must comply with the requirements in paragraphs (b)(1)(i) through (v) of this section.

(i) You must include a requirement in your scrap specifications for removal of mercury switches from vehicle bodies used to make the scrap.

(ii) You must prepare and operate according to a plan demonstrating how your facility will implement the scrap specification in paragraph (b)(1)(i) of this section for removal of mercury switches. You must submit the plan to the permitting authority for approval. You must operate according to this plan as submitted during the review and approval process, operate according to the approved plan at all times after approval, and address any deficiency identified by the permitting authority within 60 days following disapproval of a plan. You may request approval to revise the plan and may operate according to the revised plan unless and until the revision is disapproved by the permitting authority. The permitting authority may change the approval status of the plan upon 90-days written notice based upon the semiannual compliance report or other information. The plan must include:

(A) A means of communicating to scrap purchasers and scrap providers the need to obtain or provide motor vehicle scrap from which mercury switches have been removed and the need to ensure the proper management of the mercury switches removed from that scrap as required under the rules implementing subtitle C of the Resource Conservation and Recovery Act (RCRA) (40 CFR parts 261 through 265 and 268). The plan must include documentation of direction to appropriate staff to communicate to suppliers throughout the scrap supply chain the need to promote the removal of mercury switches from end-of-life vehicles. Upon the request of the permitting authority, you must provide examples of materials that are used for outreach to suppliers, such as letters, contract language, policies for purchasing agents, and scrap inspection protocols;

(B) Provisions for obtaining assurance from scrap providers that motor vehicle scrap provided to the facility meet the scrap specification;

(C) Provisions for periodic inspections or other means of corroboration to ensure that scrap providers and dismantlers are implementing appropriate steps to minimize the presence of mercury switches in motor vehicle scrap and that the mercury switches removed are being properly managed, including the minimum frequency such means of corroboration will be implemented; and

(D) Provisions for taking corrective actions (i.e., actions resulting in scrap providers removing a higher percentage of mercury switches or other mercury-containing components) if needed, based on the results of procedures implemented in paragraph (b)(1)(ii)(C) of this section).

(iii) You must require each motor vehicle scrap provider to provide an estimate of the number of mercury switches removed from motor vehicle scrap sent to your facility during the previous year and the basis for the estimate. The permitting authority may request documentation or additional information at any time.

(iv) You must establish a goal for each scrap provider to remove at least 80 percent of the mercury switches. Although a site-specific plan approved under paragraph (b)(1) of this section may require only the removal of convenience light switch mechanisms, the permitting authority will credit all documented and verifiable mercury-containing components removed from motor vehicle scrap (such as sensors in anti-locking brake systems, security systems, active ride control, and other applications) when evaluating progress towards the 80 percent goal.

(v) For each scrap provider, you must submit semiannual progress reports to the permitting authority that provide the number of mercury switches removed or the weight of mercury recovered from the switches, the estimated number of vehicles processed, an estimate of the percent of mercury switches removed, and certification that the removed mercury switches were recycled at RCRA-permitted facilities or otherwise properly managed pursuant to RCRA subtitle C regulations referenced in paragraph (b)(1)(ii)(A) of this section. This information can be submitted in aggregated form and does not have to be submitted for each scrap provider, contract, or shipment. The permitting authority may change the approval status of a site-specific plan following 90-days notice based on the progress reports or other information.

(2) *Option for approved mercury programs.* You must certify in your notification of compliance status that you participate in and purchase motor vehicle scrap only from scrap providers who participate in a program for removal of mercury switches that has been approved by the Administrator based on the criteria in paragraphs (b)(2)(i) through (iii) of this section. If you purchase motor vehicle scrap from a broker, you must certify that all scrap received from that broker was obtained from other scrap providers who participate in a program for the removal of mercury switches that has been approved by the Administrator based on the criteria in paragraphs (b)(2)(i) through (iii) of this section. The National Vehicle Mercury Switch Recovery Program and the Vehicle Switch Recovery Program mandated by Maine State law are EPA-approved programs under paragraph (b)(2) of this section unless and until the Administrator disapproves the program (in part or in whole) under paragraph (b)(2)(iii) of this section.

(i) The program includes outreach that informs the dismantlers of the need for removal of mercury switches and provides training and guidance for removing mercury switches;

(ii) The program has a goal to remove at least 80 percent of mercury switches from the motor vehicle scrap the scrap provider processes. Although a program approved under paragraph (b)(2) of this section may require only the removal of convenience light switch mechanisms, the Administrator will credit all documented and verifiable mercury-containing components removed from motor vehicle scrap (such as sensors in anti-locking brake systems, security systems, active ride control, and other applications) when evaluating progress towards the 80 percent goal; and

(iii) The program sponsor agrees to submit progress reports to the Administrator no less frequently than once every year that provide the number of mercury switches removed or the weight of mercury recovered from the switches, the estimated number of vehicles processed, an estimate of the percent of mercury switches recovered, and certification that the recovered mercury switches were recycled at facilities with permits as required under the rules implementing subtitle C of RCRA (40 CFR parts 261 through 265 and 268). The progress reports must be based on a database that includes data for each program participant; however, data may be aggregated at the State level for progress reports that will be publicly available. The Administrator may change the approval status of a program or portion of a program (e.g., at the State level) following 90-days notice based on the progress reports or on other information.

(iv) You must develop and maintain onsite a plan demonstrating the manner through which your facility is participating in the EPA-approved program.

(A) The plan must include facility-specific implementation elements, corporate-wide policies, and/or efforts coordinated by a trade association as appropriate for each facility.

(B) You must provide in the plan documentation of direction to appropriate staff to communicate to suppliers throughout the scrap supply chain the need to promote the removal of mercury switches from end-of-life vehicles. Upon the request of the permitting authority, you must provide examples of materials that are used for outreach to suppliers, such as letters, contract language, policies for purchasing agents, and scrap inspection protocols.

(C) You must conduct periodic inspections or provide other means of corroboration to ensure that scrap providers are aware of the need for and are implementing appropriate steps to minimize the presence of mercury in scrap from end-of-life vehicles.

(3) *Option for specialty metal scrap.* You must certify in your notification of compliance status that the only materials from motor vehicles in the scrap are materials recovered for their specialty alloy (including, but not limited to, chromium, nickel, molybdenum, or other alloys) content (such as certain exhaust systems) and, based on the nature of the scrap and purchase specifications, that the type of scrap is not reasonably expected to contain mercury switches.

(4) *Scrap that does not contain motor vehicle scrap.* For scrap not subject to the requirements in paragraphs (b)(1) through (3) of this section, you must certify in your notification of compliance status and maintain records of documentation that this scrap does not contain motor vehicle scrap.

(c) *Recordkeeping and reporting requirements.* In addition to the records required by §63.10, you must keep records to demonstrate compliance with the requirements for your pollution prevention plan in paragraph (a)(1) of this section and/or for the use of only restricted scrap in paragraph (a)(2) of this section and for mercury in paragraphs (b)(1) through (3) of this section as applicable. You must keep records documenting compliance with paragraph (b)(4) of this section for scrap that does not contain motor vehicle scrap.

(1) If you are subject to the requirements for a site-specific plan for mercury under paragraph (b)(1) of this section, you must:

(i) Maintain records of the number of mercury switches removed or the weight of mercury recovered from the switches and properly managed, the estimated number of vehicles processed, and an estimate of the percent of mercury switches recovered; and

(ii) Submit semiannual reports of the number of mercury switches removed or the weight of mercury recovered from the switches and properly managed, the estimated number of vehicles processed, an estimate of the percent of mercury switches recovered, and a certification that the recovered mercury switches were recycled at RCRA-permitted facilities. The semiannual reports must include a certification that you have conducted inspections or taken other means of corroboration as required under paragraph (b)(1)(ii)(C) of this section. You may include this information in the semiannual compliance reports required under paragraph (c)(3) of this section.

(2) If you are subject to the option for approved mercury programs under paragraph (b)(2) of this section, you must maintain records identifying each scrap provider and documenting the scrap provider's participation in an approved mercury switch removal program. If you purchase motor vehicle scrap from a broker, you must maintain records identifying each broker and documentation that all scrap provided by the broker was obtained from other scrap providers who participate in an approved mercury switch removal program.

(3) You must submit semiannual compliance reports to the Administrator for the control of contaminants from scrap according to the requirements in §63.10(e). The report must clearly identify any deviation from the requirements in paragraphs (a) and (b) of this section and the corrective action taken. You must identify which compliance option in paragraph (b) of this section applies to each scrap provider, contract, or shipment.

Back to Top

§63.10686 What are the requirements for electric arc furnaces and argon-oxygen decarburization vessels?

(a) You must install, operate, and maintain a capture system that collects the emissions from each EAF (including charging, melting, and tapping operations) and argon-oxygen decarburization (AOD) vessel and conveys the collected emissions to a control device for the removal of particulate matter (PM).

(b) Except as provided in paragraph (c) of this section, you must not discharge or cause the discharge into the atmosphere from an EAF or AOD vessel any gases which:

(1) Exit from a control device and contain in excess of 0.0052 grains of PM per dry standard cubic foot (gr/dscf); and

(2) Exit from a melt shop and, due solely to the operations of any affected EAF(s) or AOD vessel(s), exhibit 6 percent opacity or greater.

(c) If you own or operate a new or existing affected source that has a production capacity of less than 150,000 tons per year (tpy) of stainless or specialty steel (as determined by the maximum production if specified in the source's operating permit or EAF capacity and maximum number of operating hours per year), you must not discharge or cause the discharge into the atmosphere from an EAF or AOD vessel any gases which:

(1) Exit from a control device and contain particulate matter (PM) in excess of 0.8 pounds per ton (lb/ton) of steel. Alternatively, the owner or operator may elect to comply with a PM limit of 0.0052 grains per dry standard cubic foot (gr/dscf); and

(2) Exit from a melt shop and, due solely to the operations of any affected EAF(s) or AOD vessel(s), exhibit 6 percent opacity or greater.

(d) Except as provided in paragraph (d)(6) of this section, you must conduct performance tests to demonstrate initial compliance with the applicable emissions limit for each emissions source subject to an emissions limit in paragraph (b) or (c) of this section.

(1) You must conduct each PM performance test for an EAF or AOD vessel according to the procedures in §63.7 and 40 CFR 60.275a using the following test methods in 40 CFR part 60, appendices A-1, A-2, A-3, and A-4:

(i) Method 1 or 1A of appendix A-1 of 40 CFR part 60 to select sampling port locations and the number of traverse points in each stack or duct. Sampling sites must be located at the outlet of the control device (or at the outlet of the emissions source if no control device is present) prior to any releases to the atmosphere.

(ii) Method 2, 2A, 2C, 2D, 2F, or 2G of appendix A-1 of 40 CFR part 60 to determine the volumetric flow rate of the stack gas.

(iii) Method 3, 3A, or 3B of appendix A-3 of 40 CFR part 60 to determine the dry molecular weight of the stack gas. You may use ANSI/ASME PTC 19.10-1981, "Flue and Exhaust Gas Analyses" (incorporated by reference—see §63.14) as an alternative to EPA Method 3B.

(iv) Method 4 of appendix A-3 of 40 CFR part 60 to determine the moisture content of the stack gas.

(v) Method 5 or 5D of appendix A-3 of 40 CFR part 60 to determine the PM concentration. Three valid test runs are needed to comprise a PM performance test. For EAF, sample only when metal is being melted and refined. For AOD vessels, sample only when the operation(s) are being conducted.

(2) You must conduct each opacity test for a melt shop according to the procedures in §63.6(h) and Method 9 of appendix A-4 of 40 CFR part 60. When emissions from any EAF or AOD vessel are combined with emissions from emission sources not subject to this subpart, you must demonstrate compliance with the melt shop opacity limit based on emissions from only the emission sources subject to this subpart.

(3) During any performance test, you must monitor and record the information specified in 40 CFR 60.274a(h) for all heats covered by the test.

(4) You must notify and receive approval from the Administrator for procedures that will be used to determine compliance for an EAF or AOD vessel when emissions are combined with those from facilities not subject to this subpart.

(5) To determine compliance with the PM emissions limit in paragraph (c) of this section for an EAF or AOD vessel in a lb/ton of steel format, compute the process-weighted mass emissions (E_p) for each test run using Equation 1 of this section:

$$E_p = \frac{C \times Q \times T}{P \times K} \qquad (Eq. 1)$$

View or download PDF

Where:

E_p = Process-weighted mass emissions of PM, lb/ton;

C = Concentration of PM or total metal HAP, gr/dscf;

Q = Volumetric flow rate of stack gas, dscf/hr;

T = Total time during a test run that a sample is withdrawn from the stack during steel production cycle, hr;

P = Total amount of metal produced during the test run, tons; and

K = Conversion factor, 7,000 grains per pound.

(6) If you own or operate an existing affected source that is subject to the emissions limits in paragraph (b) or (c) of this section, you may certify initial compliance with the applicable emission limit for one or more emissions sources based on the results of a previous performance test for that emissions source in lieu of the requirement for an initial performance test provided that the test(s) were conducted within 5 years of the compliance date using the methods and procedures specified in paragraph (d)(1) or (2) of this section; the test(s) were for the affected facility; and the test(s) were representative of current or anticipated operating processes and conditions. Should the permitting authority deem the prior test data unacceptable to demonstrate compliance with an applicable emissions limit, the owner or operator must conduct an initial performance test within 180 days of the compliance date or within 90 days of receipt of the notification of disapproval of the prior test, whichever is later.

(e) You must monitor the capture system and PM control device required by this subpart, maintain records, and submit reports according to the compliance assurance monitoring requirements in 40 CFR part 64. The exemption in 40 CFR 64.2(b)(1)(i) for emissions limitations or standards proposed after November 15, 1990 under section 111 or 112 of the CAA does not apply. In lieu of the deadlines for submittal in 40 CFR 64.5, you must submit the monitoring information required by 40 CFR 64.4 to the applicable permitting authority for approval by no later than the compliance date for your affected source for this subpart and operate according to the approved plan by no later than 180 days after the date of approval by the permitting authority.

Back to Top

OTHER INFORMATION AND REQUIREMENTS

Back to Top

§63.10690 What parts of the General Provisions apply to this subpart?

(a) You must comply with the requirements of the NESHAP General Provisions (40 CFR part 63, subpart A) as provided in Table 1 of this subpart.

(b) The notification of compliance status required by §63.9(h) must include each applicable certification of compliance, signed by a responsible official, in paragraphs (b)(1) through (6) of this section.

(1) For the pollution prevention plan requirements in §63.10685(a)(1): “This facility has submitted a pollution prevention plan for metallic scrap selection and inspection in accordance with §63.10685(a)(1)”;

(2) For the restrictions on metallic scrap in §63.10685(a)(2): “This facility complies with the requirements for restricted metallic scrap in accordance with §63.10685(a)(2)”;

(3) For the mercury requirements in §63.10685(b):

(i) “This facility has prepared a site-specific plan for mercury switches in accordance with §63.10685(b)(1)”;

(ii) “This facility participates in and purchases motor vehicle scrap only from scrap providers who participate in a program for removal of mercury switches that has been approved by the EPA Administrator in accordance with §63.10685(b)(2)” and has prepared a plan demonstrating how the facility participates in the EPA-approved program in accordance with §63.10685(b)(2)(iv);

(iii) “The only materials from motor vehicles in the scrap charged to an electric arc furnace at this facility are materials recovered for their specialty alloy content in accordance with §63.10685(b)(3) which are not reasonably expected to contain mercury switches”; or

(iv) “This facility complies with the requirements for scrap that does not contain motor vehicle scrap in accordance with §63.10685(b)(4).”

(4) This certification of compliance for the capture system requirements in §63.10686(a), signed by a responsible official: “This facility operates a capture system for each electric arc furnace and argon-oxygen decarburization vessel that conveys the collected emissions to a PM control device in accordance with §63.10686(a)”.

(5) If applicable, this certification of compliance for the performance test requirements in §63.10686(d)(6): “This facility certifies initial compliance with the applicable emissions limit in §63.10686(a) or (b) based on the results of a previous performance test in accordance with §63.10686(d)(6)”.

(6) This certification of compliance for the monitoring requirements in §63.10686(e), signed by a responsible official: “This facility has developed and submitted proposed monitoring information in accordance with 40 CFR part 64”.

Back to Top

§63.10691 Who implements and enforces this subpart?

(a) This subpart can be implemented and enforced by the EPA or a delegated authority such as a State, local, or tribal agency. If the EPA Administrator has delegated authority to a State, local, or tribal agency, then that Agency 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 contained in paragraph (c) of this section are retained by the Administrator and are not transferred to the State, local, or tribal agency.

(c) The authorities that will not be delegated to State, local, or tribal agencies are listed in paragraphs (c)(1) through (6) of this section.

(1) Approval of an alternative non-opacity emissions standard under 40 CFR 63.6(g).

(2) Approval of an alternative opacity emissions standard under §63.6(h)(9).

(3) Approval of a major change to test methods under §63.7(e)(2)(ii) and (f). A “major change to test method” is defined in 40 CFR 63.90.

(4) Approval of major change to monitoring under 40 CFR 63.8(f). A "major change to monitoring" is defined in 40 CFR 63.90.

(5) Approval of a major change to recordkeeping/reporting under 40 CFR 63.10(f). A "major change to recordkeeping/reporting" is defined in 40 CFR 63.90.

(6) Approval of a program for the removal of mercury switches under §63.10685(b)(2).

Back to Top

§63.10692 What definitions apply to this subpart?

Terms used in this subpart are defined in the Clean Air Act, in §63.2, and in this section as follows:

Argon-oxygen decarburization (AOD) vessel means any closed-bottom, refractory-lined converter vessel with submerged tuyeres through which gaseous mixtures containing argon and oxygen or nitrogen may be blown into molten steel for further refining.

Capture system means the equipment (including ducts, hoods, fans, dampers, etc.) used to capture or transport emissions generated by an electric arc furnace or argon-oxygen decarburization vessel to the air pollution control device.

Chlorinated plastics means solid polymeric materials that contain chlorine in the polymer chain, such as polyvinyl chloride (PVC) and PVC copolymers.

Control device means the air pollution control equipment used to remove particulate matter from the effluent gas stream generated by an electric arc furnace or argon-oxygen decarburization vessel.

Deviation means any instance where an affected source subject to this subpart, or an owner or operator of such a source:

(1) Fails to meet any requirement or obligation established by this subpart, including but not limited to any emissions limitation or work practice standard;

(2) 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; or

(3) Fails to meet any emissions limitation in this subpart during startup, shutdown, or malfunction, regardless of whether or not such failure is permitted by this subpart.

Electric arc furnace (EAF) means a furnace that produces molten steel and heats the charge materials with electric arcs from carbon electrodes. An electric arc furnace consists of the furnace shell, roof, and the transformer.

Electric arc furnace (EAF) steelmaking facility means a steel plant that produces carbon, alloy, or specialty steels using an EAF. This definition excludes EAF steelmaking facilities at steel foundries and EAF facilities used to produce nonferrous metals.

Free organic liquids means material that fails the paint filter test by EPA Method 9095B, (revision 2, dated November 1994) (incorporated by reference—see §63.14) after accounting for water using a moisture determination test by ASTM Method D2216-05 (incorporated by reference—see §63.14). If, after conducting a moisture determination test, if any portion of the material passes through and drops from the filter within the 5-minute test period, the material contains *free organic liquids.*

Leaded steel means steel that must meet a minimum specification for lead content (typically 0.25 percent or more) and for which lead is a necessary alloy for that grade of steel.

Mercury switch means each mercury-containing capsule or switch assembly that is part of a convenience light switch mechanism installed in a vehicle.

Motor vehicle means an automotive vehicle not operated on rails and usually operated with rubber tires for use on highways.

Motor vehicle scrap means vehicle or automobile bodies, including automobile body hulks, that have been processed through a shredder. *Motor vehicle scrap* does not include automobile manufacturing bundles, or miscellaneous vehicle parts, such as wheels, bumpers or other components that do not contain mercury switches.

Nonferrous metals means any pure metal other than iron or any metal alloy for which an element other than iron is its major constituent by percent in weight.

Scrap provider means the person (including a broker) who contracts directly with a steel mill to provide scrap that contains motor vehicle scrap. Scrap processors such as shredder operators or vehicle dismantlers that do not sell scrap directly to a steel mill are not *scrap providers.*

Specialty steel means low carbon and high alloy steel other than stainless steel that is processed in an argon-oxygen decarburization vessel.

Stainless steel means low carbon steel that contains at least 10.5 percent chromium.

Back to Top

Table 1 to Subpart YYYYY of Part 63—Applicability of General Provisions to Subpart YYYYY

As required in §63.10691(a), you must comply with the requirements of the NESHAP General Provisions (40 CFR part 63, subpart A) shown in the following table.

Citation	Subject	Applies to subpart YYYYY?	Explanation
§63.1(a)(1), (a)(2), (a)(3), (a)(4), (a)(6), (a)(10)-(a)(12), (b)(1), (b)(3), (c)(1), (c)(2), (c)(5), (e)	Applicability	Yes	
§63.1(a)(5), (a)(7)-(a)(9), (b)(2), (c)(3), (c)(4), (d)	Reserved	No	
§63.2	Definitions	Yes	
§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)(1), (c)(2), (c)(5), (e)(1), (e)(3)(i), (e)(3)(iii)-(e)(3)(ix), (f), (g), (h)(1), (h)(2), (h)(5)-(h)(9), (i), (j)	Compliance with Standards and Maintenance Requirements	Yes	
§63.6(b)(6), (c)(3), (c)(4), (d), (e)(2), (e)(3)(ii), (h)(3), (h)(5)(iv)	Reserved	No	
§63.7	Applicability and Performance Test Dates	Yes	
§63.8(a)(1), (a)(2), (b), (c), (d), (e), (f)(1)-(5), (g)	Monitoring Requirements	Yes	Requirements apply if a COMS or CEMS is used.
§63.8(a)(3)	[Reserved]	No	
§63.8(a)(4)	Additional Monitoring Requirements for Control Devices in §63.11	No	
§63.8(c)(4)	Continuous Monitoring System Requirements	Yes	Requirements apply if a COMS or CEMS is used.
§63.8(f)(6)	RATA Alternative	Yes	Requirements apply if a CEMS is used.
§63.9(a), (b)(1), (b)(2), (b)(5), (c), (d), (f), (g), (h)(1)-(h)(3), (h)(5), (h)(6), (i), (j)	Notification Requirements	Yes	
§63.9(b)(3), (h)(4)	Reserved	No	
§63.9(b)(4)		No	
§63.10(a), (b)(1), (b)(2)(i)-(v), (b)(2)(xiv), (b)(3), (c)(1), (c)(5)-(c)(8), (c)(10)-(c)(15), (d), (e)(1)-(e)(4), (f)	Recordkeeping and Reporting Requirements	Yes	Additional records for CMS in §63.10(c) (1)-(6), (9)-(15), and reports in §63.10(d)(1)-(2) apply if a COMS or CEMS is used.
§63.10(b)(2)(xiii)	CMS Records for RATA Alternative	Yes	Requirements apply if a CEMS is used.
§63.10(c)(2)-(c)(4), (c)(9)	Reserved	No	

§63.11	Control Device Requirements	No	
§63.12	State Authority and Delegations	Yes	
§§63.13-63.16	Addresses, Incorporations by Reference, Availability of Information, Performance Track Provisions	Yes	

Back to Top

Appendix G

40 C.F.R. Part 63 Subpart CCCCCC

National Emission Standards for Hazardous Air Pollutants for Source Category: Gasoline Dispensing Facilities

Subpart CCCCCC—National Emission Standards for Hazardous Air Pollutants for Source Category: Gasoline Dispensing Facilities

Contents

SOURCE: 73 FR 1945, Jan. 10, 2008, unless otherwise noted.

Back to Top

WHAT THIS SUBPART COVERS

Back to Top

§63.11110 What is the purpose of this subpart?

This subpart establishes national emission limitations and management practices for hazardous air pollutants (HAP) emitted from the loading of gasoline storage tanks at gasoline dispensing facilities (GDF). This subpart also establishes requirements to demonstrate compliance with the emission limitations and management practices.

Back to Top

§63.11111 Am I subject to the requirements in this subpart?

(a) The affected source to which this subpart applies is each GDF that is located at an area source. The affected source includes each gasoline cargo tank during the delivery of product to a GDF and also includes each storage tank.

(b) If your GDF has a monthly throughput of less than 10,000 gallons of gasoline, you must comply with the requirements in §63.11116.

(c) If your GDF has a monthly throughput of 10,000 gallons of gasoline or more, you must comply with the requirements in §63.11117.

(d) If your GDF has a monthly throughput of 100,000 gallons of gasoline or more, you must comply with the requirements in §63.11118.

(e) An affected source shall, upon request by the Administrator, demonstrate that their monthly throughput is less than the 10,000-gallon or the 100,000-gallon threshold level, as applicable. For new or reconstructed affected sources, as specified in §63.11112(b) and (c), recordkeeping to document monthly throughput must begin upon startup of the affected source. For existing sources, as specified in §63.11112(d), recordkeeping to document monthly throughput must begin on January 10, 2008. For existing sources that are subject to this subpart only because they load gasoline into fuel tanks other than those in motor vehicles, as defined in §63.11132, recordkeeping to document monthly throughput must begin on January 24, 2011. Records required under this paragraph shall be kept for a period of 5 years.

(f) If you are an owner or operator of affected sources, as defined in paragraph (a) of this section, you are not required to obtain a permit under 40 CFR part 70 or 40 CFR part 71 as a result of being subject to this subpart. However, you must still apply for and obtain a permit under 40 CFR part 70 or 40 CFR part 71 if you meet one or more of the applicability criteria found in 40 CFR 70.3(a) and (b) or 40 CFR 71.3(a) and (b).

(g) The loading of aviation gasoline into storage tanks at airports, and the subsequent transfer of aviation gasoline within the airport, is not subject to this subpart.

(h) Monthly throughput is the total volume of gasoline loaded into, or dispensed from, all the gasoline storage tanks located at a single affected GDF. If an area source has two or more GDF at separate locations within the area source, each GDF is treated as a separate affected source.

(i) If your affected source's throughput ever exceeds an applicable throughput threshold, the affected source will remain subject to the requirements for sources above the threshold, even if the affected source throughput later falls below the applicable throughput threshold.

(j) The dispensing of gasoline from a fixed gasoline storage tank at a GDF into a portable gasoline tank for the on-site delivery and subsequent dispensing of the gasoline into the fuel tank of a motor vehicle or other gasoline-fueled engine or equipment used within the area source is only subject to §63.11116 of this subpart.

(k) For any affected source subject to the provisions of this subpart and another Federal rule, you may elect to comply only with the more stringent provisions of the applicable subparts. You must consider all provisions of the rules, including monitoring, recordkeeping, and reporting. You must identify the affected source and provisions with which you will comply in your Notification of Compliance Status required under §63.11124. You also must demonstrate in your Notification of Compliance Status that each provision with which you will comply is at least as stringent as the otherwise applicable requirements in this subpart. You are responsible for making accurate determinations concerning the more stringent provisions, and noncompliance with this rule is not excused if it is later determined that your determination was in error, and, as a result, you are violating this subpart. Compliance with this rule is your responsibility and the Notification of Compliance Status does not alter or affect that responsibility.

[73 FR 1945, Jan. 10, 2008, as amended at 76 FR 4181, Jan. 24, 2011]

Back to Top

§63.11112 What parts of my affected source does this subpart cover?

(a) The emission sources to which this subpart applies are gasoline storage tanks and associated equipment components in vapor or liquid gasoline service at new, reconstructed, or existing GDF that meet the criteria specified in §63.11111. Pressure/Vacuum vents on gasoline storage tanks and the equipment necessary to unload product from cargo tanks into the storage tanks at GDF are covered emission sources. The equipment used for the refueling of motor vehicles is not covered by this subpart.

(b) An affected source is a new affected source if you commenced construction on the affected source after November 9, 2006, and you meet the applicability criteria in §63.11111 at the time you commenced operation.

(c) An affected source is reconstructed if you meet the criteria for reconstruction as defined in §63.2.

(d) An affected source is an existing affected source if it is not new or reconstructed.

Back to Top

§63.11113 When do I have to comply with this subpart?

(a) If you have a new or reconstructed affected source, you must comply with this subpart according to paragraphs (a)(1) and (2) of this section, except as specified in paragraph (d) of this section.

(1) If you start up your affected source before January 10, 2008, you must comply with the standards in this subpart no later than January 10, 2008.

(2) If you start up your affected source after January 10, 2008, you must comply with the standards in this subpart upon startup of your affected source.

(b) If you have an existing affected source, you must comply with the standards in this subpart no later than January 10, 2011.

(c) If you have an existing affected source that becomes subject to the control requirements in this subpart because of an increase in the monthly throughput, as specified in §63.11111(c) or §63.11111(d), you must comply with the standards in this subpart no later than 3 years after the affected source becomes subject to the control requirements in this subpart.

(d) If you have a new or reconstructed affected source and you are complying with Table 1 to this subpart, you must comply according to paragraphs (d)(1) and (2) of this section.

(1) If you start up your affected source from November 9, 2006 to September 23, 2008, you must comply no later than September 23, 2008.

(2) If you start up your affected source after September 23, 2008, you must comply upon startup of your affected source.

(e) The initial compliance demonstration test required under §63.11120(a)(1) and (2) must be conducted as specified in paragraphs (e)(1) and (2) of this section.

(1) If you have a new or reconstructed affected source, you must conduct the initial compliance test upon installation of the complete vapor balance system.

(2) If you have an existing affected source, you must conduct the initial compliance test as specified in paragraphs (e)(2)(i) or (e)(2)(ii) of this section.

(i) For vapor balance systems installed on or before December 15, 2009, you must test no later than 180 days after the applicable compliance date specified in paragraphs (b) or (c) of this section.

(ii) For vapor balance systems installed after December 15, 2009, you must test upon installation of the complete vapor balance system.

(f) If your GDF is subject to the control requirements in this subpart only because it loads gasoline into fuel tanks other than those in motor vehicles, as defined in §63.11132, you must comply with the standards in this subpart as specified in paragraphs (f)(1) or (f)(2) of this section.

(1) If your GDF is an existing facility, you must comply by January 24, 2014.

(2) If your GDF is a new or reconstructed facility, you must comply by the dates specified in paragraphs (f)(2)(i) and (ii) of this section.

(i) If you start up your GDF after December 15, 2009, but before January 24, 2011, you must comply no later than January 24, 2011.

(ii) If you start up your GDF after January 24, 2011, you must comply upon startup of your GDF.

[73 FR 1945, Jan. 10, 2008, as amended at 73 FR 35944, June 25, 2008; 76 FR 4181, Jan. 24, 2011]

Back to Top

EMISSION LIMITATIONS AND MANAGEMENT PRACTICES

Back to Top

§63.11115 What are my general duties to minimize emissions?

Each owner or operator of an affected source under this subpart must comply with the requirements of paragraphs (a) and (b) of this section.

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

(b) You must keep applicable records and submit reports as specified in §63.11125(d) and §63.11126(b).

[76 FR 4182, Jan. 24, 2011]

Back to Top

§63.11116 Requirements for facilities with monthly throughput of less than 10,000 gallons of gasoline.

(a) You must not allow gasoline to be handled in a manner that would result in vapor releases to the atmosphere for extended periods of time. Measures to be taken include, but are not limited to, the following:

(1) Minimize gasoline spills;

(2) Clean up spills as expeditiously as practicable;

(3) Cover all open gasoline containers and all gasoline storage tank fill-pipes with a gasketed seal when not in use;

(4) Minimize gasoline sent to open waste collection systems that collect and transport gasoline to reclamation and recycling devices, such as oil/water separators.

(b) You are not required to submit notifications or reports as specified in §63.11125, §63.11126, or subpart A of this part, but you must have records available within 24 hours of a request by the Administrator to document your gasoline throughput.

(c) You must comply with the requirements of this subpart by the applicable dates specified in §63.11113.

(d) Portable gasoline containers that meet the requirements of 40 CFR part 59, subpart F, are considered acceptable for compliance with paragraph (a)(3) of this section.

[73 FR 1945, Jan. 10, 2008, as amended at 76 FR 4182, Jan. 24, 2011]

Back to Top

§63.11117 Requirements for facilities with monthly throughput of 10,000 gallons of gasoline or more.

(a) You must comply with the requirements in section §63.11116(a).

(b) Except as specified in paragraph (c) of this section, you must only load gasoline into storage tanks at your facility by utilizing submerged filling, as defined in §63.11132, and as specified in paragraphs (b)(1), (b)(2), or (b)(3) of this section. The applicable distances in paragraphs (b)(1) and (2) shall be measured from the point in the opening of the submerged fill pipe that is the greatest distance from the bottom of the storage tank.

(1) Submerged fill pipes installed on or before November 9, 2006, must be no more than 12 inches from the bottom of the tank.

(2) Submerged fill pipes installed after November 9, 2006, must be no more than 6 inches from the bottom of the tank.

(3) Submerged fill pipes not meeting the specifications of paragraphs (b)(1) or (b)(2) of this section are allowed if the owner or operator can demonstrate that the liquid level in the tank is always above the entire opening of the fill pipe. Documentation providing such demonstration must be made available for inspection by the Administrator's delegated representative during the course of a site visit.

(c) Gasoline storage tanks with a capacity of less than 250 gallons are not required to comply with the submerged fill requirements in paragraph (b) of this section, but must comply only with all of the requirements in §63.11116.

(d) You must have records available within 24 hours of a request by the Administrator to document your gasoline throughput.

(e) You must submit the applicable notifications as required under §63.11124(a).

(f) You must comply with the requirements of this subpart by the applicable dates contained in §63.11113.

[73 FR 1945, Jan. 10, 2008, as amended at 73 FR 12276, Mar. 7, 2008; 76 FR 4182, Jan. 24, 2011]

Back to Top

§63.11118 Requirements for facilities with monthly throughput of 100,000 gallons of gasoline or more.

(a) You must comply with the requirements in §§63.11116(a) and 63.11117(b).

(b) Except as provided in paragraph (c) of this section, you must meet the requirements in either paragraph (b)(1) or paragraph (b)(2) of this section.

(1) Each management practice in Table 1 to this subpart that applies to your GDF.

(2) If, prior to January 10, 2008, you satisfy the requirements in both paragraphs (b)(2)(i) and (ii) of this section, you will be deemed in compliance with this subsection.

(i) You operate a vapor balance system at your GDF that meets the requirements of either paragraph (b)(2)(i)(A) or paragraph (b)(2)(i)(B) of this section.

(A) Achieves emissions reduction of at least 90 percent.

(B) Operates using management practices at least as stringent as those in Table 1 to this subpart.

(ii) Your gasoline dispensing facility is in compliance with an enforceable State, local, or tribal rule or permit that contains requirements of either paragraph (b)(2)(i)(A) or paragraph (b)(2)(i)(B) of this section.

(c) The emission sources listed in paragraphs (c)(1) through (3) of this section are not required to comply with the control requirements in paragraph (b) of this section, but must comply with the requirements in §63.11117.

(1) Gasoline storage tanks with a capacity of less than 250 gallons that are constructed after January 10, 2008.

(2) Gasoline storage tanks with a capacity of less than 2,000 gallons that were constructed before January 10, 2008.

(3) Gasoline storage tanks equipped with floating roofs, or the equivalent.

(d) Cargo tanks unloading at GDF must comply with the management practices in Table 2 to this subpart.

(e) You must comply with the applicable testing requirements contained in §63.11120.

(f) You must submit the applicable notifications as required under §63.11124.

(g) You must keep records and submit reports as specified in §§63.11125 and 63.11126.

(h) You must comply with the requirements of this subpart by the applicable dates contained in §63.11113.

[73 FR 1945, Jan. 10, 2008, as amended at 73 FR 12276, Mar. 7, 2008]

Back to Top

TESTING AND MONITORING REQUIREMENTS

Back to Top

§63.11120 What testing and monitoring requirements must I meet?

(a) Each owner or operator, at the time of installation, as specified in §63.11113(e), of a vapor balance system required under §63.11118(b)(1), and every 3 years thereafter, must comply with the requirements in paragraphs (a)(1) and (2) of this section.

(1) You must demonstrate compliance with the leak rate and cracking pressure requirements, specified in item 1(g) of Table 1 to this subpart, for pressure-vacuum vent valves installed on your

gasoline storage tanks using the test methods identified in paragraph (a)(1)(i) or paragraph (a)(1)(ii) of this section.

(i) California Air Resources Board Vapor Recovery Test Procedure TP-201.1E,—Leak Rate and Cracking Pressure of Pressure/Vacuum Vent Valves, adopted October 8, 2003 (incorporated by reference, see §63.14).

(ii) Use alternative test methods and procedures in accordance with the alternative test method requirements in §63.7(f).

(2) You must demonstrate compliance with the static pressure performance requirement specified in item 1(h) of Table 1 to this subpart for your vapor balance system by conducting a static pressure test on your gasoline storage tanks using the test methods identified in paragraphs (a)(2)(i), (a)(2)(ii), or (a)(2)(iii) of this section.

(i) California Air Resources Board Vapor Recovery Test Procedure TP-201.3,—Determination of 2-Inch WC Static Pressure Performance of Vapor Recovery Systems of Dispensing Facilities, adopted April 12, 1996, and amended March 17, 1999 (incorporated by reference, see §63.14).

(ii) Use alternative test methods and procedures in accordance with the alternative test method requirements in §63.7(f).

(iii) Bay Area Air Quality Management District Source Test Procedure ST-30—Static Pressure Integrity Test—Underground Storage Tanks, adopted November 30, 1983, and amended December 21, 1994 (incorporated by reference, *see* §63.14).

(b) Each owner or operator choosing, under the provisions of §63.6(g), to use a vapor balance system other than that described in Table 1 to this subpart must demonstrate to the Administrator or delegated authority under paragraph §63.11131(a) of this subpart, the equivalency of their vapor balance system to that described in Table 1 to this subpart using the procedures specified in paragraphs (b)(1) through (3) of this section.

(1) You must demonstrate initial compliance by conducting an initial performance test on the vapor balance system to demonstrate that the vapor balance system achieves 95 percent reduction using the California Air Resources Board Vapor Recovery Test Procedure TP-201.1,—Volumetric Efficiency for Phase I Vapor Recovery Systems, adopted April 12, 1996, and amended February 1, 2001, and October 8, 2003, (incorporated by reference, see §63.14).

(2) You must, during the initial performance test required under paragraph (b)(1) of this section, determine and document alternative acceptable values for the leak rate and cracking pressure requirements specified in item 1(g) of Table 1 to this subpart and for the static pressure performance requirement in item 1(h) of Table 1 to this subpart.

(3) You must comply with the testing requirements specified in paragraph (a) of this section.

(c) Conduct of performance tests. Performance tests conducted for this subpart shall be conducted under such conditions as the Administrator specifies to the owner or operator based on representative performance (*i.e.,*performance based on normal operating conditions) of the affected source. Upon request, the owner or operator shall make available to the Administrator such records as may be necessary to determine the conditions of performance tests.

(d) Owners and operators of gasoline cargo tanks subject to the provisions of Table 2 to this subpart must conduct annual certification testing according to the vapor tightness testing requirements found in §63.11092(f).

[73 FR 1945, Jan. 10, 2008, as amended at 76 FR 4182, Jan. 24, 2011]

Back to Top

NOTIFICATIONS, RECORDS, AND REPORTS

Back to Top

§63.11124 What notifications must I submit and when?

(a) Each owner or operator subject to the control requirements in §63.11117 must comply with paragraphs (a)(1) through (3) of this section.

(1) You must submit an Initial Notification that you are subject to this subpart by May 9, 2008, or at the time you become subject to the control requirements in §63.11117, unless you meet the requirements in paragraph (a)(3) of this section. If your affected source is subject to the control requirements in §63.11117 only because it loads gasoline into fuel tanks other than those in motor vehicles, as defined in §63.11132, you must submit the Initial Notification by May 24, 2011. The Initial Notification must contain the information specified in paragraphs (a)(1)(i) through (iii) of this section. The notification must be submitted to the applicable EPA Regional Office and delegated State authority as specified in §63.13.

(i) The name and address of the owner and the operator.

(ii) The address (i.e., physical location) of the GDF.

(iii) A statement that the notification is being submitted in response to this subpart and identifying the requirements in paragraphs (a) through (c) of §63.11117 that apply to you.

(2) You must submit a Notification of Compliance Status to the applicable EPA Regional Office and the delegated State authority, as specified in §63.13, within 60 days of the applicable compliance date specified in §63.11113, unless you meet the requirements in paragraph (a)(3) of this section. The Notification of Compliance Status must be signed by a responsible official who must certify its accuracy, must indicate whether the source has complied with the requirements of this subpart, and must indicate whether the facilities' monthly throughput is calculated based on the volume of gasoline loaded into all storage tanks or on the volume of gasoline dispensed from all storage tanks. If your facility is in compliance with the requirements of this subpart at the time the Initial Notification required under paragraph (a)(1) of this section is due, the Notification of Compliance Status may be submitted in lieu of the Initial Notification provided it contains the information required under paragraph (a)(1) of this section.

(3) If, prior to January 10, 2008, you are operating in compliance with an enforceable State, local, or tribal rule or permit that requires submerged fill as specified in §63.11117(b), you are not required to submit an Initial Notification or a Notification of Compliance Status under paragraph (a)(1) or paragraph (a)(2) of this section.

(b) Each owner or operator subject to the control requirements in §63.11118 must comply with paragraphs (b)(1) through (5) of this section.

(1) You must submit an Initial Notification that you are subject to this subpart by May 9, 2008, or at the time you become subject to the control requirements in §63.11118. If your affected source is subject to the control requirements in §63.11118 only because it loads gasoline into fuel tanks other than those in motor vehicles, as defined in §63.11132, you must submit the Initial Notification by May 24, 2011. The Initial Notification must contain the information specified in paragraphs (b)(1)(i) through (iii) of this section. The notification must be submitted to the applicable EPA Regional Office and delegated State authority as specified in §63.13.

(i) The name and address of the owner and the operator.

(ii) The address (i.e., physical location) of the GDF.

(iii) A statement that the notification is being submitted in response to this subpart and identifying the requirements in paragraphs (a) through (c) of §63.11118 that apply to you.

(2) You must submit a Notification of Compliance Status to the applicable EPA Regional Office and the delegated State authority, as specified in §63.13, in accordance with the schedule specified in §63.9(h). The Notification of Compliance Status must be signed by a responsible official who must certify its accuracy, must indicate whether the source has complied with the requirements of this subpart, and must indicate whether the facility's throughput is determined based on the volume of gasoline loaded into all storage tanks or on the volume of gasoline dispensed from all storage tanks. If your facility is in compliance with the requirements of this subpart at the time the Initial Notification required under paragraph (b)(1) of this section is due, the Notification of Compliance Status may be submitted in lieu of the Initial Notification provided it contains the information required under paragraph (b)(1) of this section.

(3) If, prior to January 10, 2008, you satisfy the requirements in both paragraphs (b)(3)(i) and (ii) of this section, you are not required to submit an Initial Notification or a Notification of Compliance Status under paragraph (b)(1) or paragraph (b)(2) of this subsection.

(i) You operate a vapor balance system at your gasoline dispensing facility that meets the requirements of either paragraphs (b)(3)(i)(A) or (b)(3)(i)(B) of this section.

(A) Achieves emissions reduction of at least 90 percent.

(B) Operates using management practices at least as stringent as those in Table 1 to this subpart.

(ii) Your gasoline dispensing facility is in compliance with an enforceable State, local, or tribal rule or permit that contains requirements of either paragraphs (b)(3)(i)(A) or (b)(3)(i)(B) of this section.

(4) You must submit a Notification of Performance Test, as specified in §63.9(e), prior to initiating testing required by §63.11120(a) and (b).

(5) You must submit additional notifications specified in §63.9, as applicable.

[73 FR 1945, Jan. 10, 2008, as amended at 73 FR 12276, Mar. 7, 2008; 76 FR 4182, Jan. 24, 2011]

Back to Top

§63.11125 What are my recordkeeping requirements?

(a) Each owner or operator subject to the management practices in §63.11118 must keep records of all tests performed under §63.11120(a) and (b).

(b) Records required under paragraph (a) of this section shall be kept for a period of 5 years and shall be made available for inspection by the Administrator's delegated representatives during the course of a site visit.

(c) Each owner or operator of a gasoline cargo tank subject to the management practices in Table 2 to this subpart must keep records documenting vapor tightness testing for a period of 5 years. Documentation must include each of the items specified in §63.11094(b)(2)(i) through (viii). Records of vapor tightness testing must be retained as specified in either paragraph (c)(1) or paragraph (c)(2) of this section.

(1) The owner or operator must keep all vapor tightness testing records with the cargo tank.

(2) As an alternative to keeping all records with the cargo tank, the owner or operator may comply with the requirements of paragraphs (c)(2)(i) and (ii) of this section.

(i) The owner or operator may keep records of only the most recent vapor tightness test with the cargo tank, and keep records for the previous 4 years at their office or another central location.

(ii) Vapor tightness testing records that are kept at a location other than with the cargo tank must be instantly available (*e.g.,* via e-mail or facsimile) to the Administrator's delegated representative during the course of a site visit or within a mutually agreeable time frame. Such records must be an exact duplicate image of the original paper copy record with certifying signatures.

(d) Each owner or operator of an affected source under this subpart shall keep records as specified in paragraphs (d)(1) and (2) of this section.

(1) Records of the occurrence and duration of each malfunction of operation (*i.e.,* process equipment) or the air pollution control and monitoring equipment.

(2) Records of actions taken during periods of malfunction to minimize emissions in accordance with §63.11115(a), including corrective actions to restore malfunctioning process and air pollution control and monitoring equipment to its normal or usual manner of operation.

[73 FR 1945, Jan. 10, 2008, as amended at 76 FR 4183, Jan. 24, 2011]

Back to Top

§63.11126 What are my reporting requirements?

(a) Each owner or operator subject to the management practices in §63.11118 shall report to the Administrator the results of all volumetric efficiency tests required under §63.11120(b). Reports submitted under this paragraph must be submitted within 180 days of the completion of the performance testing.

(b) Each owner or operator of an affected source under this subpart shall report, by March 15 of each year, the number, duration, and a brief description of each type of malfunction which occurred during the previous calendar year 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 an owner or operator during a malfunction of an affected source to minimize emissions in accordance with §63.11115(a), including actions taken to correct a malfunction. No report is necessary for a calendar year in which no malfunctions occurred.

[76 FR 4183, Jan. 24, 2011]

Back to Top

OTHER REQUIREMENTS AND INFORMATION

Back to Top

§63.11130 What parts of the General Provisions apply to me?

Table 3 to this subpart shows which parts of the General Provisions apply to you.

Back to Top

§63.11131 Who implements and enforces this subpart?

(a) This subpart can be implemented and enforced by the U.S. EPA or a delegated authority such as the applicable State, local, or tribal agency. If the U.S. EPA Administrator has delegated authority to a State, local, or tribal agency, then that agency, in addition to the U.S. EPA, has the authority to implement and enforce this subpart. Contact the applicable U.S. EPA Regional Office to find out if implementation and enforcement of this subpart is delegated to a State, local, or tribal agency.

(b) In delegating implementation and enforcement authority of this subpart to a State, local, or tribal agency under subpart E of this part, the authorities contained in paragraph (c) of this section are retained by the Administrator of U.S. EPA and cannot be transferred to the State, local, or tribal agency.

(c) The authorities that cannot be delegated to State, local, or tribal agencies are as specified in paragraphs (c)(1) through (3) of this section.

(1) Approval of alternatives to the requirements in §§63.11116 through 63.11118 and 63.11120.

(2) Approval of major alternatives to test methods under §63.7(e)(2)(ii) and (f), as defined in §63.90, and as required in this subpart.

(3) Approval of major alternatives to recordkeeping and reporting under §63.10(f), as defined in §63.90, and as required in this subpart.

Back to Top

§63.11132 What definitions apply to this subpart?

As used in this subpart, all terms not defined herein shall have the meaning given them in the Clean Air Act (CAA), or in subparts A and BBBBBB of this part. For purposes of this subpart, definitions in this section supersede definitions in other parts or subparts.

Dual-point vapor balance system means a type of vapor balance system in which the storage tank is equipped with an entry port for a gasoline fill pipe and a separate exit port for a vapor connection.

Gasoline means any petroleum distillate or petroleum distillate/alcohol blend having a Reid vapor pressure of 27.6 kilopascals or greater, which is used as a fuel for internal combustion engines.

Gasoline cargo tank means a delivery tank truck or railcar which is loading or unloading gasoline, or which has loaded or unloaded gasoline on the immediately previous load.

Gasoline dispensing facility (GDF) means any stationary facility which dispenses gasoline into the fuel tank of a motor vehicle, motor vehicle engine, nonroad vehicle, or nonroad engine, including a nonroad vehicle or nonroad engine used solely for competition. These facilities include, but are not limited to, facilities that dispense gasoline into on- and off-road, street, or highway motor vehicles, lawn equipment, boats, test engines, landscaping equipment, generators, pumps, and other gasoline-fueled engines and equipment.

Monthly throughput means the total volume of gasoline that is loaded into, or dispensed from, all gasoline storage tanks at each GDF during a month. Monthly throughput is calculated by summing the volume of gasoline loaded into, or dispensed from, all gasoline storage tanks at each GDF during the current day, plus the total volume of gasoline loaded into, or dispensed from, all gasoline storage tanks at each GDF during the previous 364 days, and then dividing that sum by 12.

Motor vehicle means any self-propelled vehicle designed for transporting persons or property on a street or highway.

Nonroad engine means an internal combustion engine (including the fuel system) that is not used in a motor vehicle or a vehicle used solely for competition, or that is not subject to standards promulgated under section 7411 of this title or section 7521 of this title.

Nonroad vehicle means a vehicle that is powered by a nonroad engine, and that is not a motor vehicle or a vehicle used solely for competition.

Submerged filling means, for the purposes of this subpart, the filling of a gasoline storage tank through a submerged fill pipe whose discharge is no more than the applicable distance specified in §63.11117(b) from the bottom of the tank. Bottom filling of gasoline storage tanks is included in this definition.

Vapor balance system means a combination of pipes and hoses that create a closed system between the vapor spaces of an unloading gasoline cargo tank and a receiving storage tank such that vapors displaced from the storage tank are transferred to the gasoline cargo tank being unloaded.

Vapor-tight means equipment that allows no loss of vapors. Compliance with vapor-tight requirements can be determined by checking to ensure that the concentration at a potential leak source is not equal to or greater than 100 percent of the Lower Explosive Limit when measured with a combustible gas detector, calibrated with propane, at a distance of 1 inch from the source.

Vapor-tight gasoline cargo tank means a gasoline cargo tank which has demonstrated within the 12 preceding months that it meets the annual certification test requirements in §63.11092(f) of this part.

[73 FR 1945, Jan. 10, 2008, as amended at 76 FR 4183, Jan. 24, 2011]

Back to Top

Table 1 to Subpart CCCCCC of Part 63—Applicability Criteria and Management Practices for Gasoline Dispensing Facilities With Monthly Throughput of 100,000 Gallons of Gasoline or More[1]

If you own or operate	Then you must
1. A new, reconstructed, or existing GDF subject to §63.11118	Install and operate a vapor balance system on your gasoline storage tanks that meets the design criteria in paragraphs (a) through (h).

	(a) All vapor connections and lines on the storage tank shall be equipped with closures that seal upon disconnect.
	(b) The vapor line from the gasoline storage tank to the gasoline cargo tank shall be vapor-tight, as defined in §63.11132.
	(c) The vapor balance system shall be designed such that the pressure in the tank truck does not exceed 18 inches water pressure or 5.9 inches water vacuum during product transfer.
	(d) The vapor recovery and product adaptors, and the method of connection with the delivery elbow, shall be designed so as to prevent the over-tightening or loosening of fittings during normal delivery operations.
	(e) If a gauge well separate from the fill tube is used, it shall be provided with a submerged drop tube that extends the same distance from the bottom of the storage tank as specified in §63.11117(b).
	(f) Liquid fill connections for all systems shall be equipped with vapor-tight caps.
	(g) Pressure/vacuum (PV) vent valves shall be installed on the storage tank vent pipes. The pressure specifications for PV vent valves shall be: a positive pressure setting of 2.5 to 6.0 inches of water and a negative pressure setting of 6.0 to 10.0 inches of water. The total leak rate of all PV vent valves at an affected facility, including connections, shall not exceed 0.17 cubic foot per hour at a pressure of 2.0 inches of water and 0.63 cubic foot per hour at a vacuum of 4 inches of water.
	(h) The vapor balance system shall be capable of meeting the static pressure performance requirement of the following equation:
	$Pf = 2e^{-500.887/v}$
	Where:
	Pf = Minimum allowable final pressure, inches of water.
	v = Total ullage affected by the test, gallons.
	e = Dimensionless constant equal to approximately 2.718.
	2 = The initial pressure, inches water.
2. A new or reconstructed GDF, or any storage tank(s) constructed after November 9,	Equip your gasoline storage tanks with a dual-point vapor balance system, as defined in §63.11132, and comply with the requirements of item 1 in this Table.

2006, at an existing affected facility subject to §63.11118	

[1]The management practices specified in this Table are not applicable if you are complying with the requirements in §63.11118(b)(2), except that if you are complying with the requirements in §63.11118(b)(2)(i)(B), you must operate using management practices at least as stringent as those listed in this Table.

[73 FR 1945, Jan. 10, 2008, as amended at 73 FR 35944, June 25, 2008; 76 FR 4184, Jan. 24, 2011]

Back to Top

Table 2 to Subpart CCCCCC of Part 63—Applicability Criteria and Management Practices for Gasoline Cargo Tanks Unloading at Gasoline Dispensing Facilities With Monthly Throughput of 100,000 Gallons of Gasoline or More

If you own or operate	Then you must
A gasoline cargo tank	Not unload gasoline into a storage tank at a GDF subject to the control requirements in this subpart unless the following conditions are met:
	(i) All hoses in the vapor balance system are properly connected,
	(ii) The adapters or couplers that attach to the vapor line on the storage tank have closures that seal upon disconnect,
	(iii) All vapor return hoses, couplers, and adapters used in the gasoline delivery are vapor-tight,
	(iv) All tank truck vapor return equipment is compatible in size and forms a vapor-tight connection with the vapor balance equipment on the GDF storage tank, and
	(v) All hatches on the tank truck are closed and securely fastened.
	(vi) The filling of storage tanks at GDF shall be limited to unloading from vapor-tight gasoline cargo tanks. Documentation that the cargo tank has met the specifications of EPA Method 27 shall be carried with the cargo tank, as specified in §63.11125(c).

[73 FR 1945, Jan. 10, 2008, as amended at 76 FR 4184, Jan. 24, 2011]

Back to Top

Table 3 to Subpart CCCCCC of Part 63—Applicability of General Provisions

Citation	Subject	Brief description	Applies to subpart CCCCCC
§63.1	Applicability	Initial applicability determination; applicability after standard established;	Yes, specific requirements given in §63.11111.

		permit requirements; extensions, notifications	
§63.1(c)(2)	Title V Permit	Requirements for obtaining a title V permit from the applicable permitting authority	Yes, §63.11111(f) of subpart CCCCCC exempts identified area sources from the obligation to obtain title V operating permits.
§63.2	Definitions	Definitions for part 63 standards	Yes, additional definitions in §63.11132.
§63.3	Units and Abbreviations	Units and abbreviations for part 63 standards	Yes.
§63.4	Prohibited Activities and Circumvention	Prohibited activities; Circumvention, severability	Yes.
§63.5	Construction/Reconstruction	Applicability; applications; approvals	Yes, except that these notifications are not required for facilities subject to §63.11116
§63.6(a)	Compliance with Standards/Operation & Maintenance—Applicability	General Provisions apply unless compliance extension; General Provisions apply to area sources that become major	Yes.
§63.6(b)(1)-(4)	Compliance Dates for New and Reconstructed Sources	Standards apply at effective date; 3 years after effective date; upon startup; 10 years after construction or reconstruction commences for CAA section 112(f)	Yes.
§63.6(b)(5)	Notification	Must notify if commenced construction or reconstruction after proposal	Yes.
§63.6(b)(6)	[Reserved]		
§63.6(b)(7)	Compliance Dates for New and Reconstructed Area Sources That Become Major	Area sources that become major must comply with major source standards	No.

		immediately upon becoming major, regardless of whether required to comply when they were an area source	
§63.6(c)(1)-(2)	Compliance Dates for Existing Sources	Comply according to date in this subpart, which must be no later than 3 years after effective date; for CAA section 112(f) standards, comply within 90 days of effective date unless compliance extension	No, §63.11113 specifies the compliance dates.
§63.6(c)(3)-(4)	[Reserved]		
§63.6(c)(5)	Compliance Dates for Existing Area Sources That Become Major	Area sources That become major must comply with major source standards by date indicated in this subpart or by equivalent time period (e.g., 3 years)	No.
§63.6(d)	[Reserved]		
63.6(e)(1)(i)	General duty to minimize emissions	Operate to minimize emissions at all times; information Administrator will use to determine if operation and maintenance requirements were met.	No. *See*§63.11115 for general duty requirement.
63.6(e)(1)(ii)	Requirement to correct malfunctions ASAP	Owner or operator must correct malfunctions as soon as possible.	No.
§63.6(e)(2)	[Reserved]		
§63.6(e)(3)	Startup, Shutdown, and Malfunction (SSM) Plan	Requirement for SSM plan; content of SSM plan; actions during SSM	No.
§63.6(f)(1)	Compliance Except During SSM	You must comply with emission standards at all times except during SSM	No.
§63.6(f)(2)-(3)	Methods for Determining Compliance	Compliance based on performance test, operation and maintenance plans,	Yes.

		records, inspection	
§63.6(g)(1)-(3)	Alternative Standard	Procedures for getting an alternative standard	Yes.
§63.6(h)(1)	Compliance with Opacity/Visible Emission (VE) Standards	You must comply with opacity/VE standards at all times except during SSM	No.
§63.6(h)(2)(i)	Determining Compliance with Opacity/VE Standards	If standard does not State test method, use EPA Method 9 for opacity in appendix A of part 60 of this chapter and EPA Method 22 for VE in appendix A of part 60 of this chapter	No.
§63.6(h)(2)(ii)	[Reserved]		
§63.6(h)(2)(iii)	Using Previous Tests To Demonstrate Compliance With Opacity/VE Standards	Criteria for when previous opacity/VE testing can be used to show compliance with this subpart	No.
§63.6(h)(3)	[Reserved]		
§63.6(h)(4)	Notification of Opacity/VE Observation Date	Must notify Administrator of anticipated date of observation	No.
§63.6(h)(5)(i), (iii)-(v)	Conducting Opacity/VE Observations	Dates and schedule for conducting opacity/VE observations	No.
§63.6(h)(5)(ii)	Opacity Test Duration and Averaging Times	Must have at least 3 hours of observation with 30 6-minute averages	No.
§63.6(h)(6)	Records of Conditions During Opacity/VE Observations	Must keep records available and allow Administrator to inspect	No.
§63.6(h)(7)(i)	Report Continuous Opacity Monitoring System (COMS) Monitoring Data From Performance Test	Must submit COMS data with other performance test data	No.
§63.6(h)(7)(ii)	Using COMS Instead of EPA Method 9	Can submit COMS data instead of EPA Method 9 results even if rule requires	No.

		EPA Method 9 in appendix A of part 60 of this chapter, but must notify Administrator before performance test	
§63.6(h)(7)(iii)	Averaging Time for COMS During Performance Test	To determine compliance, must reduce COMS data to 6-minute averages	No.
§63.6(h)(7)(iv)	COMS Requirements	Owner/operator must demonstrate that COMS performance evaluations are conducted according to §63.8(e); COMS are properly maintained and operated according to §63.8(c) and data quality as §63.8(d)	No.
§63.6(h)(7)(v)	Determining Compliance with Opacity/VE Standards	COMS is probable but not conclusive evidence of compliance with opacity standard, even if EPA Method 9 observation shows otherwise. Requirements for COMS to be probable evidence-proper maintenance, meeting Performance Specification 1 in appendix B of part 60 of this chapter, and data have not been altered	No.
§63.6(h)(8)	Determining Compliance with Opacity/VE Standards	Administrator will use all COMS, EPA Method 9 (in appendix A of part 60 of this chapter), and EPA Method 22 (in appendix A of part 60 of this chapter) results, as well as information about operation and maintenance to determine compliance	No.
§63.6(h)(9)	Adjusted Opacity Standard	Procedures for Administrator to adjust an	No.

		opacity standard	
§63.6(i)(1)-(14)	Compliance Extension	Procedures and criteria for Administrator to grant compliance extension	Yes.
§63.6(j)	Presidential Compliance Exemption	President may exempt any source from requirement to comply with this subpart	Yes.
§63.7(a)(2)	Performance Test Dates	Dates for conducting initial performance testing; must conduct 180 days after compliance date	Yes.
§63.7(a)(3)	CAA Section 114 Authority	Administrator may require a performance test under CAA section 114 at any time	Yes.
§63.7(b)(1)	Notification of Performance Test	Must notify Administrator 60 days before the test	Yes.
§63.7(b)(2)	Notification of Re-scheduling	If have to reschedule performance test, must notify Administrator of rescheduled date as soon as practicable and without delay	Yes.
§63.7(c)	Quality Assurance (QA)/Test Plan	Requirement to submit site-specific test plan 60 days before the test or on date Administrator agrees with; test plan approval procedures; performance audit requirements; internal and external QA procedures for testing	Yes.
§63.7(d)	Testing Facilities	Requirements for testing facilities	Yes.
63.7(e)(1)	Conditions for Conducting Performance Tests	Performance test must be conducted under representative conditions	No, §63.11120(c) specifies conditions for conducting performance tests.
§63.7(e)(2)	Conditions for Conducting Performance Tests	Must conduct according to this subpart and EPA test	Yes.

		methods unless Administrator approves alternative	
§63.7(e)(3)	Test Run Duration	Must have three test runs of at least 1 hour each; compliance is based on arithmetic mean of three runs; conditions when data from an additional test run can be used	Yes.
§63.7(f)	Alternative Test Method	Procedures by which Administrator can grant approval to use an intermediate or major change, or alternative to a test method	Yes.
§63.7(g)	Performance Test Data Analysis	Must include raw data in performance test report; must submit performance test data 60 days after end of test with the Notification of Compliance Status; keep data for 5 years	Yes.
§63.7(h)	Waiver of Tests	Procedures for Administrator to waive performance test	Yes.
§63.8(a)(1)	Applicability of Monitoring Requirements	Subject to all monitoring requirements in standard	Yes.
§63.8(a)(2)	Performance Specifications	Performance Specifications in appendix B of 40 CFR part 60 apply	Yes.
§63.8(a)(3)	[Reserved]		
§63.8(a)(4)	Monitoring of Flares	Monitoring requirements for flares in §63.11 apply	Yes.
§63.8(b)(1)	Monitoring	Must conduct monitoring according to standard unless Administrator approves alternative	Yes.
§63.8(b)(2)-(3)	Multiple Effluents and Multiple Monitoring	Specific requirements for installing monitoring	No.

	Systems	systems; must install on each affected source or after combined with another affected source before it is released to the atmosphere provided the monitoring is sufficient to demonstrate compliance with the standard; if more than one monitoring system on an emission point, must report all monitoring system results, unless one monitoring system is a backup	
§63.8(c)(1)	Monitoring System Operation and Maintenance	Maintain monitoring system in a manner consistent with good air pollution control practices	No.
§63.8(c)(1)(i)-(iii)	Operation and Maintenance of Continuous Monitoring Systems (CMS)	Must maintain and operate each CMS as specified in §63.6(e)(1); must keep parts for routine repairs readily available; must develop a written SSM plan for CMS, as specified in §63.6(e)(3)	No.
§63.8(c)(2)-(8)	CMS Requirements	Must install to get representative emission or parameter measurements; must verify operational status before or at performance test	No.
§63.8(d)	CMS Quality Control	Requirements for CMS quality control, including calibration, etc.; must keep quality control plan on record for 5 years; keep old versions for 5 years after revisions	No.
§63.8(e)	CMS Performance Evaluation	Notification, performance evaluation test plan, reports	No.
§63.8(f)(1)-(5)	Alternative Monitoring Method	Procedures for Administrator to approve	No.

		alternative monitoring	
§63.8(f)(6)	Alternative to Relative Accuracy Test	Procedures for Administrator to approve alternative relative accuracy tests for continuous emissions monitoring system (CEMS)	No.
§63.8(g)	Data Reduction	COMS 6-minute averages calculated over at least 36 evenly spaced data points; CEMS 1 hour averages computed over at least 4 equally spaced data points; data that cannot be used in average	No.
§63.9(a)	Notification Requirements	Applicability and State delegation	Yes.
§63.9(b)(1)-(2), (4)-(5)	Initial Notifications	Submit notification within 120 days after effective date; notification of intent to construct/reconstruct, notification of commencement of construction/reconstruction, notification of startup; contents of each	Yes.
§63.9(c)	Request for Compliance Extension	Can request if cannot comply by date or if installed best available control technology or lowest achievable emission rate	Yes.
§63.9(d)	Notification of Special Compliance Requirements for New Sources	For sources that commence construction between proposal and promulgation and want to comply 3 years after effective date	Yes.
§63.9(e)	Notification of Performance Test	Notify Administrator 60 days prior	Yes.
§63.9(f)	Notification of VE/Opacity Test	Notify Administrator 30 days prior	No.

§63.9(g)	Additional Notifications when Using CMS	Notification of performance evaluation; notification about use of COMS data; notification that exceeded criterion for relative accuracy alternative	Yes, however, there are no opacity standards.
§63.9(h)(1)-(6)	Notification of Compliance Status	Contents due 60 days after end of performance test or other compliance demonstration, except for opacity/VE, which are due 30 days after; when to submit to Federal vs. State authority	Yes, however, there are no opacity standards.
§63.9(i)	Adjustment of Submittal Deadlines	Procedures for Administrator to approve change when notifications must be submitted	Yes.
§63.9(j)	Change in Previous Information	Must submit within 15 days after the change	Yes.
§63.10(a)	Recordkeeping/Reporting	Applies to all, unless compliance extension; when to submit to Federal vs. State authority; procedures for owners of more than one source	Yes.
§63.10(b)(1)	Recordkeeping/Reporting	General requirements; keep all records readily available; keep for 5 years	Yes.
§63.10(b)(2)(i)	Records related to SSM	Recordkeeping of occurrence and duration of startups and shutdowns	No.
§63.10(b)(2)(ii)	Records related to SSM	Recordkeeping of malfunctions	No. *See*§63.11125(d) for recordkeeping of (1) occurrence and duration and (2) actions taken during malfunction.
§63.10(b)(2)(iii)	Maintenance records	Recordkeeping of maintenance on air pollution control and monitoring equipment	Yes.

§63.10(b)(2)(iv)	Records Related to SSM	Actions taken to minimize emissions during SSM	No.
§63.10(b)(2)(v)	Records Related to SSM	Actions taken to minimize emissions during SSM	No.
§63.10(b)(2)(vi)-(xi)	CMS Records	Malfunctions, inoperative, out-of-control periods	No.
§63.10(b)(2)(xii)	Records	Records when under waiver	Yes.
§63.10(b)(2)(xiii)	Records	Records when using alternative to relative accuracy test	Yes.
§63.10(b)(2)(xiv)	Records	All documentation supporting Initial Notification and Notification of Compliance Status	Yes.
§63.10(b)(3)	Records	Applicability determinations	Yes.
§63.10(c)	Records	Additional records for CMS	No.
§63.10(d)(1)	General Reporting Requirements	Requirement to report	Yes.
§63.10(d)(2)	Report of Performance Test Results	When to submit to Federal or State authority	Yes.
§63.10(d)(3)	Reporting Opacity or VE Observations	What to report and when	No.
§63.10(d)(4)	Progress Reports	Must submit progress reports on schedule if under compliance extension	Yes.
§63.10(d)(5)	SSM Reports	Contents and submission	No. *See*§63.11126(b) for malfunction reporting requirements.
§63.10(e)(1)-(2)	Additional CMS Reports	Must report results for each CEMS on a unit; written copy of CMS performance evaluation; two-three copies of COMS performance evaluation	No.
§63.10(e)(3)(i)-	Reports	Schedule for reporting	No.

(iii)		excess emissions	
§63.10(e)(3)(iv)-(v)	Excess Emissions Reports	Requirement to revert to quarterly submission if there is an excess emissions and parameter monitor exceedances (now defined as deviations); provision to request semiannual reporting after compliance for 1 year; submit report by 30th day following end of quarter or calendar half; if there has not been an exceedance or excess emissions (now defined as deviations), report contents in a statement that there have been no deviations; must submit report containing all of the information in §§63.8(c)(7)-(8) and 63.10(c)(5)-(13)	No.
§63.10(e)(3)(iv)-(v)	Excess Emissions Reports	Requirement to revert to quarterly submission if there is an excess emissions and parameter monitor exceedances (now defined as deviations); provision to request semiannual reporting after compliance for 1 year; submit report by 30th day following end of quarter or calendar half; if there has not been an exceedance or excess emissions (now defined as deviations), report contents in a statement that there have been no deviations; must submit report containing all of the information in §§63.8(c)(7)-(8) and 63.10(c)(5)-(13)	No, §63.11130(K) specifies excess emission events for this subpart.
§63.10(e)(3)(vi)-	Excess Emissions Report	Requirements for reporting	No.

(viii)	and Summary Report	excess emissions for CMS; requires all of the information in §§63.10(c)(5)-(13) and 63.8(c)(7)-(8)	
§63.10(e)(4)	Reporting COMS Data	Must submit COMS data with performance test data	No.
§63.10(f)	Waiver for Recordkeeping/Reporting	Procedures for Administrator to waive	Yes.
§63.11(b)	Flares	Requirements for flares	No.
§63.12	Delegation	State authority to enforce standards	Yes.
§63.13	Addresses	Addresses where reports, notifications, and requests are sent	Yes.
§63.14	Incorporations by Reference	Test methods incorporated by reference	Yes.
§63.15	Availability of Information	Public and confidential information	Yes.

[73 FR 1945, Jan. 10, 2008, as amended at 76 FR 4184, Jan. 24, 2011]

Appendix H

40 C.F.R. Part 63 Subpart DDDDD

National Emissions Standards for Hazardous Air Pollutants for Major Sources: Industrial, Commercial, and Institutional Boilers and Process Heaters

Title 40: Protection of Environment
PART 63—NATIONAL EMISSION STANDARDS FOR HAZARDOUS AIR POLLUTANTS FOR SOURCE CATEGORIES (CONTINUED)

Subpart DDDDD—National Emission Standards for Hazardous Air Pollutants for Major Sources: Industrial, Commercial, and Institutional Boilers and Process Heaters

Contents

CONTINUOUS COMPLIANCE REQUIREMENTS

NOTIFICATION, REPORTS, AND RECORDS

OTHER REQUIREMENTS AND INFORMATION

SOURCE: 76 FR 15664, Mar. 21, 2011, unless otherwise noted.

Back to Top

WHAT THIS SUBPART COVERS

Back to Top

§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.

Back to Top

§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]

Back to Top

§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]

Back to Top

§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 or a natural gas-fired EGU as defined in subpart UUUUU of this part firing at least 85 percent natural gas on an annual heat input basis.

(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 and process heaters as defined in this subpart.

(k) Blast furnace gas fuel-fired boilers and process heaters as defined in this subpart.

(l) Any boiler or process heater 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.

(n) Residential boilers as defined in this subpart.

[76 FR 15664, Mar. 21, 2011, as amended at 78 FR 7162, Jan. 31, 2013; 80 FR 72806, Nov. 20, 2015]

Back to Top

§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 April 1, 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 and are no longer subject to part 60, subparts CCCC or DDDD beginning on the effective date of the switch as identified under the provisions of §60.2145(a)(2) and (3) or §60.2710(a)(2) and (3).

(f) If you own or operate an existing EGU that becomes subject to this subpart after January 31, 2016, 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.

(h) If you own or operate an existing industrial, commercial, or institutional boiler or process heater and have switched fuels or made a physical change to the boiler or process heater that resulted in the applicability of a different subcategory after the compliance date of this subpart, you must be in compliance with the applicable existing source provisions of this subpart on the effective date of the fuel switch or physical change.

(i) If you own or operate a new industrial, commercial, or institutional boiler or process heater and have switched fuels or made a physical change to the boiler or process heater that resulted in the applicability of a different subcategory, you must be in compliance with the applicable new source provisions of this subpart on the effective date of the fuel switch or physical change.

[76 FR 15664, Mar. 21, 2011, as amended at 78 FR 7162, Jan. 31, 2013; 80 FR 72807, Nov. 20, 2015]

Back to Top

EMISSION LIMITATIONS AND WORK PRACTICE STANDARDS

Back to Top

§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]

Back to Top

§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.

(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 either steam, cogenerate steam with electricity, or both. 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 only electricity. Boilers that perform multiple functions (cogeneration and electricity generation) or supply steam to common headers would calculate a total steam energy output using equation 21 of §63.7575 to demonstrate compliance with the output-based emission limits, in units of pounds per million Btu of steam output, in Tables 1 or 2 to this subpart. 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 (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 on or 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 on or after December 23, 2011 and before April 1, 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 items 5 and 6 of Table 3 to this subpart.

[76 FR 15664, Mar. 21, 2011, as amended at 78 FR 7163, Jan. 31, 2013; 80 FR 72807, Nov. 20, 2015]

Back to Top

§63.7501 [Reserved]

Back to Top

GENERAL COMPLIANCE REQUIREMENTS

Back to Top

§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 emission and operating 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), 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 stack 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 through 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.

(e) If you have an applicable emission limit, and you choose to comply using definition (2) of “startup” in §63.7575, you must develop and implement a written startup and shutdown plan (SSP) according to the requirements in Table 3 to this subpart. The SSP must be maintained onsite and available upon request for public inspection.

[76 FR 15664, Mar. 21, 2011, as amended at 78 FR 7164, Jan. 31, 2013; 80 FR 72807, Nov. 20, 2015]

Back to Top

Testing, Fuel Analyses, and Initial Compliance Requirements

Back to Top

§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 (stack) 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 Gas 1 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 non-Gas 1 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 non-Gas 1 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 1, 2, 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 demonstrations, 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.

(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 §63.7515(d) 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 §63.7515(d).

(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, 2016, 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.

(k) For affected sources, as defined in §63.7490, that switch subcategories consistent with §63.7545(h) after the initial compliance date, you must demonstrate compliance within 60 days of the effective date of the switch, unless you had previously conducted your compliance demonstration for this subcategory within the previous 12 months.

[78 FR 7164, Jan. 31, 2013, as amended at 80 FR 72808, Nov. 20, 2015]

Back to Top

§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 April 1, 2013 or the initial startup of the new or reconstructed affected source, whichever is later.

(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. If sampling is conducted on one day per month, samples should be no less than 14 days apart, but if multiple samples are taken per month, the 14-day restriction does not apply.

(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 (stack tests or fuel analyses) 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, as amended at 80 FR 72808, Nov. 20, 2015]

Back to Top

§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]

Back to Top

§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.

(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) You must obtain 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. At a minimum, for demonstrating initial compliance by fuel analysis, you must obtain three composite samples. For monthly fuel analyses, at a minimum, you must obtain a single composite sample. For fuel analyses as part of a performance stack test, as specified in §63.7510(a), you must obtain a composite fuel sample during each performance test run.

(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.

(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, or as an alternative where fuel specification analysis is not practical, you must measure mercury concentration in the exhaust gas when firing only the gaseous fuel to be demonstrated as an other gas 1 fuel in the boiler or process heater according to the procedures in Table 6 to this subpart.

(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 a site-specific fuel analysis plan for other gas 1 fuels 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 identification 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. When using a fuel supplier's fuel analysis, the owner or operator is not required to submit the information in §63.7521(g)(2)(iii).

(h) You must obtain a single fuel sample for each fuel type 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, as amended at 80 FR 72808, Nov. 20, 2015]

Back to Top

§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 April 1, 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 April 1, 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 subject to numeric emission limits 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.

$$AveWeightedEmissions = 1.1 \times \sum_{i=1}^{n}(Er \times Hm) \div \sum_{i=1}^{n} Hm \qquad \text{(Eq.1a)}$$

View or download PDF

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.

$$AveWeightedEmissions = 1.1 \times \sum_{i=1}^{n}(Er \times So) \div \sum_{i=1}^{n} So \qquad \text{(Eq.1b)}$$

View or download PDF

Where:

AveWeightedEmissions = 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.

$$AveWeightedEmissions = 1.1 \times \sum_{i=1}^{n}(Er \times Eo) \div \sum_{i=1}^{n} Eo \quad \text{(Eq.1c)}$$

View or download PDF

Where:

AveWeightedEmissions = 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.

$$AveWeightedEmissions = 1.1 \times \sum_{i=1}^{n}(Er \times Sm \times Cfi) \div \sum_{i=1}^{n}(Sm \times Cfi) \quad \text{(Eq. 2)}$$

View or download PDF

Where:

AveWeightedEmissions = 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 electrical generation for the month if you are complying with the emission limits on an electrical generation (output) basis.

$$AveWeightedEmissions = 1.1 \times \sum_{i=1}^{n} (Er \times Hb) \div \sum_{i=1}^{n} Hb \qquad \text{(Eq. 3a)}$$

View or download PDF

Where:

AveWeightedEmissions = 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.

$$AveWeightedEmissions = 1.1 \times \sum_{i=1}^{n} (Er \times So) \div \sum_{i=1}^{n} So \qquad \text{(Eq. 3b)}$$

View or download PDF

Where:

AveWeightedEmissions = 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.

$$AveWeightedEmissions = 1.1 \times \sum_{i=1}^{n} (Er \times Eo) \div \sum_{i=1}^{n} Eo \qquad \text{(Eq. 3c)}$$

View or download PDF

Where:

AveWeightedEmissions = 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.

$$AveWeightedEmissions = 1.1 \times \sum_{i=1}^{n}(Er \times Sa \times Cfi) \div \sum_{i=1}^{n}(Sa \times Cfi) \quad \text{(Eq. 4)}$$

View or download PDF

Where:

AveWeightedEmissions = 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.

$$Eavg = \sum_{i=1}^{n} ERi \div 12 \quad \text{(Eq. 5)}$$

View or download PDF

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) If requested, 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) If submitted upon request, 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 subcategory, 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.

$$En = \sum_{i=1}^{n}(ELi \times Hi) \div \sum_{i=1}^{n} Hi \qquad \text{(Eq. 6)}$$

View or download PDF

Where:

En = HAP emission limit, pounds per million British thermal units (lb/MMBtu) or parts per million (ppm).

Eli = Appropriate emission limit from Table 2 to this subpart for unit i, in units of lb/MMBtu or ppm.

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; 80 FR 72809, Nov. 20, 2015]

Back to Top

§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 (or carbon dioxide (CO_2)) according to the procedures in paragraphs (a)(1) through (6) of this section.

(1) Install the CO CEMS and oxygen (or CO_2) analyzer by the compliance date specified in §63.7495. The CO and oxygen (or CO_2) levels shall be monitored at the same location at the outlet of the boiler or process heater. An owner or operator may request an alternative test method under §63.7 of this chapter, in order that compliance with the CO emissions limit be determined using CO_2 as a diluent correction in place of oxygen at 3 percent. EPA Method 19 F-factors and EPA Method 19 equations must be used to generate the appropriate CO_2 correction percentage for the fuel type burned in the unit, and must also take into account that the 3 percent oxygen correction is to be done on a dry basis. The alternative test method request must account for any CO_2 being added to, or removed from, the emissions gas stream as a result of limestone injection, scrubber media, etc.

(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; part 75 of this chapter (if an CO_2 analyzer is used); 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.

(vi) When CO_2 is used to correct CO emissions and CO_2 is measured on a wet basis, correct for moisture as follows: Install, operate, maintain, and quality assure a continuous moisture monitoring system for measuring and recording the moisture content of the flue gases, in order to correct the measured hourly volumetric flow rates for moisture when calculating CO concentrations. The following continuous moisture monitoring systems are acceptable: A continuous moisture sensor; an oxygen analyzer (or analyzers) capable of measuring O_2 both on a wet basis and on a dry basis; or a stack temperature sensor and a moisture look-up table, *i.e.,* a psychrometric chart (for saturated gas streams following wet scrubbers or other demonstrably saturated gas streams, only). The moisture monitoring system shall include as a component the automated data acquisition and handling system (DAHS) for recording and reporting both the raw data (*e.g.,* hourly average wet-and dry basis O_2 values) and the hourly average values of the stack gas moisture content derived from those data. When a moisture look-up table is used, the moisture monitoring system shall be represented as a single component, the certified DAHS, in the monitoring plan for the unit or common stack.

(3) Complete a minimum of one cycle of CO and oxygen (or CO_2) CEMS operation (sampling, analyzing, and data recording) for each successive 15-minute period. Collect CO and oxygen (or CO_2) data concurrently. Collect at least four CO and oxygen (or CO_2) 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 (or corrected to an CO_2 percentage determined to be equivalent 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, 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, and 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, 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 have a documented detection limit of 0.5 milligram per actual cubic meter, or less.

(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) Calibrate the pH monitoring system in accordance with your monitoring plan and according to the manufacturer's instructions. Clean the pH probe at least once each process operating day. Maintain on-site documentation that your calibration frequency is sufficient to maintain the specified accuracy of your device.

(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 annually.

(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 elect to use an SO_2 CEMS to demonstrate continuous compliance with the HCl emission limit, 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 either part 60 or 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 either the applicable daily and quarterly requirements in Procedure 1 of appendix F of part 60 or 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; 80 FR 72810, Nov. 20, 2015]

Back to Top

§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). 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 stack 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.

$$Clinput = \sum_{i=1}^{n} (Ci \times Qi) \quad \text{(Eq. 7)}$$

View or download PDF

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 during the initial compliance test. 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. For continuous compliance demonstration, the actual fraction of the fuel burned during the month should be used.

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.

$$Mercuryinput = \sum_{i=1}^{n} (HGi \times Qi) \quad \text{(Eq. 8)}$$

View or download PDF

Where:

Mercuryinput = 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 during the initial compliance test. 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. For continuous compliance demonstration, the actual fraction of the fuel burned during the month should be used.

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.

$$TSMinput = \sum_{i=1}^{n} (TSMi \times Qi) \quad \text{(Eq. 9)}$$

View or download PDF

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 during the initial compliance test. 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. For continuous compliance demonstration, the actual fraction of the fuel burned during the month should be used.

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.

$$\bar{x} = \frac{1}{n}\sum_{i=1}^{n} X_1, \bar{y} = \frac{1}{n}\sum_{i=1}^{n} Y_1 \qquad \text{(Eq. 10)}$$

View or download PDF

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.

$$R = \frac{Y_1}{(X_1 - z)} \qquad \text{(Eq. 11)}$$

View or download PDF

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.

$$O_l = z + \frac{0.75(L)}{R} \qquad \text{(Eq. 12)}$$

View or download PDF

Where:

O_l = the operating limit for your PM CPMS on a 30-day rolling average, in milliamps.

L = your source 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.

$$O_h = \frac{1}{n}\sum_{i=1}^{n} X_1 \qquad \text{(Eq. 13)}$$

View or download PDF

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.

$$30-\text{day} = \frac{\sum_{i=1}^{n} Hpvi}{n} \qquad \text{(Eq. 14)}$$

View or download PDF

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 30 operating days.

(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.

(iv) 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.)

(v) 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.

(vi) 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.

(vii) 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.

(viii) 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.

(ix) 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.

$$P90 = mean + (SD \times t) \quad \text{(Eq. 15)}$$

View or download PDF

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.

$$HCl = \sum_{i=1}^{n} (Ci90 \times Qi \times 1.028) \quad \text{(Eq. 16)}$$

View or download PDF

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 15 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. For continuous compliance demonstration, the actual fraction of the fuel burned during the month should be used.

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.

$$Mercury = \sum_{i=1}^{n} (Hgi90 \times Qi) \quad \text{(Eq. 17)}$$

View or download PDF

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 15 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. For continuous compliance demonstration, the actual fraction of the fuel burned during the month should be used.

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.

$$Metals = \sum_{i=1}^{n} (TSM90i \times Qi) \quad \text{(Eq. 18)}$$

View or download PDF

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 15 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. For continuous compliance demonstration, the actual fraction of the fuel burned during the month should be used.

n = Number of different fuel types burned in your boiler or process heater for the mixture that has the highest TSM content.

(d)[Reserved]

(e) You must include with the Notification of Compliance Status a signed certification that either the energy assessment was completed according to Table 3 to this subpart, and that the assessment is an accurate depiction of your facility at the time of the assessment, or that the maximum number of on-site technical hours specified in the definition of energy assessment applicable to the facility has been expended.

(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 items 5 and 6 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 maximum 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 HCl performance test.

[76 FR 15664, Mar. 21, 2011, as amended at 78 FR 7174, Jan. 31, 2013; 80 FR 72811, Nov. 20, 2015]

Back to Top

§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:

$$ECredits = \left(\sum_{i=1}^{n} EIS_{iactual}\right) \div EI_{baseline} \quad \text{(Eq. 19)}$$

View or download PDF

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 subject to numeric emission limits, 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.

$$E_{adj} = E_m \times (1 - ECredits) \quad \text{(Eq. 20)}$$

View or download PDF

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; 80 FR 72812, Nov. 20, 2015]

Back to Top

Continuous Compliance Requirements

Back to Top

§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 periods of startup and shutdown, 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 of startup and shutdown, 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 semi-annual report.

[76 FR 15664, Mar. 21, 2011, as amended at 78 FR 7179, Jan. 31, 2013; 80 FR 72812, Nov. 20, 2015]

Back to Top

§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 §63.7555(d), 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) Equal to or lower emissions of HCl, mercury, and TSM than the applicable emission limit for each pollutant, if you demonstrate compliance through fuel analysis.

(ii) Equal to or 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 16 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 16 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 17 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 17 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 subject to numeric emission limits.

(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. You must conduct the tune-up while burning the type of fuel (or fuels in case of units that routinely burn a mixture) that provided the majority of the heat input to the boiler or process heater over the 12 months prior to the tune-up. 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 perform the burner inspection any time prior to the tune-up or 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, a 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. If an oxygen trim system is utilized on a unit without emission standards to reduce the tune-up frequency to once every 5 years, set the oxygen level no lower than the oxygen concentration measured during the most recent tune-up.

(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 30 operating days if you specified a 30 operating day basis in §63.7545(e)(2)(iii) for mercury CEMS or it must be 720 hours if you specified a 720 hour basis in §63.7545(e)(2)(iii) for mercury CEMS. 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 30 operating days if you specified a 30 operating day basis in §63.7545(e)(2)(iii) for HCl CEMS or it must be 720 hours if you specified a 720 hour basis in §63.7545(e)(2)(iii) for HCl CEMS. 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 18 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 18 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.

(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 (v) 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 items 5 and 6 of Table 3 of this subpart.

[78 FR 7179, Jan. 31, 2013, as amended at 80 FR 72813, Nov. 20, 2015]

Back to Top

§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]

Back to Top

NOTIFICATION, REPORTS, AND RECORDS

Back to Top

§63.7545   What notifications must I submit and when?

Link to an amendment published at 85 FR 73913, Nov. 19, 2020.

(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) of this section, 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) of this section and must be submitted within 60 days of the compliance date specified at §63.7495(b).

(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,

(iii) Identification of whether you are complying the arithmetic mean of all valid hours of data from the previous 30 operating days or of the previous 720 hours. This identification shall be specified separately for each operating parameter.

(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 completed the required initial tune-up for all of the boilers and process heaters covered by 40 CFR part 63 subpart DDDDD at this site 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 or process heater 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; 80 FR 72814, Nov. 20, 2015]

Back to Top

§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 subsequent annual, biennial, or 5-year tune-up according to §63.7540(a)(10), (11), or (12), respectively, and not subject to emission limits or Table 4 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 semi-annual 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 June 30 or December 31, whichever date is the first date that occurs at least 180 days after the compliance date that is specified for your source in §63.7495. If submitting an annual, biennial, or 5-year compliance report, 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 December 31

within 1, 2, or 5 years, as applicable, after the compliance date that is specified for your source in §63.7495.

(2) The first semi-annual 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 semi-annual 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 semi-annual 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.

(5) For each affected source that is subject to permitting regulations pursuant to part 70 or part 71 of this chapter, and if the permitting authority has established dates for submitting semiannual reports pursuant to 70.6(a)(3)(iii)(A) or 71.6(a)(3)(iii)(A), you may submit the first and subsequent compliance reports according to the dates the permitting authority has established in the permit instead of according to the dates in paragraphs (b)(1) through (4) of this section.

(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 the requirements of a tune up you must submit a compliance report with the information in paragraphs (c)(5)(i) through (iii) of this section, (xiv) and (xvii) of this section, and paragraph (c)(5)(iv) of this section for limited-use boiler or process heater.

(2) If you are complying with the fuel analysis you must submit a compliance report with the information in paragraphs (c)(5)(i) through (iii), (vi), (x), (xi), (xiii), (xv), (xvii), (xviii) and paragraph (d) of this section.

(3) If you are complying with the applicable emissions limit with performance testing you must submit a compliance report with the information in (c)(5)(i) through (iii), (vi), (vii), (viii), (ix), (xi), (xiii), (xv), (xvii), (xviii) and paragraph (d) of this section.

(4) If you are complying with an emissions limit using a CMS the compliance report must contain the information required in paragraphs (c)(5)(i) through (iii), (v), (vi), (xi) through (xiii), (xv) through (xviii), 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 16 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 17 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 18 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 for CEMS (CO, HCl, SO_2, and mercury), 10 day rolling average values for CO CEMS when the limit is expressed as a 10 day instead of 30 day rolling average, and the PM CPMS 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.

(xviii) For each instance of startup or shutdown include the information required to be monitored, collected, or recorded according to the requirements of §63.7555(d).

(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, or from the work practice standards for periods if startup and shutdown, 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, operating limit, or work practice standard 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 (as defined in §63.2) required by this subpart, you must submit the results of the performance tests, including any fuel analyses, following the procedure specified in either paragraph (h)(1)(i) or (ii) of this section.

(i) For data collected using test methods supported by the EPA's Electronic Reporting Tool (ERT) as listed on the EPA's ERT Web site (*http://www.epa.gov/ttn/chief/ert/index.html*), you must submit the results of the performance test to the EPA via the Compliance and Emissions Data Reporting Interface (CEDRI). (CEDRI can be accessed through the EPA's Central Data Exchange (CDX) (*https://cdx.epa.gov/*).) Performance test data must be submitted in a file format generated through use of the EPA's ERT or an electronic file format consistent with the extensible markup language (XML) schema listed on the EPA's ERT Web site. If you claim that some of the performance test information being submitted is confidential business information (CBI), you must submit a complete file generated through the use of the EPA's ERT or an alternate electronic file consistent with the XML schema listed on the EPA's ERT Web site, including information claimed to be CBI, on a compact disc, flash drive, or other commonly used electronic storage media to the EPA. The electronic media must be clearly marked as CBI and mailed to U.S. EPA/OAPQS/CORE CBI Office, Attention: Group Leader, Measurement Policy Group, MD C404-02, 4930 Old Page Rd., Durham, NC 27703. The same ERT or alternate file with the CBI omitted must be submitted to the EPA via the EPA's CDX as described earlier in this paragraph.

(ii) For data collected using test methods that are not supported by the EPA's ERT as listed on the EPA's ERT Web site at the time of the test, you must submit the results of the performance test to the Administrator at the appropriate address listed in §63.13.

(2) Within 60 days after the date of completing each CEMS performance evaluation (as defined in 63.2), you must submit the results of the performance evaluation following the procedure specified in either paragraph (h)(2)(i) or (ii) of this section.

(i) For performance evaluations of continuous monitoring systems measuring relative accuracy test audit (RATA) pollutants that are supported by the EPA's ERT as listed on the EPA's ERT Web site at the time of the evaluation, you must submit the results of the performance evaluation to the EPA via the CEDRI. (CEDRI can be accessed through the EPA's CDX.) Performance evaluation data must be submitted in a file format generated through the use of the EPA's ERT or an alternate file format consistent with the XML schema listed on the EPA's ERT Web site. If you claim that some of the performance evaluation information being transmitted is CBI, you must submit a complete file generated through the use of the EPA's ERT or an alternate electronic file consistent with the XML schema listed on the EPA's ERT Web site, including information claimed to be CBI, on a compact disc, flash drive, or other commonly used electronic storage media to the EPA. The electronic media must be clearly marked as CBI and mailed to U.S. EPA/OAPQS/CORE CBI Office, Attention: Group Leader, Measurement Policy Group, MD C404-02, 4930 Old Page Rd., Durham, NC 27703. The same ERT or alternate file with the CBI omitted must be submitted to the EPA via the EPA's CDX as described earlier in this paragraph.

(ii) For any performance evaluations of continuous monitoring systems measuring RATA pollutants that are not supported by the EPA's ERT as listed on the ERT Web site at the time of the evaluation, you must submit the results of the performance evaluation to the Administrator at the appropriate address listed in §63.13.

(3) You must submit all reports required by Table 9 of this subpart electronically to the EPA via the CEDRI. (CEDRI can be accessed through the EPA's CDX.) You must use the appropriate electronic report in CEDRI for this subpart. Instead of using the electronic report in CEDRI for this subpart, you may submit an alternate electronic file consistent with the XML schema listed on the CEDRI Web site (*http://www.epa.gov/ttn/chief/cedri/index.html*), once the XML schema is available. If the reporting form specific to this subpart is not available in CEDRI at the time that the report is due, you must submit the report to the Administrator at the appropriate address listed in §63.13. You must begin submitting reports via CEDRI no later than 90 days after the form becomes available in CEDRI.

[78 FR 7183, Jan. 31, 2013, as amended at 80 FR 72814, Nov. 20, 2015]

Back to Top

§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).

(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.

(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) 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 16 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.

(4) 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 17 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.

(5) 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.

(6) 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.

(7) 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.

(8) 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 18 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.

(9) You must maintain records of the calendar date, time, occurrence and duration of each startup and shutdown.

(10) You must maintain records of the type(s) and amount(s) of fuels used during each startup and shutdown.

(11) For each startup period, for units selecting paragraph (2) of the definition of "startup" in §63.7575 you must maintain records of the time that clean fuel combustion begins; the time when you start feeding fuels that are not clean fuels; the time when useful thermal energy is first supplied; and the time when the PM controls are engaged.

(12) If you choose to rely on paragraph (2) of the definition of "startup" in §63.7575, for each startup period, you must maintain records of the hourly steam temperature, hourly steam pressure, hourly steam flow, hourly flue gas temperature, and all hourly average CMS data (*e.g.,* CEMS, PM CPMS, COMS, ESP total secondary electric power input, scrubber pressure drop, scrubber liquid flow rate) collected during each startup period to confirm that the control devices are engaged. In addition, if compliance with the PM emission limit is demonstrated using a PM control device, you must maintain records as specified in paragraphs (d)(12)(i) through (iii) of this section.

(i) For a boiler or process heater with an electrostatic precipitator, record the number of fields in service, as well as each field's secondary voltage and secondary current during each hour of startup.

(ii) For a boiler or process heater with a fabric filter, record the number of compartments in service, as well as the differential pressure across the baghouse during each hour of startup.

(iii) For a boiler or process heater with a wet scrubber needed for filterable PM control, record the scrubber's liquid flow rate and the pressure drop during each hour of startup.

(13) If you choose to use paragraph (2) of the definition of "startup" in §63.7575 and you find that you are unable to safely engage and operate your PM control(s) within 1 hour of first firing of non-clean fuels, you may choose to rely on paragraph (1) of definition of "startup" in §63.7575 or you may submit to the delegated permitting authority a request for a variance with the PM controls requirement, as described below.

(i) The request shall provide evidence of a documented manufacturer-identified safety issue.

(ii) The request shall provide information to document that the PM control device is adequately designed and sized to meet the applicable PM emission limit.

(iii) In addition, the request shall contain documentation that:

(A) The unit is using clean fuels to the maximum extent possible to bring the unit and PM control device up to the temperature necessary to alleviate or prevent the identified safety issues prior to the combustion of primary fuel;

(B) The unit has explicitly followed the manufacturer's procedures to alleviate or prevent the identified safety issue; and

(C) Identifies with specificity the details of the manufacturer's statement of concern.

(iv) You must comply with all other work practice requirements, including but not limited to data collection, recordkeeping, and reporting requirements.

(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.

[76 FR 15664, Mar. 21, 2011, as amended at 78 FR 7185, Jan. 31, 2013; 80 FR 72816, Nov. 20, 2015]

Back to Top

§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.

Back to Top

Other Requirements and Information

Back to Top

§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.

Back to Top

§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 (4) 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 emission limits and work practice standards in §63.7500(a) and (b) under §63.6(g), except as specified in §63.7555(d)(13).

(2) Approval of major change to test methods in Table 5 to this subpart under §63.7(e)(2)(ii) and (f) and as defined in §63.90, and alternative analytical methods requested under §63.7521(b)(2).

(3) 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).

(4) 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; 80 FR 72817, Nov. 20, 2015]

Back to Top

§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 CO CEMS data. The 720 hours should be consecutive, but not necessarily continuous if operations were intermittent. For parameters other than CO, 30-day rolling average means either the arithmetic mean of all valid hours of data from 30 successive operating days or 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.

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.

Clean dry biomass means any biomass-based solid fuel that have not been painted, pigment-stained, or pressure treated, does not contain contaminants at concentrations not normally associated with virgin biomass materials and has a moisture content of less than 20 percent and is not a solid waste.

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), process heater(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), process heater(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.

Fossil fuel means natural gas, oil, coal, and any form of solid, liquid, or gaseous fuel derived from such material.

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 as demonstrated by monthly fuel analysis. 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 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, and vegetable oil.

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). For boilers and process heaters that co-fire natural gas or refinery gas with a solid or liquid fuel, the load fraction is determined by the actual heat input of the solid or liquid fuel divided by heat input of the solid or liquid fuel fired during the performance test (*e.g.,* if the performance test was conducted at 100 percent solid fuel firing, for 100 percent load firing 50 percent solid fuel and 50 percent natural gas 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 not using an acid gas wet scrubber or dry sorbent injection control technology to comply with the HCl emission limit, 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. For calculating rolling average emissions, an operating day does not include the hours of operation during startup or shutdown.

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 over its operating load range. A typical system consists of a flue gas oxygen and/or CO monitor that automatically provides a feedback signal to the combustion air controller or draft 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.

Rolling average means the average of all data collected during the applicable averaging period. For demonstration of compliance with a CO CEMS-based emission limit based on CO concentration a 30-day (10-day) rolling average is comprised of the average of all the hourly average concentrations over the previous 720 (240) operating hours calculated each operating day. To demonstrate compliance on a 30-day rolling average basis for parameters other than CO, you must indicate the basis of the 30-day rolling average period you are using for compliance, as discussed in §63.7545(e)(2)(iii). If you indicate the 30 operating day basis, you must calculate a new average value each operating day and shall include the measured hourly values for the preceding 30 operating days. If you select the 720 operating hours basis, you must average of all the hourly average concentrations over the previous 720 operating hours calculated each operating day.

Secondary material means the material as defined in §241.2 of this chapter.

Shutdown means the period in which cessation of operation of a boiler or process heater is initiated for any purpose. Shutdown begins when the boiler or process heater no longer supplies useful thermal energy (such as heat or steam) for heating, cooling, or process purposes and/or generates electricity or when no fuel is being fed to the boiler or process heater, whichever is earlier. Shutdown ends when the boiler or process heater no longer supplies useful thermal energy (such as steam or heat) for heating, cooling, or process purposes and/or generates electricity, and no fuel is being combusted 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:

(1) Either the first-ever firing of fuel in a boiler or process heater for the purpose of supplying useful thermal energy 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 useful thermal energy from the boiler or process heater is supplied for heating, and/or producing electricity, or for any other purpose, or

(2) The period in which operation of a boiler or process heater is initiated for any purpose. Startup begins with either the first-ever firing of fuel in a boiler or process heater for the purpose of

supplying useful thermal energy (such as steam or heat) for heating, cooling or process purposes, or producing electricity, or the firing of fuel in a boiler or process heater for any purpose after a shutdown event. Startup ends four hours after when the boiler or process heater supplies useful thermal energy (such as heat or steam) for heating, cooling, or process purposes, or generates electricity, whichever is earlier.

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 the appropriate emission limit from Table 1 or 2 of this subpart in units of pounds per million Btu heat input (lb per MWh).

(4) For a boiler that performs multiple functions and produces steam to be used for any combination of paragraphs (1), (2), and (3) of this definition that includes electricity generation of paragraph (3) of this definition, the total energy output, in terms of MMBtu of steam output, is the sum of the energy content of steam sent directly to the process and/or used for heating (S_1), the energy content of turbine steam sent to process plus energy in electricity according to paragraph (2) of this definition (S_2), and the energy content of electricity generated by a electricity only turbine as paragraph (3) of this definition ($MW_{(3)}$) and would be calculated using Equation 21 of this section. In the case of boilers supplying steam to one or more common heaters, S_1, S_2, and $MW_{(3)}$ for each boiler would be calculated based on the its (steam energy) contribution (fraction of total steam energy) to the common heater.

$$SO_M = S_1 + S_2 + (MW_{(3)}\ x\ CFn) \qquad \text{(Eq. 21)}$$

View or download PDF

Where:

SO_M = Total steam output for multi-function boiler, MMBtu

S_1 = Energy content of steam sent directly to the process and/or used for heating, MMBtu

S_2 = Energy content of turbine steam sent to the process plus energy in electricity according to (2) above, MMBtu

$MW_{(3)}$ = Electricity generated according to paragraph (3) of this definition, MWh

CFn = Conversion factor for the appropriate subcategory for converting electricity generated according to paragraph (3) of this definition to equivalent steam energy, MMBtu/MWh

CFn for emission limits for boilers in the unit designed to burn solid fuel subcategory = 10.8

CFn PM and CO emission limits for boilers in one of the subcategories of units designed to burn coal = 11.7

CFn PM and CO emission limits for boilers in one of the subcategories of units designed to burn biomass = 12.1

CFn for emission limits for boilers in one of the subcategories of units designed to burn liquid fuel = 11.2

CFn for emission limits for boilers in the unit designed to burn gas 2 (other) subcategory = 6.2

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 or process heater 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 or process heater is not a temporary boiler or process heater if any one of the following conditions exists:

(1) The equipment is attached to a foundation.

(2) The boiler or process heater 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 or process heater that replaces a temporary boiler or process heater 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, process heat, 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.

Useful thermal energy means energy (*i.e.,* steam, hot water, or process heat) that meets the minimum operating temperature, flow, and/or pressure required by any energy use system that uses energy provided by the affected boiler or process heater.

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; 80 FR 72817, Nov. 20, 2015]

Back to Top

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	a. Filterable	1.1E-03 lb per	1.1E-03 lb per	Collect a minimum of 3

to burn coal/solid fossil fuel	PM (or TSM)	MMBtu of heat input; or (2.3E-05 lb per MMBtu of heat input)	MMBtu 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)	dscm 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,[d] 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/others 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,[d] 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,[d] 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	a. CO (or	140 ppm by volume	1.2E-01 lb per	1 hr minimum

units with an integrated heat exchanger designed to burn coal/solid fossil fuel	CEMS)	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,[d] 30-day rolling average)	MMBtu of steam output or 1.5 lb per MWh; 3-run average	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 corrected to 3 percent oxygen,[d] 30-day rolling average)	5.8E-01 lb per MMBtu of steam output or 6.8 lb per MWh; 3-run 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)	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	Collect a minimum of 2 dscm per run.

			MMBtu of steam output or 5.6E-02 lb per MWh)	
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,[d] 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 oxygen,[d] 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)	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	Collect a minimum of 2 dscm per run.

			MMBtu of steam output or 9.1E-02 lb per MWh)	
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,[d] 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	a. CO (or CEMS)	1,100 ppm by volume on a dry basis	1.4 lb per MMBtu of steam output or	1 hr minimum sampling time.

boiler designed to burn biomass/bio-based solids		corrected to 3 percent oxygen, 3-run average; or (900 ppm by volume on a dry basis corrected to 3 percent oxygen,[d] 30-day rolling average)	12 lb per MWh; 3-run 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 April 1, 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.

[d]An owner or operator may request an alternative test method under §63.7 of this chapter, in order that compliance with the carbon monoxide emissions limit be determined using carbon dioxide as a diluent correction in place of oxygen at 3%. EPA Method 19 F-factors and EPA Method 19 equations must be used to generate the appropriate CO_2 correction percentage for the fuel type burned in the unit, and must also take into account that the 3% oxygen correction is to be done on a dry basis. The alternative test method request must account for any CO_2 being added to, or removed from, the emissions gas stream as a result of limestone injection, scrubber media, etc.

[78 FR 7193, Jan. 31, 2013, as amended at 80 FR 72819, Nov. 20, 2015]

Back to Top

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,[c] 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/others designed to burn coal/solid fossil fuel	a. CO (or CEMS)	160 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,[c] 30-day rolling average)	0.14 lb per MMBtu of steam output or 1.7 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	0.12 lb per MMBtu of steam output or 1.4 lb per MWh; 3-run average	1 hr minimum sampling time.

		basis corrected to 3 percent oxygen,[c] 30-day rolling average)		
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,[c] 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,[c] 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 PM (or TSM)	3.2E-01 lb per MMBtu of heat input; or (4.0E-03 lb per MMBtu of heat input)	3.7E-01 lb per MMBtu 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)	Collect a minimum of 1 dscm 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,[c] 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,[c] 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,[c] 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	Collect a minimum of 2 dscm per run.

			output or 8.1E-02 lb per MWh)	
13. Hybrid suspension grate units designed to burn biomass/bio-based solid	a. CO (or CEMS)	3,500 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,[c] 30-day rolling average)	3.5 lb per MMBtu of steam output or 39 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[a] lb per MMBtu of heat input	2.5E-06[a] 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	a. CO	130 ppm by volume on a dry basis	0.13 lb per MMBtu of steam	1 hr minimum sampling time.

liquid fuel		corrected to 3 percent oxygen, 3-run average	output or 1.4 lb per MWh; 3-run average	
	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[a] lb per MMBtu of heat input; or (6.2E-05 lb per MMBtu of heat input)	9.6E-03[a] lb per MMBtu of steam output or 1.1E-01[a] 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	Collect a minimum of 2 dscm per run.

			MMBtu of steam output or 1.2E-02 lb per MWh)	
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 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.

[c]An owner or operator may request an alternative test method under §63.7 of this chapter, in order that compliance with the carbon monoxide emissions limit be determined using carbon dioxide as a diluent correction in place of oxygen at 3%. EPA Method 19 F-factors and EPA Method 19 equations must be used to generate the appropriate CO_2 correction percentage for the fuel type burned in the unit, and must also take into account that the 3% oxygen correction is to be done on a dry basis. The alternative test method request must account for any CO_2 being added to, or removed from, the emissions gas stream as a result of limestone injection, scrubber media, etc.

[78 FR 7195, Jan. 31, 2013, as amended at 80 FR 72821, Nov. 20, 2015]

Back to Top

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 operated under an energy management program developed according to the ENERGY STAR guidelines for energy management or compatible with ISO 50001 for at least one year between January 1, 2008 and the compliance date specified in §63.7495 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 program and provide recommendations for improvements consistent with the definition of energy management program, 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	a. You must operate all CMS during startup. b. 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, other Gas 1 fuels, distillate oil, syngas, ultra-low sulfur diesel, fuel oil-soaked rags, kerosene, hydrogen, paper, cardboard, refinery gas, liquefied petroleum gas, clean dry biomass, and any fuels meeting the appropriate HCl, mercury and TSM emission standards by fuel analysis. c. You have the option of complying using either of the following work practice standards. (1) If you choose to comply using definition (1) of “startup” in §63.7575, once you start firing fuels that are not clean fuels, 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, and selective catalytic reduction (SCR). You must start your limestone injection in FBC boilers, dry scrubber, fabric filter, and SCR systems as expeditiously as possible. Startup ends when steam or heat is supplied for any purpose, OR (2) If you choose to comply using definition (2) of "startup" in §63.7575, once you start to feed fuels that are not clean fuels, you must vent emissions to the main stack(s) and engage all of the applicable control devices so as to comply with the emission limits within 4 hours of start of supplying useful thermal energy. You must engage and operate PM control within one hour of first feeding fuels that are not clean fuels[a]. You must start all applicable control devices as expeditiously as possible, but, in any case, when necessary to comply with other standards applicable to the source by a permit limit or a rule other than this subpart that require operation of the control devices. You must develop and implement a written startup and shutdown plan, as specified in §63.7505(e). d. You must comply with all applicable emission limits at all times except during startup and shutdown periods at which time you must meet 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 fuels that are not clean fuels 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, and SCR but, in any case, when necessary to comply with other standards applicable to the source that require operation of the control device. If, in addition to the fuel used prior to initiation of shutdown, another fuel must be used to support the shutdown process, that additional fuel must be one or a combination of the following clean fuels: Natural gas, synthetic natural gas, propane, other Gas 1 fuels, distillate oil, syngas, ultra-low sulfur diesel, refinery gas, and liquefied petroleum gas. 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.

[a]As specified in §63.7555(d)(13), the source may request an alternative timeframe with the PM controls requirement to the permitting authority (state, local, or tribal agency) that has been delegated authority for this subpart by EPA. The source must provide evidence that (1) it is unable to safely engage and operate the PM control(s) to meet the "fuel firing + 1 hour" requirement and (2) the PM control device is appropriately designed and sized to meet the filterable PM emission limit. It is acknowledged that there may be another control device that has been installed other than ESP that provides additional PM control (*e.g.*, scrubber).

[78 FR 7198, Jan. 31, 2013, as amended at 80 FR 72823, Nov. 20, 2015]

Back to Top

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:

TABLE 4 TO SUBPART DDDDD OF PART 63—OPERATING LIMITS FOR BOILERS AND PROCESS HEATERS

When complying with a Table 1, 2, 11, 12, or 13 numerical emission limit	You must meet these operating limits . . .

using . . .	
1. Wet PM scrubber control on a boiler or process heater 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 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[a] control on a boiler or process heater 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 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 a boiler or process heater not using a PM CPMS	a. Maintain opacity to less than or equal to 10 percent opacity or the highest hourly average opacity reading measured during the performance test run demonstrating compliance with the PM (or TSM) emission limitation (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 a boiler or process heater 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 or the highest hourly average opacity reading measured during the performance test run demonstrating compliance with the PM (or TSM) emission limitation (daily block average).
	b. This option is only for boilers and process heaters not subject to PM CPMS or continuous compliance with an opacity limit (*i.e.*, dry ESP). 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 or process heater 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 a boiler or process heater 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 or the highest hourly average opacity reading measured during the performance test run demonstrating compliance with the PM (or TSM) emission limitation (daily block average).
7. Performance testing	For boilers and process heaters that demonstrate compliance with a performance test, maintain the 30-day rolling average operating load of each unit such that it does not exceed 110 percent of the highest hourly average operating load recorded during the performance test.
8. Oxygen analyzer system	For boilers and process heaters subject to a CO emission limit that demonstrate compliance with an O_2 analyzer 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 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).
9. SO_2 CEMS	For boilers or process heaters subject to an HCl emission limit that demonstrate compliance with an SO_2 CEMS, maintain the 30-day rolling average SO_2 emission rate at or below the highest hourly average SO_2 concentration measured during the HCl performance test, as specified in Table 8.

[a]A wet acid gas scrubber is a control device that removes acid gases by contacting the combustion gas with an alkaline slurry or solution. Alkaline reagents include, but not limited to, lime, limestone and sodium.

[80 FR 72874, Nov. 20, 2015]

Back to Top

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, as appropriate . . .
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 concentration to lb per MMBtu emission rates	Method 19 F-factor methodology at 40 CFR part 60, 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.

[a]Incorporated by reference, see §63.14.

[76 FR 15664, Mar. 21, 2011, as amended at 78 FR 7200, Jan. 31, 2013; 80 FR 72825, Nov. 20, 2015]

Back to Top

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:

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), 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[a], or ASTM D95[a] (for liquid fuels), or ASTM D4006[a] (for liquid fuels), or equivalent.
	f. Measure mercury concentration in fuel sample	ASTM D6722[a] (for coal), EPA SW-846-7471B[a] or EPA 1631 or EPA 1631E[a] (for solid samples), or EPA SW-846-7470A[a] or EPA SW-846-7471B[a] (for liquid samples), or EPA 821-R-01-013[a] (for liquid or solid), or equivalent.
	g. Convert concentration into units of pounds of mercury per MMBtu of heat content	For fuel mixtures use Equation 8 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), 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[a], ASTM D240[a] or equivalent.
	e. Determine moisture	ASTM D3173[a] or ASTM E871[a], or D5864[a], or ASTM D240[a], or ASTM D95[a] (for liquid fuels), or

	content of the fuel type	ASTM D4006[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	For fuel mixtures use Equation 7 in §63.7530 and convert from chlorine to HCl by multiplying by 1.028.
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, or	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	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), 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[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 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	For fuel mixtures use Equation 9 in §63.7530.

[a]Incorporated by reference, see §63.14.

[83 FR 56725, Nov. 14, 2018]

Back to Top

Table 7 to Subpart DDDDD of Part 63—Establishing Operating Limits[a b]

As stated in §63.7520, you must comply with the following requirements for establishing operating limits:

TABLE 7 TO SUBPART DDDDD OF PART 63—ESTABLISHING OPERATING LIMITS[A B]

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, TSM, 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 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.
	c. Opacity	i. Establish a site-specific maximum opacity level	(1) Data from the opacity monitoring system during the PM performance	(a) You must collect opacity readings every 15 minutes during the entire period of the performance tests. (b) Determine the

			test	average hourly opacity reading for each performance test run by computing the hourly averages using all of the 15-minute readings taken during each performance test run. (c) Determine the highest hourly average opacity reading measured during the test run demonstrating compliance with the PM (or TSM) emission limitation.
2. HCl	a. Wet scrubber operating parameters	i. Establish site-specific minimum effluent pH and flow rate operating limits according to §63.7530(b)	(1) Data from the 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	(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. (b) Determine the hourly average sorbent injection rate by computing the hourly

		performance test, the average value for each sorbent becomes the site-specific operating limit for that sorbent		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, as defined in §63.7575, 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_2 CEMS and the HCl performance test	(a) You must collect the SO_2 emissions data according to §63.7525(m) during the most recent HCl performance tests. (b) The maximum SO_2emission rate is equal to the highest 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	(1) Data from the activated carbon rate monitors and mercury performance	(a) You must collect activated carbon injection rate data every 15 minutes during the entire period of the performance tests. (b) Determine the hourly

		§63.7530(b)	test	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, as defined in §63.7575, to determine the required injection rate.
4. Carbon monoxide for which compliance is demonstrated by a performance test	a. Oxygen	i. Establish a unit-specific limit for minimum oxygen level according to §63.7530(b)	(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 highest hourly average of the three test run averages during the performance test, and multiply this by 1.1 (110 percent) as your operating limit.

[a]Operating limits must be confirmed or reestablished during performance tests.

[b]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. 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.

[80 FR 72827, Nov. 20, 2015]

Back to Top

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 daily block average opacity to less than or equal to 10 percent or the highest hourly average opacity reading measured during the performance test run demonstrating compliance with the PM (or TSM) emission limitation.
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)(7) 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
	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.
	d. Calculate the HCI, mercury, and/or TSM emission rate from the boiler or process heater in units of lb/MMBtu using Equation 15 and Equations 17, 18, and/or 19 in §63.7530.

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)(7).
	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 CO performance test.
10. Boiler or process heater operating load	a. Collecting operating load data or steam generation data every 15 minutes. b. Reducing the data to 30-day rolling averages; and
	c. Maintaining the 30-day rolling average operating load such that it does not exceed 110 percent of the highest hourly average operating load recorded during the performance test according to §63.7520(c).
11. SO_2 emissions using SO_2 CEMS	a. Collecting the SO_2 CEMS output data according to §63.7525;
	b. Reducing the data to 30-day rolling averages; and
	c. Maintaining the 30-day rolling average SO_2 CEMS emission rate to a level at or below the highest hourly SO_2 rate measured during the HCl performance test according to §63.7530.

[78 FR 7204, Jan. 31, 2013, as amended at 80 FR 72829, Nov. 20, 2015]

Back to Top

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	The report must contain . . .	You must submit the

submit a(n)		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 for periods of startup and shutdown 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 for periods of startup and shutdown, 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; 80 FR 72830, Nov. 20, 2015]

Back to Top

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	No.

	requirements.	
§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, except §63.7555(d)(13) specifies the procedure for application and approval of an alternative timeframe with the PM controls requirement in the startup work practice (2).
§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	No. Subpart DDDDD specifies opacity as an operating limit not an emission standard.
§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; 80 FR 72830, Nov. 20, 2015]

Back to Top

Table 11 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	a. HCl	0.022 lb per MMBtu of	For M26A, collect a minimum of 1 dscm per

designed to burn solid fuel		heat input	run; for M26 collect a minimum of 120 liters per run.
2. Units in all subcategories designed to burn solid fuel that combust at least 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	a. Mercury	8.0E-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.
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. Mercury	2.0E-06 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.
4. Units design to burn coal/solid fossil fuel	a. 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. 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,[c] 30-day rolling average)	1 hr minimum sampling time.
6. 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	1 hr minimum sampling time.

		average; or (340 ppm by volume on a dry basis corrected to 3 percent oxygen,[c] 10-day rolling average)	
7. 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,[c] 30-day rolling average)	1 hr minimum sampling time.
8. 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,[c] 30-day rolling average)	1 hr minimum sampling time.
9. 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 corrected to 3 percent oxygen,[c] 30-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.
10. Stokers/sloped	a. CO	560 ppm by volume on a	1 hr minimum sampling

grate/others designed to burn kiln-dried biomass fuel		dry basis corrected to 3 percent oxygen, 3-run average	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)	Collect a minimum of 2 dscm per run.
11. 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,[c] 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.
12. 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,[c] 10-day rolling average)	1 hr minimum sampling time.
	b. Filterable PM (or TSM)	3.0E-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.
13. Dutch Ovens/Pile burners designed to burn biomass/bio-	a. CO (or CEMS)	1,010 ppm by volume on a dry basis corrected to 3	1 hr minimum sampling time.

based solids		percent oxygen, 3-run average; or (520 ppm by volume on a dry basis corrected to 3 percent oxygen,[c] 10-day rolling average)	
	b. Filterable PM (or TSM)	8.0E-03 lb per MMBtu of heat input; or (3.9E-05 lb per MMBtu of heat input)	Collect a minimum of 3 dscm per run.
14. 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, 3-run average	1 hr minimum sampling time.
	b. Filterable PM (or TSM)	2.0E-02 lb per MMBtu of heat input; or (2.9E-05 lb per MMBtu of heat input)	Collect a minimum of 2 dscm per run.
15. 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,[c] 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.
16. Units designed to burn liquid fuel	a. HCl	4.4E-04 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	4.8E-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.
17. 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	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)	Collect a minimum of 3 dscm per run.
18. Units designed to burn light liquid fuel	a. CO	130 ppm by volume on a dry basis corrected to 3 percent oxygen, 3-run average	1 hr minimum sampling time.
	b. Filterable PM (or TSM)	2.0E-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.
19. 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	1 hr minimum sampling time.
	b. Filterable PM (or	2.3E-02 lb per MMBtu of heat input; or (8.6E-04	Collect a minimum of 4

	TSM)	lb per MMBtu of heat input)	dscm per run.
20. Units designed to burn gas 2 (other) gases	a. CO	130 ppm by volume on a dry basis corrected to 3 percent oxygen, 3-run average	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, 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.

[c]An owner or operator may request an alternative test method under §63.7 of this chapter, in order that compliance with the carbon monoxide emissions limit be determined using carbon dioxide as a diluent correction in place of oxygen at 3%. EPA Method 19 F-factors and EPA Method 19 equations must be used to generate the appropriate CO_2 correction percentage for the fuel type burned in the unit, and must also take into account that the 3% oxygen correction is to be done on a

dry basis. The alternative test method request must account for any CO_2 being added to, or removed from, the emissions gas stream as a result of limestone injection, scrubber media, etc.

[80 FR 72831, Nov. 20, 2015]

Back to Top

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 May 20, 2011, and Before December 23, 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. 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	3.5E-06[a] 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.
2. Units design to burn coal/solid fossil fuel	a. 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.
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,[c] 30-day rolling 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,[c] 10-day rolling 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,[c] 30-day rolling 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,[c] 30-day rolling 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 corrected to 3 percent oxygen,[c] 30-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.
8. Stokers/sloped grate/others designed to burn kiln-dried	a. CO b. Filterable PM (or	460 ppm by volume on a dry basis corrected to 3 percent oxygen, 3-run average	1 hr minimum sampling time. Collect a minimum of 2 dscm per run.

biomass fuel	TSM)	3.0E-02 lb per MMBtu of heat input; or (4.0E-03 lb per MMBtu of heat input)	
9. Fluidized bed units designed to burn biomass/bio-based solids	a. CO (or CEMS)	260 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,[c] 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.
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 oxygen,[c] 10-day rolling average)	1 hr minimum sampling time.
	b. Filterable PM (or TSM)	3.0E-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.
11. Dutch Ovens/Pile burners designed to burn biomass/bio-based solids	a. CO (or CEMS)	470 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,[c] 10-day rolling average)	1 hr minimum sampling time.
	b. Filterable PM (or	3.2E-03 lb per MMBtu of heat input; or (3.9E-05 lb per	Collect a minimum of 3 dscm per run.

	TSM)	MMBtu of heat input)	
12. Fuel cell units designed to burn biomass/bio-based solids	a. CO b. Filterable PM (or TSM)	910 ppm by volume on a dry basis corrected to 3 percent oxygen, 3-run average 2.0E-02 lb per MMBtu of heat input; or (2.9E-05 lb per MMBtu of heat input)	1 hr minimum sampling time. Collect a minimum of 2 dscm per run.
13. Hybrid suspension grate boiler designed to burn biomass/bio-based solids	a. CO (or CEMS)	1,500 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,[c] 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.
14. Units designed to burn liquid fuel	a. HCl	4.4E-04 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	4.8E-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.
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	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)	Collect a minimum of 2 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, 3-run average	1 hr minimum sampling time.
	b. Filterable PM (or TSM)	1.3E-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.
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	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)	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, 3-run average	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, 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.

[c]An owner or operator may request an alternative test method under §63.7 of this chapter, in order that compliance with the carbon monoxide emissions limit be determined using carbon dioxide as a diluent correction in place of oxygen at 3%. EPA Method 19 F-factors and EPA Method 19 equations must be used to generate the appropriate CO_2 correction percentage for the fuel type burned in the unit, and must also take into account that the 3% oxygen correction is to be done on a dry basis. The alternative test method request must account for any CO_2 being added to, or removed from, the emissions gas stream as a result of limestone injection, scrubber media, etc.

[80 FR 72834, Nov. 20, 2015]

Back to Top

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 April 1, 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,[c] 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,[c] 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,[c] 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,[c] 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,[c] 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,[c] 30-day rolling	1 hr minimum sampling time.

		average)	
	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,[c] 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,[c] 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 PM (or	2.0E-02 lb per MMBtu of heat input; or (2.9E-05 lb per	Collect a minimum of 2 dscm per run.

	TSM)	MMBtu of heat input)	
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,[c] 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,[c] 10-day rolling average)	1 hr minimum sampling time.
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	1 hr minimum sampling time.

		volume on a dry basis corrected to 3 percent oxygen,[c] 1-day block average)	
	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 corrected to 3 percent oxygen, 3-hour rolling 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)	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.

[c]An owner or operator may request an alternative test method under §63.7 of this chapter, in order that compliance with the carbon monoxide emissions limit be determined using carbon dioxide as a diluent correction in place of oxygen at 3%. EPA Method 19 F-factors and EPA Method 19 equations must be used to generate the appropriate CO_2 correction percentage for the fuel type burned in the unit, and must also take into account that the 3% oxygen correction is to be done on a dry basis. The alternative test method request must account for any CO_2 being added to, or removed from, the emissions gas stream as a result of limestone injection, scrubber media, etc.

[78 FR 7210, Jan. 31, 2013, as amended at 80 FR 72836, Nov. 20, 2015]

Back to Top

Appendix I

40 C.F.R. Part 63 Subpart SSSS

National Emissions Standards for Hazardous Air Pollutants: Surface Coating of Metal Coil

Title 40: Protection of Environment
PART 63—NATIONAL EMISSION STANDARDS FOR HAZARDOUS AIR POLLUTANTS FOR SOURCE CATEGORIES (CONTINUED)

Subpart SSSS—National Emission Standards for Hazardous Air Pollutants: Surface Coating of Metal Coil

---

Contents

Source: 67 FR 39812, June 10, 2002, unless otherwise noted.

Back to Top

What This Subpart Covers

Back to Top

§63.5080   What is in this subpart?

This subpart describes the actions you must take to reduce emissions of hazardous air pollutants (HAP) if you own or operate a facility that performs metal coil surface coating operations and is a major source of HAP. This subpart establishes emission standards and states what you must do to comply. Certain requirements apply to all who must comply with the subpart; others depend on the means you use to comply with an emission standard.

Back to Top

§63.5090   Does this subpart apply to me?

(a) The provisions of this subpart apply to each facility that is a major source of HAP, as defined in §63.2, at which a coil coating line is operated, except as provided in paragraphs (b) and (e) of this section.

(b) This subpart does not apply to any coil coating line that meets the criteria of paragraph (b)(1) or (2) of this section.

(1) A coil coating line that is part of research or laboratory equipment.

(2) A coil coating line on which at least 85 percent of the metal coil coated, based on surface area, is less than 0.15 millimeter (0.006 inch) thick, except as provided in paragraph (c) of this section.

(c) If you operate a coating line subject to subpart JJJJ of this part that also meets the criteria in either paragraph (c)(1) or (2) of this section, and you choose to comply with the requirements of this subpart, then such compliance constitutes compliance with subpart JJJJ. The coating line for which you choose this option is, therefore, included in the affected source for this subpart as defined in §63.5110 and shall not be included in the affected source for subpart JJJJ as defined in §63.3300.

(1) The coating line is used to coat metal coil of thicknesses both less than and greater than or equal to 0.15 millimeter (0.006 inch) thick, regardless of the percentage of surface area of each thickness coated.

(2) The coating line is used to coat only metal coil that is less than 0.15 millimeter (0.006 inch) thick and the coating line is controlled by a common control device that also receives organic HAP emissions from a coil coating line that is subject to the requirements of this subpart.

(d) Each coil coating line that does not comply with the provisions of this subpart because it meets the criteria in paragraph (b)(2) of this section, that for any rolling 12-month period fails to meet the criteria in paragraph (b)(2) would from that point forward become subject to the provisions of this subpart. After becoming subject to the provisions of this subpart, the coil coating line would no longer be eligible to use the criteria of paragraph (b)(2) of this section, even if in subsequent 12-month periods at least 85 percent of the metal coil coated, based on surface area, is less than 0.15 millimeter (0.006 inch) thick.

(e) This subpart does not apply to the application of incidental markings (including letters, numbers, or symbols) that are added to bare metal coils and that are used for only product identification or for product inventory control. The application of letters, numbers, or symbols to a coated metal coil is considered a coil coating process and part of the coil coating affected source.

[67 FR 39812, June 10, 2002, as amended at 85 FR 10861, Feb. 25, 2020]

Back to Top

§63.5100 Which of my emissions sources are affected by this subpart?

The affected source subject to this subpart is the collection of all of the coil coating lines at your facility.

Back to Top

§63.5110 What special definitions are used in this subpart?

All terms used in this subpart that are not defined in this section have the meaning given to them in the Clean Air Act (CAA) and in subpart A of this part.

Always-controlled work station means a work station associated with a curing oven from which the curing oven exhaust is delivered to a control device with no provision for the oven exhaust to bypass the control device. Sampling lines for analyzers and relief valves needed for safety purposes are not considered bypass lines.

Capture efficiency means the fraction of all organic HAP emissions generated by a process that is delivered to a control device, expressed as a percentage.

Capture system means a hood, enclosed room, or other means of collecting organic HAP emissions and conveying them to a control device.

Car-seal means a seal that is placed on a device that is used to change the position of a valve or damper (e.g., from open to closed) in such a way that the position of the valve or damper cannot be changed without breaking the seal.

Coating means material applied onto or impregnated into a substrate for decorative, protective, or functional purposes. Such materials include, but are not limited to, paints, varnishes, sealants, inks, adhesives, maskants, and temporary coatings. Decorative, protective, or functional materials that consist only of solvents, protective oils, acids, bases, or any combination of these substances are not considered coatings for the purposes of this subpart.

Coating material means the coating and other products (e.g., a catalyst and resin in multi-component coatings) combined to make a single material at the coating facility that is applied to metal coil. For the purposes of this subpart, an organic solvent that is used to thin a coating prior to application to the metal coil is considered a coating material.

Coil coating line means a process and the collection of equipment used to apply an organic coating to the surface of metal coil. A coil coating line includes a web unwind or feed section, a series of one or more work stations, any associated curing oven, wet section, and quench station. A coil coating line does not include ancillary operations such as mixing/thinning, cleaning, wastewater treatment, and storage of coating material.

Control device means a device such as a solvent recovery device or oxidizer which reduces the organic HAP in an exhaust gas by recovery or by destruction.

Control device efficiency means the ratio of organic HAP emissions recovered or destroyed by a control device to the total organic HAP emissions that are introduced into the control device, expressed as a percentage.

Curing oven means the device that uses heat or radiation to dry or cure the coating material applied to the metal coil.

Day means a 24-consecutive-hour period.

Deviation, before August 24, 2020, means any instance in which an affected source, subject to this subpart, or an owner or operator of such a source:

(1) Fails to meet any requirement or obligation established by this subpart including, but not limited to, any emission limitation (including any operating limit) or work practice standard; or

(2) 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; or

(3) Fails to meet any emission limitation (including any operating limit) or work practice standard in this subpart during start-up, shutdown, or malfunction, regardless of whether or not such failure is permitted by this subpart.

Deviation, on and after August 24, 2020, means any instance in which an affected source, subject to this subpart, or an owner or operator of such a source:

(1) Fails to meet any requirement or obligation established by this subpart including, but not limited to, any emission limitation (including any operating limit) or work practice standard; or

(2) 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.

Existing affected source means an affected source the construction of which commenced on or before July 18, 2000, and it has not subsequently undergone reconstruction as defined in §63.2.

Facility means all contiguous or adjoining property that is under common ownership or control, including properties that are separated only by a road or other public right-of-way.

Flexible packaging means any package or part of a package the shape of which can be readily changed. Flexible packaging includes but is not limited to bags, pouches, labels, liners and wraps utilizing paper, plastic, film, aluminum foil, metalized or coated paper or film, or any combination of these materials.

HAP applied means the organic HAP content of all coating materials applied to a substrate by a coil coating line.

Intermittently-controllable work station means a work station associated with a curing oven with provisions for the curing oven exhaust to be delivered to a control device or diverted from a control device through a bypass line, depending on the position of a valve or damper. Sampling lines for analyzers and relief valves needed for safety purposes are not considered bypass lines.

Metal coil means a continuous metal strip that is at least 0.15 millimeter (0.006 inch) thick, which is packaged in a roll or coil prior to coating. After coating, it may or may not be rewound into a roll or coil. Metal coil does not include metal webs that are coated for use in flexible packaging.

Month means a calendar month or a pre-specified period of 28 days to 35 days to allow for flexibility in recordkeeping when data are based on a business accounting period.

Never-controlled work station means a work station which is not equipped with provisions by which any emissions, including those in the exhaust from any associated curing oven, may be delivered to a control device.

New affected source means an affected source the construction or reconstruction of which commenced after July 18, 2000.

Overall organic HAP control efficiency means the total efficiency of a control system, determined either by:

(1) The product of the capture efficiency as determined in accordance with the requirements of §63.5160(e) and the control device efficiency as determined in accordance with the requirements of §63.5160(a)(1)(i) and (ii) or §63.5160(d); or

(2) A liquid-liquid material balance in accordance with the requirements of §63.5170(e)(1).

Permanent total enclosure (PTE) means a permanently installed enclosure that meets the criteria of Method 204 of appendix M, 40 CFR part 51 for a PTE, and that directs all the exhaust gases from the enclosure to a control device.

Protective oil means an organic material that is applied to metal for the purpose of providing lubrication or protection from corrosion without forming a solid film. This definition of protective oil includes but is not limited to lubricating oils, evaporative oils (including those that evaporate completely), and extrusion oils.

Research or laboratory equipment means any equipment for which the primary purpose is to conduct research and development into new processes and products, where such equipment is operated under the close supervision of technically trained personnel and is not engaged in the manufacture of products for commercial sale in commerce, except in a de minimis manner.

Temporary total enclosure (TTE) means an enclosure constructed for the purpose of measuring the capture efficiency of pollutants emitted from a given source, as defined in Method 204 of 40 CFR part 51, appendix M.

Work station means a unit on a coil coating line where coating material is deposited onto the metal coil substrate.

[67 FR 39812, June 10, 2002, as amended at 85 FR 10861, Feb. 25, 2020]

Back to Top

EMISSION STANDARDS AND COMPLIANCE DATES

Back to Top

§63.5120 What emission standards must I meet?

(a) Each coil coating affected source must limit organic HAP emissions to the level specified in paragraph (a)(1), (2), or (3) of this section:

(1) No more than 2 percent of the organic HAP applied for each month during each 12-month compliance period (98 percent reduction); or

(2) No more than 0.046 kilogram (kg) of organic HAP per liter of solids applied during each 12-month compliance period; or

(3) If you use an oxidizer to control organic HAP emissions, operate the oxidizer such that an outlet organic HAP concentration of no greater than 20 parts per million by volume (ppmv) on a dry basis is achieved and the efficiency of the capture system is 100 percent.

(b) You must demonstrate compliance with one of these standards by following the applicable procedures in §63.5170.

Back to Top

§63.5121 What operating limits must I meet?

(a) Except as provided in paragraph (b) of this section, for any coil coating line for which you use an add-on control device, unless you use a solvent recovery system and conduct a liquid-liquid material balance according to §63.5170(e)(1), you must meet the applicable operating limits specified in Table 1 to this subpart. You must establish the operating limits during performance tests according to the requirements in §63.5160(d)(3) and Table 1 to §63.5160. You must meet the operating limits established during the most recent performance test required in §63.5160 at all times after you establish them.

(b) If you use an add-on control device other than those listed in Table 1 to this subpart, or wish to monitor an alternative parameter and comply with a different operating limit, you must apply to the Administrator for approval of alternative monitoring under §63.8(f).

[67 FR 39812, June 10, 2002, as amended at 85 FR 10862, Feb. 25, 2020]

Back to Top

§63.5130 When must I comply?

(a) For an existing affected source, the compliance date is June 10, 2005.

(b) If you own or operate a new affected source subject to the provisions of this subpart, you must comply immediately upon start-up of the affected source, or by June 10, 2002, whichever is later.

(c) Affected sources which have undergone reconstruction are subject to the requirements for new affected sources.

(d) The initial compliance period begins on the applicable compliance date specified in paragraph (a) or (b) of this section and ends on the last day of the 12th month following the compliance date. If the compliance date falls on any day other than the first day of a month, then the initial compliance period extends through that month plus the next 12 months.

(e) For the purpose of demonstrating continuous compliance, a compliance period consists of 12 months. Each month after the end of the initial compliance period described in paragraph (d) of this section is the end of a compliance period consisting of that month and the preceding 11 months.

[67 FR 39812, June 10, 2002, as amended at 85 FR 10862, Feb. 25, 2020]

Back to Top

General Requirements for Compliance with the Emission Standards and for Monitoring and Performance Tests

Back to Top

§63.5140 What general requirements must I meet to comply with the standards?

(a) Before August 24, 2020, you must be in compliance with the applicable emission standards in §63.5120 and the operating limits in Table 1 to this subpart at all times, except during periods of start-up, shutdown, and malfunction of any capture system and control device used to comply with this subpart. On and after August 24, 2020 you must be in compliance with the applicable emission standards in §63.5120 and the operating limits in Table 1 to this subpart at all times. If you are complying with the emission standards of this subpart without the use of a capture system and control device, you must be in compliance with the standards at all times.

(b) Before August 24, 2020, you must always operate and maintain your affected source, including air pollution control and monitoring equipment, according to the provisions in §63.6(e)(1). On and after August 24, 2020, at all times, you must operate and maintain your affected source, including associated air pollution control equipment and monitoring equipment, in a manner consistent with safety and good air pollution control practices for minimizing emissions. The general duty to minimize emissions does not require the owner or operator to make any further efforts to reduce emissions if levels required by the applicable standard have been achieved. Determination of whether a source is operating in compliance with operation and maintenance requirements 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 affected source.

(c) Table 2 of this subpart provides cross references to subpart A of this part, indicating the applicability of the General Provisions requirements to this subpart.

[67 FR 39812, June 10, 2002, as amended at 85 FR 10862, Feb. 25, 2020]

Back to Top

§63.5150 If I use a control device to comply with the emission standards, what monitoring must I do?

TABLE 1 TO §63.5150—CONTROL DEVICE MONITORING REQUIREMENTS INDEX

If you operate a coil coating line and have the following:	Then you must:
1. Control device	Monitor control device operating parameters (§63.5150(a)(3)).
2. Capture system	Monitor capture system operating parameters (§63.5150(a)(4)).
3. Intermittently controllable work station	Monitor parameters related to possible exhaust flow through any bypass to a control device (§63.5150(a)(1)).
4. Continuous emission monitors	Operate continuous emission monitors and perform a quarterly audit (§63.5150(a)(2)).

(a) To demonstrate continuing compliance with the standards, you must monitor and inspect each capture system and each control device required to comply with §63.5120 following the date on which the initial performance test of the capture system and control device is completed. You must install and operate the monitoring equipment as specified in paragraphs (a)(1) through (4) of this section. On and after August 24, 2020, you must also maintain the monitoring equipment at all times in accordance with §63.5140(b) and keep the necessary parts readily available for routine repairs of the monitoring equipment.

(1) *Bypass monitoring.* If you operate coil coating lines with intermittently-controllable work stations, you must follow at least one of the procedures in paragraphs (a)(1)(i) through (iv) of this section for each curing oven associated with these work stations to monitor for potential bypass of the control device:

(i) *Flow control position indicator.* Install, calibrate, maintain, and operate according to the manufacturer's specifications a flow control position indicator that provides a record indicating whether the exhaust stream from the curing oven is directed to the control device or is diverted from the control device. The time and flow control position must be recorded at least once per hour, as well as every time the flow direction is changed. The flow control position indicator must be installed at the entrance to any bypass line that could divert the exhaust stream away from the control device to the atmosphere.

(ii) *Car-seal or lock-and-key valve closures.* Secure any bypass line valve in the closed position with a car-seal or a lock-and-key type configuration when the control device is in operation; a visual inspection of the seal or closure mechanism will be performed at least once every month to ensure that the valve or damper is maintained in the closed position, and the exhaust stream is not diverted through the bypass line.

(iii) *Valve closure continuous monitoring.* Ensure that any bypass line valve or damper is in the closed position through continuous monitoring of valve position when the control device is in operation. The monitoring system must be inspected at least once every month to verify that the monitor will indicate valve position.

(iv) *Automatic shutdown system.* Use an automatic shutdown system in which the coil coating line is stopped when flow is diverted away from the control device to any bypass line when the control device is in operation. The automatic shutdown system must be inspected at least once every month to verify that it will detect diversions of flow and shut down operations.

(2) *Continuous emission monitoring system (CEMS).* If you are demonstrating continuous compliance with the standards in §63.5120(a)(1) or (2) through continuous emission monitoring of a control device, you must install, calibrate, operate, and maintain continuous emission monitors to measure the total organic volatile matter concentration at both the control device inlet and outlet, and you must continuously monitor flow rate. If you are demonstrating continuous compliance with the outlet organic HAP concentration limit in §63.5120(a)(3), you must install, calibrate, operate, and maintain a continuous emission monitor to measure the total organic volatile matter concentration at the control device outlet.

(i) All CEMS must comply with performance specification 8 or 9 of 40 CFR part 60, appendix B, as appropriate for the detection principle you choose. The requirements of 40 CFR part 60, procedure 1, appendix F must also be followed. In conducting the quarterly audits of the monitors as required by procedure 1, appendix F, you must use compounds representative of the gaseous emission stream being controlled.

(ii) As specified in §63.8(c)(4)(ii), each CEMS and each flow rate monitor must complete a minimum of one cycle of operation (sampling, analyzing, and data recording) for each successive

15-minute period. Information which must be determined for recordkeeping purposes, as required by §63.5190(a)(1)(i) includes:

(A) The hourly average of all recorded readings;

(B) The daily average of all recorded readings for each operating day; and

(C) The monthly average for each month during the semiannual reporting period.

(3) *Temperature monitoring of oxidizers.* If you are complying with the requirements of the standards in §63.5120 through the use of an oxidizer and demonstrating continuous compliance through monitoring of an oxidizer operating parameter, you must comply with paragraphs (a)(3)(i) through (iii) of this section.

(i) Install, calibrate, maintain, and operate temperature monitoring equipment according to manufacturer's specifications. The calibration of the chart recorder, data logger, or temperature indicator must be verified every 3 months; or the chart recorder, data logger, or temperature indicator must be replaced. You must replace the equipment either if you choose not to perform the calibration, or if the equipment cannot be calibrated properly. Each temperature monitoring device must be equipped with a continuous recorder. The device must have an accuracy of ±1 percent of the temperature being monitored in degrees Celsius, or ±1 °Celsius, whichever is greater.

(ii) For an oxidizer other than a catalytic oxidizer, to demonstrate continuous compliance with the operating limit established according to §63.5160(d)(3)(i), you must install the thermocouple or temperature sensor in the combustion chamber at a location in the combustion zone.

(iii) For a catalytic oxidizer, if you are demonstrating continuous compliance with the operating limit established according to §63.5160(d)(3)(ii)(A) and (B), then you must install the thermocouples or temperature sensors in the vent stream at the nearest feasible point to the inlet and outlet of the catalyst bed. Calculate the temperature difference across the catalyst. If you are demonstrating continuous compliance with the operating limit established according to §63.5160(d)(3)(ii)(C) and (D), then you must install the thermocouple or temperature sensor in the vent stream at the nearest feasible point to the inlet of the catalyst bed.

(4) *Capture system monitoring.* If you are complying with the requirements of the standards in §63.5120 through the use of a capture system and control device, you must develop a capture system monitoring plan containing the information specified in paragraphs (a)(4)(i) and (ii) of this section. You must monitor the capture system in accordance with paragraph (a)(4)(iii) of this section. You must make the monitoring plan available for inspection by the permitting authority upon request.

(i) The monitoring plan must identify the operating parameter to be monitored to ensure that the capture efficiency measured during compliance tests is maintained, explain why this parameter is appropriate for demonstrating ongoing compliance, and identify the specific monitoring procedures.

(ii) The plan also must specify operating limits at the capture system operating parameter value, or range of values, that demonstrates compliance with the standards in §63.5120. The operating limits must represent the conditions indicative of proper operation and maintenance of the capture system.

(iii) You must conduct monitoring in accordance with the plan.

(b) If an operating parameter monitored in accordance with paragraphs (a)(3) and (4) of this section is out of the allowed range specified in Table 1 to this subpart it will be considered a deviation from the operating limit.

[67 FR 39812, June 10, 2002, as amended at 85 FR 10862, Feb. 25, 2020]

Back to Top

§63.5160 What performance tests must I complete?

TABLE 1 TO §63.5160—REQUIRED PERFORMANCE TESTING SUMMARY

If you control HAP on your coil coating line by:	You must:
1. Limiting HAP or Volatile matter content of coatings	Determine the HAP or volatile matter and solids content of coating materials according to the procedures in §63.5160(b) and (c).
2. Using a capture system and add-on control device	Except as specified in paragraph (a) of this section, conduct an initial performance test within 180 days of the applicable compliance date in §63.5130, and conduct periodic performance tests within 5 years following the previous performance test, as follows: If you are not required to complete periodic performance tests as a requirement of renewing your facility's operating permit under 40 CFR part 70 or 40 CFR part 71, you must conduct the first periodic performance test before March 25, 2023, unless you already have conducted a performance test on or after March 25, 2018; thereafter, you must conduct a performance test no later than 5 years following the previous performance test. Operating limits must be confirmed or reestablished during each performance test. If you are required to complete periodic performance tests as a requirement of renewing your facility's operating permit under 40 CFR part 70 or 40 CFR part 71, you must conduct the periodic testing in accordance with the terms and schedule required by your permit conditions. For each performance test: (1) For each capture and control system, determine the destruction or removal efficiency of each control device according to §63.5160(d) and the capture efficiency of each capture system according to §63.5160(e), and (2) confirm or re-establish the operating limits.

(a) If you use a control device to comply with the requirements of §63.5120, you are not required to conduct a performance test to demonstrate compliance if one or more of the criteria in paragraphs (a)(1) through (3) of this section are met:

(1) The control device is equipped with continuous emission monitors for determining total organic volatile matter concentration, and capture efficiency has been determined in accordance with the requirements of this subpart; and the continuous emission monitors are used to demonstrate continuous compliance in accordance with §63.5150(a)(2); or

(2) You have received a waiver of performance testing under §63.7(h); or

(3) The control device is a solvent recovery system and you choose to comply by means of a monthly liquid-liquid material balance.

(b) *Organic HAP content.* You must determine the organic HAP weight fraction of each coating material applied by following one of the procedures in paragraphs (b)(1) through (4) of this section:

(1) *Method 311.* You may test the material in accordance with Method 311 of appendix A of this part. The Method 311 determination may be performed by the manufacturer of the material and the results provided to you. The organic HAP content must be calculated according to the criteria and procedures in paragraphs (b)(1)(i) through (iii) of this section.

(i) Count only those organic HAP in Table 3 to this subpart that are measured to be present at greater than or equal to 0.1 weight percent and greater than or equal to 1.0 weight percent for other organic HAP compounds.

(ii) Express the weight fraction of each organic HAP you count according to paragraph (b)(1)(i) of this section as a value truncated to four places after the decimal point (for example, 0.3791).

(iii) Calculate the total weight fraction of organic HAP in the tested material by summing the counted individual organic HAP weight fractions and truncating the result to three places after the decimal point (for example, 0.763).

(2) *Method 24 in appendix A-7 of part 60.* For coatings, you may determine the total volatile matter content as weight fraction of nonaqueous volatile matter and use it as a substitute for organic HAP, using Method 24 in appendix A-7 of part 60. As an alternative to using Method 24, you may use ASTM D2369-10 (2015), "Test Method for Volatile Content of Coatings" (incorporated by reference, see §63.14). The determination of total volatile matter content using a method specified in this paragraph (b)(2) or as provided in paragraph (b)(3) of this section may be performed by the manufacturer of the coating and the results provided to you.

(3) *Alternative method.* You may use an alternative test method for determining the organic HAP weight fraction once the Administrator has approved it. You must follow the procedure in §63.7(f) to submit an alternative test method for approval.

(4) *Formulation data.* You may use formulation data provided that the information represents each organic HAP in Table 3 to this subpart that is present at a level equal to or greater than 0.1 percent and equal to or greater than 1.0 percent for other organic HAP compounds in any raw material used, weighted by the mass fraction of each raw material used in the material. Formulation data may be provided to you by the manufacturer of the coating material. In the event of any

inconsistency between test data obtained with the test methods specified in paragraphs (b)(1) through (3) of this section and formulation data, the test data will govern.

(c) *Solids content and density.* You must determine the solids content and the density of each coating material applied. You may determine the volume solids content using ASTM D2697-03(2014) Standard Test Method for Volume Nonvolatile Matter in Clear or Pigmented Coatings (incorporated by reference, see §63.14) or ASTM D6093-97 (2016) Standard Test Method for Percent Volume Nonvolatile Matter in Clear or Pigmented Coatings Using a Helium Gas Pycnometer (incorporated by reference, see §63.14), or an EPA approved alternative method. You must determine the density of each coating using ASTM D1475-13 "Standard Test Method for Density of Liquid Coatings, Inks, and Related Products" (incorporated by reference, see §63.14) or ASTM D2111-10 (2015) "Standard Test Methods for Specific Gravity and Density of Halogenated Organic Solvents and Their Admixtures" (incorporated by reference, see §63.14). The solids determination using ASTM D2697-03(2014) or ASTM D6093-97 (2016) and the density determination using ASTM D1475-13 or ASTM 2111-10 (2015) may be performed by the manufacturer of the material and the results provided to you. Alternatively, you may rely on formulation data provided by material providers to determine the volume solids. In the event of any inconsistency between test data obtained with the ASTM test methods specified in this section and formulation data, the test data will govern.

(d) *Control device destruction or removal efficiency.* If you are using an add-on control device, such as an oxidizer, to comply with the standard in §63.5120, you must conduct performance tests according to Table 1 to §63.5160 to establish the destruction or removal efficiency of the control device or the outlet HAP concentration achieved by the oxidizer, according to the methods and procedures in paragraphs (d)(1) and (2) of this section. During performance tests, you must establish the operating limits required by §63.5121 according to paragraph (d)(3) of this section.

(1) Performance tests conducted to determine the destruction or removal efficiency of the control device must be performed such that control device inlet and outlet testing is conducted simultaneously. To determine the outlet organic HAP concentration achieved by the oxidizer, only oxidizer outlet testing must be conducted. The data must be reduced in accordance with the test methods and procedures in paragraphs (d)(1)(i) through (ix).

(i) Method 1 or 1A of 40 CFR part 60, appendix A, is used for sample and velocity traverses to determine sampling locations.

(ii) Method 2, 2A, 2C, 2D, 2F, or 2G of 40 CFR part 60, appendix A, is used to determine gas volumetric flow rate.

(iii) Method 3, 3A, or 3B of 40 CFR part 60, appendix A, used for gas analysis to determine dry molecular weight. You may also use as an alternative to Method 3B, the manual method for measuring the oxygen, carbon dioxide, and carbon monoxide content of exhaust gas, ANSI/ASME PTC 19.10-1981, "Flue and Exhaust Gas Analyses" (incorporated by reference, see §63.14).

(iv) Method 4 of 40 CFR part 60, appendix A, is used to determine stack gas moisture.

(v) Methods for determining gas volumetric flow rate, dry molecular weight, and stack gas moisture must be performed, as applicable, during each test run, as specified in paragraph (d)(1)(vii) of this section.

(vi) Method 25 or 25A in appendix A-7 of part 60 is used to determine total gaseous non-methane organic matter concentration. You may use Method 18 in appendix A-6 of part 60 to subtract methane emissions from measured total gaseous organic mass emissions as carbon. Use the same test method for both the inlet and outlet measurements, which must be conducted simultaneously. You must submit notification of the intended test method to the Administrator for approval along with notification of the performance test required under §63.7 (b). You must use Method 25A if any of the conditions described in paragraphs (d)(1)(vi)(A) through (D) of this section apply to the control device.

(A) The control device is not an oxidizer.

(B) The control device is an oxidizer, but an exhaust gas volatile organic matter concentration of 50 ppmv or less is required to comply with the standards in §63.5120; or

(C) The control device is an oxidizer, but the volatile organic matter concentration at the inlet to the control system and the required level of control are such that they result in exhaust gas volatile organic matter concentrations of 50 ppmv or less; or

(D) The control device is an oxidizer, but because of the high efficiency of the control device, the anticipated volatile organic matter concentration at the control device exhaust is 50 ppmv or less, regardless of inlet concentration.

(vii) Each performance test must consist of three separate runs, except as provided by §63.7(e)(3); each run must be conducted for at least 1 hour under the conditions that exist when the affected source is operating under normal operating conditions. For the purpose of determining volatile organic matter concentrations and mass flow rates, the average of the results of all runs will apply. If you are demonstrating compliance with the outlet organic HAP concentration limit in §63.5120(a)(3), only the average outlet volatile organic matter concentration must be determined.

(viii) If you are determining the control device destruction or removal efficiency, for each run, determine the volatile organic matter mass flow rates using Equation 1 of this section:

$$M_f = Q_{sd} C_C (12)(0.0416)\left(10^{-6}\right) \quad (Eq.\ 1)$$

View or download PDF

Where:

M_f = total organic volatile matter mass flow rate, kg/per hour (h).

C_c = concentration of organic compounds as carbon in the vent gas, as determined by Method 25 or Method 25A, ppmv, dry basis.

Q_{sd} = volumetric flow rate of gases entering or exiting the control device, as determined by Method 2, 2A, 2C, 2D, 2F, or 2G, dry standard cubic meters (dscm)/h.

0.0416 = conversion factor for molar volume, kg-moles per cubic meter (mol/m^3) (@ 293 Kelvin (K) and 760 millimeters of mercury (mmHg)).

(ix) For each run, determine the control device destruction or removal efficiency, DRE, using Equation 2 of this section:

$$DRE = \frac{M_{fi} - M_{fo}}{M_{fi}} \times 100 \qquad \text{(Eq. 2)}$$

View or download PDF

Where:

DRE = organic emissions destruction or removal efficiency of the add-on control device, percent.

M_{fi} = organic volatile matter mass flow rate at the inlet to the control device, kg/h.

M_{fo} = organic volatile matter mass flow rate at the outlet of the control device, kg/h.

(x) The control device destruction or removal efficiency is determined as the average of the efficiencies determined in the three test runs and calculated in Equation 2 of this section.

(2) You must record such process information as may be necessary to determine the conditions in existence at the time of the performance test. Before August 24, 2020, operations during periods of start-up, shutdown, and malfunction will not constitute representative conditions for the purpose of a performance test. On and after August 24, 2020, you must conduct the performance test under representative operating conditions for the coating operation. Operations during periods of start-up, shutdown, or nonoperation do not constitute representative conditions for the purpose of a performance test. The owner or operator may not conduct performance tests during periods of malfunction. You must record the process information that is necessary to document operating conditions during the test and explain why the conditions represent normal operation. Upon request, you must make available to the Administrator such records as may be necessary to determine the conditions of performance tests.

(3) *Operating limits.* If you are using a capture system and add-on control device other than a solvent recovery system for which you conduct a liquid-liquid material balance to comply with the requirements in §63.5120, you must establish the applicable operating limits required by §63.5121. These operating limits apply to each capture system and to each add-on emission control device that is not monitored by CEMS, and you must establish the operating limits during performance tests required by paragraph (d) of this section according to the requirements in paragraphs (d)(3)(i) through (iii) of this section.

(i) *Thermal oxidizer.* If your add-on control device is a thermal oxidizer, establish the operating limits according to paragraphs (d)(3)(i)(A) and (B) of this section.

(A) During performance tests, you must monitor and record the combustion temperature at least once every 15 minutes during each of the three test runs. You must monitor the temperature in the firebox of the thermal oxidizer or immediately downstream of the firebox before any substantial heat exchange occurs.

(B) Use the data collected during the performance test to calculate and record the average combustion temperature maintained during the performance test. This average combustion temperature is the minimum operating limit for your thermal oxidizer.

(ii) *Catalytic oxidizer.* If your add-on control device is a catalytic oxidizer, establish the operating limits according to either paragraphs (d)(3)(ii)(A) and (B) or paragraphs (d)(3)(ii)(C) and (D) of this section.

(A) During the performance test, you must monitor and record the temperature just before the catalyst bed and the temperature difference across the catalyst bed at least once every 15 minutes during each of the three test runs.

(B) Use the data collected during the performance test to calculate and record the average temperature just before the catalyst bed and the average temperature difference across the catalyst bed maintained during the performance test. These are the minimum operating limits for your catalytic oxidizer.

(C) As an alternative to monitoring the temperature difference across the catalyst bed, you may monitor the temperature at the inlet to the catalyst bed and implement a site-specific inspection and maintenance plan for your catalytic oxidizer as specified in paragraph (d)(3)(ii)(D) of this section. During the performance test, you must monitor and record the temperature just before the catalyst bed at least once every 15 minutes during each of the three test runs. Use the data collected during the performance test to calculate and record the average temperature just before the catalyst bed during the performance test. This is the minimum operating limit for your catalytic oxidizer.

(D) You must develop and implement an inspection and maintenance plan for your catalytic oxidizer(s) for which you elect to monitor according to paragraph (d)(3)(ii)(C) of this section. The plan must address, at a minimum, the elements specified in paragraphs (d)(3)(ii)(D) *(1) through (3)* of this section.

(*1*) Annual sampling and analysis of the catalyst activity (*i.e.,* conversion efficiency) following the manufacturer's or catalyst supplier's recommended procedures.

(*2*) Monthly inspection of the oxidizer system including the burner assembly and fuel supply lines for problems and,

(*3*) Annual internal and monthly external visual inspection of the catalyst bed to check for channeling, abrasion, and settling. If problems are found, you must take corrective action consistent with the manufacturer's recommendations and conduct a new performance test to determine destruction efficiency according to §63.5160.

(iii) *Other types of control devices.* If you use a control device other than an oxidizer or a solvent recovery system for which you choose to comply by means of a monthly liquid-liquid material balance, or wish to monitor an alternative parameter and comply with a different operating limit, you must apply to the Administrator for approval of alternative monitoring under §63.8(f).

(e) *Capture efficiency.* If you are required to determine capture efficiency to meet the requirements of §63.5170(e)(2), (f)(1) and (2), (g)(2) through (4), or (i)(2) and (3), you must determine capture efficiency using the procedures in paragraph (e)(1), (2), or (3) of this section, as applicable.

(1) For an enclosure that meets the criteria for a PTE, you may assume it achieves 100 percent capture efficiency. You must confirm that your capture system is a PTE by demonstrating that it meets the requirements of section 6 of EPA Method 204 of 40 CFR part 51, appendix M (or an EPA approved alternative method), and that all exhaust gases from the enclosure are delivered to a control device.

(2) You may determine capture efficiency, CE, according to the protocols for testing with temporary total enclosures that are specified in Method 204A through F of 40 CFR part 51, appendix M. You may exclude never-controlled work stations from such capture efficiency determinations.

(3) As an alternative to the procedures specified in paragraphs (e)(1) and (2) of this section, if you are required to conduct a capture efficiency test, you may use any capture efficiency protocol and test methods that satisfy the criteria of either the Data Quality Objective or the Lower Confidence Limit approach as described in appendix A to subpart KK of this part. You may exclude never-controlled work stations from such capture efficiency determinations.

[67 FR 39812, June 10, 2002, as amended at 85 FR 10862, Feb. 25, 2020]

Back to Top

Requirements for Showing Compliance

Back to Top

§63.5170 How do I demonstrate compliance with the standards?

You must include all coating materials (as defined in §63.5110) used in the affected source when determining compliance with the applicable emission limit in §63.5120. To make this determination, you must use at least one of the four compliance options listed in Table 1 of this section. You may apply any of the compliance options to an individual coil coating line, or to multiple lines as a group, or to the entire affected source. You may use different compliance options for different coil coating lines, or at different times on the same line. However, you may not use different compliance options at the same time on the same coil coating line. If you switch between compliance options for any coil coating line or group of lines, you must document this switch as required by §63.5190(a), and you must report it in the next semiannual compliance report required in §63.5180.

Table 1 to §63.5170—Compliance Demonstration Requirements Index

If you choose to demonstrate compliance by:	Then you must demonstrate that:
1. Use of “as purchased” compliant coatings	a. Each coating material used during the 12-month compliance period does not exceed 0.046 kg HAP per liter solids, as purchased. Paragraph (a) of this section.
2. Use of “as applied” compliant coatings	a. Each coating material used does not exceed 0.046 kg HAP per liter solids on a rolling 12-month average as applied basis, determined monthly. Paragraphs (b)(1) of this section; or
	b. Average of all coating materials used does not exceed 0.046 kg HAP per liter solids on a rolling 12-month average as applied basis, determined monthly. Paragraph (b)(2) of this section.
3. Use of a capture system and	Overall organic HAP control efficiency is at least 98 percent on a

control device	monthly basis for individual or groups of coil coating lines; or overall organic HAP control efficiency is at least 98 percent during performance tests conducted according to Table 1 to §63.5170 and operating limits are achieved continuously for individual coil coating lines; or oxidizer outlet HAP concentration is no greater than 20 ppmv and there is 100-percent capture efficiency during performance tests conducted according to Table 1 to §63.5170 and operating limits are achieved continuously for individual coil coating lines. Paragraph (c) of this section.
4. Use of a combination of compliant coatings and control devices and maintaining an acceptable equivalent emission rate	Average equivalent emission rate does not exceed 0.046 kg HAP per liter solids on a rolling 12-month average as applied basis, determined monthly. Paragraph (d) of this section.

(a) *As-purchased compliant coatings.* If you elect to use coatings that individually meet the organic HAP emission limit in §63.5120(a)(2) as-purchased, to which you will not add HAP during distribution or application, you must demonstrate that each coating material applied during the 12-month compliance period contains no more than 0.046 kg HAP per liter of solids on an as-purchased basis.

(1) Determine the organic HAP content for each coating material in accordance with §63.5160(b) and the volume solids content in accordance with §63.5160(c).

(2) Combine these results using Equation 1 of this section and compare the result to the organic HAP emission limit in §63.5120(a)(2) to demonstrate that each coating material contains no more organic HAP than the limit.

$$H_{siap} = \frac{C_{hi} D_i}{V_{si}} \qquad (Eq.\ 1)$$

View or download PDF

Where:

H_{siap} = as-purchased, organic HAP to solids ratio of coating material, i, kg organic HAP/liter solids applied.

C_{hi} = organic HAP content of coating material, i, expressed as a weight-fraction, kg/kg.

D_i = density of coating material, i, kg/l.

Vsi = volume fraction of solids in coating, i, l/l.

(b) *As-applied compliant coatings.* If you choose to use "as-applied" compliant coatings, you must demonstrate that the average of each coating material applied during the 12-month compliance period contains no more than 0.046 kg of organic HAP per liter of solids applied in accordance with (b)(1) of this section, or demonstrate that the average of all coating materials applied during the 12-month compliance period contain no more than 0.046 kg of organic HAP per liter of solids applied in accordance with paragraph (b)(2) of this section.

(1) To demonstrate that the average organic HAP content on the basis of solids applied for each coating material applied, $H_{Si\ yr}$, is less than 0.046 kg HAP per liter solids applied for the 12-month compliance period, use Equation 2 of this section:

$$H_{Si\ yr} = \frac{\sum_{y=1}^{12}\left[V_i D_i C_{ahi} + \sum_{j=1}^{q} V_j D_j C_{hij}\right]}{\sum_{y=1}^{12} V_i V_{si}} \qquad (Eq.\ 2)$$

View or download PDF

Where:

$H_{si\ yr}$ = average for the 12-month compliance period, as-applied, organic HAP to solids ratio of material, i, kg organic HAP/liter solids applied.

V_i = volume of coating material, i, l.

D_i = density of coating material, i, kg/l.

C_{ahi} = monthly average, as-applied, organic HAP content of solids-containing coating material, i, expressed as a weight fraction, kilogram (kg)/kg.

V_j = volume of solvent, j, l.

D_j = density of solvent, j, kg/l.

C_{hij} = organic HAP content of solvent, j, added to coating material, i, expressed as a weight fraction, kg/kg.

V_{si} = volume fraction of solids in coating, i, l/l.

y = identifier for months.

q = number of different solvents, thinners, reducers, diluents, or other non-solids-containing coating materials applied in a month.

(2) To demonstrte that the average organic HAP content on the basis of solids applied, $H_{S\ yr}$, of all coating materials applied is less than 0.046 kg HAP per liter solids applied for the 12-month compliance period, use Equation 3 of this section:

$$H_{S\ yr} = \frac{\sum_{y=1}^{12}\left[\sum_{i=1}^{p} V_i D_i C_{ahi} + \sum_{j=1}^{q} V_j D_j C_{hij}\right]}{\sum_{y=1}^{12}\left[\sum_{i=1}^{p} V_i V_{si}\right]} \qquad (Eq.\ 3)$$

View or download PDF

Where:

$H_{s\,yr}$ = average for the 12-month compliance period, as-applied, organic HAP to solids ratio of all materials applied, kg organic HAP/liter solids applied.

Vi = volume of coating material, i, l.

D_i = density of coating material, i, kg/l.

C_{ahi} = monthly average, as-applied, organic HAP content of solids-containing coating material, i, expressed as a weight fraction, kilogram (kg)/kg.

Vj = volume of solvent, j, l.

D_j = density of solvent, j, kg/l.

C_{hij} = organic HAP content of solvent, j, added to coating material, i, expressed as a weight fraction, kg/kg.

Vsi = volume fraction of solids in coating, i, l/l.

p = number of different coating materials applied in a month.

q = number of different solvents, thinners, reducers, diluents, or other non-solids-containing coating materials applied in a month.

y = identifier for months.

(c) *Capture and control to reduce emissions to no more than the allowable limit.* If you use one or more capture systems and one or more control devices and demonstrate an average overall organic HAP control efficiency of at least 98 percent for each month to comply with §63.5120(a)(1); or operate a capture system and oxidizer so that the capture efficiency is 100 percent and the oxidizer outlet HAP concentration is no greater than 20 ppmv on a dry basis to comply with §63.5120(a)(3), you must follow one of the procedures in paragraphs (c)(1) through (4) of this section. Alternatively, you may demonstrate compliance for an individual coil coating line by operating its capture system and control device and continuous parameter monitoring system according to the procedures in paragraph (i) of this section.

(1) If the affected source uses one compliance procedure to limit organic HAP emissions to the level specified in §63.5120(a)(1) or (3) and has only always-controlled work stations, then you must demonstrate compliance with the provisions of paragraph (e) of this section when emissions from the affected source are controlled by one or more solvent recovery devices.

(2) If the affected source uses one compliance procedure to limit organic HAP emissions to the level specified in §63.5120(a)(1) or (3) and has only always-controlled work stations, then you must demonstrate compliance with the provisions of paragraph (f) of this section when emissions are controlled by one or more oxidizers.

(3) If the affected source operates both solvent recovery and oxidizer control devices, one or more never-controlled work stations, or one or more intermittently-controllable work stations, or uses more than one compliance procedure, then you must demonstrate compliance with the provisions of paragraph (g) of this section.

(4) The method of limiting organic HAP emissions to the level specified in §63.5120(a)(3) is the installation and operation of a PTE around each work station and associated curing oven in the

coating line and the ventilation of all organic HAP emissions from each PTE to an oxidizer with an outlet organic HAP concentration of no greater than 20 ppmv on a dry basis. An enclosure that meets the requirements in §63.5160(e)(1) is considered a PTE. Compliance of the oxidizer with the outlet organic HAP concentration limit is demonstrated either through continuous emission monitoring according to paragraph (c)(4)(ii) of this section or through performance tests according to the requirements of §63.5160(d) and Table 1 to §63.5160. If this method is selected, you must meet the requirements of paragraph (c)(4)(i) of this section to demonstrate continuing achievement of 100 percent capture of organic HAP emissions and either paragraph (c)(4)(ii) or paragraph (c)(4)(iii) of this section, respectively, to demonstrate continuous compliance with the oxidizer outlet organic HAP concentration limit through continuous emission monitoring or continuous operating parameter monitoring:

(i) Whenever a work station is operated, continuously monitor the capture system operating parameter established in accordance with §63.5150(a)(4).

(ii) To demonstrate that the value of the exhaust gas organic HAP concentration at the outlet of the oxidizer is no greater than 20 ppmv, on a dry basis, install, calibrate, operate, and maintain CEMS according to the requirements of §63.5150(a)(2).

(iii) To demonstrate continuous compliance with operating limits established in accordance with §63.5150(a)(3), whenever a work station is operated, continuously monitor the applicable oxidizer operating parameter.

(d) *Capture and control to achieve the emission rate limit.* If you use one or more capture systems and one or more control devices and limit the organic HAP emission rate to no more than 0.046 kg organic HAP emitted per liter of solids applied on a 12-month average as-applied basis, then you must follow one of the procedures in paragraphs (d)(1) through (3) of this section.

(1) If you use one or more solvent recovery devices, you must demonstrate compliance with the provisions in paragraph (e) of this section.

(2) If you use one or more oxidizers, you must demonstrate compliance with the provisions in paragraph (f) of this section.

(3) If you use both solvent recovery devices and oxidizers, or operate one or more never-controlled work stations or one or more intermittently controllable work stations, you must demonstrate compliance with the provisions in paragraph (g) of this section.

(e) *Use of solvent recovery to demonstrate compliance.* If you use one or more solvent recovery devices to control emissions from always-controlled work stations, you must show compliance by following the procedures in either paragraph (e)(1) or (2) of this section:

(1) *Liquid-liquid material balance.* Perform a liquid-liquid material balance for each month as specified in paragraphs (e)(1)(i) through (vi) of this section and use Equations 4 through 6 of this section to convert the data to units of this standard. All determinations of quantity of coating and composition of coating must be made at a time and location in the process after all ingredients (including any dilution solvent) have been added to the coating, or appropriate adjustments must be made to account for any ingredients added after the amount of coating has been determined.

(i) Measure the mass of each coating material applied on the work station or group of work stations controlled by one or more solvent recovery devices during the month.

(ii) If demonstrating compliance with the organic HAP emission rate based on solids applied, determine the organic HAP content of each coating material applied during the month following the procedure in §63.5160(b).

(iii) Determine the volatile matter content of each coating material applied during the month following the procedure in §63.5160(c).

(iv) If demonstrating compliance with the organic HAP emission rate based on solids applied, determine the solids content of each coating material applied during the month following the procedure in §63.5160(c).

(v) For each solvent recovery device used to comply with §63.5120(a), install, calibrate, maintain, and operate according to the manufacturer's specifications, a device that indicates the cumulative amount of volatile matter recovered by the solvent recovery device on a monthly basis. The device must be initially certified by the manufacturer to be accurate to within ±2.0 percent.

(vi) For each solvent recovery device used to comply with §63.5120(a), measure the amount of volatile matter recovered for the month.

(vii) *Recovery efficiency, R_v*. Calculate the volatile organic matter collection and recovery efficiency, R_v, using Equation 4 of this section:

$$R_v = 100 \frac{\sum_{k=1}^{s} M_{kvr}}{\sum_{i=1}^{p} M_i C_{vi} + \sum_{j=1}^{q} M_j} \qquad (Eq.\ 4)$$

View or download PDF

Where:

R_v = organic volatile matter collection and recovery efficiency, percent.

M_{kvr} = mass of volatile matter recovered in a month by solvent recovery device, k, kg.

M_i = mass of coating material, i, applied in a month, kg.

C_{vi} = volatile matter content of coating material, i, expressed as a weight fraction, kg/kg.

M_j = mass of solvent, thinner, reducer, diluent, or other non-solids-containing coating material (excluding H_2O), j, applied in a month, kg.

p = number of different coating materials applied in a month.

q = number of different solvents, thinners, reducers, diluents, or other non-solids-containing coating materials applied in a month.

s = number of solvent recovery devices used to comply with the standard of §63.5120 of this subpart, in the facility.

(viii) *Organic HAP emitted, H_e*. Calculate the mass of organic HAP emitted during the month, H_e, using Equation 5 of this section:

$$H_e = \left[1 - \frac{R_v}{100}\right]\left[\sum_{i=1}^{p}\left(C_{hi}M_i + \sum_{j=1}^{q} C_{hij}M_{ij}\right)\right] \qquad (Eq.\ 5)$$

View or download PDF

Where:

H_e = total monthly organic HAP emitted, kg.

R_v = organic volatile matter collection and recovery efficiency, percent.

C_{hi} = organic HAP content of coating material, i, expressed as a weight-fraction, kg/kg.

M_i = mass of coating material, i, applied in a month, kg.

C_{hij} = organic HAP content of solvent, j, added to coating material, i, expressed as a weight fraction, kg/kg.

M_{ij} = mass of solvent, thinner, reducer, diluent, or other non-solids-containing coating material, j, added to solids-containing coating material, i, in a month, kg.

p = number of different coating materials applied in a month.

q = number of different solvents, thinners, reducers, diluents, or other non-solids-containing coating materials applied in a month.

(ix) *Organic HAP emission rate based on solids applied for the 12-month compliance period,* L_{ANNUAL}. Calculate the organic HAP emission rate based on solids applied for the 12-month compliance period, L_{ANNUAL}, using Equation 6 of this section:

$$L_{ANNUAL} = \frac{\sum_{y=1}^{12} H_e}{\sum_{y=1}^{12}\left[\sum_{i=1}^{p} C_{si}M_i\right]} \qquad (Eq.\ 6)$$

View or download PDF

Where:

L_{ANNUAL} = mass organic HAP emitted per volume of solids applied for the 12-month compliance period, kg/liter.

H_e = total monthly organic HAP emitted, kg.

C_{si} = solids content of coating material, i, expressed as liter of solids/kg of material.

M_i = mass of coating material, i, applied in a month, kg.

y = identifier for months.

p = number of different coating materials applied in a month.

(x) *Compare actual performance to performance required by compliance option.* The affected source is in compliance with §63.5120(a) if it meets the requirement in either paragraph (e)(1)(x)(A) or (B) of this section:

(A) The average volatile organic matter collection and recovery efficiency, R_v, is 98 percent or greater each month of the 12-month compliance period; or

(B) The organic HAP emission rate based on solids applied for the 12-month compliance period, L_{ANNUAL}, is 0.046 kg organic HAP per liter solids applied or less.

(2) *Continuous emission monitoring of control device performance.* Use continuous emission monitors to demonstrate recovery efficiency, conduct performance tests of capture efficiency and volumetric flow rate, and continuously monitor a site specific operating parameter to ensure that capture efficiency and volumetric flow rate are maintained following the procedures in paragraphs (e)(2)(i) through (xi) of this section:

(i) *Control device destruction or removal efficiency, DRE.* For each control device used to comply with §63.5120(a), continuously monitor the gas stream entering and exiting the control device to determine the total volatile organic matter mass flow rate (e.g., by determining the concentration of the vent gas in grams per cubic meter and the volumetric flow rate in cubic meters per second, such that the total volatile organic matter mass flow rate in grams per second can be calculated using Equation 1 of §63.5160, and the percent destruction or removal efficiency, DRE, of the control device can be calculated for each month using Equation 2 of §63.5160.

(ii) Determine the percent capture efficiency, CE, for each work station in accordance with §63.5160(e).

(iii) *Capture efficiency monitoring.* Whenever a work station is operated, continuously monitor the operating parameter established in accordance with §63.5150(a)(4).

(iv) *Control efficiency, R.* Calculate the overall organic HAP control efficiency, R, achieved for each month using Equation 7 of this section:

$$R = 100\,\frac{\sum_{A=1}^{w}\left[\left(DRE_{K}CE_{A}\right)\left(\sum_{i=1}^{p}M_{Ai}C_{vi}+\sum_{j=1}^{q}M_{Aj}\right)\right]}{\sum_{i=1}^{p}M_{i}C_{vi}+\sum_{j=1}^{q}M_{j}} \qquad (Eq.\ 7)$$

View or download PDF

Where:

R = overall organic HAP control efficiency, percent.

DRE_k = organic volatile matter destruction or removal efficiency of control device, k, percent.

CE_A = organic volatile matter capture efficiency of the capture system for work station, A, percent.

M_{Ai} = mass of coating material, i, applied on work station, A, in a month, kg.

C_{vi} = volatile matter content of coating material, i, expressed as a weight fraction, kg/kg.

M_{Aj} = mass of solvent, thinner, reducer, diluent, or other non-solids-containing coating material (including H_2O), j, applied on work station, A, in a month, kg.

M_i = mass of coating material, i, applied in a month, kg.

M_j = mass of solvent, thinner, reducer, diluent, or other non-solids-containing coating material (excluding H_2O), j, applied in a month, kg.

w = number of always-controlled work stations in the facility.

p = number of different coating materials applied in a month.

q = number of different solvents, thinners, reducers, diluents, or other non-solids-containing coating materials applied in a month.

(v) If demonstrating compliance with the organic HAP emission rate based on solids applied, measure the mass of each coating material applied on each work station during the month.

(vi) If demonstrating compliance with the organic HAP emission rate based on solids applied, determine the organic HAP content of each coating material applied during the month in accordance with §63.5160(b).

(vii) If demonstrating compliance with the organic HAP emission rate based on solids applied, determine the solids content of each coating material applied during the month in accordance with §63.5160(c).

(viii) If demonstrating compliance with the organic HAP emission rate based on solids applied, calculate the organic HAP emitted during the month, H_e, for each month using Equation 8 of this section:

$$H_e = \sum_{A=1}^{w} \left[\left(1 - (DRE_K CE_A) \left(\sum_{i=1}^{p} \left(C_{hi} M_{Ai} + \sum_{j=1}^{q} C_{hij} M_{Aij} \right) \right) \right) \right] \qquad (Eq.\ 8)$$

View or download PDF

Where:

H_e = total monthly organic HAP emitted, kg.

DRE_k = organic volatile matter destruction or removal efficiency of control device, k, percent.

CE_A = organic volatile matter capture efficiency of the capture system for work station, A, percent.

C_{hi} = organic HAP content of coating material, i, expressed as a weight-fraction, kg/kg.

M_{Ai} = mass of coating material, i, applied on work station, A, in a month, kg.

C_{hij} = organic HAP content of solvent, j, added to coating material, i, expressed as a weight fraction, kg/kg.

M_{Aij} = mass of solvent, thinner, reducer, diluent, or other non-solids-containing coating material, j, added to solids-containing coating material, i, applied on work station, A, in a month, kg.

w = number of always-controlled work stations in the facility.

p = number of different coating materials applied in a month.

q = number of different solvents, thinners, reducers, diluents, or other non-solids-containing coating materials applied in a month.

(ix) *Organic HAP emission rate based on solids applied for the 12-month compliance period, L_{ANNUAL}*. Calculate the organic HAP emission rate based on solids applied for the 12-month compliance period, L_{ANNUAL}, using Equation 6 of this section.

(x) *Compare actual performance to performance required by compliance option.* The affected source is in compliance with §63.5120(a) if each capture system operating parameter is operated at an average value greater than or less than (as appropriate) the operating parameter value established in accordance with §63.5150 for each 3-hour period; and

(A) The overall organic HAP control efficiency, R, is 98 percent or greater for each; or

(B) The organic HAP emission rate based on solids applied for the 12-month compliance period, L_{ANNUAL}, is 0.046 kg organic HAP per liter solids applied or less.

(f) *Use of oxidation to demonstrate compliance.* If you use one or more oxidizers to control emissions from always controlled work stations, you must follow the procedures in either paragraph (f)(1) or (2) of this section:

(1) *Continuous monitoring of capture system and control device operating parameters.* Demonstrate compliance through performance tests of capture efficiency and control device efficiency and continuous monitoring of capture system and control device operating parameters as specified in paragraphs (f)(1)(i) through (xi) of this section:

(i) For each oxidizer used to comply with §63.5120(a), determine the oxidizer destruction or removal efficiency, DRE, using the procedure in §63.5160(d).

(ii) Whenever a work station is operated, continuously monitor the operating parameter established in accordance with §63.5150(a)(3).

(iii) Determine the capture system capture efficiency, CE, for each work station in accordance with §63.5160(e).

(iv) Whenever a work station is operated, continuously monitor the operating parameter established in accordance with §63.5150(a)(4).

(v) Calculate the overall organic HAP control efficiency, R, achieved using Equation 7 of this section.

(vi) If demonstrating compliance with the organic HAP emission rate based on solids applied, measure the mass of each coating material applied on each work station during the month.

(vii) If demonstrating compliance with the organic HAP emission rate based on solids applied, determine the organic HAP content of each coating material applied during the month following the procedure in §63.5160(b).

(viii) If demonstrating compliance with the organic HAP emission rate based on solids applied, determine the solids content of each coating material applied during the month following the procedure in §63.5160(c).

(ix) Calculate the organic HAP emitted during the month, H_e, for each month:

(A) For each work station and its associated oxidizer, use Equation 8 of this section.

(B) For periods when the oxidizer has not operated within its established operating limit, the control device efficiency is determined to be zero.

(x) *Organic HAP emission rate based on solids applied for the 12-month compliance period,* L_{ANNUAL}. If demonstrating compliance with the organic HAP emission rate based on solids applied for the 12-month compliance period, calculate the organic HAP emission rate based on solids applied, L_{ANNUAL}, for the 12-month compliance period using Equation 6 of this section.

(xi) *Compare actual performance to performance required by compliance option.* The affected source is in compliance with §63.5120(a) if each oxidizer is operated such that the average operating parameter value is greater than the operating parameter value established in §63.5150(a)(3) for each 3-hour period, and each capture system operating parameter average value is greater than or less than (as appropriate) the operating parameter value established in §63.5150(a)(4) for each 3-hour period; and the requirement in either paragraph (f)(1)(xi)(A) or (B) of this section is met.

(A) The overall organic HAP control efficiency, R, is 98 percent or greater for each; or

(B) The organic HAP emission rate based on solids applied, L_{ANNUAL}, is 0.046 kg organic HAP per liter solids applied or less for the 12-month compliance period.

(2) *Continuous emission monitoring of control device performance.* Use continuous emission monitors, conduct performance tests of capture efficiency, and continuously monitor a site specific operating parameter to ensure that capture efficiency is maintained. Compliance must be demonstrated in accordance with paragraph (e)(2) of this section.

(g) *Combination of capture and control.* You must demonstrate compliance according to the procedures in paragraphs (g)(1) through (8) of this section if both solvent recovery and oxidizer control devices, one or more never controlled coil coating stations, or one or more intermittently controllable coil coating stations are operated; or more than one compliance procedure is used.

(1) *Solvent recovery system using liquid/liquid material balance compliance demonstration.* For each solvent recovery system used to control one or more work stations for which you choose to comply by means of a liquid-liquid material balance, you must determine the organic HAP emissions each month of the 12-month compliance period for those work stations controlled by that solvent recovery system according to either paragraph (g)(1)(i) or (ii) of this section:

(i) In accordance with paragraphs (e)(1)(i) through (iii) and (e)(1)(v) through (viii) of this section if the work stations controlled by that solvent recovery system are only always-controlled work stations; or

(ii) In accordance with paragraphs (e)(1)(ii) through (iii), (e)(1)(v) through (vi), and (h) of this section if the work stations controlled by that solvent recovery system include one or more never-controlled or intermittently-controllable work stations.

(2) *Solvent recovery system using performance test and continuous monitoring compliance demonstration.* For each solvent recovery system used to control one or more coil coating stations for which you choose to comply by means of performance testing of capture efficiency, continuous emission monitoring of the control device, and continuous monitoring of a capture system operating

parameter, each month of the 12-month compliance period you must meet the requirements of paragraphs (g)(2)(i) and (ii) of this section:

(i) For each capture system delivering emissions to that solvent recovery system, monitor an operating parameter established in §63.5150(a)(4) to ensure that capture system efficiency is maintained; and

(ii) Determine the organic HAP emissions for those work stations served by each capture system delivering emissions to that solvent recovery system according to either paragraph (g)(2)(ii)(A) or (B) of this section:

(A) In accordance with paragraphs (e)(2)(i) through (iii) and (e)(2)(v) through (viii) of this section if the work stations served by that capture system are only always-controlled coil coating stations; or

(B) In accordance with paragraphs (e)(2)(i) through (iii), (e)(2)(v) through (vii), and (h) of this section if the work stations served by that capture system include one or more never-controlled or intermittently-controllable work stations.

(3) *Oxidizer using performance tests and continuous monitoring of operating parameters compliance demonstration.* For each oxidizer used to control emissions from one or more work stations for which you choose to demonstrate compliance through performance tests of capture efficiency, control device efficiency, and continuous monitoring of capture system and control device operating parameters, each month of the 12-month compliance period you must meet the requirements of paragraphs (g)(3)(i) through (iii) of this section:

(i) Monitor an operating parameter established in §63.5150(a)(3) to ensure that control device destruction or removal efficiency is maintained; and

(ii) For each capture system delivering emissions to that oxidizer, monitor an operating parameter established in §63.5150(a)(4) to ensure capture efficiency; and

(iii) Determine the organic HAP emissions for those work stations served by each capture system delivering emissions to that oxidizer according to either paragraph (g)(3)(iii)(A) or (B) of this section:

(A) In accordance with paragraphs (f)(1)(i) through (v) and (ix) of this section if the work stations served by that capture system are only always-controlled work stations; or

(B) In accordance with paragraphs (f)(1)(i) through (v), (ix), and (h) of this section if the work stations served by that capture system include one or more never-controlled or intermittently-controllable work stations.

(4) *Oxidizer using continuous emission monitoring compliance demonstration.* For each oxidizer used to control emissions from one or more work stations for which you choose to demonstrate compliance through capture efficiency testing, continuous emission monitoring of the control device, and continuous monitoring of a capture system operating parameter, each month of the 12-month compliance period you must meet the requirements in paragraphs (g)(4)(i) and (ii) of this section:

(i) For each capture system delivering emissions to that oxidizer, monitor an operating parameter established in §63.5150(a)(4) to ensure capture efficiency; and

(ii) Determine the organic HAP emissions for those work stations served by each capture system delivering emissions to that oxidizer according to either paragraph (g)(4)(ii)(A) or (B) of this section:

(A) In accordance with paragraphs (e)(2)(i) through (iii) and (e)(2)(v) through (viii) of this section if the work stations served by that capture system are only always-controlled work stations; or

(B) In accordance with paragraphs (e)(2)(i) through (iii), (e)(2)(v) through (vii), and (h) of this section if the work stations served by that capture system include one or more never-controlled or intermittently-controllable work stations.

(5) *Uncontrolled work stations.* For uncontrolled work stations, each month of the 12-month compliance period you must determine the organic HAP applied on those work stations using Equation 9 of this section. The organic HAP emitted from an uncontrolled work station is equal to the organic HAP applied on that work station:

$$H_m = \sum_{A=1}^{x}\left(\sum_{i=1}^{p} C_{hi} M_{Ai} + \sum_{j=1}^{q} C_{hij} M_{Aij}\right) \qquad \text{(Eq. 9)}$$

View or download PDF

Where:

H_m = facility total monthly organic HAP applied on uncontrolled coil coating stations, kg.

C_{hi} = organic HAP content of coating material, i, expressed as a weight-fraction, kg/kg.

M_{Ai} = mass of coating material, i, applied on work station, A, in a month, kg.

C_{hij} = organic HAP content of solvent, j, added to coating material, i, expressed as a weight fraction, kg/kg.

M_{Aij} = mass of solvent, thinner, reducer, diluent, or other non-solids-containing coating material, j, added to solids-containing coating material, i, applied on work station, A, in a month, kg.

x = number of uncontrolled work stations in the facility.

p = number of different coating materials applied in a month.

q = number of different solvents, thinners, reducers, diluents, or other non-solids-containing coating materials applied in a month.

(6) If demonstrating compliance with the organic HAP emission rate based on solids applied, each month of the 12-month compliance period you must determine the solids content of each coating material applied during the month following the procedure in §63.5160(c).

(7) *Organic HAP emitted.* You must determine the organic HAP emissions for the affected source for each 12-month compliance period by summing all monthly organic HAP emissions calculated according to paragraphs (g)(1), (g)(2)(ii), (g)(3)(iii), (g)(4)(ii), and (g)(5) of this section.

(8) *Compare actual performance to performance required by compliance option.* The affected source is in compliance with §63.5120(a) for the 12-month compliance period if all operating parameters required to be monitored under paragraphs (g)(2) through (4) of this section were

maintained at the values established in §63.5150; and it meets the requirement in either paragraph (g)(8)(i) or (ii) of this section.

(i) The total mass of organic HAP emitted by the affected source was not more than 0.046 kg HAP per liter of solids applied for the 12-month compliance period; or

(ii) The total mass of organic HAP emitted by the affected source was not more than 2 percent of the total mass of organic HAP applied by the affected source each month. You must determine the total mass of organic HAP applied by the affected source in each month of the 12-month compliance period using Equation 9 of this section.

(h) *Organic HAP emissions from intermittently-controllable or never-controlled coil coating stations.* If you have been expressly referenced to this paragraph by paragraphs (g)(1)(ii), (g)(2)(ii)(B), (g)(3)(iii)(B), or (g)(4)(ii)(B) of this section for calculation procedures to determine organic HAP emissions, you must for your intermittently-controllable or never-controlled work stations meet the requirements of paragraphs (h)(1) through (6) of this section:

(1) Determine the sum of the mass of all solids-containing coating materials which are applied on intermittently-controllable work stations in bypass mode, and the mass of all solids-containing coating materials which are applied on never-controlled coil coating stations during each month of the 12-month compliance period, M_{Bi}.

(2) Determine the sum of the mass of all solvents, thinners, reducers, diluents, and other nonsolids-containing coating materials which are applied on intermittently-controllable work stations in bypass mode, and the mass of all solvents, thinners, reducers, diluents and other nonsolids-containing coating materials which are applied on never-controlled work stations during each month of the 12-month compliance period, M_{Bj}.

(3) Determine the sum of the mass of all solids-containing coating materials which are applied on intermittently-controllable work stations in controlled mode, and the mass of all solids-containing coating materials which are applied on always-controlled work stations during each month of the 12-month compliance period, M_{Ci}.

(4) Determine the sum of the mass of all solvents, thinners, reducers, diluents, and other nonsolids-containing coating materials which are applied on intermittently-controllable work stations in controlled mode, and the mass of all solvents, thinners, reducers, diluents, and other nonsolids-containing coating materials which are applied on always-controlled work stations during each month of the 12-month compliance period, M_{Cj}.

(5) *Liquid-liquid material balance calculation of HAP emitted.* For each work station or group of work stations for which you use the provisions of paragraph (g)(1)(ii) of this section, you must calculate the organic HAP emitted during the month using Equation 10 of this section:

$$H_e = \left[\sum_{i=1}^{p} M_{Ci} C_{hi} + \sum_{j=1}^{q} M_{Cj} C_{hj}\right]\left[1 - \frac{\sum_{k=1}^{s} M_{kvr}}{\sum_{i=1}^{p} M_{Ci} C_{vi} + \sum_{j=1}^{q} M_{Cj}}\right] + \left[\sum_{i=1}^{p} M_{Bi} C_{hi} + \sum_{j=1}^{q} M_{Bj} C_{hj}\right] \qquad \text{(Eq. 10)}$$

View or download PDF

Where:

H_e = total monthly organic HAP emitted, kg.

M_{ci} = sum of the mass of solids-containing coating material, i, applied on intermittently-controllable work stations operating in controlled mode and the mass of solids-containing coating material, i, applied on always-controlled work stations, in a month, kg.

C_{hi} = organic HAP content of coating material, i, expressed as a weight-fraction, kg/kg.

M_{cj} = sum of the mass of solvent, thinner, reducer, diluent, or other non-solids-containing coating material, j, applied on intermittently-controllable work stations operating in controlled mode and the mass of solvent, thinner, reducer, diluent, or other non-solids-containing coating material, j, applied on always-controlled work stations in a month, kg.

C_{hj} = organic HAP content of solvent, j, expressed as a weight fraction, kg/kg.

M_{kvr} = mass of volatile matter recovered in a month by solvent recovery device, k, kg.

C_{vi} = volatile matter content of coating material, i, expressed as a weight fraction, kg/kg.

M_{Bi} = sum of the mass of solids-containing coating material, i, applied on intermittently-controllable work stations operating in bypass mode and the mass of solids-containing coating material, i, applied on never-controlled work stations, in a month, kg.

M_{Bj} = sum of the mass of solvent, thinner, reducer, diluent, or other non-solids-containing coating material, j, applied on intermittently-controllable work stations operating in bypass mode and the mass of solvent, thinner, reducer, diluent, or other non-solids-containing coating material, j, applied on never-controlled work stations, in a month, kg.

p = number of different coating materials applied in a month.

q = number of different solvents, thinners, reducers, diluents, or other non-solids-containing coating materials applied in a month.

s = number of solvent recovery devices used to comply with the standard of §63.5120 of this subpart, in the facility.

(6) *Control efficiency calculation of HAP emitted.* For each work station or group of work stations for which you use the provisions of paragraphs (g)(2)(ii)(B), (g)(3)(iii)(B), or (g)(4)(ii)(B) of this section, you must calculate the organic HAP emitted during the month, H_e, using Equation 11 of this section:

$$He = \sum_{A=1}^{w_i}\left[\left(\sum_{i=1}^{p} M_{ci}C_{hi} + \sum_{j=1}^{q} M_{cj}C_{hj}\right)(1 - DRE_k CE_A)\right] + \left[\sum_{i=1}^{p} M_{Bi}C_{hi} + \sum_{j=1}^{q} M_{Bj}C_{hj}\right] \quad \text{(Eq. 11)}$$

View or download PDF

Where:

H_e = total monthly organic HAP emitted, kg.

M_{ci} = sum of the mass of solids-containing coating material, i, applied on intermittently-controllable work stations operating in controlled mode and the mass of solids-containing coating material, i, applied on always-controlled work stations, in a month, kg.

C_{hi} = organic HAP content of coating material, i, expressed as a weight-fraction, kg/kg.

M_{cj} = sum of the mass of solvent, thinner, reducer, diluent, or other non-solids-containing coating material, j, applied on intermittently-controllable work stations operating in controlled mode and the mass of solvent, thinner, reducer, diluent, or other non-solids-containing coating material, j, applied on always-controlled work stations in a month, kg.

C_{hj} = organic HAP content of solvent, j, expressed as a weight fraction, kg/kg.

DRE_k = organic volatile matter destruction or removal efficiency of control device, k, percent.

CE_A = organic volatile matter capture efficiency of the capture system for work station, A, percent.

M_{Bi} = sum of the mass of solids-containing coating material, i, applied on intermittently-controllable work stations operating in bypass mode and the mass of solids-containing coating material, i, applied on never-controlled work stations, in a month, kg.

M_{Bj} = sum of the mass of solvent, thinner, reducer, diluent, or other non-solids-containing coating material, j, applied on intermittently-controllable work stations operating in bypass mode and the mass of solvent, thinner, reducer, diluent, or other non-solids-containing coating material, j, applied on never-controlled work stations, in a month, kg.

w_i = number of intermittently-controllable work stations in the facility.

p = number of different coating materials applied in a month.

q = number of different solvents, thinners, reducers, diluents, or other non-solids-containing coating materials applied in a month.

(i) *Capture and control system compliance demonstration procedures using a CPMS for a coil coating line.* If you use an add-on control device, to demonstrate compliance for each capture system and each control device through performance tests and continuous monitoring of capture system and control device operating parameters, you must meet the requirements in paragraphs (i)(1) through (3) of this section.

(1) Conduct performance tests according to the schedule in Table 1 to §63.5160 to determine the control device destruction or removal efficiency, DRE, according to §63.5160(d) and Table 1 to §63.5160.

(2) Determine the emission capture efficiency, CE, in accordance with §63.5160(e).

(3) Whenever a coil coating line is operated, continuously monitor the operating parameters established according to §63.5150(a)(3) and (4) to ensure capture and control efficiency.

[67 FR 39812, June 10, 2002, as amended at 85 FR 10864, Feb. 25, 2020]

Back to Top

Reporting and Recordkeeping

Back to Top

§63.5180 What reports must I submit?

Link to an amendment published at 85 FR 73908, Nov. 19, 2020.

(a) Submit the reports specified in paragraphs (b) through (i) of this section to the EPA Regional Office that serves the State or territory in which the affected source is located and to the delegated State agency:

(b) You must submit an initial notification required in §63.9(b).

(1) Submit an initial notification for an existing source no later than 2 years after June 10, 2002.

(2) Submit an initial notification for a new or reconstructed source as required by §63.9(b).

(3) For the purpose of this subpart, a title V permit application may be used in lieu of the initial notification required under §63.9(b), provided the same information is contained in the permit application as required by §63.9(b), and the State to which the permit application has been submitted has an approved operating permit program under part 70 of this chapter and has received delegation of authority from the EPA.

(4) Submit a title V permit application used in lieu of the initial notification required under §63.9(b) by the same due dates as those specified in paragraphs (b)(1) and (2) of this section for the initial notifications.

(c) You must submit a Notification of Performance Test as specified in §§63.7 and 63.9(e) if you are complying with the emission standard using a control device. This notification and the site-specific test plan required under §63.7(c)(2) must identify the operating parameter to be monitored to ensure that the capture efficiency measured during the performance test is maintained. You may consider the operating parameter identified in the site-specific test plan to be approved unless explicitly disapproved, or unless comments received from the Administrator require monitoring of an alternate parameter.

(d) You must submit a Notification of Compliance Status as specified in §63.9(h). You must submit the Notification of Compliance Status no later than 30 calendar days following the end of the initial 12-month compliance period described in §63.5130.

(e) You must submit performance test reports as specified in §63.10(d)(2) if you are using a control device to comply with the emission standards and you have not obtained a waiver from the performance test requirement.

(f) Before August 24, 2020, you must submit start-up, shutdown, and malfunction reports as specified in §63.10(d)(5) if you use a control device to comply with this subpart.

(1) Before August 24, 2020, if your actions during a start-up, shutdown, or malfunction of an affected source (including actions taken to correct a malfunction) are not completely consistent with the procedures specified in the source's start-up, shutdown, and malfunction plan specified in §63.6 (e)(3) and required before August 24, 2020, you must state such information in the report. The start-up, shutdown, or malfunction report will consist of a letter containing the name, title, and signature of the responsible official who is certifying its accuracy, that will be submitted to the Administrator. Separate start-up, shutdown, or malfunction reports are not required if the information is included in the report specified in paragraph (g) of this section. The start-up, shutdown, and malfunction plan and start-up, shutdown, and malfunction report are no longer required on and after August 24, 2020.

(2) [Reserved]

(g) You must submit semi-annual compliance reports containing the information specified in paragraphs (g)(1) and (2) of this section.

(1) Compliance report dates.

(i) The first semiannual reporting period begins 1 day after the end of the initial compliance period described in §63.5130(d) that applies to your affected source and ends 6 months later.

(ii) The first semiannual compliance report must cover the first semiannual reporting period and be postmarked or delivered no later than 30 days after the reporting period ends.

(iii) 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.

(iv) Each subsequent compliance report must be postmarked or delivered no later than July 31 or January 31, whichever date is the first date following the end of the semiannual reporting period.

(v) For each affected source that is subject to permitting regulations pursuant to 40 CFR part 70 or part 71, and the permitting authority has established dates for submitting semiannual reports pursuant to 40 CFR 70.6(a)(3)(iii)(A) or 40 CFR 71.6(a)(3)(iii)(A), you may submit the first and subsequent compliance reports according to the dates the permitting authority has established instead of according to the dates in paragraphs (g)(1)(i) through (iv) of this section.

(2) The semi-annual compliance report must contain the following information:

(i) Company name and address.

(ii) Statement by a responsible official with that official's name, title, and signature, certifying the accuracy of the content of the report.

(iii) Date of report and beginning and ending dates of the reporting period. The reporting period is the 6-month period ending on June 30 or December 31. Note that the information reported for each of the 6 months in the reporting period will be based on the last 12 months of data prior to the date of each monthly calculation.

(iv) Identification of the compliance option or options specified in Table 1 to §63.5170 that you used on each coating operation during the reporting period. If you switched between compliance options during the reporting period, you must report the beginning dates you used each option.

(v) A statement that there were no deviations from the applicable emission limit in §63.5120 or the applicable operating limit(s) established according to §63.5121 during the reporting period, and that no CEMS were inoperative, inactive, malfunctioning, out-of-control, repaired, or adjusted.

(h) You must submit, for each deviation occurring at an affected source where you are not using CEMS to comply with the standards in this subpart, the semi-annual compliance report containing the information in paragraphs (g)(2)(i) through (iv) of this section and the information in paragraphs (h)(1) through (4) of this section:

(1) The total operating time of each affected source during the reporting period.

(2) Before August 24, 2020, you must provide information on the number, duration, and cause of deviations (including unknown cause, if applicable) as applicable, and the corrective action taken. On and after August 24, 2020, you must provide information on the number, date, time, duration, and cause of deviations from an emission limit in §63.5120 or any applicable operating limit established according to §63.5121 (including unknown cause, if applicable) as applicable, and the corrective action taken.

(3) Before August 24, 2020, you must provide information on the number, duration, and cause for continuous parameter monitoring system downtime incidents (including unknown cause other than downtime associated with zero and span and other daily calibration checks, if applicable). On and after August 24, 2020, you must provide the information specified in paragraphs (h)(3)(i) and (ii) of this section.

(i) Number, date, time, duration, cause (including unknown cause), and descriptions of corrective actions taken for continuous parameter monitoring systems that are inoperative (except for zero (low-level) and high-level checks).

(ii) Number, date, time, duration, cause (including unknown cause), and descriptions of corrective actions taken for continuous parameter monitoring systems that are out of control as specified in §63.8(c)(7).

(4) On and after August 24, 2020, for each deviation from an emission limit in §63.5120 or any applicable operating limit established according to §63.5121, you must provide a list of the affected source or equipment, an estimate of the quantity of each regulated pollutant emitted over any emission limit in §63.5120, a description of the method used to estimate the emissions, and the actions you took to minimize emissions in accordance with §63.5140(b).

(i) You must submit, for each deviation from the applicable emission limit in §63.5120 or the applicable operation limit(s) established according to §63.5121 occurring at an affected source where you are using CEMS to comply with the standards in this subpart, the semi-annual compliance report containing the information in paragraphs (g)(2)(i) through (iv) of this section, and the information in paragraphs (i)(1) through (12) of this section:

(1) The date and time that each malfunction of the capture system or add-on control devices started and stopped.

(2) Before August 24, 2020, the date and time that each CEMS was inoperative, except for zero (low-level) and high-level checks. On and after August 24, 2020, for each instance that the CEMS was inoperative, except for zero (low-level) and high-level checks, the date, time, and duration that the CEMS was inoperative; the cause (including unknown cause) for the CEMS being inoperative; and a description of corrective actions taken.

(3) Before August 24, 2020, the date and time that each CEMS was out-of-control, including the information in §63.8(c)(8). On and after August 24, 2020, for each instance that the CEMS was out-of-control, as specified in §63.8(c)(7), the date, time, and duration that the CEMS was out-of-control; the cause (including unknown cause) for the CEMS being out-of-control; and descriptions of corrective actions taken.

(4) Before August 24, 2020, the date and time that each deviation started and stopped, and whether each deviation occurred during a period of start-up, shutdown, or malfunction or during another period. On and after August 24, 2020, the date, time, and duration of each deviation from an emission limit in §63.5120. For each deviation, an estimate of the quantity of each regulated

pollutant emitted over any emission limit in §63.5120 to this subpart, and a description of the method used to estimate the emissions.

(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) Before August 24, 2020, a breakdown of the total duration of the deviations during the reporting period into those that are due to start-up, shutdown, control equipment problems, process problems, other known causes, and other unknown causes. On and after August 24, 2020, a breakdown 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 CEMS downtime during the reporting period, and the total duration of CEMS downtime as a percent of the total source operating time during that reporting period.

(8) A breakdown of the total duration of CEMS downtime during the reporting period into periods that are due to monitoring equipment malfunctions, nonmonitoring equipment malfunctions, quality assurance/quality control calibrations, other known causes, and other unknown causes.

(9) Before August 24, 2020, a brief description of the metal coil coating line. On and after August 24, 2020, a list of the affected source or equipment, including a brief description of the metal coil coating line.

(10) The monitoring equipment manufacturer(s) and model number(s).

(11) The date of the latest CEMS certification or audit.

(12) A description of any changes in CEMS, processes, or controls since the last reporting period.

[67 FR 39812, June 10, 2002, as amended at 68 FR 12592, Mar. 17, 2003; 85 FR 10865, Feb. 25, 2020]

Back to Top

§63.5181 What are my electronic reporting requirements?

(a) Beginning no later than August 24, 2020, you must submit the results of each performance test as required in §63.5180(e) following the procedure specified in paragraphs (a)(1) through (3) of this section.

(1) For data collected using test methods supported by the EPA's Electronic Reporting Tool (ERT) as listed on the EPA's ERT website (*https://www.epa.gov/electronic-reporting-air-emissions/electronic-reporting-tool-ert*) at the time of the test, you must submit the results of the performance test to the EPA via the Compliance and Emissions Data Reporting Interface (CEDRI). The CEDRI interface can be accessed through the EPA's Central Data Exchange (CDX) (*https://cdx.epa.gov/*). Performance test data must be submitted in a file format generated through the use of the EPA's ERT or an alternate electronic file format consistent with the extensible markup language (XML) schema listed on the EPA's ERT website.

(2) For data collected using test methods that are not supported by the EPA's ERT as listed on the EPA's ERT website at the time of the test, you must submit the results of the performance test in portable document format (PDF) using the attachment module of the ERT.

(3) If you claim that some of the performance test information being submitted under paragraph (a)(1) of this section is confidential business information (CBI), you must submit a complete file generated through the use of the EPA's ERT or an alternate electronic file consistent with the XML schema listed on the EPA's ERT website, including information claimed to be CBI, on a compact disc, flash drive or other commonly used electronic storage medium to the EPA. The electronic medium must be clearly marked as CBI and mailed to U.S. EPA/OAQPS/CORE CBI Office, Attention: Group Leader, Measurement Policy Group, MD C404-02, 4930 Old Page Rd., Durham, NC 27703. The same ERT or alternate file with the CBI omitted must be submitted to the EPA via the EPA's CDX as described in paragraph (a)(1) of this section.

(b) Beginning on August 24, 2020, the owner or operator shall submit the initial notifications required in §63.9(b) and the notification of compliance status required in §§63.9(h) and 63.5180(d) to the EPA via the CEDRI. The CEDRI interface can be accessed through the EPA's CDX (*https://cdx.epa.gov*). The owner or operator must upload to CEDRI an electronic copy of each applicable notification in PDF. The applicable notification must be submitted by the deadline specified in this subpart, regardless of the method in which the reports are submitted. Owners or operators who claim that some of the information required to be submitted via CEDRI is CBI shall submit a complete report generated using the appropriate form in CEDRI or an alternate electronic file consistent with the XML schema listed on the EPA's CEDRI website, including information claimed to be CBI, on a compact disc, flash drive, or other commonly used electronic storage medium to the EPA. The electronic medium shall be clearly marked as CBI and mailed to U.S. EPA/OAQPS/CORE CBI Office, Attention: Group Leader, Measurement Policy Group, MD C404-02, 4930 Old Page Rd., Durham, NC 27703. The same file with the CBI omitted shall be submitted to the EPA via the EPA's CDX as described earlier in this paragraph.

(c) Beginning on March 25, 2021, or once the reporting template has been available on the CEDRI website for 1 year, whichever date is later, the owner or operator shall submit the semiannual compliance report required in §63.5180(g) through (i), as applicable, to the EPA via the CEDRI. The CEDRI interface can be accessed through the EPA's CDX (*https://cdx.epa.gov*). The owner or operator must use the appropriate electronic template on the CEDRI website for this subpart (*https://www.epa.gov/electronic-reporting-air-emissions/compliance-and-emissions-data-reporting-interface-cedri*). The date on which the report templates become available will be listed on the CEDRI website. If the reporting form for the semiannual compliance report specific to this subpart is not available in CEDRI at the time that the report is due, you must submit the report to the Administrator at the appropriate addresses listed in §63.13. Once the form has been available in CEDRI for 1 year, you must begin submitting all subsequent reports via CEDRI. The reports must be submitted by the deadlines specified in this subpart, regardless of the method in which the reports are submitted. Owners or operators who claim that some of the information required to be submitted via CEDRI is CBI shall submit a complete report generated using the appropriate form in CEDRI, including information claimed to be CBI, on a compact disc, flash drive, or other commonly used electronic storage medium to the EPA. The electronic medium shall be clearly marked as CBI and mailed to U.S. EPA/OAQPS/CORE CBI Office, Attention: Group Leader, Measurement Policy Group, MD C404-02, 4930 Old Page Rd., Durham, NC 27703. The same file with the CBI omitted shall be submitted to the EPA via the EPA's CDX as described earlier in this paragraph.

(d) If you are required to electronically submit a report through the CEDRI in the EPA's CDX, you may assert a claim of EPA system outage for failure to timely comply with the reporting requirement. To assert a claim of EPA system outage, you must meet the requirements outlined in paragraphs (g)(1) through (7) of this section.

(1) You must have been or will be precluded from accessing CEDRI and submitting a required report within the time prescribed due to an outage of either the EPA's CEDRI or CDX systems.

(2) The outage must have occurred within the period of time beginning five business days prior to the date that the submission is due.

(3) The outage may be planned or unplanned.

(4) You must submit notification to the Administrator in writing as soon as possible following the date you first knew, or through due diligence should have known, that the event may cause or caused a delay in reporting.

(5) You must provide to the Administrator a written description identifying:

(i) The date(s) and time(s) when CDX or CEDRI was accessed and the system was unavailable;

(ii) A rationale for attributing the delay in reporting beyond the regulatory deadline to the EPA system outage;

(iii) Measures taken or to be taken to minimize the delay in reporting; and

(iv) The date by which you propose to report, or if you have already met the reporting requirement at the time of the notification, the date you reported.

(6) The decision to accept the claim of EPA system outage and allow an extension to the reporting deadline is solely within the discretion of the Administrator.

(7) In any circumstance, the report must be submitted electronically as soon as possible after the outage is resolved.

(e) If you are required to electronically submit a report through CEDRI in the EPA's CDX, you may assert a claim of force majeure for failure to timely comply with the reporting requirement. To assert a claim of force majeure, you must meet the requirements outlined in paragraphs (h)(1) through (5) of this section.

(1) You may submit a claim if a force majeure event is about to occur, occurs, or has occurred or there are lingering effects from such an event within the period of time beginning five business days prior to the date the submission is due. For the purposes of this section, a force majeure event is defined as an event that will be or has been caused by circumstances beyond the control of the affected facility, its contractors, or any entity controlled by the affected facility that prevents you from complying with the requirement to submit a report electronically within the time period prescribed. Examples of such events are acts of nature (*e.g.,* hurricanes, earthquakes, or floods), acts of war or terrorism, or equipment failure or safety hazard beyond the control of the affected facility (*e.g.,* large scale power outage).

(2) You must submit notification to the Administrator in writing as soon as possible following the date you first knew, or through due diligence should have known, that the event may cause or has caused a delay in reporting.

(3) You must provide to the Administrator:

(i) A written description of the force majeure event;

(ii) A rationale for attributing the delay in reporting beyond the regulatory deadline to the force majeure event;

(iii) Measures taken or to be taken to minimize the delay in reporting; and

(iv) The date by which you propose to report, or if you have already met the reporting requirement at the time of the notification, the date you reported.

(4) The decision to accept the claim of force majeure and allow an extension to the reporting deadline is solely within the discretion of the Administrator.

(5) In any circumstance, the reporting must occur as soon as possible after the force majeure event occurs.

[85 FR 10866, Feb. 25, 2020]

Back to Top

§63.5190   What records must I maintain?

(a) You must maintain the records specified in paragraphs (a) and (b) of this section in accordance with §63.10(b)(1):

(1) Records of the coating lines on which you used each compliance option and the time periods (beginning and ending dates and times) you used each option.

(2) Records specified in §63.10(b)(2) of all measurements needed to demonstrate compliance with this subpart, including:

(i) Continuous emission monitor data in accordance with §63.5150(a)(2);

(ii) Control device and capture system operating parameter data in accordance with §63.5150(a)(1), (3), and (4);

(iii) Organic HAP content data for the purpose of demonstrating compliance in accordance with §63.5160(b);

(iv) Volatile matter and solids content data for the purpose of demonstrating compliance in accordance with §63.5160(c);

(v) Overall control efficiency determination or alternative outlet HAP concentration using capture efficiency tests and control device destruction or removal efficiency tests in accordance with §63.5160(d), (e), and (f); and

(vi) Material usage, HAP usage, volatile matter usage, and solids usage and compliance demonstrations using these data in accordance with §63.5170(a), (b), and (d);

(3) Records specified in §63.10(b)(3); and

(4) Additional records specified in §63.10(c) for each continuous monitoring system operated by the owner or operator in accordance with §63.5150(a)(2).

(5) On and after August 24, 2020, for each deviation from an emission limitation reported under §63.5180(h) or (i), a record of the information specified in paragraphs (a)(5)(i) through (iv) of this section, as applicable.

(i) The date, time, and duration of the deviation, as reported under §63.5180(h) and (i).

(ii) A list of the affected sources or equipment for which the deviation occurred and the cause of the deviation, as reported under §63.5180(h) and (i).

(iii) An estimate of the quantity of each regulated pollutant emitted over any applicable emission limit in §63.5120 to this subpart or any applicable operating limit established according to §63.5121 to this subpart, and a description of the method used to calculate the estimate, as reported under §63.5180(h) and (i).

(iv) A record of actions taken to minimize emissions in accordance with §63.5140(b) and any corrective actions taken to return the affected unit to its normal or usual manner of operation.

(b) Maintain records of all liquid-liquid material balances that are performed in accordance with the requirements of §63.5170.

(c) Any records required to be maintained by this subpart that are in reports that were submitted electronically via the EPA's CEDRI may be maintained in electronic format. This ability to maintain electronic copies does not affect the requirement for facilities to make records, data, and reports available upon request to a delegated air agency or the EPA as part of an on-site compliance evaluation.

[67 FR 39812, June 10, 2002, as amended at 85 FR 10867, Feb. 25, 2020]

Back to Top

DELEGATION OF AUTHORITY

Back to Top

§63.5200 What authorities may be delegated to the States?

(a) This subpart can be implemented and enforced by us, the EPA, or a delegated authority such as your State, local, or tribal agency. If the EPA Administrator has delegated authority to your State, local, or tribal agency, then that agency 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 section 40 CFR part 63, subpart E, the authorities contained in paragraph (c) of this section are retained by the EPA Administrator and not transferred to the State, local, or tribal agency.

(c) Authority which will not be delegated to States, local, or tribal agencies:

(1) Approval of alternatives to the emission limitations in §63.5120;

(2) Approval of major alternatives to test methods under §63.7(e)(2)(ii) and (f) and as defined in §63.5160;

(3) Approval of major alternatives to monitoring under §63.8(f) and as defined in §63.5150; and

(4) Approval of major alternatives to recordkeeping and reporting under §63.10(f) and as defined in §§63.5180 and 63.5190.

Back to Top

§§63.5201-63.5209 [Reserved]

Back to Top

Table 1 to Subpart SSSS of Part 63—Operating Limits if Using Add-on Control Devices and Capture System

If you are required to comply with operating limits by §63.5121, you must comply with the applicable operating limits in the following table:

For the following device . . .	You must meet the following operating limit . . .	And you must demonstrate continuous compliance with the operating limit by . . .
1. thermal oxidizer	a. the average combustion temperature in any 3-hour period must not fall below the combustion temperature limit established according to §63.5160(d)(3)(i)	i. collecting the combustion temperature data according to §63.5150(a)(3); ii. reducing the data to 3-hour block averages; and iii. maintaining the 3-hour average combustion temperature at or above the temperature limit.
2. catalytic oxidizer	a. the average temperature measured just before the catalyst bed in any 3-hour period must not fall below the limit established according to §63.5160(d)(3)(ii); and either	i. collecting the temperature data according to §63.5150(a)(3); ii. reducing the data to 3-hour block averages; and iii. maintaining the 3-hour average temperature before the catalyst bed at or above the temperature limit.
	b. ensure that the average temperature difference across the catalyst bed in any 3-hour period	i. collecting the temperature data according to §63.5150(a)(3); ii. reducing the data to 3-hour block averages;

	does not fall below the temperature difference limit established according to §63.5160(d)(3)(ii); or	and iii. maintaining the 3-hour average temperature difference at or above the temperature difference limit.
	c. develop and implement an inspection and maintenance plan according to §63.5160(d)(3)(ii)	maintaining an up-to-date inspection and maintenance plan, records of annual catalyst activity checks, records of monthly inspections of the oxidizer system, and records of the annual internal inspections of the catalyst bed. If a problem is discovered during a monthly or annual inspection required by §63.5160(d)(3)(ii), you must take corrective action as soon as practicable consistent with the manufacturer's recommendations.
3. emission capture system	develop a monitoring plan that identifies operating parameter to be monitored and specifies operating limits according to §63.5150(a)(4)	conducting monitoring according to the plan §63.5150(a)(4).

Back to Top

Table 2 to Subpart SSSS of Part 63—Applicability of General Provisions to Subpart SSSS

Link to an amendment published at 85 FR 73908, Nov. 19, 2020.

You must comply with the applicable General Provisions requirements according to the following table:

General provisions reference	Subject	Applicable to subpart SSSS	Explanation
§63.1(a)(1)-(4)	General Applicability	Yes	
§63.1(a)(6)	Source Category Listing	Yes	
§63.1(a)(10)-(12)	Timing and Overlap Clarifications	Yes	

§63.1(b)(1)	Initial Applicability Determination	Yes	Applicability to Subpart SSSS is also specified in §63.5090.
§63.1(b)(3)	Applicability Determination Recordkeeping	Yes	
§63.1(c)(1)	Applicability after Standard Established	Yes	
§63.1(c)(2)	Applicability of Permit Program for Area Sources	Yes	
§63.1(c)(5)	Extensions and Notifications	Yes	
§63.1(e)	Applicability of Permit Program Before Relevant Standard is Set	Yes	
§63.2	Definitions	Yes	Additional definitions are specified in §63.5110.
§63.3	Units and Abbreviations	Yes	
§63.4(a)(1)-(2)	Prohibited Activities	Yes	
§63.4(b)-(c)	Circumvention/Fragmentation	Yes	
§63.5(a)	Construction/Reconstruction	Yes	
§63.5(b)(1), (3), (4), (6)	Requirements for Existing, Newly Constructed, and Reconstructed Sources	Yes	
§63.5(d)(1)(i)-(ii)(F), (d)(1)(ii)(H), (d)(1)(ii)(J), (d)(1)(iii), (d)(2)-	Application for Approval of Construction/Reconstruction	Yes	Only total HAP emissions in terms of tons per year are required for §63.5(d)(1)(ii)(H).

(4)			
§63.5(e)	Approval of Construction/Reconstruction	Yes	
§63.5(f)	Approval of Construction/Reconstruction Based on Prior State Review	Yes	
§63.6(a)	Compliance with Standards and Maintenance Requirements-Applicability	Yes	
§63.6(b)(1)-(5), (b)(7)	Compliance Dates for New and Reconstructed Sources	Yes	Section 63.5130 specifies the compliance dates.
§63.6(c)(1), (2), (5)	Compliance Dates for Existing Sources	Yes	Section 63.5130 specifies the compliance dates.
§63.6(e)(1)(i)-(ii)	General Duty to Minimize Emissions and Requirement to Correct Malfunctions As Soon As Possible	Yes before August 24, 2020, No on and after August 24, 2020	See §63.5140(b) for general duty requirement.
§63.6(e)(1)(iii)	Operation and Maintenance Requirements	Yes	
§63.6(e)(3)(i), (e)(3)(iii)-(ix)	SSMP Requirements	Yes before August 24, 2020, No on and after August 24, 2020	
§63.6(f)(1)	SSM Exemption	Yes before August 24, 2020, No on	See §63.5140(b) for general duty requirement.

		and after August 24, 2020	
§63.6(f)(2)-(3)	Compliance with Non-Opacity Emission Standards	Yes	
§63.6(g)	Alternative Non-Opacity Emission Standard	Yes	
§63.6(h)	Compliance with Opacity/Visible Emission Standards	No	Subpart SSSS does not establish opacity standards or visible emission standards.
§63.6(i)(1)-(14), (i)(16)	Extension of Compliance and Administrator's Authority	Yes	
§63.6(j)	Presidential Compliance Exemption	Yes	
§63.7(a)-(d) except (a)(2)(i)-(viii)	Performance Test Requirements	Yes	
§63.7(e)(1)	Performance Testing	Yes before August 24, 2020, No on and after August 24, 2020	See §63.5160(d)(2).
§63.7(e)(2)-(4)	Conduct of Performance Tests	Yes	
§63.7(f)	Alternative Test Method	Yes	EPA retains approval authority.
§63.7(g)-(h)	Data Analysis and Waiver of Tests	Yes	

§63.8(a)(1)-(2)	Monitoring Requirements—Applicability	Yes	Additional requirements for monitoring are specified in §63.5150(a).
§63.8(a)(4)	Additional Monitoring Requirements	No	Subpart SSSS does not have monitoring requirements for flares.
§63.8(b)	Conduct of Monitoring	Yes	
§63.8(c)(1)	Operation and Maintenance of Continuous Monitoring System (CMS)	Yes before August 24, 2020, No on and after August 24, 2020	Section 63.5150(a) specifies the requirements for the operation of CMS for capture systems and add-on control devices at sources using these to comply.
§63.8(c)(2)-(3)	CMS Operation and Maintenance	Yes	Applies only to monitoring of capture system and add-on control device efficiency at sources using these to comply with the standards. Additional requirements for CMS operations and maintenance are specified in §63.5170.
§63.8(c)(4)-(5)	CMS Continuous Operation Procedures	No	Subpart SSSS does not require COMS.
§63.8(c)(6)-(8)	CMS Requirements	Yes	Provisions only apply if CEMS are used.
§63.8(d)-(e)	CMS Quality Control, Written Procedures, and Performance	Yes	Provisions only apply if CEMS are used.

	Evaluation		
§63.8(f)(1)-(5)	Use of an Alternative Monitoring Method	Yes	EPA retains approval authority.
§63.8(f)(6)	Alternative to Relative Accuracy Test	No	Section 63.8(f)(6) provisions are not applicable because subpart SSSS does not require CEMS.
§63.8(g)	Data Reduction	No	Sections 63.5170, 63.5140, 63.5150, and 63.5150 specify monitoring data reduction.
§63.9(a)	Notification of Applicability	Yes	
§63.9(b)(1)	Initial Notifications	Yes	
§63.9(b)(2)	Initial Notifications	Yes	With the exception that §63.5180(b)(1) provides 2 years after the proposal date for submittal of the initial notification for existing sources.
§63.9(b)(4)(i), (b)(4)(v), (b)(5)	Application for Approval of Construction or Reconstruction	Yes	
§63.9(c)-(e)	Request for Extension of Compliance, New Source Notification for Special Compliance Requirements, and Notification of Performance Test	Yes	Notification of performance test requirement applies only to capture system and add-on control device performance tests at sources using these to comply with the

			standards.
§63.9(f)	Notification of Visible Emissions/Opacity Test	No	Subpart SSSS does not require opacity and visible emissions observations.
§63.9(g)	Additional Notifications When Using CMS	No	Provisions for COMS are not applicable.
§63.9(h)(1)-(3)	Notification of Compliance Status	Yes	Section 63.5130 specifies the dates for submitting the notification of compliance status.
§63.9(h)(5)-(6)	Clarifications	Yes	
§63.9(i)	Adjustment of Submittal Deadlines	Yes	
§63.9(j)	Change in Previous Information	Yes	
§63.10(a)	Recordkeeping/Reporting—Applicability and General Information	Yes	
§63.10(b)(1)	General Recordkeeping Requirements	Yes	Additional requirements are specified in §63.5190.
§63.10(b)(2)(i)-(ii)	Recordkeeping of Occurrence and Duration of Startups and Shutdowns and Recordkeeping of Failures to Meet Standards	Yes before August 24, 2020, No on and after August 24, 2020	See §63.5190(a)(5).
§63.10(b)(2)(iii)	Maintenance Records	Yes	
§63.10(b)(2)(iv)-	Actions Taken to Minimize Emissions During Startup,	Yes before August 24,	See §63.5190(a)(5).

(v)	Shutdown, and Malfunction	2020, No on and after August 24, 2020	
§63.10(b)(2)(vi)	Recordkeeping for CMS Malfunctions	Yes before August 24, 2020, No on and after August 24, 2020	See §63.5190(a)(5).
§63.10(b)(2)(vii)-(xiv)	Other CMS Requirements	Yes	
§63.10(b)(3)	Recordkeeping Requirements for Applicability Determinations	Yes	
§63.10(c)	Additional CMS Recordkeeping Requirements	No	See §63.5190(a)(5).
§63.10(d)(1)-(2)	General Reporting Requirements and Report of Performance Test Results	Yes	Additional requirements are specified in §63.5180(e).
§63.10(d)(3)	Reporting Opacity or Visible Emissions Observations	No	Subpart SSSS does not require opacity and visible emissions observations.
§63.10(d)(4)	Progress Reports for Sources with Compliance Extensions	Yes	
§63.10(d)(5)	Startup, Shutdown, Malfunction Reports	Yes before August 24, 2020, No on and after August 24, 2020	

§63.10(e)	Additional Reporting Requirements for Sources with CMS	No	
§63.10(f)	Recordkeeping/Reporting Waiver	Yes	
§63.11	Control Device Requirements/Flares	No	Subpart SSSS does not specify use of flares for compliance.
§63.12	State Authority and Delegations	Yes	
§63.13(a)	Addresses	Yes before August 24, 2020, No on and after August 24, 2020	
§63.13(b)	Submittal to State Agencies	Yes	
§63.13(c)	Submittal to State Agencies	Yes before August 24, 2020, No unless the state requires the submittal via CEDRI, on and after August 24, 2020	
§63.14	Incorporation by Reference	Yes	Subpart SSSS includes provisions for alternative ASTM and ASME test methods that are incorporated by reference.

§63.15	Availability of Information/Confidentiality	Yes	

[85 FR 10868, Feb. 25, 2020]

Back to Top

Table 3 to Subpart SSSS of Part 63—List of Hazardous Air Pollutants That Must Be Counted Toward Total Organic HAP Content if Present at 0.1 Percent or More by Mass

Chemical name	CAS No.
1,1,2,2-Tetrachloroethane	79-34-5
1,1,2-Trichloroethane	79-00-5
1,1-Dimethylhydrazine	57-14-7
1,2-Dibromo-3-chloropropane	96-12-8
1,2-Diphenylhydrazine	122-66-7
1,3-Butadiene	106-99-0
1,3-Dichloropropene	542-75-6
1,4-Dioxane	123-91-1
2,4,6-Trichlorophenol	88-06-2
2,4/2,6-Dinitrotoluene (mixture)	25321-14-6
2,4-Dinitrotoluene	121-14-2
2,4-Toluene diamine	95-80-7
2-Nitropropane	79-46-9

3,3′-Dichlorobenzidine	91-94-1
3,3′-Dimethoxybenzidine	119-90-4
3,3′-Dimethylbenzidine	119-93-7
4,4′-Methylene bis(2-chloroaniline)	101-14-4
Acetaldehyde	75-07-0
Acrylamide	79-06-1
Acrylonitrile	107-13-1
Allyl chloride	107-05-1
alpha-Hexachlorocyclohexane (a-HCH)	319-84-6
Aniline	62-53-3
Benzene	71-43-2
Benzidine	92-87-5
Benzotrichloride	98-07-7
Benzyl chloride	100-44-7
beta-Hexachlorocyclohexane (b-HCH)	319-85-7
Bis(2-ethylhexyl)phthalate	117-81-7
Bis(chloromethyl)ether	542-88-1
Bromoform	75-25-2

Captan	133-06-2
Carbon tetrachloride	56-23-5
Chlordane	57-74-9
Chlorobenzilate	510-15-6
Chloroform	67-66-3
Chloroprene	126-99-8
Cresols (mixed)	1319-77-3
DDE	3547-04-4
Dichloroethyl ether	111-44-4
Dichlorvos	62-73-7
Epichlorohydrin	106-89-8
Ethyl acrylate	140-88-5
Ethylene dibromide	106-93-4
Ethylene dichloride	107-06-2
Ethylene oxide	75-21-8
Ethylene thiourea	96-45-7
Ethylidene dichloride (1,1-Dichloroethane)	75-34-3
Formaldehyde	50-00-0
Heptachlor	76-44-8

Hexachlorobenzene	118-74-1
Hexachlorobutadiene	87-68-3
Hexachloroethane	67-72-1
Hydrazine	302-01-2
Isophorone	78-59-1
Lindane (hexachlorocyclohexane, all isomers)	58-89-9
m-Cresol	108-39-4
Methylene chloride	75-09-2
Naphthalene	91-20-3
Nitrobenzene	98-95-3
Nitrosodimethylamine	62-75-9
o-Cresol	95-48-7
o-Toluidine	95-53-4
Parathion	56-38-2
p-Cresol	106-44-5
p-Dichlorobenzene	106-46-7
Pentachloronitrobenzene	82-68-8
Pentachlorophenol	87-86-5
Propoxur	114-26-1

Propylene dichloride	78-87-5
Propylene oxide	75-56-9
Quinoline	91-22-5
Tetrachloroethene	127-18-4
Toxaphene	8001-35-2
Trichloroethylene	79-01-6
Trifluralin	1582-09-8
Vinyl bromide	593-60-2
Vinyl chloride	75-01-4
Vinylidene chloride	75-35-4

[85 FR 10870, Feb. 25, 2020]

Appendix J

40 C.F.R. Part 63 Subpart CCC

National Emissions Standards for Hazardous Air Pollutants for Steel Pickling – HCl Process Facilities and Hydrochloric Acid Regeneration Plants

Title 40: Protection of Environment
PART 63—NATIONAL EMISSION STANDARDS FOR HAZARDOUS AIR POLLUTANTS FOR SOURCE CATEGORIES (CONTINUED)

Subpart CCC—National Emission Standards for Hazardous Air Pollutants for Steel Pickling—HCl Process Facilities and Hydrochloric Acid Regeneration Plants

---

Contents

SOURCE: 64 FR 33218, June 22, 1999, unless otherwise noted.

Back to Top

§63.1155 Applicability.

(a) The provisions of this subpart apply to the following facilities and plants that are major sources for hazardous air pollutants (HAP) or are parts of facilities that are major sources for HAP:

(1) All new and existing steel pickling facilities that pickle carbon steel using hydrochloric acid solution that contains 6 percent or more by weight HCl and is at a temperature of 100 °F or higher; and

(2) All new and existing hydrochloric acid regeneration plants.

(3) The provisions of this subpart do not apply to facilities that pickle carbon steel without using hydrochloric acid, to facilities that pickle only specialty steel, or to acid regeneration plants that regenerate only acids other than hydrochloric acid.

(b) For the purposes of implementing this subpart, the affected sources at a facility or plant subject to this subpart are as follows: Continuous and batch pickling lines, hydrochloric acid regeneration plants, and hydrochloric acid storage vessels.

(c) Table 1 to this subpart specifies the provisions of this part 63, subpart A that apply and those that do not apply to owners and operators of steel pickling facilities and hydrochloric acid regeneration plants subject to this subpart.

(d) In response to an action to enforce the standards set forth in this subpart, the owner or operator may assert an affirmative defense to a claim for civil penalties for violations of such standards that are caused by a malfunction, as defined in §63.2. Appropriate penalties may be assessed, however, if the owner or operator fails to meet the burden of proving all the requirements in the affirmative defense. The affirmative defense shall not be available for claims for injunctive relief.

(1) To establish the affirmative defense in any action to enforce such a standard, the owner or operator must timely meet the reporting requirements of paragraph (d)(2) of this section, and must prove by a preponderance of evidence that:

(i) The violation was caused by a sudden, infrequent, and unavoidable failure of air pollution control equipment, process equipment, or a process to operate in a normal and usual manner; and could not have been prevented through careful planning, proper design, or better operation and maintenance practices; and did not stem from any activity or event that could have been foreseen and avoided, or planned for; and was not part of a recurring pattern indicative of inadequate design, operation, or maintenance; and

(ii) Repairs were made as expeditiously as possible when exceeded violation occurred. Off-shift and overtime labor were used, to the extent practicable to make these repairs; and

(iii) The frequency, amount, and duration of the violation (including any bypass) were minimized to the maximum extent practicable; and

(iv) 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

(v) All possible steps were taken to minimize the impact of the violation on ambient air quality, the environment, and human health; and

(vi) All emissions monitoring and control systems were kept in operation if at all possible, consistent with safety and good air pollution control practices; and

(vii) All of the actions in response to the violation were documented by properly signed, contemporaneous operating logs; and

(viii) At all times, the affected source was operated in a manner consistent with good practices for minimizing emissions; and

(ix) 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 the best monitoring methods and engineering judgment, the amount of excess emissions that were the result of the malfunction.

(2) *Report.* The owner of 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 paragraph (d)(1) 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 affirmation 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.

[64 FR 33218, June 22, 1999, as amended at 77 FR 58250, Sept. 19, 2012]

Back to Top

§63.1156 Definitions.

Terms used in this subpart are defined in the Clean Air Act, in subpart A of this part, or in this section as follows:

Affirmative defense means, in the context of an enforcement proceeding, a response or a 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.

Batch pickling line means the collection of equipment and tanks configured for pickling metal in any form but usually in discrete shapes where the material is lowered in batches into a bath of acid solution, allowed to remain until the scale is dissolved, then removed from the solution, drained, and rinsed by spraying or immersion in one or more rinse tanks to remove residual acid.

Carbon steel means steel that contains approximately 2 percent or less carbon, 1.65 percent or less manganese, 0.6 percent or less silicon, and 0.6 percent or less copper.

Closed-vent system means a system that is not open to the atmosphere and that is composed of piping, ductwork, connections, and, if necessary, flow-inducing devices that transport emissions from a process unit or piece of equipment (e.g., pumps, pressure relief devices, sampling connections, open-ended valves or lines, connectors, and instrumentation systems) back into a closed system or into any device that is capable of reducing or collecting emissions.

Continuous pickling line means the collection of equipment and tanks configured for pickling metal strip, rod, wire, tube, or pipe that is passed through an acid solution in a continuous or nearly continuous manner and rinsed in another tank or series of tanks to remove residual acid. This definition includes continuous spray towers.

Hydrochloric acid regeneration plant means the collection of equipment and processes configured to reconstitute fresh hydrochloric acid pickling solution from spent pickle liquor using a thermal treatment process.

Hydrochloric acid regeneration plant production mode means operation under conditions that result in production of usable regenerated acid or iron oxide.

Hydrochloric acid storage vessel means a stationary vessel used for the bulk containment of virgin or regenerated hydrochloric acid.

Responsible maintenance official means a person designated by the owner or operator as having the knowledge and the authority to sign records and reports required under this rule.

Specialty steel means a category of steel that includes silicon electrical, alloy, tool, and stainless steels.

Spray tower means an enclosed vertical tower in which acid pickling solution is sprayed onto moving steel strip in multiple vertical passes.

Steel pickling means the chemical removal of iron oxide mill scale that is formed on steel surfaces during hot rolling or hot forming of semi-finished steel products through contact with an aqueous solution of acid where such contact occurs prior to shaping or coating of the finished steel product. This definition does not include removal of light rust or scale from finished steel products or activation of the metal surface prior to plating or coating.

Steel pickling facility means any facility that operates one or more batch or continuous steel pickling lines.

[64 FR 33218, June 22, 1999, as amended at 77 FR 58250, Sept. 19, 2012]

Back to Top

§63.1157 Emission standards for existing sources.

(a) *Pickling lines.* No owner or operator of an existing affected continuous or batch pickling line at a steel pickling facility shall cause or allow to be discharged into the atmosphere from the affected pickling line:

(1) Any gases that contain HCl in a concentration in excess of 18 parts per million by volume (ppmv); or

(2) HCl at a mass emission rate that corresponds to a collection efficiency of less than 97 percent.

(b) *Hydrochloric acid regeneration plants.* (1) No owner or operator of an existing affected plant shall cause or allow to be discharged into the atmosphere from the affected plant any gases that contain HCl in a concentration greater than 25 ppmv.

(2) In addition to the requirement of paragraph (b)(1) of this section, no owner or operator of an existing plant shall cause or allow to be discharged into the atmosphere from the affected plant any gases that contain chlorine (Cl_2) in a concentration in excess of 6 ppmv.

[64 FR 33218, June 22, 1999, as amended at 77 FR 58250, Sept. 19, 2012]

Back to Top

§63.1158 Emission standards for new or reconstructed sources.

(a) *Pickling lines*—(1) *Continuous pickling lines.* No owner or operator of a new or reconstructed affected continuous pickling line at a steel pickling facility shall cause or allow to be discharged into the atmosphere from the affected pickling line:

(i) Any gases that contain HCl in a concentration in excess of 6 ppmv; or

(ii) HCl at a mass emission rate that corresponds to a collection efficiency of less than 99 percent.

(2) *Batch pickling lines.* No owner or operator of a new or reconstructed affected batch pickling line at a steel pickling facility shall cause or allow to be discharged into the atmosphere from the affected pickling line:

(i) Any gases that contain HCl in a concentration in excess of 18 ppmv; or

(ii) HCl at a mass emission rate that corresponds to a collection efficiency of less than 97 percent.

(b) *Hydrochloric acid regeneration plants.* (1) No owner or operator of a new or reconstructed affected plant shall cause or allow to be discharged into the atmosphere from the affected plant any gases that contain HCl in a concentration greater than 12 ppmv.

(2) In addition to the requirement of paragraph (b)(1) of this section, no owner or operator of a new or reconstructed affected plant shall cause or allow to be discharged into the atmosphere from the affected plant any gases that contain Cl_2 in a concentration in excess of 6 ppmv.

Back to Top

§63.1159 Operational and equipment standards for existing, new, or reconstructed sources.

(a) *Hydrochloric acid regeneration plant.* The owner or operator of an affected plant must operate the affected plant at all times while in production mode in a manner that minimizes the proportion of excess air fed to the process and maximizes the process offgas temperature consistent with producing usable regenerated acid or iron oxide.

(b) *Hydrochloric acid storage vessels.* The owner or operator of an affected vessel shall provide and operate, except during loading and unloading of acid, a closed-vent system for each vessel. Loading and unloading shall be conducted either through enclosed lines or each point where the acid is exposed to the atmosphere shall be equipped with a local fume capture system, ventilated through an air pollution control device.

(c) *General duty to minimize emissions.* At all times, each owner or operator must operate and maintain any affected source subject to the requirements of this subpart, including associated air pollution control equipment and monitoring equipment in a manner consistent with safety and good air pollution control practices for minimizing emissions. The general duty to minimize emissions does not require the owner or operator to make any further efforts to reduce emissions if levels required by this standard have been achieved. Determination of whether such operation 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, review of operation and maintenance procedures, review of operation and maintenance records, and inspection of the source.

[64 FR 33218, June 22, 1999, as amended at 77 FR 58250, Sept. 19, 2012]

Back to Top

§63.1160 Compliance dates and maintenance requirements.

(a) *Compliance dates.* (1) The owner or operator of an affected existing steel pickling facility and/or hydrochloric acid regeneration plant subject to this subpart shall achieve initial compliance with the requirements of this subpart no later than June 22, 2001.

(2) The owner or operator of a new or reconstructed steel pickling facility and/or hydrochloric acid regeneration plant subject to this subpart that commences construction or reconstruction after September 18, 1997, shall achieve compliance with the requirements of this subpart immediately upon startup of operations or by June 22, 1999, whichever is later.

(b) *Maintenance requirements.* (1) The owner or operator shall prepare an operation and maintenance plan for each emission control device to be implemented no later than the compliance date. The plan shall be incorporated by reference into the source's title V permit. All such plans must be consistent with good maintenance practices, and, for a scrubber emission control device, must at a minimum:

(i) Require monitoring and recording the pressure drop across the scrubber once per shift while the scrubber is operating in order to identify changes that may indicate a need for maintenance;

(ii) Require the manufacturer's recommended maintenance at the recommended intervals on fresh solvent pumps, recirculating pumps, discharge pumps, and other liquid pumps, in addition to exhaust system and scrubber fans and motors associated with those pumps and fans;

(iii) Require cleaning of the scrubber internals and mist eliminators at intervals sufficient to prevent buildup of solids or other fouling;

(iv) Require an inspection of each scrubber at intervals of no less than 3 months with:

(A) Cleaning or replacement of any plugged spray nozzles or other liquid delivery devices;

(B) Repair or replacement of missing, misaligned, or damaged baffles, trays, or other internal components;

(C) Repair or replacement of droplet eliminator elements as needed;

(D) Repair or replacement of heat exchanger elements used to control the temperature of fluids entering or leaving the scrubber; and

(E) Adjustment of damper settings for consistency with the required air flow.

(v) If the scrubber is not equipped with a viewport or access hatch allowing visual inspection, alternate means of inspection approved by the Administrator may be used.

(vi) The owner or operator shall initiate procedures for corrective action within 1 working day of detection of an operating problem and complete all corrective actions as soon as practicable. Procedures to be initiated are the applicable actions that are specified in the maintenance plan.

Failure to initiate or provide appropriate repair, replacement, or other corrective action is a violation of the maintenance requirement of this subpart.

(vii) The owner or operator shall maintain a record of each inspection, including each item identified in paragraph (b)(2)(iv) of this section, that is signed by the responsible maintenance official and that shows the date of each inspection, the problem identified, a description of the repair, replacement, or other corrective action taken, and the date of the repair, replacement, or other corrective action taken.

(2) The owner or operator of each hydrochloric acid regeneration plant shall develop and implement a written maintenance program. The program shall require:

(i) Performance of the manufacturer's recommended maintenance at the recommended intervals on all required systems and components;

(ii) Initiation of procedures for appropriate and timely repair, replacement, or other corrective action within 1 working day of detection; and

(iii) Maintenance of a daily record, signed by a responsible maintenance official, showing the date of each inspection for each requirement, the problems found, a description of the repair, replacement, or other action taken, and the date of repair or replacement.

[64 FR 33218, June 22, 1999, as amended at 77 FR 58250, Sept. 19, 2012]

Back to Top

§63.1161 Performance testing and test methods.

(a) *Demonstration of compliance.* The owner or operator shall conduct an initial performance test for each process or emission control device to determine and demonstrate compliance with the applicable emission limitation according to the requirements in §63.7 of subpart A of this part and in this section. Performance tests shall be conducted under such conditions as the Administrator specifies to the owner or operator based on representative performance of the affected source for the period being tested. Upon request, the owner or operator shall make available to the Administrator such records as may be necessary to determine the conditions of performance tests.

(b) *Establishment of scrubber operating parameters.* During the performance test for each emission control device, the owner or operator using a wet scrubber to achieve compliance shall establish site-specific operating parameter values for the minimum scrubber makeup water flow rate and, for scrubbers that operate with recirculation, the minimum recirculation water flow rate. During the emission test, each operating parameter must be monitored continuously and recorded with sufficient frequency to establish a representative average value for that parameter, but no less frequently than once every 15 minutes. The owner or operator shall determine the operating parameter monitoring values as the averages of the values recorded during any of the runs for which results are used to establish the emission concentration or collection efficiency per paragraph (a)(2) of this section. An owner or operator may conduct multiple performance tests to establish alternative compliant operating parameter values. Also, an owner or operator may reestablish compliant operating parameter values as part of any performance test that is conducted subsequent to the initial test or tests.

(c) *Establishment of hydrochloric acid regeneration plant operating parameters.* (1) During the performance test for hydrochloric acid regeneration plants, the owner or operator shall establish site-specific operating parameter values for the minimum process offgas temperature and the maximum proportion of excess air fed to the process as described in §63.1162(b)(1) of this subpart. During the emission test, each operating parameter must be monitored and recorded with sufficient frequency to establish a representative average value for that parameter, but no less frequently than once every 15 minutes for parameters that are monitored continuously. Amount of iron in the spent pickle liquor shall be determined for each run by sampling the liquor every 15 minutes and analyzing a composite of the samples. The owner or operator shall determine the compliant monitoring values as the averages of the values recorded during any of the runs for which results are used to establish the emission concentration per paragraph (a)(2) of this section. An owner or operator may conduct multiple performance tests to establish alternative compliant operating parameter values. Also, an owner or operator may reestablish compliant operating parameter values as part of any performance test that is conducted subsequent to the initial test or tests.

(2) [Reserved]

(d) *Test methods.* (1) The following test methods in appendix A of 40 CFR part 60 shall be used to determine compliance under §§63.1157(a), 63.1157(b), 63.1158(a), and 63.1158(b) of this subpart:

(i) Method 1, to determine the number and location of sampling points, with the exception that no traverse point shall be within one inch of the stack or duct wall;

(ii) Method 2, to determine gas velocity and volumetric flow rate;

(iii) Method 3, to determine the molecular weight of the stack gas;

(iv) Method 4, to determine the moisture content of the stack gas; and

(v) Method 26A, "Determination of Hydrogen Halide and Halogen Emissions from Stationary Sources—Isokinetic Method," to determine the HCl mass flows at the inlet and outlet of a control device or the concentration of HCl discharged to the atmosphere, and also to determine the concentration of Cl_2 discharged to the atmosphere from acid regeneration plants. If compliance with a collection efficiency standard is being demonstrated, inlet and outlet measurements shall be performed simultaneously. The minimum sampling time for each run shall be 60 minutes and the minimum sample volume 0.85 dry standard cubic meters (30 dry standard cubic feet). The concentrations of HCl and Cl_2 shall be calculated for each run as follows:

C_{HCl} (ppmv) = 0.659 C_{HCl} (mg/dscm),

and C_{C12} (ppmv) = 0.339 C_{C12} (mg/dscm),

where C(ppmv) is concentration in ppmv and C(mg/dscm) is concentration in milligrams per dry standard cubic meter as calculated by the procedure given in Method 26A.

(2) The owner or operator may use equivalent alternative measurement methods approved by the Administrator.

[64 FR 33218, June 22, 1999, as amended at 77 FR 58251, Sept. 19, 2012]

Back to Top

§63.1162 Monitoring requirements.

(a) The owner or operator of a new, reconstructed, or existing steel pickling facility or acid regeneration plant subject to this subpart shall:

(1) Conduct performance tests to measure the HCl mass flows at the control device inlet and outlet or the concentration of HCl exiting the control device according to the procedures described in §63.1161 of this subpart. Performance tests shall be conducted either annually or according to an alternative schedule that is approved by the applicable permitting authority, but no less frequently than every 2½ years or twice per title V permit term. If any performance test shows that the HCl emission limitation is being exceeded, then the owner or operator is in violation of the emission limit.

(2) In addition to conducting performance tests, if a wet scrubber is used as the emission control device, install, operate, and maintain systems for the measurement and recording of the scrubber makeup water flow rate and, if required, recirculation water flow rate. These flow rates must be monitored continuously and recorded at least once per shift while the scrubber is operating. Operation of the wet scrubber with excursions of scrubber makeup water flow rate and recirculation water flow rate less than the minimum values established during the performance test or tests will require initiation of corrective action as specified by the maintenance requirements in §63.1160(b)(2) of this subpart.

(3) If an emission control device other than a wet scrubber is used, install, operate, and maintain systems for the measurement and recording of the appropriate operating parameters.

(4) Failure to record each of the operating parameters listed in paragraph (a)(2) of this section is a violation of the monitoring requirements of this subpart.

(5) Each monitoring device shall be certified by the manufacturer to be accurate to within 5 percent and shall be calibrated in accordance with the manufacturer's instructions but not less frequently than once per year.

(6) The owner or operator may develop and implement alternative monitoring requirements subject to approval by the Administrator.

(b) The owner or operator of a new, reconstructed, or existing acid regeneration plant subject to this subpart shall also install, operate, and maintain systems for the measurement and recording of the:

(1) Process offgas temperature, which shall be monitored continuously and recorded at least once every shift while the facility is operating in production mode; and

(2) Parameters from which proportion of excess air is determined. Proportion of excess air shall be determined by a combination of total air flow rate, fuel flow rate, spent pickle liquor addition rate, and amount of iron in the spent pickle liquor, or by any other combination of parameters approved by the Administrator in accordance with §63.8(f) of subpart A of this part. Proportion of excess air shall be determined and recorded at least once every shift while the plant is operating in production mode.

(3) Each monitoring device must be certified by the manufacturer to be accurate to within 5 percent and must be calibrated in accordance with the manufacturer's instructions but not less frequently than once per year.

(4) Operation of the plant with the process offgas temperature lower than the value established during performance testing or with the proportion of excess air greater than the value established during performance testing is a violation of the operational standard specified in §63.1159(a) of this subpart.

(c) The owner or operator of an affected hydrochloric acid storage vessel shall inspect each vessel semiannually to determine that the closed-vent system and either the air pollution control device or the enclosed loading and unloading line, whichever is applicable, are installed and operating when required.

Back to Top

§63.1163 Notification requirements.

Link to an amendment published at 85 FR 73897, Nov. 19, 2020.

(a) *Initial notifications.* As required by §63.9(b) of subpart A of this part, the owner or operator shall submit the following written notifications to the Administrator:

(1) The owner or operator of an area source that subsequently becomes subject to the requirements of the standard shall provide notification to the applicable permitting authority as required by §63.9(b)(1) of subpart A of this part.

(2) As required by §63.9(b)(2) of subpart A of this part, the owner or operator of an affected source that has an initial startup before June 22, 1999, shall notify the Administrator that the source is subject to the requirements of the standard. The notification shall be submitted not later than October 20, 1999 (or within 120 calendar days after the source becomes subject to this standard), and shall contain the information specified in §§63.9(b)(2)(i) through 63.9(b)(2)(v) of subpart A of this part.

(3) As required by §63.9(b)(3) of subpart A of this part, the owner or operator of a new or reconstructed affected source, or a source that has been reconstructed such that it is an affected source, that has an initial startup after the effective date and for which an application for approval of construction or reconstruction is not required under §63.5(d) of subpart A of this part, shall notify the Administrator in writing that the source is subject to the standards no later than 120 days after initial startup. The notification shall contain the information specified in §§63.9(b)(2)(i) through 63.9(b)(2)(v) of subpart A of this part, delivered or postmarked with the notification required in §63.9(b)(5) of subpart A of this part.

(4) As required by §63.9(b)(4) of subpart A of this part, the owner or operator of a new or reconstructed major affected source that has an initial startup after June 22, 1999, and for which an application for approval of construction or reconstruction is required under §63.5(d) of subpart A of this part shall provide the information specified in §§63.9(b)(4)(i) through 63.9(b)(4)(v) of subpart A of this part.

(5) As required by §63.9(b)(5) of subpart A of this part, the owner or operator who, after June 22, 1999, intends to construct a new affected source or reconstruct an affected source subject to this standard, or reconstruct a source such that it becomes an affected source subject to this standard, shall notify the Administrator, in writing, of the intended construction or reconstruction.

(b) *Request for extension of compliance.* As required by §63.9(c) of subpart A of this part, if the owner or operator of an affected source cannot comply with this standard by the applicable compliance date for that source, or if the owner or operator has installed BACT or technology to meet LAER consistent with §63.6(i)(5) of subpart A of this part, he/she may submit to the Administrator (or the State with an approved permit program) a request for an extension of compliance as specified in §§63.6(i)(4) through 63.6(i)(6) of subpart A of this part.

(c) *Notification that source is subject to special compliance requirements.* As required by §63.9(d) of subpart A of this part, an owner or operator of a new source that is subject to special compliance requirements as specified in §§63.6(b)(3) and 63.6(b)(4) of subpart A of this part shall notify the Administrator of his/her compliance obligations not later than the notification dates established in §63.9(b) of subpart A of this part for new sources that are not subject to the special provisions.

(d) *Notification of performance test.* As required by §63.9(e) of subpart A of this part, the owner or operator of an affected source shall notify the Administrator in writing of his or her intention to conduct a performance test at least 60 calendar days before the performance test is scheduled to begin, to allow the Administrator to review and approve the site-specific test plan required under §63.7(c) of subpart A of this part and, if requested by the Administrator, to have an observer present during the test.

(e) *Notification of compliance status.* The owner or operator of an affected source shall submit a notification of compliance status as required by §63.9(h) of subpart A of this part when the source becomes subject to this standard.

Back to Top

§63.1164 Reporting requirements.

(a) *Reporting results of performance tests.* 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 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, flash drive or other commonly used electronic storage media 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 delegated authority, you must also submit these reports, including the confidential business information, to the delegated authority in the format specified by the delegated authority. 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 to the Administrator at the appropriate address listed in §63.13.

(b) *Progress reports.* The owner or operator of an affected source who is required to submit progress reports under §63.6(i) of subpart A of this part shall submit such reports to the

Administrator (or the State with an approved permit program) by the dates specified in the written extension of compliance.

(c) *Reporting malfunctions.* 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 shall be stated in a semiannual report. The report must also include a description of actions taken by an owner or operator during a malfunction of an affected source to minimize emissions in accordance with §63.1159(c), including actions taken to correct a malfunction. The report, to be certified by the owner or operator or other responsible official, shall be submitted semiannually and delivered or postmarked by the 30th day following the end of each calendar half.

[64 FR 33218, June 22, 1999, as amended at 71 FR 20458, Apr. 20, 2006; 77 FR 58251, Sept. 19, 2012]

Back to Top

§63.1165 Recordkeeping requirements.

(a) *General recordkeeping requirements.* As required by §63.10(b)(2) of subpart A of this part, the owner or operator shall maintain records for 5 years from the date of each record of:

(1) The occurrence and duration of each malfunction of operation (*i.e.,* process equipment);

(2) The occurrence and duration of each malfunction of the air pollution control equipment;

(3) All maintenance performed on the air pollution control equipment;

(4) Actions taken during periods of malfunction to minimize emissions in accordance with §63.1259(c) and the dates of such actions (including corrective actions to restore malfunctioning process and air pollution control equipment to its normal or usual manner of operation);

(5) All required measurements needed to demonstrate compliance with the standard and to support data that the source is required to report, including, but not limited to, performance test measurements (including initial and any subsequent performance tests) and measurements as may be necessary to determine the conditions of the initial test or subsequent tests;

(6) All results of initial or subsequent performance tests;

(7) If the owner or operator has been granted a waiver from recordkeeping or reporting requirements under §63.10(f) of subpart A of this part, any information demonstrating whether a source is meeting the requirements for a waiver of recordkeeping or reporting requirements;

(8) If the owner or operator has been granted a waiver from the initial performance test under §63.7(h) of subpart A of this part, a copy of the full request and the Administrator's approval or disapproval;

(9) All documentation supporting initial notifications and notifications of compliance status required by §63.9 of subpart A of this part; and

(10) Records of any applicability determination, including supporting analyses.

(b) *Subpart CCC records.* (1) In addition to the general records required by paragraph (a) of this section, the owner or operator shall maintain records for 5 years from the date of each record of:

(i) Scrubber makeup water flow rate and recirculation water flow rate if a wet scrubber is used;

(ii) Calibration and manufacturer certification that monitoring devices are accurate to within 5 percent; and

(iii) Each maintenance inspection and repair, replacement, or other corrective action.

(2) The owner or operator of an acid regeneration plant shall also maintain records for 5 years from the date of each record of process offgas temperature and parameters that determine proportion of excess air.

(3) The owner or operator shall keep the written operation and maintenance plan on record after it is developed to be made available for inspection, upon request, by the Administrator for the life of the affected source or until the source is no longer subject to the provisions of this subpart. In addition, if the operation and maintenance plan is revised, the owner or operator shall keep previous (i.e., superseded) versions of the plan on record to be made available for inspection by the Administrator for a period of 5 years after each revision to the plan.

(c) *Recent records.* General records and subpart CCC records for the most recent 2 years of operation must be maintained on site. Records for the previous 3 years may be maintained off site.

[64 FR 33218, June 22, 1999, as amended at 77 FR 58251, Sept. 19, 2012]

Back to Top

§63.1166 Implementation and enforcement.

(a) This subpart can be implemented and enforced by the U.S. EPA, or a delegated authority such as the applicable State, local, or Tribal agency. If the U.S. EPA Administrator has delegated authority to a State, local, or Tribal agency, then that agency, in addition to the U.S. EPA, has the authority to implement and enforce this subpart. Contact the applicable U.S. EPA Regional Office to find out if implementation and enforcement of this subpart is delegated to a State, local, or Tribal agency.

(b) In delegating implementation and enforcement authority of this subpart to a State, local, or Tribal agency under subpart E of this part, the authorities contained in paragraph (c) of this section are retained by the Administrator of U.S. EPA and cannot be transferred to the State, local, or Tribal agency.

(c) The authorities that cannot be delegated to State, local, or Tribal agencies are as specified in paragraphs (c)(1) through (8) of this section.

(1) Approval of alternatives to the requirements in §§63.1155, 63.1157 through 63.1159, and 63.1160(a).

(2) Approval of major alternatives to test methods under §63.7(e)(2)(ii) and (f), as defined in §63.90, and as required in this subpart.

(3) Approval of any alternative measurement methods for HCl and CL_2 to those specified in §63.1161(d)(1).

(4) Approval of major alternatives to monitoring under §63.8(f), as defined in §63.90, and as required in this subpart.

(5) Approval of any alternative monitoring requirements to those specified in §§63.1162(a)(2) through (5) and 63.1162(b)(1) through (3).

(6) Approval of major alternatives to recordkeeping and reporting under §63.10(f), as defined in §63.90, and as required in this subpart.

(7) Waiver of recordkeeping requirements specified in §63.1165.

(8) Approval of an alternative schedule for conducting performance tests to the requirement specified in §63.1162(a)(1).

[68 FR 37356, June 23, 2003]

Back to Top

§§63.1167-63.1174 [Reserved]

Back to Top

Table 1 to Subpart CCC of Part 63—Applicability of General Provisions (40 CFR Part 63, Subpart A) to Subpart CCC

Link to an amendment published at 85 FR 73897, Nov. 19, 2020.

Reference	Applies to Subpart CCC	Explanation
63.1-63.5	Yes.	
63.6 (a)-(d)	Yes	
63.6(e)(1)(i)	No	See §63.1259(c) for general duty requirement. Any cross-reference to §63.6(e)(1)(i) in any other general provision incorporated by reference shall be treated as a cross-reference to §63.1259(c).
63.6(e)(1)(ii)	No	

63.6(e)(1)(iii)	Yes	
63.6(e)(2)	No	Section reserved.
63.6(e)(3)	No	
63.6(f)(1)	No	
63.6(f)(2)-(3)	Yes	
63.6(g)	Yes	
63.6(h)	No	Subpart CCC does not contain an opacity or visible emission standard.
63.6 (i)-(j)	Yes.	
63.7	Yes	
63.8(a)-(c)	Yes	
63.8(d)(1)-(2)	Yes	
63.8(d)(3)	Yes, except for last sentence	
63.8(e)-(f)	Yes	
63.10(a)	Yes	
63.10(b)(1)	Yes	
63.10(b)(2)(i)	No	
63.10(b)(2)(ii)	No	See §63.1265(a)(1) for recordkeeping of occurrence and duration of malfunctions. See §63.1265(a)(4) for recordkeeping of actions taken during malfunction. Any cross-reference to §63.10(b)(2)(ii)

		in any other general provision incorporated by reference shall be treated as a cross-reference to §63.1265(a)(1).
63.10(b)(2)(iii)	Yes	
63.10(b)(2)(iv)-(b)(2)(v)	No	
63.10(b)(2)(vi)-(b)(2)(xiv)	Yes	
63.10(b)(3)	Yes	
63.10(c)(1)-(9)	Yes	
63.10(c)(10)	No	See §63.1164(c) for reporting malfunctions. Any cross-reference to §63.10(c)(10) in any other general provision incorporated by reference shall be treated as a cross-reference to §63.1164(c).
63.10(c)(11)	No	See §63.1164(c) for reporting malfunctions. Any cross-reference to §63.10(c)(11) in any other general provision incorporated by reference shall be treated as a cross-reference to §63.1164(c).
63.10(c)(12)-(c)(14)	Yes	
63.10(c)(15)	No	
63.10(d)(1)-(2)	Yes.	
63.10(d)(3)	No	Subpart CCC does not contain an opacity or visible emission standard.
63.10(d)(4)	Yes	
63.10(d)(5)	No	
63.10(e)-(f)	Yes.	

63.11	No	Subpart CCC does not require the use of flares.
63.12-63.15	Yes	

[64 FR 33218, June 22, 1999, as amended at 77 FR 58252, Sept. 19, 2012]