State of Ohio Environmental Protection Agency

Street Address:
Lazarus Gov. Center
122 S. Front Street
Columbus, OH 43215

TELE: (614) 644-3020 **FAX:** (614) 644-2329

Mailing Address:
Lazarus Gov. Center
P.O. Box 1049
Columbus, OH 43216-1049

08/24/04

RE: Proposed Title V Chapter 3745-77 Permit
14-09-12-0656
CINCINNATI GAS & ELECTRIC CO.,
WOODSDALE STATION

Attn: Genevieve Damico AR-18J
United States Environmental Protection Agency
Region V
77 West Jackson Blvd.
Chicago, IL 60604-3590

Dear Ms. Damico:

The proposed issuance of the Title V permit for CINCINNATI GAS & ELECTRIC CO., WOODSDALE STATION, has been created in Ohio EPA's State Air Resources System (STARS) on 08/24/04, for review by USEPA. This proposed action is identified in STARS as 3-Title V Proposed Permit T+C covering the facility specific terms and conditions, and Title V Proposed Permit covering the general terms and conditions. This proposed permit will be processed for issuance as a final action after forty-five (45) days from USEPA's receipt of this certified letter if USEPA does not object to the proposed permit. Please contact me at (614) 644-3631 by the end of the forty-five (45) day review period if you wish to object to the proposed permit.

Very truly yours,

Michael W. Ahern

Michael W. Ahern, Supervisor
Field Operations and Permit Section
Division of Air Pollution Control

cc: Hamilton County Dept. of Environmental Services
File, DAPC PMU

State of Ohio Environmental Protection Agency

PROPOSED TITLE V PERMIT

Issue Date: 08/24/04	Effective Date: To be entered upon final issuance	Expiration Date: To be entered upon final issuance

This document constitutes issuance of a Title V permit for Facility ID: 14-09-12-0656 to:
CINCINNATI GAS & ELECTRIC CO., WOODSDALE STATION
2100 Woodsdale Road
Trenton, OH 45067-0000

Emissions Unit ID (Company ID)/Emissions Unit Activity Description

B001 (Combustion Turbine Unit 1)
ABB model GT-11N combustion turbine.

B002 (Combustion Turbine Unit 2)
ABB model GT-11N combustion turbine.

B003 (Combustion Turbine Unit 3)
ABB model GT-11N combustion turbine.

B004 (Combustion Turbine Unit 4)
ABB model GT-11N combustion turbine.

B005 (Combustion Turbine Unit 5)
ABB model GT-11N combustion turbine.

B006 (Combustion Turbine Unit 6)
ABB model GT-11N combustion turbine.

B013 (Vaporizing Boiler # 1)
Cleaver Brooks model CB 700-500 propane vaporizing boiler

B014 (Vaporizing Boiler # 2)
Cleaver Brooks model CB 700-500 propane vaporizing boiler

B015 (Vaporizing Boiler # 3)
Cleaver Brooks model CB 700-500 propane vaporizing boiler

B016 (Vaporizing Boiler # 4)
Cleaver Brooks model CB 700-500 propane vaporizing boiler

B017 (Vaporizing Boiler # 5)
Cleaver Brooks model CB 700-500 propane vaporizing boiler

B018 (Vaporizing Boiler # 6)
Cleaver Brooks model CB 700-500 propane vaporizing boiler

You will be contacted approximately eighteen (18) months prior to the expiration date regarding the renewal of this permit. If you are not contacted, please contact the appropriate Ohio EPA District Office or local air agency listed below. This permit and the authorization to operate the air contaminant sources (emissions units) at this facility shall expire at midnight on the expiration date shown above. If a renewal permit is not issued prior to the expiration date, the permittee may continue to operate pursuant to OAC rule 3745-77-08(E) and in accordance with the terms of this permit beyond the expiration date, provided that a complete renewal application is submitted no earlier than eighteen (18) months and no later than one-hundred eighty (180) days prior to the expiration date.

Described below is the current Ohio EPA District Office or local air agency that is responsible for processing and administering your Title V permit:

Hamilton County Dept. of Environmental Services
250 William Howard Taft Rd
Cincinnati, OH 45219-2660
(513) 946-7777

OHIO ENVIRONMENTAL PROTECTION AGENCY

Christopher Jones
Director

PART I - GENERAL TERMS AND CONDITIONS

A. State and Federally Enforceable Section

1. Monitoring and Related Record Keeping and Reporting Requirements

a. Except as may otherwise be provided in the terms and conditions for a specific emissions unit, i.e., in Section A.III of Part III of this Title V permit, the permittee shall maintain records that include the following, where applicable, for any required monitoring under this permit:

i. The date, place (as defined in the permit), and time of sampling or measurements.
ii. The date(s) analyses were performed.
iii. The company or entity that performed the analyses.
iv. The analytical techniques or methods used.
v. The results of such analyses.
vi. The operating conditions existing at the time of sampling or measurement.
(Authority for term: OAC rule 3745-77-07(A)(3)(b)(i))

b. Each record of any monitoring data, testing data, and support information required pursuant to this permit shall be retained for a period of five years from the date the record was created. Support information shall include all calibration and maintenance records and all original strip-chart recordings for continuous monitoring instrumentation, and copies of all reports required by this permit. Such records may be maintained in computerized form.
(Authority for term: OAC rule 3745-77-07(A)(3)(b)(ii))

c. The permittee shall submit required reports in the following manner:

i. **All reporting required in accordance with OAC rule 3745-77-07(A)(3)(c) for deviations caused by malfunctions shall be submitted in the following manner:**

Any malfunction, as defined in OAC rule 3745-15-06(B)(1), shall be promptly reported to the Ohio EPA in accordance with OAC rule 3745-15-06. In addition, to fulfill the OAC rule 3745-77-07(A)(3)(c) deviation reporting requirements for malfunctions, written reports that identify each malfunction that occurred during each calendar quarter (including each malfunction reported only verbally in accordance with OAC rule 3745-15-06) shall be submitted by January 31, April 30, July 31, and October 31 of each year in accordance with General Term and Condition A.1.c.ii below; and each report shall cover the previous calendar quarter.

In accordance with OAC rule 3745-15-06, a malfunction constitutes a violation of an emission limitation (or control requirement) and, therefore, is a deviation of the federally enforceable permit requirements. Even though verbal notifications and written reports are required for malfunctions pursuant to OAC rule 3745-15-06, the written reports required pursuant to this term must be submitted quarterly to satisfy the prompt reporting provision of OAC rule 3745-77-07(A)(3)(c).

In identifying each deviation caused by a malfunction, the permittee shall specify the emission limitation(s) (or control requirement(s)) for which the deviation occurred, describe each deviation, and provide the magnitude and duration of each deviation. For a specific malfunction, if this information has been provided in a written report that was submitted in accordance with OAC rule 3745-15-06, the permittee may simply reference that written report to identify the deviation. Nevertheless, all malfunctions, including those reported only verbally in accordance with OAC rule 3745-15-06, must be reported in writing on a quarterly basis.

Any scheduled maintenance, as referenced in OAC rule 3745-15-06(A)(1), that results in a deviation from a federally enforceable emission limitation (or control requirement) shall be reported in the same manner as described above for malfunctions.
(Authority for term: OAC rule 3745-77-07(A)(3)(c))

ii. **Except as may otherwise be provided in the terms and conditions for a specific emissions unit, i.e., in Section A.IV of Part III of this Title V permit or, in some cases, in Part II of this Title V permit, all reporting required in accordance with OAC rule 3745-77-07(A)(3)(c) for deviations of the emission limitations, operational restrictions, and control device operating parameter limitations shall be submitted in the following manner:**

Written reports of (a) any deviations from federally enforceable emission limitations, operational restrictions, and control device operating parameter limitations, (b) the probable cause of such deviations, and (c) any corrective actions or preventive measures taken, shall be promptly made to the appropriate Ohio EPA District Office or local air agency. Except as provided below, the written reports shall be submitted by January 31, April 30, July 31, and October 31 of each year; and each report shall cover the previous calendar quarter.

In identifying each deviation, the permittee shall specify the emission limitation(s), operational restriction(s), and/or control device operating parameter limitation(s) for which the deviation occurred, describe each deviation, and provide the estimated magnitude and duration of each deviation.

These written reports shall satisfy the requirements (in part) of OAC rule 3745-77-07(A)(3)(c) pertaining to the submission of monitoring reports every six months and to the prompt reporting of all deviations. OAC rule 3745-77-07(A)(3)(c) is not fully satisfied until the permittee addresses all other deviations of the federally enforceable requirements specified in the permit.

If an emissions unit has a deviation reporting requirement for a specific emission limitation, operational restriction, or control device operating parameter limitation that is not on a quarterly basis (e.g., within 30 days following the end of the calendar month, or within 30 or 45 days after the exceedance occurs), that deviation reporting requirement overrides the reporting requirements specified in this General Term and Condition for that specific emission limitation, operational restriction, or control device parameter limitation. Following the provisions of that non-quarterly deviation reporting requirement will also satisfy the requirements (in part) of OAC rule 3745-77-07(A)(3)(c) pertaining to the submission of monitoring reports every six months and to the prompt reporting of all deviations, and additional quarterly deviation reports for that specific emission limitation, operational restriction, or control device parameter limitation are not required pursuant to this General Term and Condition.

See B.6 below if no deviations occurred during the quarter.
(Authority for term: OAC rule 3745-77-07(A)(3)(c))

iii. **All reporting required in accordance with the OAC rule 3745-77-07(A)(3)(c) for other deviations of the federally enforceable permit requirements which are not reported in accordance with General Term and Condition A.1.c.ii above shall be submitted in the following manner:**

Written reports that identify all other deviations of the federally enforceable requirements contained in this permit, including the monitoring, record keeping, and reporting requirements, which are not reported in accordance with General Term and Condition A.1.c.ii above shall be

submitted to the appropriate Ohio EPA District Office or local air agency by January 31 and July 31 of each year; and each report shall cover the previous six calendar months.

In identifying each deviation, the permittee shall specify the federally enforceable requirement for which the deviation occurred, describe each deviation, and provide the magnitude and duration of each deviation.

These semi-annual written reports shall satisfy the reporting requirements of OAC rule 3745-77-07(A)(3)(c) for any deviations from the federally enforceable requirements contained in this permit that are not reported in accordance with General Term and Condition A.1.c.ii above.

If no such deviations occurred during a six-month period, the permittee shall submit a semi-annual report which states that no such deviations occurred during that period.
(Authority for term: OAC rules 3745-77-07(A)(3)(c)(i) and (ii))

iv. Each written report shall be signed by a responsible official certifying that, "based on information and belief formed after reasonable inquiry, the statements and information in the report (including any written malfunction reports required by OAC rule 3745-15-06 that are referenced in the deviation reports) are true, accurate, and complete."
(Authority for term: OAC rule 3745-77-07(A)(3)(c)(iv))

v. Reports of any required monitoring and/or record keeping information shall be submitted to the appropriate Ohio EPA District Office or local air agency.
(Authority for term: OAC rule 3745-77-07(A)(3)(c))

2. Scheduled Maintenance

Any scheduled maintenance of air pollution control equipment shall be performed in accordance with paragraph (A) of OAC rule 3745-15-06. Except as provided in OAC rule 3745-15-06(A)(3), any scheduled maintenance necessitating the shutdown or bypassing of any air pollution control system(s) shall be accompanied by the shutdown of the emissions unit(s) that is (are) served by such control system(s). Any scheduled maintenance, as defined in OAC rule 3745-15-06(A)(1), that results in a deviation from a federally enforceable emission limitation (or control requirement) shall be reported in the same manner as described for malfunctions in General Term and Condition A.1.c.i above.
(Authority for term: OAC rule 3745-77-07(A)(3)(c))

3. Risk Management Plans

If applicable, the permittee shall develop and register a risk management plan pursuant to section 112(r) of the Clean Air Act, as amended, 42 U.S.C. § 7401 et seq. ("Act"); and, pursuant to 40 C.F.R. 68.215(a), the permittee shall submit either of the following:

a. a compliance plan for meeting the requirements of 40 C.F.R. Part 68 by the date specified in 40 C.F.R. 68.10(a) and OAC 3745-104-05(A); or

b. as part of the compliance certification submitted under 40 C.F.R. 70.6(c)(5), a certification statement that the source is in compliance with all requirements of 40 C.F.R. Part 68 and OAC Chapter 3745-104, including the registration and submission of the risk management plan.

(Authority for term: OAC rule 3745-77-07(A)(4))

4. Title IV Provisions

If the permittee is subject to the requirements of 40 CFR Part 72 concerning acid rain, the permittee shall ensure that any affected emissions unit complies with those requirements. Emissions exceeding any allowances that are lawfully held under Title IV of the Act, or any regulations adopted thereunder, are prohibited.
(Authority for term: OAC rule 3745-77-07(A)(5))

5. Severability Clause

A determination that any term or condition of this permit is invalid shall not invalidate the force or effect of any other term or condition thereof, except to the extent that any other term or condition depends in whole or in part for its operation or implementation upon the term or condition declared invalid.
(Authority for term: OAC rule 3745-77-07(A)(6))

6. General Requirements

a. The permittee must comply with all terms and conditions of this permit. Any noncompliance with the federally enforceable terms and conditions of this permit constitutes a violation of the Act, and is grounds for enforcement action or for permit revocation, revocation and reissuance, or modification, or for denial of a permit renewal application.

b. It shall not be a defense for the permittee in an enforcement action that it would have been necessary to halt or reduce the permitted activity in order to maintain compliance with the federally enforceable terms and conditions of this permit.

c. This permit may be modified, reopened, revoked, or revoked and reissued, for cause, in accordance with A.10 below. The filing of a request by the permittee for a permit modification, revocation and reissuance, or revocation, or of a notification of planned changes or anticipated noncompliance does not stay any term and condition of this permit.

d. This permit does not convey any property rights of any sort, or any exclusive privilege.

e. The permittee shall furnish to the Director of the Ohio EPA, or an authorized representative of the Director, upon receipt of a written request and within a reasonable time, any information that may be requested to determine whether cause exists for modifying, reopening or revoking this permit or to determine compliance with this permit. Upon request, the permittee shall also furnish to the Director or an authorized representative of the Director, copies of records required to be kept by this permit. For information claimed to be confidential in the submittal to the Director, if the Administrator of the U.S. EPA requests such information, the permittee may furnish such records directly to the Administrator along with a claim of confidentiality.

(Authority for term: OAC rule 3745-77-07(A)(7))

7. Fees

The permittee shall pay fees to the Director of the Ohio EPA in accordance with ORC section 3745.11 and OAC Chapter 3745-78.
(Authority for term: OAC rule 3745-77-07(A)(8))

8. Marketable Permit Programs

No revision of this permit is required under any approved economic incentive, marketable permits, emissions trading, and other similar programs or processes for changes that are provided for in this permit.
(Authority for term: OAC rule 3745-77-07(A)(9))

9. Reasonably Anticipated Operating Scenarios

The permittee is hereby authorized to make changes among operating scenarios authorized in this permit without notice to the Ohio EPA, but, contemporaneous with making a change from one operating scenario to another, the permittee must record in a log at the permitted facility the scenario under which the permittee is operating. The permit shield provided in these general terms and conditions shall apply to all operating scenarios authorized in this permit.
(Authority for term: OAC rule 3745-77-07(A)(10))

10. Reopening for Cause

This Title V permit will be reopened prior to its expiration date under the following conditions:

a. Additional applicable requirements under the Act become applicable to one or more emissions units covered by this permit, and this permit has a remaining term of three or more years. Such a reopening shall be completed not later than eighteen (18) months after promulgation of the applicable requirement. No such reopening is required if the effective date of the requirement is later than the date on which the permit is due to expire, unless the original permit or any of its terms and conditions has been extended pursuant to paragraph (E)(1) of OAC rule 3745-77-08.

b. This permit is issued to an affected source under the acid rain program and additional requirements (including excess emissions requirements) become applicable. Upon approval by the Administrator, excess emissions offset plans shall be deemed to be incorporated into the permit, and shall not require a reopening of this permit.

c. The Director of the Ohio EPA or the Administrator of the U.S. EPA determines that the federally applicable requirements in this permit are based on a material mistake, or that inaccurate statements were made in establishing the emissions standards or other terms and conditions of this permit related to such federally applicable requirements.

d. The Administrator of the U.S. EPA or the Director of the Ohio EPA determines that this permit must be revised or revoked to assure compliance with the applicable requirements.

(Authority for term: OAC rules 3745-77-07(A)(12) and 3745-77-08(D))

11. Federal and State Enforceability

Only those terms and conditions designated in this permit as federally enforceable, that are required under the Act, or any of its applicable requirements, including relevant provisions designed to limit the potential to emit of a source, are enforceable by the Administrator of the U.S. EPA, the State, and citizens under the Act. All other terms and conditions of this permit shall not be federally enforceable and shall be enforceable under State law only.

(Authority for term: OAC rule 3745-77-07(B))

12. Compliance Requirements

a. Any document (including reports) required to be submitted and required by a federally applicable requirement in this Title V permit shall include a certification by a responsible official that, based on information and belief formed after reasonable inquiry, the statements in the document are true, accurate, and complete.

b. Upon presentation of credentials and other documents as may be required by law, the permittee shall allow the Director of the Ohio EPA or an authorized representative of the Director to:

i. At reasonable times, enter upon the permittee's premises where a source is located or the emissions-related activity is conducted, or where records must be kept under the conditions of this permit.

ii. Have access to and copy, at reasonable times, any records that must be kept under the conditions of this permit, subject to the protection from disclosure to the public of confidential information consistent with paragraph (E) of OAC rule 3745-77-03.

iii. Inspect at reasonable times any facilities, equipment (including monitoring and air pollution control equipment), practices, or operations regulated or required under this permit.

iv. As authorized by the Act, sample or monitor at reasonable times substances or parameters for the purpose of assuring compliance with the permit and applicable requirements.

c. The permittee shall submit progress reports to the appropriate Ohio EPA District Office or local air agency concerning any schedule of compliance for meeting an applicable requirement. Progress reports

shall be submitted semiannually, or more frequently if specified in the applicable requirement or by the Director of the Ohio EPA. Progress reports shall contain the following:

i. Dates for achieving the activities, milestones, or compliance required in any schedule of compliance, and dates when such activities, milestones, or compliance were achieved.
ii. An explanation of why any dates in any schedule of compliance were not or will not be met, and any preventive or corrective measures adopted.

d. Compliance certifications concerning the terms and conditions contained in this permit that are federally enforceable emission limitations, standards, or work practices, shall be submitted to the Director (the appropriate Ohio EPA District Office or local air agency) and the Administrator of the U.S. EPA in the following manner and with the following content:

i. Compliance certifications shall be submitted annually on a calendar year basis. The annual certification shall be submitted on or before April 30th of each year during the permit term.
ii. Compliance certifications shall include the following:
   (a) An identification of each term or condition of this permit that is the basis of the certification.
   (b) The permittee's current 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 required reporting period.
   (e) Such other facts as the Director of the Ohio EPA may require in the permit to determine the compliance status of the source.
iii. Compliance certifications shall contain such additional requirements as may be specified pursuant to sections 114(a)(3) and 504(b) of the Act.

(Authority for term: OAC rules 3745-77-07(C)(1),(2),(4) and (5) and ORC section 3704.03(L))

13. Permit Shield

a. Compliance with the terms and conditions of this permit (including terms and conditions established for alternate operating scenarios, emissions trading, and emissions averaging, but excluding terms and conditions for which the permit shield is expressly prohibited under OAC rule 3745-77-07) shall be deemed compliance with the applicable requirements identified and addressed in this permit as of the date of permit issuance.

b. This permit shield provision shall apply to any requirement identified in this permit pursuant to OAC rule 3745-77-07(F)(2), as a requirement that does not apply to the source or to one or more emissions units within the source.

(Authority for term: OAC rule 3745-77-07(F))

14. Operational Flexibility

The permittee is authorized to make the changes identified in OAC rule 3745-77-07(H)(1)(a) to (H)(1)(c) within the permitted stationary source without obtaining a permit revision, if such change is not a modification under any provision of Title I of the Act [as defined in OAC rule 3745-77-01(JJ)], and does not result in an exceedance of the emissions allowed under this permit (whether expressed therein as a rate of emissions or in terms of total emissions), and the permittee provides the Administrator of the U.S. EPA and the appropriate Ohio EPA District Office or local air agency with written notification within a minimum of seven days in advance of the proposed changes, unless the change is associated with, or in response to, emergency conditions. If less than seven days notice is provided because of a need to respond more quickly to such emergency conditions, the permittee shall provide notice to the Administrator of the U.S. EPA and the appropriate District Office of the Ohio EPA or local air agency as soon as possible after learning of the need to make the change. The notification shall contain the items required under OAC rule 3745-77-07(H)(2)(d).

(Authority for term: OAC rules 3745-77-07(H)(1) and (2))

15. Emergencies

The permittee shall have an affirmative defense of emergency to an action brought for noncompliance with technology-based emission limitations if the conditions of OAC rule 3745-77-07(G)(3) are met. This emergency defense provision is in addition to any emergency or upset provision contained in any applicable requirement.
(Authority for term: OAC rule 3745-77-07(G))

16. Off-Permit Changes

The owner or operator of a Title V source may make any change in its operations or emissions at the source that is not specifically addressed or prohibited in the Title V permit, without obtaining an amendment or modification of the permit, provided that the following conditions are met:

a. The change does not result in conditions that violate any applicable requirements or that violate any existing federally enforceable permit term or condition.

b. The permittee provides contemporaneous written notice of the change to the Director and the Administrator of the U.S. EPA. Such written notice shall describe each such change, the date of such change, any change in emissions or pollutants emitted, and any federally applicable requirement that would apply as a result of the change.

c. The change shall not qualify for the permit shield under OAC rule 3745-77-07(F).

d. The permittee shall keep a record describing all changes made at the source that result in emissions of a regulated air pollutant subject to an applicable requirement, but not otherwise regulated under the permit, and the emissions resulting from those changes.

e. The change is not subject to any applicable requirement under Title IV of the Act or is not a modification under any provision of Title I of the Act.

Paragraph (I) of rule 3745-77-07 of the Administrative Code applies only to modification or amendment of the permittee's Title V permit. The change made may require a permit to install under Chapter 3745-31 of the Administrative Code if the change constitutes a modification as defined in that Chapter. Nothing in paragraph (I) of rule 3745-77-07 of the Administrative Code shall affect any applicable obligation under Chapter 3745-31 of the Administrative Code.
(Authority for term: OAC rule 3745-77-07(I))

17. Compliance Method Requirements

Nothing in this permit shall alter or affect the ability of any person to establish compliance with, or a violation of, any applicable requirement through the use of credible evidence to the extent authorized by law. Nothing in this permit shall be construed to waive any defenses otherwise available to the permittee, including but not limited to, any challenge to the Credible Evidence Rule (see 62 Fed. Reg. 8314, Feb. 24, 1997), in the context of any future proceeding.
(This term is provided for informational purposes only.)

18. Insignificant Activities

Each insignificant activity that has one or more applicable requirements shall comply with those applicable requirements.
(Authority for term: OAC rule 3745-77-07(A)(1))

19. Permit to Install Requirement

Prior to the "installation" or "modification" of any "air contaminant source," as those terms are defined in OAC rule 3745-31-01, a permit to install must be obtained from the Ohio EPA pursuant to OAC Chapter 3745-31.
(Authority for term: OAC rule 3745-77-07(A)(1))

20. Air Pollution Nuisance

The air contaminants emitted by the emissions units covered by this permit shall not cause a public nuisance, in violation of OAC rule 3745-15-07.
(Authority for term: OAC rule 3745-77-07(A)(1))

21. Permanent Shutdown of an Emissions Unit

The permittee may notify Ohio EPA of any emissions unit that is permanently shut down by submitting a certification by the responsible official of the date on which the emissions unit was permanently shut down. Authorization to operate the affected part or activity of the stationary source shall cease upon the date certified by the responsible official that the emissions unit was permanently shut down.

If an emissions unit is permanently shut down (i.e., that has been physically removed from service or has been altered in such a way that it can no longer operate without a subsequent "modification" or "installation" as defined in OAC Chapter 3745-31 and therefore ceases to meet the definition of an "emissions unit" as defined in OAC rule 3745-77-01(O)), rendering existing permit terms and conditions irrelevant, the permittee shall not be required, after the date of the certification and submission to Ohio EPA, to meet any monitoring, record keeping, reporting, or testing requirements, applicable to that emissions unit, except for any residual requirements, such as the quarterly deviation reports, semi-annual deviation reports and annual compliance certification covering the period during which the emissions unit last operated. All records relating to the shutdown emissions unit, generated while the emissions unit was in operation, must be maintained in accordance with law.

No emissions unit certified by the responsible official as being permanently shut down may resume operation without first applying for and obtaining a permit to install pursuant to OAC Chapter 3745-31.

B. *State Only Enforceable Section*

1. Reporting Requirements Related to Monitoring and Record Keeping Requirements

The permittee shall submit required reports in the following manner:

a. Reports of any required monitoring and/or record keeping information shall be submitted to the appropriate Ohio EPA District Office or local air agency.

b. Except as otherwise may be provided in the terms and conditions for a specific emissions unit, quarterly written reports of (i) any deviations (excursions) from emission limitations, operational restrictions, and control device operating parameter limitations that have been detected by the testing, monitoring, and record keeping requirements specified in this permit, (ii) the probable cause of such deviations, and (iii) any corrective actions or preventive measures which have been or will be taken, shall be submitted to the appropriate Ohio EPA District Office or local air agency. In identifying each deviation, the permittee shall specify the applicable requirement for which the deviation occurred, describe each deviation, and provide the magnitude and duration of each deviation. If no deviations occurred during a calendar quarter, the permittee shall submit a quarterly report, which states that no deviations occurred during that quarter. The reports shall be submitted quarterly, i.e., by January 31, April 30, July 31, and October 31 of each year and shall cover the previous calendar quarters. (These quarterly reports shall exclude deviations resulting from malfunctions reported in accordance with OAC rule 3745-15-06.)

2. Records Retention Requirements

Each record of any monitoring data, testing data, and support information required pursuant to this permit shall be retained for a period of five years from the date the record was created. Support information shall include, but not be limited to, all calibration and maintenance records and all original strip-chart recordings for continuous monitoring instrumentation, and copies of all reports required by this permit. Such records may be maintained in computerized form.

3. Inspections and Information Requests

The Director of the Ohio EPA, or an authorized representative of the Director, may, subject to the safety requirements of the permittee and without undue delay, enter upon the premises of this source at any reasonable time for purposes of making inspections, conducting tests, examining records or reports pertaining to any emission of air contaminants, and determining compliance with any applicable State air pollution laws and regulations and the terms and conditions of this permit. The permittee shall furnish to the Director of the Ohio EPA, or an authorized representative of the Director, upon receipt of a written request and within a reasonable time, any information that may be requested to determine whether cause exists for modifying, reopening or revoking this permit or to determine compliance with this permit. Upon verbal or written request, the permittee shall also furnish to the Director of the Ohio EPA, or an authorized representative of the Director, copies of records required to be kept by this permit.

4. Scheduled Maintenance/Malfunction Reporting

Any scheduled maintenance of air pollution control equipment shall be performed in accordance with paragraph (A) of OAC rule 3745-15-06. The malfunction of any emissions units or any associated air pollution control system(s) shall be reported to the appropriate Ohio EPA District Office or local air agency in accordance with paragraph (B) of OAC rule 3745-15-06. Except as provided in that rule, any scheduled maintenance or malfunction necessitating the shutdown or bypassing of any air pollution control system(s) shall be accompanied by the shutdown of the emissions unit(s) that is (are) served by such control system(s).

5. Permit Transfers

Any transferee of this permit shall assume the responsibilities of the prior permit holder. The appropriate Ohio EPA District Office or local air agency must be notified in writing of any transfer of this permit.

6. Additional Reporting Requirements When There Are No Deviations of <u>Federally Enforceable</u> Emission Limitations, Operational Restrictions, or Control Device Operating Parameter Limitations (See Section A of This Permit)

If no emission limitation (or control requirement), operational restriction and/or control device parameter limitation deviations occurred during a calendar quarter, the permittee shall submit a quarterly report, which states that no deviations occurred during that quarter. The reports shall be submitted by January 31, April 30, July 31, and October 31 of each year; and each report shall cover the previous calendar quarter.

The permittee is not required to submit a quarterly report which states that no deviations occurred during that quarter for the following situations:

a. where an emissions unit has deviation reporting requirements for a specific emission limitation, operational restriction, or control device parameter limitation that override the deviation reporting requirements specified in General Term and Condition A.1.c.ii;

b. where an uncontrolled emissions unit has no monitoring, record keeping, or reporting requirements and the emissions unit's applicable emission limitations are established at the potentials to emit; and

c. where the company's responsible official has certified that an emissions unit has been permanently shut down.

Part II - Specific Facility Terms and Conditions

A. State and Federally Enforceable Section

1. This facility is subject to the applicable requirements specified in OAC Chapter 3745-25. In accordance with Ohio EPA Engineering Guide #64, the emission control action programs, as specified in OAC rule 3745-25-03, shall be developed and submitted within 60 days after receiving notification from the Ohio EPA.

2. All asbestos renovation and demolition activities conducted at this facility shall be performed in accordance with the applicable requirements specified in 40 CFR Part 61 and OAC Chapter 3745-20.

3. The permittee shall comply with all applicable provisions specified in 40 CFR Part 82, Subparts B and F as related to the operations at this facility.

4. Nitrogen Oxides (NOx) Budget Trading Program

OAC Chapter 3745-14

4.a Office of Regulatory Information System Facility Code - 7158

4.b The following regulated electrical generating units are subject to the applicable requirements specified in OAC Chapter 3745-14 and the annual NOx allowance allocations listed below:

. . Emissions Unit	Annual Allowance for Calendar Years 2004 and 2005	Annual Allowance for Calendar Years 2006 and 2007
B001 - GT1	30	29
B002 - GT2	30	29
B003 - GT3	39	38
B004 - GT4	37	36
B005 - GT5	40	39
B006 - GT6	39	38

4.c The emissions units identified in Section A.4.b above are NOx budget units under OAC rule 3745-14-01(C)(1).
[OAC rule 3745-14-01(C)(1)(a)(i)]

4.d The NOx authorized account representative shall submit a complete NOx budget permit application in accordance with the deadlines specified in paragraphs (B)(2) and (B)(3) of OAC rule 3745-14-03. The NOx authorized account representative shall also submit, in a timely manner, any supplemental information that the Director determines is necessary in order to review a NOx budget permit application and issue or deny a NOx budget permit.
[OAC rules 3745-14-01(E)(1)(a)(i), 3745-14-01(E)(1)(a)(ii), and 3745-14-03(B)(1)]

4.e Beginning May 31, 2004, the owners and operators of each NOx budget source and each NOx budget unit at the source shall hold NOx allowances available for compliance deductions under paragraph (E) of OAC rule 3745-14-06, as of the NOx allowance transfer deadline, in the unit's compliance account and the source's overdraft account in an amount not less than the total NOx emissions for the control period from the unit, as determined in accordance with OAC rule 3745-14-08, plus any amount necessary to account for actual utilization under paragraph (C)(5) of OAC rule 3745-14-05 for the control period.
[OAC rules 3745-14-01(E)(3)(a) and 3745-14-01(E)(3)(c)]

4.f NOx allowances shall be held in, deducted from, or transferred among NOx allowance tracking system accounts in accordance with OAC rules 3745-14-05, 3745-14-06, 3745-14-07, and 3745-14-09.
[OAC rule 3745-14-01(E)(3)(d)]

4.g A NOx allowance shall not be deducted, in order to comply with the requirement under paragraph (E)(3)(a) of OAC rule 3745-14-01, for a control period in a year prior to the year for which the NOx allowance was allocated.
[OAC rule 3745-14-01(E)(3)(e)]

A. State and Federally Enforceable Section (continued)

4.h Each ton of NOx emitted in excess of the NOx budget emission limitation, as defined in OAC rule 3745-14-01(B)(2)(yy), shall constitute a separate violation of OAC Chapter 3745-14, the Clean Air Act, and applicable Ohio law. The owners and operators of a NOx budget unit that has excess emissions in any control period shall surrender the NOx allowances required for deduction under paragraph (E)(4)(a) of OAC rule 3745-14-06 and pay any fine, penalty, or assessment or comply with any other remedy imposed under paragraph (E)(4)(c) of OAC rule 3745-14-06.
[OAC rules 3745-14-01(E)(3)(b), 3745-14-01(E)(4)(a) and 3745-14-01(E)(4)(b)]

4.i When recorded by the Administrator pursuant to OAC rules 3745-14-06 and 3745-14-07, every allocation, transfer, or deduction of a NOx allowance to or from a NOx budget unit's compliance account or the overdraft account of the source where the unit is located is deemed to amend automatically, and become a part of, any NOx budget permit of the NOx budget unit by operation of law without any further review.
[OAC rule 3745-14-01(E)(3)(h)]

4.j Except as provided below, the Director shall revise the NOx budget permit, as necessary, in accordance with OAC rule 3745-77-08.

Each NOx budget permit is deemed to incorporate automatically the definitions of terms under paragraph (B) of OAC rule 3745-14-01 and, when recorded by the Administrator, in accordance with OAC rules 3745-14-06 and 3745-14-07, every allocation, transfer, or deduction of a NOx allowance to or from the compliance accounts of the NOx budget units covered by the permit or the overdraft account of the NOx budget source covered by the permit.
[OAC rules 3745-14-03(D)(2) and 3745-14-03(E)(1)]

4.k The owner or operator of a NOx budget unit shall comply with the prohibitions under OAC rule 3745-14-08(A)(5).
[OAC rule 3745-14-08(A)(5)]

4.l The owners and operators of the NOx budget unit shall keep on site at the source each of the following documents for a period of five years from the date the document is created: (This period may be extended for cause, at any time prior to the end of five years, in writing by the Director or Administrator.)

i. the account certificate of representation for the NOx authorized account representative for the NOx budget unit and all documents that demonstrate the truth of the statements in the account certificate of representation, in accordance with paragraph (D) of OAC rule 3745-14-02, provided that the certificate and documents shall be retained on site at the source beyond such five-year period until such documents are superseded because of the submission of a new account certificate or representation changing the NOx authorized account representative;

ii. all emission monitoring information, in accordance with OAC rule 3745-14-08;

iii. copies of all reports, compliance certifications, and other submissions and all records made or required under the NOx budget trading program; and

iv. copies of all documents used to complete a NOx budget permit application and any other submission under the NOx budget trading program or to demonstrate compliance with the requirements of the NOx budget trading program.
[OAC rule 3745-14-01(E)(5)(a)(i) through (iv)]

A. State and Federally Enforceable Section (continued)

4.m The permittee shall operate and maintain equipment to continuously estimate and record nitrogen oxides emissions from these emissions units in units of the applicable standard(s). Such continuous estimating and recording equipment shall comply with the requirements specified in 40 CFR Part 75, Appendix E.

The permittee shall comply with the initial and re-certification procedures of 40 CFR Part 75.

The permittee shall maintain records of the following data obtained by the continuous nitrogen oxides estimating system: emissions of nitrogen oxides in lb/mmBtu actual heat input on an hourly average basis and emissions of nitrogen oxides in lbs/hr.

Whenever the monitoring system fails to meet the quality assurance or data validation requirements of 40 CFR Part 75, data shall be substituted using the applicable procedures in Subpart D, Appendix D, or Appendix E of 40 CFR Part 75.
[OAC rules 3745-14-01(E)(2)(a), 3745-14-01(E)(5)(a)(ii), 3745-14-08(A)(2)(a) through (A)(2)(d), 3745-14-08(B)(1), and 3745-14-08(C)(1)]

4.n The permittee shall comply with the monitoring plan requirements of 40 CFR Part 75.62, except that the monitoring plan shall also include all of the information required by Subpart H of 40 CFR Part 75.
[OAC rule 3745-14-08(E)(2)(a)]

4.o The NOx authorized account representative of the NOx budget unit shall submit the reports and compliance certifications required under the NOx budget trading program, including those under OAC rules 3745-14-04 and 3745-14-08, to the Director and Administrator.
[OAC rule 3745-14-01(E)(5)(b)]

4.p Each submission under the NOx budget trading program shall be submitted, signed, and certified by the NOx authorized account representative for each NOx budget source on behalf of which the submission is made. Each such submission shall include the following certification statement by the NOx authorized account representative:

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

If the NOx authorized account representative for a NOx budget unit subject to an acid rain emission limitation who signed and certified any submission that is made under Subpart F or G of 40 CFR Part 75 and which includes data and information required under OAC rule 3745-14-08 or Subpart H of 40 CFR Part 75 is not the same person as the designated representative or the alternate designated representative for the unit under 40 CFR Part 72, then the submission shall also be signed by the designated representative or the alternate designated representative.
[OAC rules 3745-14-02(A)(5) and 3745-14-08(E)(1)(b)]

4.q The NOx authorized account representative shall submit quarterly reports that include all of the data and information required in Subpart H of 40 CFR Part 75 for each NOx budget unit (or group of units using a common stack) and the data and information in Subpart G of 40 CFR Part 75. These quarterly excess emission reports shall be submitted by January 30, April 30, July 30 and October 30 of each year and shall be submitted in the manner specified in Subpart H of 40 CFR Part 75 and 40 CFR Part 75.64.
[OAC rules 3745-14-08(E)(4)(a) and 3745-14-08(E)(4)(c)(i)]

A. State and Federally Enforceable Section (continued)

4.r The NOx authorized account representative shall submit to the Administrator a compliance certification in support of each quarterly report based on a reasonable inquiry of those persons with primary responsibility for ensuring that all of the unit's emissions are correctly and fully monitored. The compliance certification shall state that:

i. the monitoring data submitted were recorded in accordance with the applicable requirements of OAC rule 3745-14-08 and 40 CFR Part 75, including the quality assurance procedures and specifications; and

ii. for a unit with add-on NOx emission controls and for all hours where data are substituted in accordance with 40 CFR Part 75.34(a)(1), the add-on emission control were operating within the range of parameters listed in the quality assurance program under Appendix B of 40 CFR Part 75 and the substitute values do not systematically underestimate the NOx emissions.
[OAC rule 3745-14-08(E)(4)(d)(i) and (ii)]

4.s The NOx authorized account representative for a NOx budget unit shall submit written notice of monitoring system certification and re-certification test dates to the Director and the Administrator in accordance with 40 CFR Part 75.61. The NOx authorized account representative shall submit a certification application to the Administrator, U.S. EPA, Region V Office, and the Director within forty-five days after completing all initial or re-certification tests required under paragraph (B) of OAC rule 3745-14-08, including the information required under Subpart H of 40 CFR Part 75.
[OAC rules 3745-14-08(D) and 3745-14-08(E)(3)]

4.t For each control period in which one or more NOx budget units at a source are subject to the NOx budget emission limitation, the NOx authorized account representative of the source shall submit to the Director and the Administrator, by November 30 of that year, a compliance certification report for each source covering all such units.

The NOx authorized account representative shall include the following elements in the compliance certification report, in a format prescribed by the Administrator, concerning each unit at the source and subject to the NOx budget emission limitation for the control period covered by the report:

i. identification of each NOx budget unit;

ii. at the NOx authorized account representative's option, the serial numbers of the NOx allowances that are to be deducted from each unit's compliance account under paragraph (E) of OAC rule 3745-14-06 for the control period;

iii. at the NOx authorized account representative's option, for units sharing a common stack and having NOx emissions that are not monitored separately or apportioned in accordance with OAC rule 3745-14-08, the percentage of allowances that is to be deducted from each unit's compliance account under paragraph (E)(5) of OAC rule 3745-14-06; and

iv. the compliance certification under paragraph (A)(3) of OAC rule 3745-14-04.
[OAC rules 3745-14-04(A)(1) and 3745-14-04(A)(2)]

A. State and Federally Enforceable Section (continued)

4.u In the compliance certification report under Section A.4.t.iv above, the NOx authorized account representative shall certify, based upon reasonable inquiry of those persons with the primary responsibility for operating the source and the NOx budget units at the source in compliance with the NOx budget trading program, whether each NOx budget unit for which the compliance certification is submitted was operated during the calendar year covered by the report in compliance with the requirements of the NOx budget trading program applicable to the unit, including all the following:

i. whether the unit was operated in compliance with the NOx budget emission limitation;

ii. whether the monitoring plan that governs the unit has been maintained to reflect the actual operation and monitoring of the unit, and contains all information necessary to attribute NOx emissions to the unit, in accordance with OAC rule 3745-14-08;

iii. whether all the NOx emissions from the unit, or group of units (including the unit) using a common stack, were monitored or accounted for through the missing data procedures and reported in the quarterly monitoring reports, including whether conditional data were reported in the quarterly reports in accordance with OAC rule 3745-14-08, and if conditional data were reported, the permittee shall indicate whether the status of all conditional data has been resolved and all necessary quarterly report submissions have been made; and

iv. whether the facts that form the basis for certification under OAC rule 3745-14-08 of each monitor at the unit or group of units (including the unit) using a common stack, or for using an excepted monitoring method or alternative monitoring method approved under OAC rule 3745-14-08, if any, have changed.

If a change is required to be reported under Section A.4.u.iv above, specify the nature of the change, the reason for the change, when the change occurred, and how the unit's compliance status was determined subsequent to the change, including what method was used to determine emissions when a change mandated the need for monitor re-certification.
[OAC rule 3745-14-04(A)(3)]

4.v The NOx authorized account representative shall submit a complete NOx budget permit renewal application for the NOx budget source covering the NOx budget units at the source in accordance with paragraph (E) of OAC rule 3745-77-08.
[OAC rule 3745-14-03(B)(3)(a)]

4.w The emission measurements recorded and reported in accordance with OAC rule 3745-14-08 shall be used to determine compliance by the unit with the NOx budget emission limitation under paragraph (E)(3) of OAC rule 3745-14-01.
[OAC rule 3745-14-01(E)(2)(b)]

4.x The permittee shall develop and maintain a written quality assurance/quality control plan for each continuous NOx monitoring system designed to ensure continuous valid and representative readings of NOx emissions in units of the applicable standard. The plan shall follow the requirements of 40 CFR Part 75, Appendix B. The quality assurance/quality control plan and a logbook dedicated to the continuous NOx monitoring system must be kept on-site and available for inspection during regular office hours.
[OAC rules 3745-14-08(A)(2)(c) and 3745-14-08(A)(2)(d)]

5. The permittee is subject to the applicable emission limitation(s) and/or control measures, operational restrictions, monitoring and/or record keeping requirements, reporting requirements, testing requirements and the general and/or other requirements specified in 40 CFR Part 63, Subpart YYYY (NESHAP for Combustion Turbines), in accordance with 40 CFR Parts 63.6080 through 63.6175 (including the Table(s) and Appendix(ices) referenced in Subpart YYYY), which are included in the text of Attachment 1 hereto, and are hereby incorporated into this permit as if fully rewritten.

Ordinarily, these requirements would be incorporated into Part II of this Title V permit; however, incorporating Subpart YYYY into Part II of this Title V permit was not practical due to technical incompatibilities and the limitations of the STARS program. In addition, numerous difficulties were encountered in attempting to copy and paste the Subpart's tables and/or equations into STARS format.

The following emissions units in this permit are subject to the aforementioned requirements: emissions units B001 through B006.

A. State and Federally Enforceable Section (continued)

6. The permittee is subject to the applicable emission limitation(s) and/or control measures, operational restrictions, monitoring and/or record keeping requirements, reporting requirements, testing requirements and the general and/or other requirements specified in 40 CFR Part 63, Subpart DDDDD (NESHAP for Industrial/Commercial/Institutional Boilers and Process Heaters), in accordance with 40 CFR Parts 63.7480 through 63.7575 (including the Table(s) and Appendix(ices) referenced in Subpart DDDDD), which are included in the text of Attachment 2 hereto, and are hereby incorporated into this permit as if fully rewritten.

Ordinarily, these requirements would be incorporated into Part II of this Title V permit; however, incorporating Subpart DDDDD into Part II of this Title V permit was not practical due to technical incompatibilities and the limitations of the STARS program. In addition, numerous difficulties were encountered in attempting to copy and paste the Subpart's tables and/or equations into STARS format.

The following emissions units in this permit are subject to the aforementioned requirements: emissions units B013 through B018.

7. The following insignificant emissions units are located at this facility:

B025 - combustion turbine black start unit (Permit to Install 14-1984);
B026 - diesel fire pump (Permit to Install 14-2179);
G001 - gasoline dispensing operation (Permit to Install 14-2520);
L001 - non-halogenated solvent cold parts cleaner (Permit to Install 14-2954); and
Z006 - 275,000 Btu/hr propane-fired generator.

Each insignificant emissions unit at this facility must comply with all applicable State and federal regulations, as well as any emission limitations and/or control requirements contained within the identified permit to install for the emissions unit. Insignificant emissions units listed above that are not subject to specific permit to install requirements are subject to one or more applicable requirements contained in the federally-approved versions of OAC Chapter 3745-17.

B. State Only Enforceable Section

None

Part III - Terms and Conditions for Emissions Units

Emissions Unit ID: Combustion Turbine Unit 1 (B001)

Activity Description: ABB model GT-11N combustion turbine.

A. State and Federally Enforceable Section

I. Applicable Emissions Limitations and/or Control Requirements

1. The specific operation(s), property, and/or equipment which constitute this emissions unit are listed in the following table along with the applicable rules and/or requirements and with the applicable emissions limitations and/or control measures. Emissions from this unit shall not exceed the listed limitations, and the listed control measures shall be employed. Additional applicable emissions limitations and/or control measures (if any) may be specified in narrative form following the table.

Operations, Property, and/or Equipment	Applicable Rules/ Requirements	Applicable Emissions Limitations/Control Measures
natural gas, liquid petroleum gas (LPG), and fuel oil-fired, simple cycle combustion turbine having a nominal heat input capacity of 1034 MMBtu/hr with a water injection system for the control of nitrogen oxides	40 CFR Part 52.21 and OAC rules 3745-31-11 through 3745-31-20 (PTI 14-1905)	See A.I.2.a through A.I.2.f and A.II.1 through A.II.3 below.
	OAC rule 3745-31-05(A)(3) (PTI 14-1905)	Compliance with this rule also includes compliance with 40 CFR Part 52.21 and OAC rules 3745-31-11 through 3745-31-20. See A.II.4 below.
	40 CFR Part 60, Subpart GG	The nitrogen oxides and sulfur dioxide emission limitations and/or content restrictions specified in 40 CFR Part 60, Subpart GG are equivalent to or less stringent than the emission limitations and/or content restrictions established in PTI 14-1905 pursuant to 40 CFR Part 52.21.
	OAC rule 3745-17-07(A)	The visible particulate emission limitations specified in OAC rule 3745-17-07(A) are less stringent than the visible particulate emission limitation established in PTI 14-1905 pursuant to 40 CFR Part 52.21.
	OAC rule 3745-17-11(B)(4)	The particulate emission limitation specified in OAC rule 3745-17-11(B)(4) is less stringent than The particulate emission limitation established in PTI 14-1905 pursuant to 40 CFR Part 52.21.

Operations, Property, and/or Equipment	Applicable Rules/ Requirements	Applicable Emissions Limitations/Control Measures
	OAC rule 3745-18-15(P)	The sulfur dioxide emission limitation specified in OAC rule 3745-18-15(P) is less stringent than the sulfur dioxide emission limitations established in PTI 14-1905 pursuant to 40 CFR Part 52.21.
	OAC rules 3745-21-08(B) and 3745-23-06(B)	See A.I.2.g below.

2. Additional Terms and Conditions

2.a Particulate Emission Limitations:

i. Emissions of particulates and particulates less than 10 microns in diameter (PE/PM10)* shall not exceed 40.4 lbs/hr.

ii. Visible PE from any combustion turbine stack shall not exceed 10% opacity, as a 6-minute average, except for cold start-up and shutdown periods. Cold start-up shall be defined as the time necessary to bring this emissions unit on line from a cold state to turbine synchronization.

iii. Best available control technology (BACT) for the PE/PM10 emissions from this emissions unit was determined to be burner design, combustion control, and compliance with the visible particulate emission limitation.

*The total PM10 emissions were evaluated and did not trigger any additional federal requirements, therefore, the emissions are being regulated as particulate emissions (PE).

2.b Nitrogen Oxides (NOx) Emission Limitations:

i. NOx emissions shall not exceed 261.4 lbs/hr.

ii. When burning natural gas, NOx emissions shall not exceed 42 ppm at 15% oxygen, on a dry basis.

iii. When burning LPG or fuel oil, NOx emissions shall not exceed 65 ppm at 15% oxygen, on a dry basis.

iv. BACT for the NOx emissions from this emissions unit was determined to be a low NOx burner design and water injection.

Pursuant to 40 CFR Part 60.332(f), this emissions unit is exempt from the NOx concentration emission limitations when ice fog, as defined in 40 CFR Part 60.331(f), is deemed a traffic hazard by the permittee.

2.c Sulfur Dioxide (SO2) Emission Limitations:

i. When burning fuel oil, SO2 emissions shall not exceed 516 lbs/hr from this emissions unit.

ii. When burning fuel oil, the total combined SO2 emissions from emissions units B001 through B006 shall not exceed 4911 lbs per 3-hour period and 22,152 lbs per 24-hour period.

iii. When burning natural gas or LPG in this emissions unit, SO2 emissions shall not exceed 0.015%, by volume, at 15% oxygen on a dry basis.

iv. BACT for the SO2 emissions from this emissions unit was determined to be use of a low sulfur content fuel and compliance with the emission limitations in 2.c.ii above.

2. Additional Terms and Conditions (continued)

2.d Volatile Organic Compound (VOC) Emission Limitation:

i. VOC emissions shall not exceed 6.97 lbs/hr.

ii. BACT for the VOC emissions from this emissions unit was determined to be the low VOC emission rate and compliance with the operational restrictions.

2.e Carbon Monoxide (CO) Emission Limitation:

i. CO emissions shall not exceed 25.34 lbs/hr.

ii. BACT for the CO emissions from this emissions unit was determined to be burner design.

2.f The hourly emission limitations established in PTI 14-1905 were based on the emissions unit's potentials to emit. Therefore, it is not necessary to develop any additional monitoring, record keeping or reporting requirements to ensure compliance with these emission limitations.

2.g The permittee has satisfied the "best available control techniques and operating practices" required pursuant to OAC rule 3745-21-08(B) by committing to comply with the best available control technology requirements established pursuant to 40 CFR Part 52.21 in Permit to Install 14-1905.

On November 5, 2002, OAC rule 3745-21-08 was revised to delete paragraph (B); therefore, paragraph (B) is no longer part of the State regulations. However, that rule revision has not yet been submitted to the U.S. EPA as a revision to Ohio's State Implementation Plan (SIP). Therefore, until the SIP revision occurs and the U.S. EPA approves the revisions to OAC rule 3745-21-08, the requirement to satisfy the "best available control techniques and operating practices" still exists as part of the federally-approved SIP for Ohio.

The permittee has satisfied the "latest available control techniques and operating practices" required pursuant to OAC rule 3745-23-06(B) by committing to comply with the best available control technology requirements established pursuant to 40 CFR Part 52.21 in Permit to Install 14-1905.

II. Operational Restrictions

1. The sulfur content of the fuel oil burned in this emissions unit shall not exceed 0.5%, by weight.

2. The total combined amount of fuel oil burned in emissions units B001 through B006 shall not exceed the amounts specified by the following equations:

For any 3-hour period:

gallons of fuel oil = 35078 / S

where: S = the sulfur content of the fuel oil, in percent, by weight
(e.g., if the fuel oil sulfur content is 0.5%, then S = 0.5)

For any 24-hour period:

gallons of fuel oil = 158228 / S

where: S = the sulfur content of the fuel oil, in percent, by weight
(e.g., if the fuel oil sulfur content is 0.5%, then S = 0.5)

3. The total combined operating hours for emissions units B001 through B006 shall not exceed 17,844 hours per rolling, 12-month period.

4. The minimum stack height for this emissions unit shall be at least 213 feet above the ground.

5. The permittee shall burn only natural gas, LPG, and/or fuel oil in this emissions unit.

III. Monitoring and/or Record Keeping Requirements

1. For each day during which the permittee burns a fuel other than natural gas, LPG, and/or fuel oil, the permittee shall maintain a record of the type and quantity of fuel burned in this emissions unit.

2. The permittee shall operate and maintain a continuous monitoring system to monitor and record the fuel consumption and the ratio of water-to-fuel being fired in this emissions unit. This system shall be accurate to within plus or minus 5% and shall be approved by the Administrator of the U.S. EPA.

3. The permittee shall monitor the sulfur content and nitrogen content of the fuel being fired in this emissions unit as specified below.

Sulfur Content:

For each shipment of oil received for burning in this emissions unit, the permittee shall maintain records of the total quantity of oil received and the permittee's or oil supplier's analyses for sulfur content (in %, by weight). A shipment may be comprised of multiple tank truck loads from the same supplier's batch, or may be represented by single or multiple pipeline deliveries from the same supplier's batch, and the quality of the oil for those loads or pipeline deliveries may be represented by a single batch analysis from the supplier.

The permittee shall collect and record the sulfur content of the natural gas and LPG being fired in this emissions unit on a quarterly basis in accordance with the approved custom schedule for this facility.

The permittee shall perform or require the supplier to perform the analyses for sulfur content and heat content in accordance with 40 CFR Part 60.335(d), 40 CFR Part 75, or the appropriate ASTM methods, or equivalent methods as approved by the Administrator of the U.S. EPA.

Should any sulfur analysis indicate noncompliance with 40 CFR Part 60.333 or the sulfur content limitation stated in section A.I. of this permit, the permittee shall notify Hamilton County Department of Environmental Services - Air Quality Division of the exceedance and the custom schedule shall be re-examined. During the re-examination period the permittee shall conduct daily sulfur monitoring and submit these analyses to Hamilton County Department of Environmental Services - Air Quality Division.

Nitrogen Content:

To compute the NOx emissions, the permittee shall use analytical methods and procedures that are accurate to within 5% and are approved by the Administrator of the U.S. EPA to determine the nitrogen content of the fuel being fired.

4. The permittee shall collect and record the following information on a monthly basis:

a. The total hours of operation for this emissions unit.

b. The total combined hours of operation for emissions units B001 through B006.

c. The rolling, 12-month summation of the total combined hours of operation for emissions units B001 through B006 (the summation of the current month's total combined hours of operation recorded in 4.b added to the previous 11 months total combined hours of operation).

III. Monitoring and/or Record Keeping Requirements (continued)

5. The permittee shall collect and record the following information:

a. The total combined number of gallons of fuel oil supplied to emissions units B001 through B006 for all 3-hour periods of operation.

b. The percent sulfur content, by weight, of the fuel oil supplied to emissions units B001 through B006 for all 3-hour periods of operation.

c. The total combined number of gallons of fuel oil supplied to emissions units B001 through B006 for all 24-hour periods of operation.

d. The percent sulfur content, by weight, of the fuel oil supplied to emissions units B001 through B006 for all 24-hour periods of operation.

e. The total combined SO2 emissions, in lbs, for emissions units B001 through B006 for all 3-hour periods of operation when burning fuel oil. (The SO2 emissions shall be calculated using the fuel oil usage and fuel oil sulfur content data above.)

f. The total combined SO2 emissions, in lbs, for emissions units B001 through B006 for all 24-hour periods of operation when burning fuel oil. (The SO2 emissions shall be calculated using the fuel oil usage and fuel oil sulfur content data above.)

g. Identification of each cold start-up for this emissions unit.

h. Identification of each shutdown for this emissions unit.

IV. Reporting Requirements

1. Pursuant to 40 CFR Parts 60.7 and 60.13(h), the permittee shall submit reports within 30 days following the end of each calendar quarter to the Hamilton County Department of Environmental Services - Air Quality Division documenting any 1-hour period during which the average water-to-fuel ratio, as measured by the continuous monitoring system, falls below the water-to-fuel ratio established during the most recent performance test that demonstrated that the emissions unit was in compliance with the applicable NOx emission limitations or any period during which the fuel-bound nitrogen of the fuel is greater than the maximum nitrogen content allowed by the fuel-bound nitrogen allowance used during the most recent performance test that demonstrated that the emissions unit was in compliance with the applicable NOx emission limitations. Each report shall include the average water-to-fuel ratio, average fuel consumption, ambient conditions, gas turbine load, and the nitrogen content of the fuel during the period of excess emissions. The graphs or figures developed under 40 CFR Part 60.335(a) shall also be submitted with each report.

The permittee shall submit reports within 30 days following the end of each calendar quarter to the Hamilton County Department of Environmental Services - Air Quality Division documenting any continuous water-to-fuel monitoring system downtime while the emissions unit was on line (date, time, duration and reason) along with any corrective action(s) taken. The permittee shall provide the emissions unit operating time during the reporting period and the date, time, reason and corrective action(s) taken for each time period of emissions unit and control equipment malfunctions. The total operating time of the emissions unit and the total operating time of the continuous monitoring system while the emissions unit was on line shall also be included in the quarterly report.

If there are no excess emissions during the calendar quarter, the permittee shall submit a statement to that effect along with the date, time, reason, and corrective action(s) taken for each time period of monitoring system malfunctions. The total operating time of the emissions unit and the total operating time of the continuous monitoring system while the emissions unit was on line also shall be included in the quarterly report. These quarterly excess emission reports shall be submitted by January 30, April 30, July 30, and October 30 of each year and shall address the data obtained during the previous calendar quarter.

IV. Reporting Requirements (continued)

Pursuant to 40 CFR Part 60.7, the permittee shall submit a summary of the excess emission report. The summary shall be submitted in accordance with 40 CFR Part 60.7(d) to the Hamilton County Department of Environmental Services - Air Quality Division within 30 days following the end of each calendar quarter in a manner prescribed by the Director.

2. The permittee shall submit quarterly reports that identify each period during which an exemption for ice-fog provided in 40 CFR Part 60.332(f) is in effect. The report shall include the ambient conditions existing during the period, the date and time the air pollution control system was deactivated, and the date and time when the air pollution control system was reactivated.

3. The permittee shall submit quarterly deviation (excursion) reports that identify the following:

a. Any exceedance of the 3-hour and/or 24-hour total combined fuel oil usage restrictions for emissions units B001 through B006 when burning fuel oil as calculated in section A.II.2.

b. Any exceedance of the 3-hour and/or 24-hour SO2 emission limitations when burning fuel oil for emissions units B001 through B006.

c. Any exceedance of the total combined operating hours restriction for emissions units B001 through B006.

d. Any exceedance of the 0.5%, by weight, fuel oil sulfur content restriction for this emissions unit.

e. Each day when a fuel other than natural gas, LPG, and/or fuel oil was burned in this emissions unit.

The quarterly deviation reports shall be submitted in accordance with the reporting requirements specified in Part I - General Term and Condition A.1.c.ii.

V. Testing Requirements

1. Emission Limitation:
Emissions of PE/PM10 shall not exceed 40.4 lbs/hr.

Applicable Compliance Method:
This emission limitation reflects the emissions unit's potential to emit. Compliance with this emission limitation may be demonstrated through the emission factors and equations found in Table 2.3 of the technical support document submitted 8/25/89 for PSD Permit to Install 14-1905. The PE/PM10 emission factor in Table 2.3 of Permit to Install 14-1905 is 5.10 grams of PE/PM10 per second when burning fuel oil, and 0.24 gram of PE/PM10 per second when burning natural gas or LPG.

If required, the permittee shall demonstrate compliance with the PE and PM10 emission limitation through emission tests performed in accordance with 40 CFR Part 60, Appendix A, Methods 1 through 5 while burning natural gas. Alternate U.S. EPA-approved test methods may be used with prior approval from the Ohio EPA.

2. Emission Limitation:
Visible PE from any combustion turbine stack shall not exceed 10% opacity, as a 6-minute average, except for cold start-up and shutdown periods.

Applicable Compliance Method:
If required, compliance with this emission limitation shall be demonstrated through visible emissions observations performed in accordance with 40 CFR Part 60, Appendix A, Method 9.

V. Testing Requirements (continued)

3. Emission Limitations:
NOx emissions shall not exceed 261.4 lbs/hr.

When burning natural gas, NOx emissions shall not exceed 42 ppm at 15% oxygen, on a dry basis.

When burning LPG or fuel oil, NOx emissions shall not exceed 65 ppm at 15% oxygen, on a dry basis.

Applicable Compliance Method:
The hourly NOx emission limitation reflects the emissions unit's potential to emit. Compliance with this emission limitation may be demonstrated through the emission factors and equations found in Table 2.3 of the technical support document submitted 8/25/89 for PSD Permit to Install 14-1905. The NOx emission factor in Table 2.3 of Permit to Install 14-1905 is 33.00 grams of NOx per second when burning fuel oil, and 32.50 grams of NOx per second when burning natural gas or LPG.

If required, the permittee shall demonstrate compliance with the hourly emission limitation through emission tests performed in accordance with 40 CFR Part 60, Appendix A, Methods 1 through 4 and 7 while burning natural gas. Alternate U.S. EPA-approved test methods may be used with prior approval from the Ohio EPA.

Compliance with the NOx concentration emission limitations may be demonstrated based upon the records required pursuant to Section A.III.2.

If required, the permittee shall demonstrate compliance with the NOx concentration emission limitations in accordance with the methods and procedures specified in 40 CFR Part 60.335(c).

4. Emission Limitations:
When burning fuel oil, SO2 emissions shall not exceed 516 lbs/hr from this emissions unit.

When burning fuel oil, the total combined SO2 emissions from emissions units B001 through B006 shall not exceed 4911 lbs per 3-hour period and 22,152 lbs per 24-hour period.

When burning natural gas or LPG, SO2 emissions shall not exceed 0.015%, by volume, at 15% oxygen on a dry basis from this emissions unit.

Applicable Compliance Method:
The hourly SO2 emission limitation reflects the emissions unit's potential to emit. Compliance with this emission limitation may be demonstrated through the emission factors and equations found in Table 2.3 of the technical support document submitted 8/25/89 for PSD Permit to Install 14-1905. The SO2 emission factor in Table 2.3 of Permit to Install 14-1905 is 65.13 grams of SO2 per second when burning fuel oil, and 0.00 gram of SO2 per second when burning natural gas or LPG.

If required, the permittee shall demonstrate compliance with the hourly emission limitation through emission tests performed in accordance with 40 CFR Part 60, Appendix A, Methods 1 through 4 and 6 while burning natural gas. Alternate U.S. EPA-approved test methods may be used with prior approval from the Ohio EPA.

If required, the permittee shall demonstrate compliance with the SO2 concentration emission limitation in accordance with the method and procedures specified in 40 CFR Part 60.335(c)(3).

Compliance with the total combined 3-hour and 24-hour SO2 emission limitations for emissions units B001 through B006 may be demonstrated based upon the records required pursuant to Section A.III.5.

V. Testing Requirements (continued)

5. Emission Limitation:
CO emissions shall not exceed 25.34 lbs/hr.

Applicable Compliance Method:
This emission limitation reflects the emissions unit's potential to emit. Compliance with this emission limitation may be demonstrated through the emission factors and equations found in Table 2.3 of the technical support document submitted 8/25/89 for PSD permit 14-1905. The CO emission factor in Table 2.3 of Permit to Install 14-1905 is 3.20 grams of CO per second when burning fuel oil, natural gas, or LPG.

If required, the permittee shall demonstrate compliance with this emission limitation through emission tests performed in accordance with 40 CFR Part 60, Appendix A, Methods 1 through 4 and 10 while burning natural gas. Alternate U.S. EPA-approved test methods may be used with prior approval from the Ohio EPA.

6. Emission Limitation:
VOC emissions shall not exceed 6.97 lbs/hr.

Applicable Compliance Method:
This emission limitation reflects the emissions unit's potential to emit. Compliance with this emission limitation may be demonstrated through the emission factors and equations found in Table 2.3 of the technical support document submitted 8/25/89 for PSD permit 14-1905. The VOC emission factor in Table 2.3 of Permit to Install 14-1905 is 0.88 gram of VOC per second when burning fuel oil, natural gas, or LPG.

If required, the permittee shall demonstrate compliance with this emission limitation through emission tests performed in accordance with 40 CFR Part 60, Appendix A, Methods 1 through 4 and 25 while burning natural gas. Alternate U.S. EPA-approved test methods may be used with prior approval from the Ohio EPA.

7. Upon initial use of fuel oil, the permittee shall conduct, or have conducted, emission testing for this emissions unit to demonstrate compliance with the applicable PE/PM10, NOx, SO2, VOC, and CO emission limitations in accordance with the following requirements:

The emission testing shall be conducted within 90 days of initiating fuel oil firing, unless an alternative schedule is submitted and approved by Hamilton County Department of Environmental Services-Air Quality Control Division. The frequency for future emission testing while burning fuel oil will be determined based upon the results of the initial emission tests and the procedures specified in Ohio EPA Engineering Guide 16.

Compliance with the applicable PE/PM10, NOx, SO2, VOC, and CO emission limitations shall be determined in accordance with the following:

for PE/PM10 - 40 CFR Part 60, Appendix A, Methods 1 through 5;
for NOx (hourly) - 40 CFR Part 60, Appendix A, Methods 1 through 4 and 7;
for NOx (concentration) - 40 CFR Part 60, Appendix A, Method 20
for SO2 - 40 CFR Part 60, Appendix A, Methods 1 through 4 and 6;
for VOC - 40 CFR Part 60, Appendix A, Methods 1 through 4 and 25; and
for CO - 40 CFR Part 60, Appendix A, Methods 1 through 4 and 10.

Alternate U.S. EPA-approved test methods may be used with prior approval from the Ohio EPA.

Testing for PE/PM10, NOx, and SO2 shall be performed on each emissions unit. Testing for CO and VOC shall be performed on one emissions unit that is representative of the permitted combustion turbine units (B001 through B006). Prior to performing CO and VOC testing, the permittee shall obtain agreement on the emissions unit to be tested as a representative unit from the Hamilton County Department of Environmental Services-Air Quality Control Division.

The tests shall be conducted while the emissions unit is operating at or near its maximum capacity.

V. Testing Requirements (continued)

Not later than 30 days prior to the proposed test date(s), the permittee shall submit an "Intent to Test" notification to the Hamilton County Department of Environmental Services. The "Intent to Test" notification shall describe in detail the proposed test methods and procedures, the emissions unit operating parameters, the time(s) and date(s) of the test(s), and the person(s) who will be conducting the test(s). Failure to submit such notification for review and approval prior to the test(s) may result in the Hamilton County Department of Environmental Services' refusal to accept the results of the emission test(s).

Personnel from the Hamilton County Department of Environmental Services and Ohio EPA shall be permitted to witness the test(s), examine the testing equipment, and acquire data and information necessary to ensure that the operation of the emissions unit and the testing procedures provide a valid characterization of the emissions from the emissions unit and/or the performance of the control equipment.

A comprehensive written report on the results of the emission test(s) shall be signed by the person or persons responsible for the tests and submitted to the Hamilton County Department of Environmental Services within 30 days following completion of the test(s). The permittee may request additional time for the submittal of the written report, where warranted, with prior approval from the Hamilton County Department of Environmental Services.

VI. Miscellaneous Requirements

None

B. State Enforceable Section

I. Applicable Emissions Limitations and/or Control Requirements

1. The specific operation(s), property, and/or equipment which constitute this emissions unit are listed in the following table along with the applicable rules and/or requirements and with the applicable emissions limitations and/or control measures. Emissions from this unit shall not exceed the listed limitations, and the listed control measures shall be employed. Additional applicable emissions limitations and/or control measures (if any) may be specified in narrative form following the table.

Operations, Property, and/or Equipment	Applicable Rules/ Requirements	Applicable Emissions Limitations/Control Measures

2. Additional Terms and Conditions

None

II. Operational Restrictions

None

III. Monitoring and/or Record Keeping Requirements

None

IV. Reporting Requirements

None

V. Testing Requirements

None

VI. Miscellaneous Requirements

None

Part III - Terms and Conditions for Emissions Units

Emissions Unit ID: Combustion Turbine Unit 2 (B002)

Activity Description: ABB model GT-11N combustion turbine.

A. State and Federally Enforceable Section

I. Applicable Emissions Limitations and/or Control Requirements

1. The specific operation(s), property, and/or equipment which constitute this emissions unit are listed in the following table along with the applicable rules and/or requirements and with the applicable emissions limitations and/or control measures. Emissions from this unit shall not exceed the listed limitations, and the listed control measures shall be employed. Additional applicable emissions limitations and/or control measures (if any) may be specified in narrative form following the table.

Operations, Property, and/or Equipment	Applicable Rules/ Requirements	Applicable Emissions Limitations/Control Measures
natural gas, liquid petroleum gas (LPG), and fuel oil-fired, simple cycle combustion turbine having a nominal heat input capacity of 1034 MMBtu/hr with a water injection system for the control of nitrogen oxides	40 CFR Part 52.21 and OAC rules 3745-31-11 through 3745-31-20 (PTI 14-1905)	See A.I.2.a through A.I.2.f and A.II.1 through A.II.3 below.
	OAC rule 3745-31-05(A)(3) (PTI 14-1905)	Compliance with this rule also includes compliance with 40 CFR Part 52.21 and OAC rules 3745-31-11 through 3745-31-20. See A.II.4 below.
	40 CFR Part 60, Subpart GG	The nitrogen oxides and sulfur dioxide emission limitations and/or content restrictions specified in 40 CFR Part 60, Subpart GG are equivalent to or less stringent than the emission limitations and/or content restrictions established in PTI 14-1905 pursuant to 40 CFR Part 52.21.
	OAC rule 3745-17-07(A)	The visible particulate emission limitations specified in OAC rule 3745-17-07(A) are less stringent than the visible particulate emission limitation established in PTI 14-1905 pursuant to 40 CFR Part 52.21.
	OAC rule 3745-17-11(B)(4)	The particulate emission limitation specified in OAC rule 3745-17-11(B)(4) is less stringent than The particulate emission limitation established in PTI 14-1905 pursuant to 40 CFR Part 52.21.

Operations, Property, and/or Equipment	Applicable Rules/ Requirements	Applicable Emissions Limitations/Control Measures
	OAC rule 3745-18-15(P)	The sulfur dioxide emission limitation specified in OAC rule 3745-18-15(P) is less stringent than the sulfur dioxide emission limitations established in PTI 14-1905 pursuant to 40 CFR Part 52.21.
	OAC rules 3745-21-08(B) and 3745-23-06(B)	See A.I.2.g below.

2. Additional Terms and Conditions

2.a Particulate Emission Limitations:

i. Emissions of particulates and particulates less than 10 microns in diameter (PE/PM10)* shall not exceed 40.4 lbs/hr.

ii. Visible PE from any combustion turbine stack shall not exceed 10% opacity, as a 6-minute average, except for cold start-up and shutdown periods. Cold start-up shall be defined as the time necessary to bring this emissions unit on line from a cold state to turbine synchronization.

iii. Best available control technology (BACT) for the PE/PM10 emissions from this emissions unit was determined to be burner design, combustion control, and compliance with the visible particulate emission limitation.

*The total PM10 emissions were evaluated and did not trigger any additional federal requirements, therefore, the emissions are being regulated as particulate emissions (PE).

2.b Nitrogen Oxides (NOx) Emission Limitations:

i. NOx emissions shall not exceed 261.4 lbs/hr.

ii. When burning natural gas, NOx emissions shall not exceed 42 ppm at 15% oxygen, on a dry basis.

iii. When burning LPG or fuel oil, NOx emissions shall not exceed 65 ppm at 15% oxygen, on a dry basis.

iv. BACT for the NOx emissions from this emissions unit was determined to be a low NOx burner design and water injection.

Pursuant to 40 CFR Part 60.332(f), this emissions unit is exempt from the NOx concentration emission limitations when ice fog, as defined in 40 CFR Part 60.331(f), is deemed a traffic hazard by the permittee.

2.c Sulfur Dioxide (SO2) Emission Limitations:

i. When burning fuel oil, SO2 emissions shall not exceed 516 lbs/hr from this emissions unit.

ii. When burning fuel oil, the total combined SO2 emissions from emissions units B001 through B006 shall not exceed 4911 lbs per 3-hour period and 22,152 lbs per 24-hour period.

iii. When burning natural gas or LPG in this emissions unit, SO2 emissions shall not exceed 0.015%, by volume, at 15% oxygen on a dry basis.

iv. BACT for the SO2 emissions from this emissions unit was determined to be use of a low sulfur content fuel and compliance with the emission limitations in 2.c.ii above.

2. Additional Terms and Conditions (continued)

2.d Volatile Organic Compound (VOC) Emission Limitation:

i. VOC emissions shall not exceed 6.97 lbs/hr.

ii. BACT for the VOC emissions from this emissions unit was determined to be the low VOC emission rate and compliance with the operational restrictions.

2.e Carbon Monoxide (CO) Emission Limitation:

i. CO emissions shall not exceed 25.34 lbs/hr.

ii. BACT for the CO emissions from this emissions unit was determined to be burner design.

2.f The hourly emission limitations established in PTI 14-1905 were based on the emissions unit's potentials to emit. Therefore, it is not necessary to develop any additional monitoring, record keeping or reporting requirements to ensure compliance with these emission limitations.

2.g The permittee has satisfied the "best available control techniques and operating practices" required pursuant to OAC rule 3745-21-08(B) by committing to comply with the best available control technology requirements established pursuant to 40 CFR Part 52.21 in Permit to Install 14-1905.

On November 5, 2002, OAC rule 3745-21-08 was revised to delete paragraph (B); therefore, paragraph (B) is no longer part of the State regulations. However, that rule revision has not yet been submitted to the U.S. EPA as a revision to Ohio's State Implementation Plan (SIP). Therefore, until the SIP revision occurs and the U.S. EPA approves the revisions to OAC rule 3745-21-08, the requirement to satisfy the "best available control techniques and operating practices" still exists as part of the federally-approved SIP for Ohio.

The permittee has satisfied the "latest available control techniques and operating practices" required pursuant to OAC rule 3745-23-06(B) by committing to comply with the best available control technology requirements established pursuant to 40 CFR Part 52.21 in Permit to Install 14-1905.

II. Operational Restrictions

1. The sulfur content of the fuel oil burned in this emissions unit shall not exceed 0.5%, by weight.

2. The total combined amount of fuel oil burned in emissions units B001 through B006 shall not exceed the amounts specified by the following equations:

For any 3-hour period:

gallons of fuel oil = 35078 / S

where: S = the sulfur content of the fuel oil, in percent, by weight
(e.g., if the fuel oil sulfur content is 0.5%, then S = 0.5)

For any 24-hour period:

gallons of fuel oil = 158228 / S

where: S = the sulfur content of the fuel oil, in percent, by weight
(e.g., if the fuel oil sulfur content is 0.5%, then S = 0.5)

3. The total combined operating hours for emissions units B001 through B006 shall not exceed 17,844 hours per rolling, 12-month period.

4. The minimum stack height for this emissions unit shall be at least 213 feet above the ground.

5. The permittee shall burn only natural gas, LPG, and/or fuel oil in this emissions unit.

III. Monitoring and/or Record Keeping Requirements

1. For each day during which the permittee burns a fuel other than natural gas, LPG, and/or fuel oil, the permittee shall maintain a record of the type and quantity of fuel burned in this emissions unit.

2. The permittee shall operate and maintain a continuous monitoring system to monitor and record the fuel consumption and the ratio of water-to-fuel being fired in this emissions unit. This system shall be accurate to within plus or minus 5% and shall be approved by the Administrator of the U.S. EPA.

3. The permittee shall monitor the sulfur content and nitrogen content of the fuel being fired in this emissions unit as specified below.

Sulfur Content:

For each shipment of oil received for burning in this emissions unit, the permittee shall maintain records of the total quantity of oil received and the permittee's or oil supplier's analyses for sulfur content (in %, by weight). A shipment may be comprised of multiple tank truck loads from the same supplier's batch, or may be represented by single or multiple pipeline deliveries from the same supplier's batch, and the quality of the oil for those loads or pipeline deliveries may be represented by a single batch analysis from the supplier.

The permittee shall collect and record the sulfur content of the natural gas and LPG being fired in this emissions unit on a quarterly basis in accordance with the approved custom schedule for this facility.

The permittee shall perform or require the supplier to perform the analyses for sulfur content and heat content in accordance with 40 CFR Part 60.335(d), 40 CFR Part 75, or the appropriate ASTM methods, or equivalent methods as approved by the Administrator of the U.S. EPA.

Should any sulfur analysis indicate noncompliance with 40 CFR Part 60.333 or the sulfur content limitation stated in section A.I. of this permit, the permittee shall notify Hamilton County Department of Environmental Services - Air Quality Division of the exceedance and the custom schedule shall be re-examined. During the re-examination period the permittee shall conduct daily sulfur monitoring and submit these analyses to Hamilton County Department of Environmental Services - Air Quality Division.

Nitrogen Content:

To compute the NOx emissions, the permittee shall use analytical methods and procedures that are accurate to within 5% and are approved by the Administrator of the U.S. EPA to determine the nitrogen content of the fuel being fired.

4. The permittee shall collect and record the following information on a monthly basis:

a. The total hours of operation for this emissions unit.

b. The total combined hours of operation for emissions units B001 through B006.

c. The rolling, 12-month summation of the total combined hours of operation for emissions units B001 through B006 (the summation of the current month's total combined hours of operation recorded in 4.b added to the previous 11 months total combined hours of operation).

III. Monitoring and/or Record Keeping Requirements (continued)

5. The permittee shall collect and record the following information:

a. The total combined number of gallons of fuel oil supplied to emissions units B001 through B006 for all 3-hour periods of operation.

b. The percent sulfur content, by weight, of the fuel oil supplied to emissions units B001 through B006 for all 3-hour periods of operation.

c. The total combined number of gallons of fuel oil supplied to emissions units B001 through B006 for all 24-hour periods of operation.

d. The percent sulfur content, by weight, of the fuel oil supplied to emissions units B001 through B006 for all 24-hour periods of operation.

e. The total combined SO2 emissions, in lbs, for emissions units B001 through B006 for all 3-hour periods of operation when burning fuel oil. (The SO2 emissions shall be calculated using the fuel oil usage and fuel oil sulfur content data above.)

f. The total combined SO2 emissions, in lbs, for emissions units B001 through B006 for all 24-hour periods of operation when burning fuel oil. (The SO2 emissions shall be calculated using the fuel oil usage and fuel oil sulfur content data above.)

g. Identification of each cold start-up for this emissions unit.

h. Identification of each shutdown for this emissions unit.

IV. Reporting Requirements

1. Pursuant to 40 CFR Parts 60.7 and 60.13(h), the permittee shall submit reports within 30 days following the end of each calendar quarter to the Hamilton County Department of Environmental Services - Air Quality Division documenting any 1-hour period during which the average water-to-fuel ratio, as measured by the continuous monitoring system, falls below the water-to-fuel ratio established during the most recent performance test that demonstrated that the emissions unit was in compliance with the applicable NOx emission limitations or any period during which the fuel-bound nitrogen of the fuel is greater than the maximum nitrogen content allowed by the fuel-bound nitrogen allowance used during the most recent performance test that demonstrated that the emissions unit was in compliance with the applicable NOx emission limitations. Each report shall include the average water-to-fuel ratio, average fuel consumption, ambient conditions, gas turbine load, and the nitrogen content of the fuel during the period of excess emissions. The graphs or figures developed under 40 CFR Part 60.335(a) shall also be submitted with each report.

The permittee shall submit reports within 30 days following the end of each calendar quarter to the Hamilton County Department of Environmental Services - Air Quality Division documenting any continuous water-to-fuel monitoring system downtime while the emissions unit was on line (date, time, duration and reason) along with any corrective action(s) taken. The permittee shall provide the emissions unit operating time during the reporting period and the date, time, reason and corrective action(s) taken for each time period of emissions unit and control equipment malfunctions. The total operating time of the emissions unit and the total operating time of the continuous monitoring system while the emissions unit was on line shall also be included in the quarterly report.

If there are no excess emissions during the calendar quarter, the permittee shall submit a statement to that effect along with the date, time, reason, and corrective action(s) taken for each time period of monitoring system malfunctions. The total operating time of the emissions unit and the total operating time of the continuous monitoring system while the emissions unit was on line also shall be included in the quarterly report. These quarterly excess emission reports shall be submitted by January 30, April 30, July 30, and October 30 of each year and shall address the data obtained during the previous calendar quarter.

IV. Reporting Requirements (continued)

Pursuant to 40 CFR Part 60.7, the permittee shall submit a summary of the excess emission report. The summary shall be submitted in accordance with 40 CFR Part 60.7(d) to the Hamilton County Department of Environmental Services - Air Quality Division within 30 days following the end of each calendar quarter in a manner prescribed by the Director.

2. The permittee shall submit quarterly reports that identify each period during which an exemption for ice-fog provided in 40 CFR Part 60.332(f) is in effect. The report shall include the ambient conditions existing during the period, the date and time the air pollution control system was deactivated, and the date and time when the air pollution control system was reactivated.

3. The permittee shall submit quarterly deviation (excursion) reports that identify the following:

a. Any exceedance of the 3-hour and/or 24-hour total combined fuel oil usage restrictions for emissions units B001 through B006 when burning fuel oil as calculated in section A.II.2.

b. Any exceedance of the 3-hour and/or 24-hour SO2 emission limitations when burning fuel oil for emissions units B001 through B006.

c. Any exceedance of the total combined operating hours restriction for emissions units B001 through B006.

d. Any exceedance of the 0.5%, by weight, fuel oil sulfur content restriction for this emissions unit.

e. Each day when a fuel other than natural gas, LPG, and/or fuel oil was burned in this emissions unit.

The quarterly deviation reports shall be submitted in accordance with the reporting requirements specified in Part I - General Term and Condition A.1.c.ii.

V. Testing Requirements

1. Emission Limitation:
Emissions of PE/PM10 shall not exceed 40.4 lbs/hr.

Applicable Compliance Method:
This emission limitation reflects the emissions unit's potential to emit. Compliance with this emission limitation may be demonstrated through the emission factors and equations found in Table 2.3 of the technical support document submitted 8/25/89 for PSD Permit to Install 14-1905. The PE/PM10 emission factor in Table 2.3 of Permit to Install 14-1905 is 5.10 grams of PE/PM10 per second when burning fuel oil, and 0.24 gram of PE/PM10 per second when burning natural gas or LPG.

If required, the permittee shall demonstrate compliance with the PE and PM10 emission limitation through emission tests performed in accordance with 40 CFR Part 60, Appendix A, Methods 1 through 5 while burning natural gas. Alternate U.S. EPA-approved test methods may be used with prior approval from the Ohio EPA.

2. Emission Limitation:
Visible PE from any combustion turbine stack shall not exceed 10% opacity, as a 6-minute average, except for cold start-up and shutdown periods.

Applicable Compliance Method:
If required, compliance with this emission limitation shall be demonstrated through visible emissions observations performed in accordance with 40 CFR Part 60, Appendix A, Method 9.

V. Testing Requirements (continued)

3. Emission Limitations:
NOx emissions shall not exceed 261.4 lbs/hr.

When burning natural gas, NOx emissions shall not exceed 42 ppm at 15% oxygen, on a dry basis.

When burning LPG or fuel oil, NOx emissions shall not exceed 65 ppm at 15% oxygen, on a dry basis.

Applicable Compliance Method:
The hourly NOx emission limitation reflects the emissions unit's potential to emit. Compliance with this emission limitation may be demonstrated through the emission factors and equations found in Table 2.3 of the technical support document submitted 8/25/89 for PSD Permit to Install 14-1905. The NOx emission factor in Table 2.3 of Permit to Install 14-1905 is 33.00 grams of NOx per second when burning fuel oil, and 32.50 grams of NOx per second when burning natural gas or LPG.

If required, the permittee shall demonstrate compliance with the hourly emission limitation through emission tests performed in accordance with 40 CFR Part 60, Appendix A, Methods 1 through 4 and 7 while burning natural gas. Alternate U.S. EPA-approved test methods may be used with prior approval from the Ohio EPA.

Compliance with the NOx concentration emission limitations may be demonstrated based upon the records required pursuant to Section A.III.2.

If required, the permittee shall demonstrate compliance with the NOx concentration emission limitations in accordance with the methods and procedures specified in 40 CFR Part 60.335(c).

4. Emission Limitations:
When burning fuel oil, SO2 emissions shall not exceed 516 lbs/hr from this emissions unit.

When burning fuel oil, the total combined SO2 emissions from emissions units B001 through B006 shall not exceed 4911 lbs per 3-hour period and 22,152 lbs per 24-hour period.

When burning natural gas or LPG, SO2 emissions shall not exceed 0.015%, by volume, at 15% oxygen on a dry basis from this emissions unit.

Applicable Compliance Method:
The hourly SO2 emission limitation reflects the emissions unit's potential to emit. Compliance with this emission limitation may be demonstrated through the emission factors and equations found in Table 2.3 of the technical support document submitted 8/25/89 for PSD Permit to Install 14-1905. The SO2 emission factor in Table 2.3 of Permit to Install 14-1905 is 65.13 grams of SO2 per second when burning fuel oil, and 0.00 gram of SO2 per second when burning natural gas or LPG.

If required, the permittee shall demonstrate compliance with the hourly emission limitation through emission tests performed in accordance with 40 CFR Part 60, Appendix A, Methods 1 through 4 and 6 while burning natural gas. Alternate U.S. EPA-approved test methods may be used with prior approval from the Ohio EPA.

If required, the permittee shall demonstrate compliance with the SO2 concentration emission limitation in accordance with the method and procedures specified in 40 CFR Part 60.335(c)(3).

Compliance with the total combined 3-hour and 24-hour SO2 emission limitations for emissions units B001 through B006 may be demonstrated based upon the records required pursuant to Section A.III.5.

V. Testing Requirements (continued)

5. Emission Limitation:
CO emissions shall not exceed 25.34 lbs/hr.

Applicable Compliance Method:
This emission limitation reflects the emissions unit's potential to emit. Compliance with this emission limitation may be demonstrated through the emission factors and equations found in Table 2.3 of the technical support document submitted 8/25/89 for PSD permit 14-1905. The CO emission factor in Table 2.3 of Permit to Install 14-1905 is 3.20 grams of CO per second when burning fuel oil, natural gas, or LPG.

If required, the permittee shall demonstrate compliance with this emission limitation through emission tests performed in accordance with 40 CFR Part 60, Appendix A, Methods 1 through 4 and 10 while burning natural gas. Alternate U.S. EPA-approved test methods may be used with prior approval from the Ohio EPA.

6. Emission Limitation:
VOC emissions shall not exceed 6.97 lbs/hr.

Applicable Compliance Method:
This emission limitation reflects the emissions unit's potential to emit. Compliance with this emission limitation may be demonstrated through the emission factors and equations found in Table 2.3 of the technical support document submitted 8/25/89 for PSD permit 14-1905. The VOC emission factor in Table 2.3 of Permit to Install 14-1905 is 0.88 gram of VOC per second when burning fuel oil, natural gas, or LPG.

If required, the permittee shall demonstrate compliance with this emission limitation through emission tests performed in accordance with 40 CFR Part 60, Appendix A, Methods 1 through 4 and 25 while burning natural gas. Alternate U.S. EPA-approved test methods may be used with prior approval from the Ohio EPA.

7. Upon initial use of fuel oil, the permittee shall conduct, or have conducted, emission testing for this emissions unit to demonstrate compliance with the applicable PE/PM10, NOx, SO2, VOC, and CO emission limitations in accordance with the following requirements:

The emission testing shall be conducted within 90 days of initiating fuel oil firing, unless an alternative schedule is submitted and approved by Hamilton County Department of Environmental Services-Air Quality Control Division. The frequency for future emission testing while burning fuel oil will be determined based upon the results of the initial emission tests and the procedures specified in Ohio EPA Engineering Guide 16.

Compliance with the applicable PE/PM10, NOx, SO2, VOC, and CO emission limitations shall be determined in accordance with the following:

for PE/PM10 - 40 CFR Part 60, Appendix A, Methods 1 through 5;
for NOx (hourly) - 40 CFR Part 60, Appendix A, Methods 1 through 4 and 7;
for NOx (concentration) - 40 CFR Part 60, Appendix A, Method 20
for SO2 - 40 CFR Part 60, Appendix A, Methods 1 through 4 and 6;
for VOC - 40 CFR Part 60, Appendix A, Methods 1 through 4 and 25; and
for CO - 40 CFR Part 60, Appendix A, Methods 1 through 4 and 10.

Alternate U.S. EPA-approved test methods may be used with prior approval from the Ohio EPA.

Testing for PE/PM10, NOx, and SO2 shall be performed on each emissions unit. Testing for CO and VOC shall be performed on one emissions unit that is representative of the permitted combustion turbine units (B001 through B006). Prior to performing CO and VOC testing, the permittee shall obtain agreement on the emissions unit to be tested as a representative unit from the Hamilton County Department of Environmental Services-Air Quality Control Division.

The tests shall be conducted while the emissions unit is operating at or near its maximum capacity.

V. Testing Requirements (continued)

Not later than 30 days prior to the proposed test date(s), the permittee shall submit an "Intent to Test" notification to the Hamilton County Department of Environmental Services. The "Intent to Test" notification shall describe in detail the proposed test methods and procedures, the emissions unit operating parameters, the time(s) and date(s) of the test(s), and the person(s) who will be conducting the test(s). Failure to submit such notification for review and approval prior to the test(s) may result in the Hamilton County Department of Environmental Services' refusal to accept the results of the emission test(s).

Personnel from the Hamilton County Department of Environmental Services and Ohio EPA shall be permitted to witness the test(s), examine the testing equipment, and acquire data and information necessary to ensure that the operation of the emissions unit and the testing procedures provide a valid characterization of the emissions from the emissions unit and/or the performance of the control equipment.

A comprehensive written report on the results of the emission test(s) shall be signed by the person or persons responsible for the tests and submitted to the Hamilton County Department of Environmental Services within 30 days following completion of the test(s). The permittee may request additional time for the submittal of the written report, where warranted, with prior approval from the Hamilton County Department of Environmental Services.

VI. Miscellaneous Requirements

None

B. State Enforceable Section

I. Applicable Emissions Limitations and/or Control Requirements

1. The specific operation(s), property, and/or equipment which constitute this emissions unit are listed in the following table along with the applicable rules and/or requirements and with the applicable emissions limitations and/or control measures. Emissions from this unit shall not exceed the listed limitations, and the listed control measures shall be employed. Additional applicable emissions limitations and/or control measures (if any) may be specified in narrative form following the table.

Operations, Property, and/or Equipment	Applicable Rules/ Requirements	Applicable Emissions Limitations/Control Measures

2. Additional Terms and Conditions

None

II. Operational Restrictions

None

III. Monitoring and/or Record Keeping Requirements

None

IV. Reporting Requirements

None

V. Testing Requirements

None

VI. Miscellaneous Requirements

None

Part III - Terms and Conditions for Emissions Units

Emissions Unit ID: Combustion Turbine Unit 3 (B003)

Activity Description: ABB model GT-11N combustion turbine.

A. State and Federally Enforceable Section

I. Applicable Emissions Limitations and/or Control Requirements

1. The specific operation(s), property, and/or equipment which constitute this emissions unit are listed in the following table along with the applicable rules and/or requirements and with the applicable emissions limitations and/or control measures. Emissions from this unit shall not exceed the listed limitations, and the listed control measures shall be employed. Additional applicable emissions limitations and/or control measures (if any) may be specified in narrative form following the table.

Operations, Property, and/or Equipment	Applicable Rules/ Requirements	Applicable Emissions Limitations/Control Measures
natural gas, liquid petroleum gas (LPG), and fuel oil-fired, simple cycle combustion turbine having a nominal heat input capacity of 1034 MMBtu/hr with a water injection system for the control of nitrogen oxides	40 CFR Part 52.21 and OAC rules 3745-31-11 through 3745-31-20 (PTI 14-1905)	See A.I.2.a through A.I.2.f and A.II.1 through A.II.3 below.
	OAC rule 3745-31-05(A)(3) (PTI 14-1905)	Compliance with this rule also includes compliance with 40 CFR Part 52.21 and OAC rules 3745-31-11 through 3745-31-20. See A.II.4 below.
	40 CFR Part 60, Subpart GG	The nitrogen oxides and sulfur dioxide emission limitations and/or content restrictions specified in 40 CFR Part 60, Subpart GG are equivalent to or less stringent than the emission limitations and/or content restrictions established in PTI 14-1905 pursuant to 40 CFR Part 52.21.
	OAC rule 3745-17-07(A)	The visible particulate emission limitations specified in OAC rule 3745-17-07(A) are less stringent than the visible particulate emission limitation established in PTI 14-1905 pursuant to 40 CFR Part 52.21.
	OAC rule 3745-17-11(B)(4)	The particulate emission limitation specified in OAC rule 3745-17-11(B)(4) is less stringent than The particulate emission limitation established in PTI 14-1905 pursuant to 40 CFR Part 52.21.

Operations, Property, and/or Equipment	Applicable Rules/ Requirements	Applicable Emissions Limitations/Control Measures
	OAC rule 3745-18-15(P)	The sulfur dioxide emission limitation specified in OAC rule 3745-18-15(P) is less stringent than the sulfur dioxide emission limitations established in PTI 14-1905 pursuant to 40 CFR Part 52.21.
	OAC rules 3745-21-08(B) and 3745-23-06(B)	See A.I.2.g below.

2. Additional Terms and Conditions

2.a Particulate Emission Limitations:

i. Emissions of particulates and particulates less than 10 microns in diameter (PE/PM10)* shall not exceed 40.4 lbs/hr.

ii. Visible PE from any combustion turbine stack shall not exceed 10% opacity, as a 6-minute average, except for cold start-up and shutdown periods. Cold start-up shall be defined as the time necessary to bring this emissions unit on line from a cold state to turbine synchronization.

iii. Best available control technology (BACT) for the PE/PM10 emissions from this emissions unit was determined to be burner design, combustion control, and compliance with the visible particulate emission limitation.

*The total PM10 emissions were evaluated and did not trigger any additional federal requirements, therefore, the emissions are being regulated as particulate emissions (PE).

2.b Nitrogen Oxides (NOx) Emission Limitations:

i. NOx emissions shall not exceed 261.4 lbs/hr.

ii. When burning natural gas, NOx emissions shall not exceed 42 ppm at 15% oxygen, on a dry basis.

iii. When burning LPG or fuel oil, NOx emissions shall not exceed 65 ppm at 15% oxygen, on a dry basis.

iv. BACT for the NOx emissions from this emissions unit was determined to be a low NOx burner design and water injection.

Pursuant to 40 CFR Part 60.332(f), this emissions unit is exempt from the NOx concentration emission limitations when ice fog, as defined in 40 CFR Part 60.331(f), is deemed a traffic hazard by the permittee.

2.c Sulfur Dioxide (SO2) Emission Limitations:

i. When burning fuel oil, SO2 emissions shall not exceed 516 lbs/hr from this emissions unit.

ii. When burning fuel oil, the total combined SO2 emissions from emissions units B001 through B006 shall not exceed 4911 lbs per 3-hour period and 22,152 lbs per 24-hour period.

iii. When burning natural gas or LPG in this emissions unit, SO2 emissions shall not exceed 0.015%, by volume, at 15% oxygen on a dry basis.

iv. BACT for the SO2 emissions from this emissions unit was determined to be use of a low sulfur content fuel and compliance with the emission limitations in 2.c.ii above.

2. Additional Terms and Conditions (continued)

2.d Volatile Organic Compound (VOC) Emission Limitation:

i. VOC emissions shall not exceed 6.97 lbs/hr.

ii. BACT for the VOC emissions from this emissions unit was determined to be the low VOC emission rate and compliance with the operational restrictions.

2.e Carbon Monoxide (CO) Emission Limitation:

i. CO emissions shall not exceed 25.34 lbs/hr.

ii. BACT for the CO emissions from this emissions unit was determined to be burner design.

2.f The hourly emission limitations established in PTI 14-1905 were based on the emissions unit's potentials to emit. Therefore, it is not necessary to develop any additional monitoring, record keeping or reporting requirements to ensure compliance with these emission limitations.

2.g The permittee has satisfied the "best available control techniques and operating practices" required pursuant to OAC rule 3745-21-08(B) by committing to comply with the best available control technology requirements established pursuant to 40 CFR Part 52.21 in Permit to Install 14-1905.

On November 5, 2002, OAC rule 3745-21-08 was revised to delete paragraph (B); therefore, paragraph (B) is no longer part of the State regulations. However, that rule revision has not yet been submitted to the U.S. EPA as a revision to Ohio's State Implementation Plan (SIP). Therefore, until the SIP revision occurs and the U.S. EPA approves the revisions to OAC rule 3745-21-08, the requirement to satisfy the "best available control techniques and operating practices" still exists as part of the federally-approved SIP for Ohio.

The permittee has satisfied the "latest available control techniques and operating practices" required pursuant to OAC rule 3745-23-06(B) by committing to comply with the best available control technology requirements established pursuant to 40 CFR Part 52.21 in Permit to Install 14-1905.

II. Operational Restrictions

1. The sulfur content of the fuel oil burned in this emissions unit shall not exceed 0.5%, by weight.

2. The total combined amount of fuel oil burned in emissions units B001 through B006 shall not exceed the amounts specified by the following equations:

For any 3-hour period:

gallons of fuel oil = 35078 / S

where: S = the sulfur content of the fuel oil, in percent, by weight
(e.g., if the fuel oil sulfur content is 0.5%, then S = 0.5)

For any 24-hour period:

gallons of fuel oil = 158228 / S

where: S = the sulfur content of the fuel oil, in percent, by weight
(e.g., if the fuel oil sulfur content is 0.5%, then S = 0.5)

3. The total combined operating hours for emissions units B001 through B006 shall not exceed 17,844 hours per rolling, 12-month period.

4. The minimum stack height for this emissions unit shall be at least 213 feet above the ground.

5. The permittee shall burn only natural gas, LPG, and/or fuel oil in this emissions unit.

III. Monitoring and/or Record Keeping Requirements

1. For each day during which the permittee burns a fuel other than natural gas, LPG, and/or fuel oil, the permittee shall maintain a record of the type and quantity of fuel burned in this emissions unit.

2. The permittee shall operate and maintain a continuous monitoring system to monitor and record the fuel consumption and the ratio of water-to-fuel being fired in this emissions unit. This system shall be accurate to within plus or minus 5% and shall be approved by the Administrator of the U.S. EPA.

3. The permittee shall monitor the sulfur content and nitrogen content of the fuel being fired in this emissions unit as specified below.

Sulfur Content:

For each shipment of oil received for burning in this emissions unit, the permittee shall maintain records of the total quantity of oil received and the permittee's or oil supplier's analyses for sulfur content (in %, by weight). A shipment may be comprised of multiple tank truck loads from the same supplier's batch, or may be represented by single or multiple pipeline deliveries from the same supplier's batch, and the quality of the oil for those loads or pipeline deliveries may be represented by a single batch analysis from the supplier.

The permittee shall collect and record the sulfur content of the natural gas and LPG being fired in this emissions unit on a quarterly basis in accordance with the approved custom schedule for this facility.

The permittee shall perform or require the supplier to perform the analyses for sulfur content and heat content in accordance with 40 CFR Part 60.335(d), 40 CFR Part 75, or the appropriate ASTM methods, or equivalent methods as approved by the Administrator of the U.S. EPA.

Should any sulfur analysis indicate noncompliance with 40 CFR Part 60.333 or the sulfur content limitation stated in section A.I. of this permit, the permittee shall notify Hamilton County Department of Environmental Services - Air Quality Division of the exceedance and the custom schedule shall be re-examined. During the re-examination period the permittee shall conduct daily sulfur monitoring and submit these analyses to Hamilton County Department of Environmental Services - Air Quality Division.

Nitrogen Content:

To compute the NOx emissions, the permittee shall use analytical methods and procedures that are accurate to within 5% and are approved by the Administrator of the U.S. EPA to determine the nitrogen content of the fuel being fired.

4. The permittee shall collect and record the following information on a monthly basis:

a. The total hours of operation for this emissions unit.

b. The total combined hours of operation for emissions units B001 through B006.

c. The rolling, 12-month summation of the total combined hours of operation for emissions units B001 through B006 (the summation of the current month's total combined hours of operation recorded in 4.b added to the previous 11 months total combined hours of operation).

III. Monitoring and/or Record Keeping Requirements (continued)

5. The permittee shall collect and record the following information:

a. The total combined number of gallons of fuel oil supplied to emissions units B001 through B006 for all 3-hour periods of operation.

b. The percent sulfur content, by weight, of the fuel oil supplied to emissions units B001 through B006 for all 3-hour periods of operation.

c. The total combined number of gallons of fuel oil supplied to emissions units B001 through B006 for all 24-hour periods of operation.

d. The percent sulfur content, by weight, of the fuel oil supplied to emissions units B001 through B006 for all 24-hour periods of operation.

e. The total combined SO2 emissions, in lbs, for emissions units B001 through B006 for all 3-hour periods of operation when burning fuel oil. (The SO2 emissions shall be calculated using the fuel oil usage and fuel oil sulfur content data above.)

f. The total combined SO2 emissions, in lbs, for emissions units B001 through B006 for all 24-hour periods of operation when burning fuel oil. (The SO2 emissions shall be calculated using the fuel oil usage and fuel oil sulfur content data above.)

g. Identification of each cold start-up for this emissions unit.

h. Identification of each shutdown for this emissions unit.

IV. Reporting Requirements

1. Pursuant to 40 CFR Parts 60.7 and 60.13(h), the permittee shall submit reports within 30 days following the end of each calendar quarter to the Hamilton County Department of Environmental Services - Air Quality Division documenting any 1-hour period during which the average water-to-fuel ratio, as measured by the continuous monitoring system, falls below the water-to-fuel ratio established during the most recent performance test that demonstrated that the emissions unit was in compliance with the applicable NOx emission limitations or any period during which the fuel-bound nitrogen of the fuel is greater than the maximum nitrogen content allowed by the fuel-bound nitrogen allowance used during the most recent performance test that demonstrated that the emissions unit was in compliance with the applicable NOx emission limitations. Each report shall include the average water-to-fuel ratio, average fuel consumption, ambient conditions, gas turbine load, and the nitrogen content of the fuel during the period of excess emissions. The graphs or figures developed under 40 CFR Part 60.335(a) shall also be submitted with each report.

The permittee shall submit reports within 30 days following the end of each calendar quarter to the Hamilton County Department of Environmental Services - Air Quality Division documenting any continuous water-to-fuel monitoring system downtime while the emissions unit was on line (date, time, duration and reason) along with any corrective action(s) taken. The permittee shall provide the emissions unit operating time during the reporting period and the date, time, reason and corrective action(s) taken for each time period of emissions unit and control equipment malfunctions. The total operating time of the emissions unit and the total operating time of the continuous monitoring system while the emissions unit was on line shall also be included in the quarterly report.

If there are no excess emissions during the calendar quarter, the permittee shall submit a statement to that effect along with the date, time, reason, and corrective action(s) taken for each time period of monitoring system malfunctions. The total operating time of the emissions unit and the total operating time of the continuous monitoring system while the emissions unit was on line also shall be included in the quarterly report. These quarterly excess emission reports shall be submitted by January 30, April 30, July 30, and October 30 of each year and shall address the data obtained during the previous calendar quarter.

IV. Reporting Requirements (continued)

Pursuant to 40 CFR Part 60.7, the permittee shall submit a summary of the excess emission report. The summary shall be submitted in accordance with 40 CFR Part 60.7(d) to the Hamilton County Department of Environmental Services - Air Quality Division within 30 days following the end of each calendar quarter in a manner prescribed by the Director.

2. The permittee shall submit quarterly reports that identify each period during which an exemption for ice-fog provided in 40 CFR Part 60.332(f) is in effect. The report shall include the ambient conditions existing during the period, the date and time the air pollution control system was deactivated, and the date and time when the air pollution control system was reactivated.

3. The permittee shall submit quarterly deviation (excursion) reports that identify the following:

a. Any exceedance of the 3-hour and/or 24-hour total combined fuel oil usage restrictions for emissions units B001 through B006 when burning fuel oil as calculated in section A.II.2.

b. Any exceedance of the 3-hour and/or 24-hour SO2 emission limitations when burning fuel oil for emissions units B001 through B006.

c. Any exceedance of the total combined operating hours restriction for emissions units B001 through B006.

d. Any exceedance of the 0.5%, by weight, fuel oil sulfur content restriction for this emissions unit.

e. Each day when a fuel other than natural gas, LPG, and/or fuel oil was burned in this emissions unit.

The quarterly deviation reports shall be submitted in accordance with the reporting requirements specified in Part I - General Term and Condition A.1.c.ii.

V. Testing Requirements

1. Emission Limitation:
Emissions of PE/PM10 shall not exceed 40.4 lbs/hr.

Applicable Compliance Method:
This emission limitation reflects the emissions unit's potential to emit. Compliance with this emission limitation may be demonstrated through the emission factors and equations found in Table 2.3 of the technical support document submitted 8/25/89 for PSD Permit to Install 14-1905. The PE/PM10 emission factor in Table 2.3 of Permit to Install 14-1905 is 5.10 grams of PE/PM10 per second when burning fuel oil, and 0.24 gram of PE/PM10 per second when burning natural gas or LPG.

If required, the permittee shall demonstrate compliance with the PE and PM10 emission limitation through emission tests performed in accordance with 40 CFR Part 60, Appendix A, Methods 1 through 5 while burning natural gas. Alternate U.S. EPA-approved test methods may be used with prior approval from the Ohio EPA.

2. Emission Limitation:
Visible PE from any combustion turbine stack shall not exceed 10% opacity, as a 6-minute average, except for cold start-up and shutdown periods.

Applicable Compliance Method:
If required, compliance with this emission limitation shall be demonstrated through visible emissions observations performed in accordance with 40 CFR Part 60, Appendix A, Method 9.

V. Testing Requirements (continued)

3. Emission Limitations:
NOx emissions shall not exceed 261.4 lbs/hr.

When burning natural gas, NOx emissions shall not exceed 42 ppm at 15% oxygen, on a dry basis.

When burning LPG or fuel oil, NOx emissions shall not exceed 65 ppm at 15% oxygen, on a dry basis.

Applicable Compliance Method:
The hourly NOx emission limitation reflects the emissions unit's potential to emit. Compliance with this emission limitation may be demonstrated through the emission factors and equations found in Table 2.3 of the technical support document submitted 8/25/89 for PSD Permit to Install 14-1905. The NOx emission factor in Table 2.3 of Permit to Install 14-1905 is 33.00 grams of NOx per second when burning fuel oil, and 32.50 grams of NOx per second when burning natural gas or LPG.

If required, the permittee shall demonstrate compliance with the hourly emission limitation through emission tests performed in accordance with 40 CFR Part 60, Appendix A, Methods 1 through 4 and 7 while burning natural gas. Alternate U.S. EPA-approved test methods may be used with prior approval from the Ohio EPA.

Compliance with the NOx concentration emission limitations may be demonstrated based upon the records required pursuant to Section A.III.2.

If required, the permittee shall demonstrate compliance with the NOx concentration emission limitations in accordance with the methods and procedures specified in 40 CFR Part 60.335(c).

4. Emission Limitations:
When burning fuel oil, SO2 emissions shall not exceed 516 lbs/hr from this emissions unit.

When burning fuel oil, the total combined SO2 emissions from emissions units B001 through B006 shall not exceed 4911 lbs per 3-hour period and 22,152 lbs per 24-hour period.

When burning natural gas or LPG, SO2 emissions shall not exceed 0.015%, by volume, at 15% oxygen on a dry basis from this emissions unit.

Applicable Compliance Method:
The hourly SO2 emission limitation reflects the emissions unit's potential to emit. Compliance with this emission limitation may be demonstrated through the emission factors and equations found in Table 2.3 of the technical support document submitted 8/25/89 for PSD Permit to Install 14-1905. The SO2 emission factor in Table 2.3 of Permit to Install 14-1905 is 65.13 grams of SO2 per second when burning fuel oil, and 0.00 gram of SO2 per second when burning natural gas or LPG.

If required, the permittee shall demonstrate compliance with the hourly emission limitation through emission tests performed in accordance with 40 CFR Part 60, Appendix A, Methods 1 through 4 and 6 while burning natural gas. Alternate U.S. EPA-approved test methods may be used with prior approval from the Ohio EPA.

If required, the permittee shall demonstrate compliance with the SO2 concentration emission limitation in accordance with the method and procedures specified in 40 CFR Part 60.335(c)(3).

Compliance with the total combined 3-hour and 24-hour SO2 emission limitations for emissions units B001 through B006 may be demonstrated based upon the records required pursuant to Section A.III.5.

V. Testing Requirements (continued)

5. Emission Limitation:
CO emissions shall not exceed 25.34 lbs/hr.

Applicable Compliance Method:
This emission limitation reflects the emissions unit's potential to emit. Compliance with this emission limitation may be demonstrated through the emission factors and equations found in Table 2.3 of the technical support document submitted 8/25/89 for PSD permit 14-1905. The CO emission factor in Table 2.3 of Permit to Install 14-1905 is 3.20 grams of CO per second when burning fuel oil, natural gas, or LPG.

If required, the permittee shall demonstrate compliance with this emission limitation through emission tests performed in accordance with 40 CFR Part 60, Appendix A, Methods 1 through 4 and 10 while burning natural gas. Alternate U.S. EPA-approved test methods may be used with prior approval from the Ohio EPA.

6. Emission Limitation:
VOC emissions shall not exceed 6.97 lbs/hr.

Applicable Compliance Method:
This emission limitation reflects the emissions unit's potential to emit. Compliance with this emission limitation may be demonstrated through the emission factors and equations found in Table 2.3 of the technical support document submitted 8/25/89 for PSD permit 14-1905. The VOC emission factor in Table 2.3 of Permit to Install 14-1905 is 0.88 gram of VOC per second when burning fuel oil, natural gas, or LPG.

If required, the permittee shall demonstrate compliance with this emission limitation through emission tests performed in accordance with 40 CFR Part 60, Appendix A, Methods 1 through 4 and 25 while burning natural gas. Alternate U.S. EPA-approved test methods may be used with prior approval from the Ohio EPA.

7. Upon initial use of fuel oil, the permittee shall conduct, or have conducted, emission testing for this emissions unit to demonstrate compliance with the applicable PE/PM10, NOx, SO2, VOC, and CO emission limitations in accordance with the following requirements:

The emission testing shall be conducted within 90 days of initiating fuel oil firing, unless an alternative schedule is submitted and approved by Hamilton County Department of Environmental Services-Air Quality Control Division. The frequency for future emission testing while burning fuel oil will be determined based upon the results of the initial emission tests and the procedures specified in Ohio EPA Engineering Guide 16.

Compliance with the applicable PE/PM10, NOx, SO2, VOC, and CO emission limitations shall be determined in accordance with the following:

for PE/PM10 - 40 CFR Part 60, Appendix A, Methods 1 through 5;
for NOx (hourly) - 40 CFR Part 60, Appendix A, Methods 1 through 4 and 7;
for NOx (concentration) - 40 CFR Part 60, Appendix A, Method 20
for SO2 - 40 CFR Part 60, Appendix A, Methods 1 through 4 and 6;
for VOC - 40 CFR Part 60, Appendix A, Methods 1 through 4 and 25; and
for CO - 40 CFR Part 60, Appendix A, Methods 1 through 4 and 10.

Alternate U.S. EPA-approved test methods may be used with prior approval from the Ohio EPA.

Testing for PE/PM10, NOx, and SO2 shall be performed on each emissions unit. Testing for CO and VOC shall be performed on one emissions unit that is representative of the permitted combustion turbine units (B001 through B006). Prior to performing CO and VOC testing, the permittee shall obtain agreement on the emissions unit to be tested as a representative unit from the Hamilton County Department of Environmental Services-Air Quality Control Division.

The tests shall be conducted while the emissions unit is operating at or near its maximum capacity.

V. Testing Requirements (continued)

Not later than 30 days prior to the proposed test date(s), the permittee shall submit an "Intent to Test" notification to the Hamilton County Department of Environmental Services. The "Intent to Test" notification shall describe in detail the proposed test methods and procedures, the emissions unit operating parameters, the time(s) and date(s) of the test(s), and the person(s) who will be conducting the test(s). Failure to submit such notification for review and approval prior to the test(s) may result in the Hamilton County Department of Environmental Services' refusal to accept the results of the emission test(s).

Personnel from the Hamilton County Department of Environmental Services and Ohio EPA shall be permitted to witness the test(s), examine the testing equipment, and acquire data and information necessary to ensure that the operation of the emissions unit and the testing procedures provide a valid characterization of the emissions from the emissions unit and/or the performance of the control equipment.

A comprehensive written report on the results of the emission test(s) shall be signed by the person or persons responsible for the tests and submitted to the Hamilton County Department of Environmental Services within 30 days following completion of the test(s). The permittee may request additional time for the submittal of the written report, where warranted, with prior approval from the Hamilton County Department of Environmental Services.

VI. Miscellaneous Requirements

None

B. State Enforceable Section

I. Applicable Emissions Limitations and/or Control Requirements

1. The specific operation(s), property, and/or equipment which constitute this emissions unit are listed in the following table along with the applicable rules and/or requirements and with the applicable emissions limitations and/or control measures. Emissions from this unit shall not exceed the listed limitations, and the listed control measures shall be employed. Additional applicable emissions limitations and/or control measures (if any) may be specified in narrative form following the table.

Operations, Property, and/or Equipment	Applicable Rules/ Requirements	Applicable Emissions Limitations/Control Measures

2. Additional Terms and Conditions

None

II. Operational Restrictions

None

III. Monitoring and/or Record Keeping Requirements

None

IV. Reporting Requirements

None

V. Testing Requirements

None

VI. Miscellaneous Requirements

None

Part III - Terms and Conditions for Emissions Units

Emissions Unit ID: Combustion Turbine Unit 4 (B004)

Activity Description: ABB model GT-11N combustion turbine.

A. State and Federally Enforceable Section

I. Applicable Emissions Limitations and/or Control Requirements

1. The specific operation(s), property, and/or equipment which constitute this emissions unit are listed in the following table along with the applicable rules and/or requirements and with the applicable emissions limitations and/or control measures. Emissions from this unit shall not exceed the listed limitations, and the listed control measures shall be employed. Additional applicable emissions limitations and/or control measures (if any) may be specified in narrative form following the table.

Operations, Property, and/or Equipment	Applicable Rules/ Requirements	Applicable Emissions Limitations/Control Measures
natural gas, liquid petroleum gas (LPG), and fuel oil-fired, simple cycle combustion turbine having a nominal heat input capacity of 1034 MMBtu/hr with a water injection system for the control of nitrogen oxides	40 CFR Part 52.21 and OAC rules 3745-31-11 through 3745-31-20 (PTI 14-1905)	See A.I.2.a through A.I.2.f and A.II.1 through A.II.3 below.
	OAC rule 3745-31-05(A)(3) (PTI 14-1905)	Compliance with this rule also includes compliance with 40 CFR Part 52.21 and OAC rules 3745-31-11 through 3745-31-20. See A.II.4 below.
	40 CFR Part 60, Subpart GG	The nitrogen oxides and sulfur dioxide emission limitations and/or content restrictions specified in 40 CFR Part 60, Subpart GG are equivalent to or less stringent than the emission limitations and/or content restrictions established in PTI 14-1905 pursuant to 40 CFR Part 52.21.
	OAC rule 3745-17-07(A)	The visible particulate emission limitations specified in OAC rule 3745-17-07(A) are less stringent than the visible particulate emission limitation established in PTI 14-1905 pursuant to 40 CFR Part 52.21.
	OAC rule 3745-17-11(B)(4)	The particulate emission limitation specified in OAC rule 3745-17-11(B)(4) is less stringent than The particulate emission limitation established in PTI 14-1905 pursuant to 40 CFR Part 52.21.

Operations, Property, and/or Equipment	Applicable Rules/ Requirements	Applicable Emissions Limitations/Control Measures
	OAC rule 3745-18-15(P)	The sulfur dioxide emission limitation specified in OAC rule 3745-18-15(P) is less stringent than the sulfur dioxide emission limitations established in PTI 14-1905 pursuant to 40 CFR Part 52.21.
	OAC rules 3745-21-08(B) and 3745-23-06(B)	See A.I.2.g below.

2. Additional Terms and Conditions

2.a Particulate Emission Limitations:

i. Emissions of particulates and particulates less than 10 microns in diameter (PE/PM10)* shall not exceed 40.4 lbs/hr.

ii. Visible PE from any combustion turbine stack shall not exceed 10% opacity, as a 6-minute average, except for cold start-up and shutdown periods. Cold start-up shall be defined as the time necessary to bring this emissions unit on line from a cold state to turbine synchronization.

iii. Best available control technology (BACT) for the PE/PM10 emissions from this emissions unit was determined to be burner design, combustion control, and compliance with the visible particulate emission limitation.

*The total PM10 emissions were evaluated and did not trigger any additional federal requirements, therefore, the emissions are being regulated as particulate emissions (PE).

2.b Nitrogen Oxides (NOx) Emission Limitations:

i. NOx emissions shall not exceed 261.4 lbs/hr.

ii. When burning natural gas, NOx emissions shall not exceed 42 ppm at 15% oxygen, on a dry basis.

iii. When burning LPG or fuel oil, NOx emissions shall not exceed 65 ppm at 15% oxygen, on a dry basis.

iv. BACT for the NOx emissions from this emissions unit was determined to be a low NOx burner design and water injection.

Pursuant to 40 CFR Part 60.332(f), this emissions unit is exempt from the NOx concentration emission limitations when ice fog, as defined in 40 CFR Part 60.331(f), is deemed a traffic hazard by the permittee.

2.c Sulfur Dioxide (SO2) Emission Limitations:

i. When burning fuel oil, SO2 emissions shall not exceed 516 lbs/hr from this emissions unit.

ii. When burning fuel oil, the total combined SO2 emissions from emissions units B001 through B006 shall not exceed 4911 lbs per 3-hour period and 22,152 lbs per 24-hour period.

iii. When burning natural gas or LPG in this emissions unit, SO2 emissions shall not exceed 0.015%, by volume, at 15% oxygen on a dry basis.

iv. BACT for the SO2 emissions from this emissions unit was determined to be use of a low sulfur content fuel and compliance with the emission limitations in 2.c.ii above.

2. Additional Terms and Conditions (continued)

2.d Volatile Organic Compound (VOC) Emission Limitation:

i. VOC emissions shall not exceed 6.97 lbs/hr.

ii. BACT for the VOC emissions from this emissions unit was determined to be the low VOC emission rate and compliance with the operational restrictions.

2.e Carbon Monoxide (CO) Emission Limitation:

i. CO emissions shall not exceed 25.34 lbs/hr.

ii. BACT for the CO emissions from this emissions unit was determined to be burner design.

2.f The hourly emission limitations established in PTI 14-1905 were based on the emissions unit's potentials to emit. Therefore, it is not necessary to develop any additional monitoring, record keeping or reporting requirements to ensure compliance with these emission limitations.

2.g The permittee has satisfied the "best available control techniques and operating practices" required pursuant to OAC rule 3745-21-08(B) by committing to comply with the best available control technology requirements established pursuant to 40 CFR Part 52.21 in Permit to Install 14-1905.

On November 5, 2002, OAC rule 3745-21-08 was revised to delete paragraph (B); therefore, paragraph (B) is no longer part of the State regulations. However, that rule revision has not yet been submitted to the U.S. EPA as a revision to Ohio's State Implementation Plan (SIP). Therefore, until the SIP revision occurs and the U.S. EPA approves the revisions to OAC rule 3745-21-08, the requirement to satisfy the "best available control techniques and operating practices" still exists as part of the federally-approved SIP for Ohio.

The permittee has satisfied the "latest available control techniques and operating practices" required pursuant to OAC rule 3745-23-06(B) by committing to comply with the best available control technology requirements established pursuant to 40 CFR Part 52.21 in Permit to Install 14-1905.

II. Operational Restrictions

1. The sulfur content of the fuel oil burned in this emissions unit shall not exceed 0.5%, by weight.

2. The total combined amount of fuel oil burned in emissions units B001 through B006 shall not exceed the amounts specified by the following equations:

For any 3-hour period:

gallons of fuel oil = 35078 / S

where: S = the sulfur content of the fuel oil, in percent, by weight
(e.g., if the fuel oil sulfur content is 0.5%, then S = 0.5)

For any 24-hour period:

gallons of fuel oil = 158228 / S

where: S = the sulfur content of the fuel oil, in percent, by weight
(e.g., if the fuel oil sulfur content is 0.5%, then S = 0.5)

3. The total combined operating hours for emissions units B001 through B006 shall not exceed 17,844 hours per rolling, 12-month period.

4. The minimum stack height for this emissions unit shall be at least 213 feet above the ground.

5. The permittee shall burn only natural gas, LPG, and/or fuel oil in this emissions unit.

III. Monitoring and/or Record Keeping Requirements

1. For each day during which the permittee burns a fuel other than natural gas, LPG, and/or fuel oil, the permittee shall maintain a record of the type and quantity of fuel burned in this emissions unit.

2. The permittee shall operate and maintain a continuous monitoring system to monitor and record the fuel consumption and the ratio of water-to-fuel being fired in this emissions unit. This system shall be accurate to within plus or minus 5% and shall be approved by the Administrator of the U.S. EPA.

3. The permittee shall monitor the sulfur content and nitrogen content of the fuel being fired in this emissions unit as specified below.

Sulfur Content:

For each shipment of oil received for burning in this emissions unit, the permittee shall maintain records of the total quantity of oil received and the permittee's or oil supplier's analyses for sulfur content (in %, by weight). A shipment may be comprised of multiple tank truck loads from the same supplier's batch, or may be represented by single or multiple pipeline deliveries from the same supplier's batch, and the quality of the oil for those loads or pipeline deliveries may be represented by a single batch analysis from the supplier.

The permittee shall collect and record the sulfur content of the natural gas and LPG being fired in this emissions unit on a quarterly basis in accordance with the approved custom schedule for this facility.

The permittee shall perform or require the supplier to perform the analyses for sulfur content and heat content in accordance with 40 CFR Part 60.335(d), 40 CFR Part 75, or the appropriate ASTM methods, or equivalent methods as approved by the Administrator of the U.S. EPA.

Should any sulfur analysis indicate noncompliance with 40 CFR Part 60.333 or the sulfur content limitation stated in section A.I. of this permit, the permittee shall notify Hamilton County Department of Environmental Services - Air Quality Division of the exceedance and the custom schedule shall be re-examined. During the re-examination period the permittee shall conduct daily sulfur monitoring and submit these analyses to Hamilton County Department of Environmental Services - Air Quality Division.

Nitrogen Content:

To compute the NOx emissions, the permittee shall use analytical methods and procedures that are accurate to within 5% and are approved by the Administrator of the U.S. EPA to determine the nitrogen content of the fuel being fired.

4. The permittee shall collect and record the following information on a monthly basis:

a. The total hours of operation for this emissions unit.

b. The total combined hours of operation for emissions units B001 through B006.

c. The rolling, 12-month summation of the total combined hours of operation for emissions units B001 through B006 (the summation of the current month's total combined hours of operation recorded in 4.b added to the previous 11 months total combined hours of operation).

III. Monitoring and/or Record Keeping Requirements (continued)

5. The permittee shall collect and record the following information:

a. The total combined number of gallons of fuel oil supplied to emissions units B001 through B006 for all 3-hour periods of operation.

b. The percent sulfur content, by weight, of the fuel oil supplied to emissions units B001 through B006 for all 3-hour periods of operation.

c. The total combined number of gallons of fuel oil supplied to emissions units B001 through B006 for all 24-hour periods of operation.

d. The percent sulfur content, by weight, of the fuel oil supplied to emissions units B001 through B006 for all 24-hour periods of operation.

e. The total combined SO2 emissions, in lbs, for emissions units B001 through B006 for all 3-hour periods of operation when burning fuel oil. (The SO2 emissions shall be calculated using the fuel oil usage and fuel oil sulfur content data above.)

f. The total combined SO2 emissions, in lbs, for emissions units B001 through B006 for all 24-hour periods of operation when burning fuel oil. (The SO2 emissions shall be calculated using the fuel oil usage and fuel oil sulfur content data above.)

g. Identification of each cold start-up for this emissions unit.

h. Identification of each shutdown for this emissions unit.

IV. Reporting Requirements

1. Pursuant to 40 CFR Parts 60.7 and 60.13(h), the permittee shall submit reports within 30 days following the end of each calendar quarter to the Hamilton County Department of Environmental Services - Air Quality Division documenting any 1-hour period during which the average water-to-fuel ratio, as measured by the continuous monitoring system, falls below the water-to-fuel ratio established during the most recent performance test that demonstrated that the emissions unit was in compliance with the applicable NOx emission limitations or any period during which the fuel-bound nitrogen of the fuel is greater than the maximum nitrogen content allowed by the fuel-bound nitrogen allowance used during the most recent performance test that demonstrated that the emissions unit was in compliance with the applicable NOx emission limitations. Each report shall include the average water-to-fuel ratio, average fuel consumption, ambient conditions, gas turbine load, and the nitrogen content of the fuel during the period of excess emissions. The graphs or figures developed under 40 CFR Part 60.335(a) shall also be submitted with each report.

The permittee shall submit reports within 30 days following the end of each calendar quarter to the Hamilton County Department of Environmental Services - Air Quality Division documenting any continuous water-to-fuel monitoring system downtime while the emissions unit was on line (date, time, duration and reason) along with any corrective action(s) taken. The permittee shall provide the emissions unit operating time during the reporting period and the date, time, reason and corrective action(s) taken for each time period of emissions unit and control equipment malfunctions. The total operating time of the emissions unit and the total operating time of the continuous monitoring system while the emissions unit was on line shall also be included in the quarterly report.

If there are no excess emissions during the calendar quarter, the permittee shall submit a statement to that effect along with the date, time, reason, and corrective action(s) taken for each time period of monitoring system malfunctions. The total operating time of the emissions unit and the total operating time of the continuous monitoring system while the emissions unit was on line also shall be included in the quarterly report. These quarterly excess emission reports shall be submitted by January 30, April 30, July 30, and October 30 of each year and shall address the data obtained during the previous calendar quarter.

IV. Reporting Requirements (continued)

Pursuant to 40 CFR Part 60.7, the permittee shall submit a summary of the excess emission report. The summary shall be submitted in accordance with 40 CFR Part 60.7(d) to the Hamilton County Department of Environmental Services - Air Quality Division within 30 days following the end of each calendar quarter in a manner prescribed by the Director.

2. The permittee shall submit quarterly reports that identify each period during which an exemption for ice-fog provided in 40 CFR Part 60.332(f) is in effect. The report shall include the ambient conditions existing during the period, the date and time the air pollution control system was deactivated, and the date and time when the air pollution control system was reactivated.

3. The permittee shall submit quarterly deviation (excursion) reports that identify the following:

a. Any exceedance of the 3-hour and/or 24-hour total combined fuel oil usage restrictions for emissions units B001 through B006 when burning fuel oil as calculated in section A.II.2.

b. Any exceedance of the 3-hour and/or 24-hour SO2 emission limitations when burning fuel oil for emissions units B001 through B006.

c. Any exceedance of the total combined operating hours restriction for emissions units B001 through B006.

d. Any exceedance of the 0.5%, by weight, fuel oil sulfur content restriction for this emissions unit.

e. Each day when a fuel other than natural gas, LPG, and/or fuel oil was burned in this emissions unit.

The quarterly deviation reports shall be submitted in accordance with the reporting requirements specified in Part I - General Term and Condition A.1.c.ii.

V. Testing Requirements

1. Emission Limitation:
Emissions of PE/PM10 shall not exceed 40.4 lbs/hr.

Applicable Compliance Method:
This emission limitation reflects the emissions unit's potential to emit. Compliance with this emission limitation may be demonstrated through the emission factors and equations found in Table 2.3 of the technical support document submitted 8/25/89 for PSD Permit to Install 14-1905. The PE/PM10 emission factor in Table 2.3 of Permit to Install 14-1905 is 5.10 grams of PE/PM10 per second when burning fuel oil, and 0.24 gram of PE/PM10 per second when burning natural gas or LPG.

If required, the permittee shall demonstrate compliance with the PE and PM10 emission limitation through emission tests performed in accordance with 40 CFR Part 60, Appendix A, Methods 1 through 5 while burning natural gas. Alternate U.S. EPA-approved test methods may be used with prior approval from the Ohio EPA.

2. Emission Limitation:
Visible PE from any combustion turbine stack shall not exceed 10% opacity, as a 6-minute average, except for cold start-up and shutdown periods.

Applicable Compliance Method:
If required, compliance with this emission limitation shall be demonstrated through visible emissions observations performed in accordance with 40 CFR Part 60, Appendix A, Method 9.

V. Testing Requirements (continued)

3. Emission Limitations:
NOx emissions shall not exceed 261.4 lbs/hr.

When burning natural gas, NOx emissions shall not exceed 42 ppm at 15% oxygen, on a dry basis.

When burning LPG or fuel oil, NOx emissions shall not exceed 65 ppm at 15% oxygen, on a dry basis.

Applicable Compliance Method:
The hourly NOx emission limitation reflects the emissions unit's potential to emit. Compliance with this emission limitation may be demonstrated through the emission factors and equations found in Table 2.3 of the technical support document submitted 8/25/89 for PSD Permit to Install 14-1905. The NOx emission factor in Table 2.3 of Permit to Install 14-1905 is 33.00 grams of NOx per second when burning fuel oil, and 32.50 grams of NOx per second when burning natural gas or LPG.

If required, the permittee shall demonstrate compliance with the hourly emission limitation through emission tests performed in accordance with 40 CFR Part 60, Appendix A, Methods 1 through 4 and 7 while burning natural gas. Alternate U.S. EPA-approved test methods may be used with prior approval from the Ohio EPA.

Compliance with the NOx concentration emission limitations may be demonstrated based upon the records required pursuant to Section A.III.2.

If required, the permittee shall demonstrate compliance with the NOx concentration emission limitations in accordance with the methods and procedures specified in 40 CFR Part 60.335(c).

4. Emission Limitations:
When burning fuel oil, SO2 emissions shall not exceed 516 lbs/hr from this emissions unit.

When burning fuel oil, the total combined SO2 emissions from emissions units B001 through B006 shall not exceed 4911 lbs per 3-hour period and 22,152 lbs per 24-hour period.

When burning natural gas or LPG, SO2 emissions shall not exceed 0.015%, by volume, at 15% oxygen on a dry basis from this emissions unit.

Applicable Compliance Method:
The hourly SO2 emission limitation reflects the emissions unit's potential to emit. Compliance with this emission limitation may be demonstrated through the emission factors and equations found in Table 2.3 of the technical support document submitted 8/25/89 for PSD Permit to Install 14-1905. The SO2 emission factor in Table 2.3 of Permit to Install 14-1905 is 65.13 grams of SO2 per second when burning fuel oil, and 0.00 gram of SO2 per second when burning natural gas or LPG.

If required, the permittee shall demonstrate compliance with the hourly emission limitation through emission tests performed in accordance with 40 CFR Part 60, Appendix A, Methods 1 through 4 and 6 while burning natural gas. Alternate U.S. EPA-approved test methods may be used with prior approval from the Ohio EPA.

If required, the permittee shall demonstrate compliance with the SO2 concentration emission limitation in accordance with the method and procedures specified in 40 CFR Part 60.335(c)(3).

Compliance with the total combined 3-hour and 24-hour SO2 emission limitations for emissions units B001 through B006 may be demonstrated based upon the records required pursuant to Section A.III.5.

V. Testing Requirements (continued)

5. Emission Limitation:
CO emissions shall not exceed 25.34 lbs/hr.

Applicable Compliance Method:
This emission limitation reflects the emissions unit's potential to emit. Compliance with this emission limitation may be demonstrated through the emission factors and equations found in Table 2.3 of the technical support document submitted 8/25/89 for PSD permit 14-1905. The CO emission factor in Table 2.3 of Permit to Install 14-1905 is 3.20 grams of CO per second when burning fuel oil, natural gas, or LPG.

If required, the permittee shall demonstrate compliance with this emission limitation through emission tests performed in accordance with 40 CFR Part 60, Appendix A, Methods 1 through 4 and 10 while burning natural gas. Alternate U.S. EPA-approved test methods may be used with prior approval from the Ohio EPA.

6. Emission Limitation:
VOC emissions shall not exceed 6.97 lbs/hr.

Applicable Compliance Method:
This emission limitation reflects the emissions unit's potential to emit. Compliance with this emission limitation may be demonstrated through the emission factors and equations found in Table 2.3 of the technical support document submitted 8/25/89 for PSD permit 14-1905. The VOC emission factor in Table 2.3 of Permit to Install 14-1905 is 0.88 gram of VOC per second when burning fuel oil, natural gas, or LPG.

If required, the permittee shall demonstrate compliance with this emission limitation through emission tests performed in accordance with 40 CFR Part 60, Appendix A, Methods 1 through 4 and 25 while burning natural gas. Alternate U.S. EPA-approved test methods may be used with prior approval from the Ohio EPA.

7. Upon initial use of fuel oil, the permittee shall conduct, or have conducted, emission testing for this emissions unit to demonstrate compliance with the applicable PE/PM10, NOx, SO2, VOC, and CO emission limitations in accordance with the following requirements:

The emission testing shall be conducted within 90 days of initiating fuel oil firing, unless an alternative schedule is submitted and approved by Hamilton County Department of Environmental Services-Air Quality Control Division. The frequency for future emission testing while burning fuel oil will be determined based upon the results of the initial emission tests and the procedures specified in Ohio EPA Engineering Guide 16.

Compliance with the applicable PE/PM10, NOx, SO2, VOC, and CO emission limitations shall be determined in accordance with the following:

for PE/PM10 - 40 CFR Part 60, Appendix A, Methods 1 through 5;
for NOx (hourly) - 40 CFR Part 60, Appendix A, Methods 1 through 4 and 7;
for NOx (concentration) - 40 CFR Part 60, Appendix A, Method 20
for SO2 - 40 CFR Part 60, Appendix A, Methods 1 through 4 and 6;
for VOC - 40 CFR Part 60, Appendix A, Methods 1 through 4 and 25; and
for CO - 40 CFR Part 60, Appendix A, Methods 1 through 4 and 10.

Alternate U.S. EPA-approved test methods may be used with prior approval from the Ohio EPA.

Testing for PE/PM10, NOx, and SO2 shall be performed on each emissions unit. Testing for CO and VOC shall be performed on one emissions unit that is representative of the permitted combustion turbine units (B001 through B006). Prior to performing CO and VOC testing, the permittee shall obtain agreement on the emissions unit to be tested as a representative unit from the Hamilton County Department of Environmental Services-Air Quality Control Division.

The tests shall be conducted while the emissions unit is operating at or near its maximum capacity.

V. Testing Requirements (continued)

Not later than 30 days prior to the proposed test date(s), the permittee shall submit an "Intent to Test" notification to the Hamilton County Department of Environmental Services. The "Intent to Test" notification shall describe in detail the proposed test methods and procedures, the emissions unit operating parameters, the time(s) and date(s) of the test(s), and the person(s) who will be conducting the test(s). Failure to submit such notification for review and approval prior to the test(s) may result in the Hamilton County Department of Environmental Services' refusal to accept the results of the emission test(s).

Personnel from the Hamilton County Department of Environmental Services and Ohio EPA shall be permitted to witness the test(s), examine the testing equipment, and acquire data and information necessary to ensure that the operation of the emissions unit and the testing procedures provide a valid characterization of the emissions from the emissions unit and/or the performance of the control equipment.

A comprehensive written report on the results of the emission test(s) shall be signed by the person or persons responsible for the tests and submitted to the Hamilton County Department of Environmental Services within 30 days following completion of the test(s). The permittee may request additional time for the submittal of the written report, where warranted, with prior approval from the Hamilton County Department of Environmental Services.

VI. Miscellaneous Requirements

None

B. State Enforceable Section

I. Applicable Emissions Limitations and/or Control Requirements

1. The specific operation(s), property, and/or equipment which constitute this emissions unit are listed in the following table along with the applicable rules and/or requirements and with the applicable emissions limitations and/or control measures. Emissions from this unit shall not exceed the listed limitations, and the listed control measures shall be employed. Additional applicable emissions limitations and/or control measures (if any) may be specified in narrative form following the table.

Operations, Property, and/or Equipment	Applicable Rules/ Requirements	Applicable Emissions Limitations/Control Measures

2. Additional Terms and Conditions

None

II. Operational Restrictions

None

III. Monitoring and/or Record Keeping Requirements

None

IV. Reporting Requirements

None

V. Testing Requirements

None

VI. Miscellaneous Requirements

None

Part III - Terms and Conditions for Emissions Units

Emissions Unit ID: Combustion Turbine Unit 5 (B005)

Activity Description: ABB model GT-11N combustion turbine.

A. State and Federally Enforceable Section

I. Applicable Emissions Limitations and/or Control Requirements

1. The specific operation(s), property, and/or equipment which constitute this emissions unit are listed in the following table along with the applicable rules and/or requirements and with the applicable emissions limitations and/or control measures. Emissions from this unit shall not exceed the listed limitations, and the listed control measures shall be employed. Additional applicable emissions limitations and/or control measures (if any) may be specified in narrative form following the table.

Operations, Property, and/or Equipment	Applicable Rules/ Requirements	Applicable Emissions Limitations/Control Measures
natural gas, liquid petroleum gas (LPG), and fuel oil-fired, simple cycle combustion turbine having a nominal heat input capacity of 1034 MMBtu/hr with a water injection system for the control of nitrogen oxides	40 CFR Part 52.21 and OAC rules 3745-31-11 through 3745-31-20 (PTI 14-1905)	See A.I.2.a through A.I.2.f and A.II.1 through A.II.3 below.
	OAC rule 3745-31-05(A)(3) (PTI 14-1905)	Compliance with this rule also includes compliance with 40 CFR Part 52.21 and OAC rules 3745-31-11 through 3745-31-20. See A.II.4 below.
	40 CFR Part 60, Subpart GG	The nitrogen oxides and sulfur dioxide emission limitations and/or content restrictions specified in 40 CFR Part 60, Subpart GG are equivalent to or less stringent than the emission limitations and/or content restrictions established in PTI 14-1905 pursuant to 40 CFR Part 52.21.
	OAC rule 3745-17-07(A)	The visible particulate emission limitations specified in OAC rule 3745-17-07(A) are less stringent than the visible particulate emission limitation established in PTI 14-1905 pursuant to 40 CFR Part 52.21.
	OAC rule 3745-17-11(B)(4)	The particulate emission limitation specified in OAC rule 3745-17-11(B)(4) is less stringent than The particulate emission limitation established in PTI 14-1905 pursuant to 40 CFR Part 52.21.

Operations, Property, and/or Equipment	Applicable Rules/ Requirements	Applicable Emissions Limitations/Control Measures
	OAC rule 3745-18-15(P)	The sulfur dioxide emission limitation specified in OAC rule 3745-18-15(P) is less stringent than the sulfur dioxide emission limitations established in PTI 14-1905 pursuant to 40 CFR Part 52.21.
	OAC rules 3745-21-08(B) and 3745-23-06(B)	See A.I.2.g below.

2. Additional Terms and Conditions

2.a Particulate Emission Limitations:

i. Emissions of particulates and particulates less than 10 microns in diameter (PE/PM10)* shall not exceed 40.4 lbs/hr.

ii. Visible PE from any combustion turbine stack shall not exceed 10% opacity, as a 6-minute average, except for cold start-up and shutdown periods. Cold start-up shall be defined as the time necessary to bring this emissions unit on line from a cold state to turbine synchronization.

iii. Best available control technology (BACT) for the PE/PM10 emissions from this emissions unit was determined to be burner design, combustion control, and compliance with the visible particulate emission limitation.

*The total PM10 emissions were evaluated and did not trigger any additional federal requirements, therefore, the emissions are being regulated as particulate emissions (PE).

2.b Nitrogen Oxides (NOx) Emission Limitations:

i. NOx emissions shall not exceed 261.4 lbs/hr.

ii. When burning natural gas, NOx emissions shall not exceed 42 ppm at 15% oxygen, on a dry basis.

iii. When burning LPG or fuel oil, NOx emissions shall not exceed 65 ppm at 15% oxygen, on a dry basis.

iv. BACT for the NOx emissions from this emissions unit was determined to be a low NOx burner design and water injection.

Pursuant to 40 CFR Part 60.332(f), this emissions unit is exempt from the NOx concentration emission limitations when ice fog, as defined in 40 CFR Part 60.331(f), is deemed a traffic hazard by the permittee.

2.c Sulfur Dioxide (SO2) Emission Limitations:

i. When burning fuel oil, SO2 emissions shall not exceed 516 lbs/hr from this emissions unit.

ii. When burning fuel oil, the total combined SO2 emissions from emissions units B001 through B006 shall not exceed 4911 lbs per 3-hour period and 22,152 lbs per 24-hour period.

iii. When burning natural gas or LPG in this emissions unit, SO2 emissions shall not exceed 0.015%, by volume, at 15% oxygen on a dry basis.

iv. BACT for the SO2 emissions from this emissions unit was determined to be use of a low sulfur content fuel and compliance with the emission limitations in 2.c.ii above.

2. Additional Terms and Conditions (continued)

2.d Volatile Organic Compound (VOC) Emission Limitation:

i. VOC emissions shall not exceed 6.97 lbs/hr.

ii. BACT for the VOC emissions from this emissions unit was determined to be the low VOC emission rate and compliance with the operational restrictions.

2.e Carbon Monoxide (CO) Emission Limitation:

i. CO emissions shall not exceed 25.34 lbs/hr.

ii. BACT for the CO emissions from this emissions unit was determined to be burner design.

2.f The hourly emission limitations established in PTI 14-1905 were based on the emissions unit's potentials to emit. Therefore, it is not necessary to develop any additional monitoring, record keeping or reporting requirements to ensure compliance with these emission limitations.

2.g The permittee has satisfied the "best available control techniques and operating practices" required pursuant to OAC rule 3745-21-08(B) by committing to comply with the best available control technology requirements established pursuant to 40 CFR Part 52.21 in Permit to Install 14-1905.

On November 5, 2002, OAC rule 3745-21-08 was revised to delete paragraph (B); therefore, paragraph (B) is no longer part of the State regulations. However, that rule revision has not yet been submitted to the U.S. EPA as a revision to Ohio's State Implementation Plan (SIP). Therefore, until the SIP revision occurs and the U.S. EPA approves the revisions to OAC rule 3745-21-08, the requirement to satisfy the "best available control techniques and operating practices" still exists as part of the federally-approved SIP for Ohio.

The permittee has satisfied the "latest available control techniques and operating practices" required pursuant to OAC rule 3745-23-06(B) by committing to comply with the best available control technology requirements established pursuant to 40 CFR Part 52.21 in Permit to Install 14-1905.

II. Operational Restrictions

1. The sulfur content of the fuel oil burned in this emissions unit shall not exceed 0.5%, by weight.

2. The total combined amount of fuel oil burned in emissions units B001 through B006 shall not exceed the amounts specified by the following equations:

For any 3-hour period:

gallons of fuel oil = 35078 / S

where: S = the sulfur content of the fuel oil, in percent, by weight
(e.g., if the fuel oil sulfur content is 0.5%, then S = 0.5)

For any 24-hour period:

gallons of fuel oil = 158228 / S

where: S = the sulfur content of the fuel oil, in percent, by weight
(e.g., if the fuel oil sulfur content is 0.5%, then S = 0.5)

3. The total combined operating hours for emissions units B001 through B006 shall not exceed 17,844 hours per rolling, 12-month period.

4. The minimum stack height for this emissions unit shall be at least 213 feet above the ground.

5. The permittee shall burn only natural gas, LPG, and/or fuel oil in this emissions unit.

III. Monitoring and/or Record Keeping Requirements

1. For each day during which the permittee burns a fuel other than natural gas, LPG, and/or fuel oil, the permittee shall maintain a record of the type and quantity of fuel burned in this emissions unit.

2. The permittee shall operate and maintain a continuous monitoring system to monitor and record the fuel consumption and the ratio of water-to-fuel being fired in this emissions unit. This system shall be accurate to within plus or minus 5% and shall be approved by the Administrator of the U.S. EPA.

3. The permittee shall monitor the sulfur content and nitrogen content of the fuel being fired in this emissions unit as specified below.

Sulfur Content:

For each shipment of oil received for burning in this emissions unit, the permittee shall maintain records of the total quantity of oil received and the permittee's or oil supplier's analyses for sulfur content (in %, by weight). A shipment may be comprised of multiple tank truck loads from the same supplier's batch, or may be represented by single or multiple pipeline deliveries from the same supplier's batch, and the quality of the oil for those loads or pipeline deliveries may be represented by a single batch analysis from the supplier.

The permittee shall collect and record the sulfur content of the natural gas and LPG being fired in this emissions unit on a quarterly basis in accordance with the approved custom schedule for this facility.

The permittee shall perform or require the supplier to perform the analyses for sulfur content and heat content in accordance with 40 CFR Part 60.335(d), 40 CFR Part 75, or the appropriate ASTM methods, or equivalent methods as approved by the Administrator of the U.S. EPA.

Should any sulfur analysis indicate noncompliance with 40 CFR Part 60.333 or the sulfur content limitation stated in section A.I. of this permit, the permittee shall notify Hamilton County Department of Environmental Services - Air Quality Division of the exceedance and the custom schedule shall be re-examined. During the re-examination period the permittee shall conduct daily sulfur monitoring and submit these analyses to Hamilton County Department of Environmental Services - Air Quality Division.

Nitrogen Content:

To compute the NOx emissions, the permittee shall use analytical methods and procedures that are accurate to within 5% and are approved by the Administrator of the U.S. EPA to determine the nitrogen content of the fuel being fired.

4. The permittee shall collect and record the following information on a monthly basis:

a. The total hours of operation for this emissions unit.

b. The total combined hours of operation for emissions units B001 through B006.

c. The rolling, 12-month summation of the total combined hours of operation for emissions units B001 through B006 (the summation of the current month's total combined hours of operation recorded in 4.b added to the previous 11 months total combined hours of operation).

III. Monitoring and/or Record Keeping Requirements (continued)

5. The permittee shall collect and record the following information:

a. The total combined number of gallons of fuel oil supplied to emissions units B001 through B006 for all 3-hour periods of operation.

b. The percent sulfur content, by weight, of the fuel oil supplied to emissions units B001 through B006 for all 3-hour periods of operation.

c. The total combined number of gallons of fuel oil supplied to emissions units B001 through B006 for all 24-hour periods of operation.

d. The percent sulfur content, by weight, of the fuel oil supplied to emissions units B001 through B006 for all 24-hour periods of operation.

e. The total combined SO2 emissions, in lbs, for emissions units B001 through B006 for all 3-hour periods of operation when burning fuel oil. (The SO2 emissions shall be calculated using the fuel oil usage and fuel oil sulfur content data above.)

f. The total combined SO2 emissions, in lbs, for emissions units B001 through B006 for all 24-hour periods of operation when burning fuel oil. (The SO2 emissions shall be calculated using the fuel oil usage and fuel oil sulfur content data above.)

g. Identification of each cold start-up for this emissions unit.

h. Identification of each shutdown for this emissions unit.

IV. Reporting Requirements

1. Pursuant to 40 CFR Parts 60.7 and 60.13(h), the permittee shall submit reports within 30 days following the end of each calendar quarter to the Hamilton County Department of Environmental Services - Air Quality Division documenting any 1-hour period during which the average water-to-fuel ratio, as measured by the continuous monitoring system, falls below the water-to-fuel ratio established during the most recent performance test that demonstrated that the emissions unit was in compliance with the applicable NOx emission limitations or any period during which the fuel-bound nitrogen of the fuel is greater than the maximum nitrogen content allowed by the fuel-bound nitrogen allowance used during the most recent performance test that demonstrated that the emissions unit was in compliance with the applicable NOx emission limitations. Each report shall include the average water-to-fuel ratio, average fuel consumption, ambient conditions, gas turbine load, and the nitrogen content of the fuel during the period of excess emissions. The graphs or figures developed under 40 CFR Part 60.335(a) shall also be submitted with each report.

The permittee shall submit reports within 30 days following the end of each calendar quarter to the Hamilton County Department of Environmental Services - Air Quality Division documenting any continuous water-to-fuel monitoring system downtime while the emissions unit was on line (date, time, duration and reason) along with any corrective action(s) taken. The permittee shall provide the emissions unit operating time during the reporting period and the date, time, reason and corrective action(s) taken for each time period of emissions unit and control equipment malfunctions. The total operating time of the emissions unit and the total operating time of the continuous monitoring system while the emissions unit was on line shall also be included in the quarterly report.

If there are no excess emissions during the calendar quarter, the permittee shall submit a statement to that effect along with the date, time, reason, and corrective action(s) taken for each time period of monitoring system malfunctions. The total operating time of the emissions unit and the total operating time of the continuous monitoring system while the emissions unit was on line also shall be included in the quarterly report. These quarterly excess emission reports shall be submitted by January 30, April 30, July 30, and October 30 of each year and shall address the data obtained during the previous calendar quarter.

IV. Reporting Requirements (continued)

Pursuant to 40 CFR Part 60.7, the permittee shall submit a summary of the excess emission report. The summary shall be submitted in accordance with 40 CFR Part 60.7(d) to the Hamilton County Department of Environmental Services - Air Quality Division within 30 days following the end of each calendar quarter in a manner prescribed by the Director.

2. The permittee shall submit quarterly reports that identify each period during which an exemption for ice-fog provided in 40 CFR Part 60.332(f) is in effect. The report shall include the ambient conditions existing during the period, the date and time the air pollution control system was deactivated, and the date and time when the air pollution control system was reactivated.

3. The permittee shall submit quarterly deviation (excursion) reports that identify the following:

a. Any exceedance of the 3-hour and/or 24-hour total combined fuel oil usage restrictions for emissions units B001 through B006 when burning fuel oil as calculated in section A.II.2.

b. Any exceedance of the 3-hour and/or 24-hour SO2 emission limitations when burning fuel oil for emissions units B001 through B006.

c. Any exceedance of the total combined operating hours restriction for emissions units B001 through B006.

d. Any exceedance of the 0.5%, by weight, fuel oil sulfur content restriction for this emissions unit.

e. Each day when a fuel other than natural gas, LPG, and/or fuel oil was burned in this emissions unit.

The quarterly deviation reports shall be submitted in accordance with the reporting requirements specified in Part I - General Term and Condition A.1.c.ii.

V. Testing Requirements

1. Emission Limitation:
Emissions of PE/PM10 shall not exceed 40.4 lbs/hr.

Applicable Compliance Method:
This emission limitation reflects the emissions unit's potential to emit. Compliance with this emission limitation may be demonstrated through the emission factors and equations found in Table 2.3 of the technical support document submitted 8/25/89 for PSD Permit to Install 14-1905. The PE/PM10 emission factor in Table 2.3 of Permit to Install 14-1905 is 5.10 grams of PE/PM10 per second when burning fuel oil, and 0.24 gram of PE/PM10 per second when burning natural gas or LPG.

If required, the permittee shall demonstrate compliance with the PE and PM10 emission limitation through emission tests performed in accordance with 40 CFR Part 60, Appendix A, Methods 1 through 5 while burning natural gas. Alternate U.S. EPA-approved test methods may be used with prior approval from the Ohio EPA.

2. Emission Limitation:
Visible PE from any combustion turbine stack shall not exceed 10% opacity, as a 6-minute average, except for cold start-up and shutdown periods.

Applicable Compliance Method:
If required, compliance with this emission limitation shall be demonstrated through visible emissions observations performed in accordance with 40 CFR Part 60, Appendix A, Method 9.

V. Testing Requirements (continued)

3. Emission Limitations:
NOx emissions shall not exceed 261.4 lbs/hr.

When burning natural gas, NOx emissions shall not exceed 42 ppm at 15% oxygen, on a dry basis.

When burning LPG or fuel oil, NOx emissions shall not exceed 65 ppm at 15% oxygen, on a dry basis.

Applicable Compliance Method:
The hourly NOx emission limitation reflects the emissions unit's potential to emit. Compliance with this emission limitation may be demonstrated through the emission factors and equations found in Table 2.3 of the technical support document submitted 8/25/89 for PSD Permit to Install 14-1905. The NOx emission factor in Table 2.3 of Permit to Install 14-1905 is 33.00 grams of NOx per second when burning fuel oil, and 32.50 grams of NOx per second when burning natural gas or LPG.

If required, the permittee shall demonstrate compliance with the hourly emission limitation through emission tests performed in accordance with 40 CFR Part 60, Appendix A, Methods 1 through 4 and 7 while burning natural gas. Alternate U.S. EPA-approved test methods may be used with prior approval from the Ohio EPA.

Compliance with the NOx concentration emission limitations may be demonstrated based upon the records required pursuant to Section A.III.2.

If required, the permittee shall demonstrate compliance with the NOx concentration emission limitations in accordance with the methods and procedures specified in 40 CFR Part 60.335(c).

4. Emission Limitations:
When burning fuel oil, SO2 emissions shall not exceed 516 lbs/hr from this emissions unit.

When burning fuel oil, the total combined SO2 emissions from emissions units B001 through B006 shall not exceed 4911 lbs per 3-hour period and 22,152 lbs per 24-hour period.

When burning natural gas or LPG, SO2 emissions shall not exceed 0.015%, by volume, at 15% oxygen on a dry basis from this emissions unit.

Applicable Compliance Method:
The hourly SO2 emission limitation reflects the emissions unit's potential to emit. Compliance with this emission limitation may be demonstrated through the emission factors and equations found in Table 2.3 of the technical support document submitted 8/25/89 for PSD Permit to Install 14-1905. The SO2 emission factor in Table 2.3 of Permit to Install 14-1905 is 65.13 grams of SO2 per second when burning fuel oil, and 0.00 gram of SO2 per second when burning natural gas or LPG.

If required, the permittee shall demonstrate compliance with the hourly emission limitation through emission tests performed in accordance with 40 CFR Part 60, Appendix A, Methods 1 through 4 and 6 while burning natural gas. Alternate U.S. EPA-approved test methods may be used with prior approval from the Ohio EPA.

If required, the permittee shall demonstrate compliance with the SO2 concentration emission limitation in accordance with the method and procedures specified in 40 CFR Part 60.335(c)(3).

Compliance with the total combined 3-hour and 24-hour SO2 emission limitations for emissions units B001 through B006 may be demonstrated based upon the records required pursuant to Section A.III.5.

V. Testing Requirements (continued)

5. Emission Limitation:
CO emissions shall not exceed 25.34 lbs/hr.

Applicable Compliance Method:
This emission limitation reflects the emissions unit's potential to emit. Compliance with this emission limitation may be demonstrated through the emission factors and equations found in Table 2.3 of the technical support document submitted 8/25/89 for PSD permit 14-1905. The CO emission factor in Table 2.3 of Permit to Install 14-1905 is 3.20 grams of CO per second when burning fuel oil, natural gas, or LPG.

If required, the permittee shall demonstrate compliance with this emission limitation through emission tests performed in accordance with 40 CFR Part 60, Appendix A, Methods 1 through 4 and 10 while burning natural gas. Alternate U.S. EPA-approved test methods may be used with prior approval from the Ohio EPA.

6. Emission Limitation:
VOC emissions shall not exceed 6.97 lbs/hr.

Applicable Compliance Method:
This emission limitation reflects the emissions unit's potential to emit. Compliance with this emission limitation may be demonstrated through the emission factors and equations found in Table 2.3 of the technical support document submitted 8/25/89 for PSD permit 14-1905. The VOC emission factor in Table 2.3 of Permit to Install 14-1905 is 0.88 gram of VOC per second when burning fuel oil, natural gas, or LPG.

If required, the permittee shall demonstrate compliance with this emission limitation through emission tests performed in accordance with 40 CFR Part 60, Appendix A, Methods 1 through 4 and 25 while burning natural gas. Alternate U.S. EPA-approved test methods may be used with prior approval from the Ohio EPA.

7. Upon initial use of fuel oil, the permittee shall conduct, or have conducted, emission testing for this emissions unit to demonstrate compliance with the applicable PE/PM10, NOx, SO2, VOC, and CO emission limitations in accordance with the following requirements:

The emission testing shall be conducted within 90 days of initiating fuel oil firing, unless an alternative schedule is submitted and approved by Hamilton County Department of Environmental Services-Air Quality Control Division. The frequency for future emission testing while burning fuel oil will be determined based upon the results of the initial emission tests and the procedures specified in Ohio EPA Engineering Guide 16.

Compliance with the applicable PE/PM10, NOx, SO2, VOC, and CO emission limitations shall be determined in accordance with the following:

for PE/PM10 - 40 CFR Part 60, Appendix A, Methods 1 through 5;
for NOx (hourly) - 40 CFR Part 60, Appendix A, Methods 1 through 4 and 7;
for NOx (concentration) - 40 CFR Part 60, Appendix A, Method 20
for SO2 - 40 CFR Part 60, Appendix A, Methods 1 through 4 and 6;
for VOC - 40 CFR Part 60, Appendix A, Methods 1 through 4 and 25; and
for CO - 40 CFR Part 60, Appendix A, Methods 1 through 4 and 10.

Alternate U.S. EPA-approved test methods may be used with prior approval from the Ohio EPA.

Testing for PE/PM10, NOx, and SO2 shall be performed on each emissions unit. Testing for CO and VOC shall be performed on one emissions unit that is representative of the permitted combustion turbine units (B001 through B006). Prior to performing CO and VOC testing, the permittee shall obtain agreement on the emissions unit to be tested as a representative unit from the Hamilton County Department of Environmental Services-Air Quality Control Division.

The tests shall be conducted while the emissions unit is operating at or near its maximum capacity.

V. Testing Requirements (continued)

Not later than 30 days prior to the proposed test date(s), the permittee shall submit an "Intent to Test" notification to the Hamilton County Department of Environmental Services. The "Intent to Test" notification shall describe in detail the proposed test methods and procedures, the emissions unit operating parameters, the time(s) and date(s) of the test(s), and the person(s) who will be conducting the test(s). Failure to submit such notification for review and approval prior to the test(s) may result in the Hamilton County Department of Environmental Services' refusal to accept the results of the emission test(s).

Personnel from the Hamilton County Department of Environmental Services and Ohio EPA shall be permitted to witness the test(s), examine the testing equipment, and acquire data and information necessary to ensure that the operation of the emissions unit and the testing procedures provide a valid characterization of the emissions from the emissions unit and/or the performance of the control equipment.

A comprehensive written report on the results of the emission test(s) shall be signed by the person or persons responsible for the tests and submitted to the Hamilton County Department of Environmental Services within 30 days following completion of the test(s). The permittee may request additional time for the submittal of the written report, where warranted, with prior approval from the Hamilton County Department of Environmental Services.

VI. Miscellaneous Requirements

None

B. State Enforceable Section

I. Applicable Emissions Limitations and/or Control Requirements

1. The specific operation(s), property, and/or equipment which constitute this emissions unit are listed in the following table along with the applicable rules and/or requirements and with the applicable emissions limitations and/or control measures. Emissions from this unit shall not exceed the listed limitations, and the listed control measures shall be employed. Additional applicable emissions limitations and/or control measures (if any) may be specified in narrative form following the table.

Operations, Property, and/or Equipment	Applicable Rules/ Requirements	Applicable Emissions Limitations/Control Measures

2. Additional Terms and Conditions

None

II. Operational Restrictions

None

III. Monitoring and/or Record Keeping Requirements

None

IV. Reporting Requirements

None

V. Testing Requirements

None

VI. Miscellaneous Requirements

None

Part III - Terms and Conditions for Emissions Units

Emissions Unit ID: Combustion Turbine Unit 6 (B006)

Activity Description: ABB model GT-11N combustion turbine.

A. State and Federally Enforceable Section

I. Applicable Emissions Limitations and/or Control Requirements

1. The specific operation(s), property, and/or equipment which constitute this emissions unit are listed in the following table along with the applicable rules and/or requirements and with the applicable emissions limitations and/or control measures. Emissions from this unit shall not exceed the listed limitations, and the listed control measures shall be employed. Additional applicable emissions limitations and/or control measures (if any) may be specified in narrative form following the table.

Operations, Property, and/or Equipment	Applicable Rules/ Requirements	Applicable Emissions Limitations/Control Measures
natural gas, liquid petroleum gas (LPG), and fuel oil-fired, simple cycle combustion turbine having a nominal heat input capacity of 1034 MMBtu/hr with a water injection system for the control of nitrogen oxides	40 CFR Part 52.21 and OAC rules 3745-31-11 through 3745-31-20 (PTI 14-1905)	See A.I.2.a through A.I.2.f and A.II.1 through A.II.3 below.
	OAC rule 3745-31-05(A)(3) (PTI 14-1905)	Compliance with this rule also includes compliance with 40 CFR Part 52.21 and OAC rules 3745-31-11 through 3745-31-20. See A.II.4 below.
	40 CFR Part 60, Subpart GG	The nitrogen oxides and sulfur dioxide emission limitations and/or content restrictions specified in 40 CFR Part 60, Subpart GG are equivalent to or less stringent than the emission limitations and/or content restrictions established in PTI 14-1905 pursuant to 40 CFR Part 52.21.
	OAC rule 3745-17-07(A)	The visible particulate emission limitations specified in OAC rule 3745-17-07(A) are less stringent than the visible particulate emission limitation established in PTI 14-1905 pursuant to 40 CFR Part 52.21.
	OAC rule 3745-17-11(B)(4)	The particulate emission limitation specified in OAC rule 3745-17-11(B)(4) is less stringent than The particulate emission limitation established in PTI 14-1905 pursuant to 40 CFR Part 52.21.

Operations, Property, and/or Equipment	Applicable Rules/ Requirements	Applicable Emissions Limitations/Control Measures
	OAC rule 3745-18-15(P)	The sulfur dioxide emission limitation specified in OAC rule 3745-18-15(P) is less stringent than the sulfur dioxide emission limitations established in PTI 14-1905 pursuant to 40 CFR Part 52.21.
	OAC rules 3745-21-08(B) and 3745-23-06(B)	See A.I.2.g below.

2. Additional Terms and Conditions

2.a Particulate Emission Limitations:

i. Emissions of particulates and particulates less than 10 microns in diameter (PE/PM10)* shall not exceed 40.4 lbs/hr.

ii. Visible PE from any combustion turbine stack shall not exceed 10% opacity, as a 6-minute average, except for cold start-up and shutdown periods. Cold start-up shall be defined as the time necessary to bring this emissions unit on line from a cold state to turbine synchronization.

iii. Best available control technology (BACT) for the PE/PM10 emissions from this emissions unit was determined to be burner design, combustion control, and compliance with the visible particulate emission limitation.

*The total PM10 emissions were evaluated and did not trigger any additional federal requirements, therefore, the emissions are being regulated as particulate emissions (PE).

2.b Nitrogen Oxides (NOx) Emission Limitations:

i. NOx emissions shall not exceed 261.4 lbs/hr.

ii. When burning natural gas, NOx emissions shall not exceed 42 ppm at 15% oxygen, on a dry basis.

iii. When burning LPG or fuel oil, NOx emissions shall not exceed 65 ppm at 15% oxygen, on a dry basis.

iv. BACT for the NOx emissions from this emissions unit was determined to be a low NOx burner design and water injection.

Pursuant to 40 CFR Part 60.332(f), this emissions unit is exempt from the NOx concentration emission limitations when ice fog, as defined in 40 CFR Part 60.331(f), is deemed a traffic hazard by the permittee.

2.c Sulfur Dioxide (SO2) Emission Limitations:

i. When burning fuel oil, SO2 emissions shall not exceed 516 lbs/hr from this emissions unit.

ii. When burning fuel oil, the total combined SO2 emissions from emissions units B001 through B006 shall not exceed 4911 lbs per 3-hour period and 22,152 lbs per 24-hour period.

iii. When burning natural gas or LPG in this emissions unit, SO2 emissions shall not exceed 0.015%, by volume, at 15% oxygen on a dry basis.

iv. BACT for the SO2 emissions from this emissions unit was determined to be use of a low sulfur content fuel and compliance with the emission limitations in 2.c.ii above.

2. Additional Terms and Conditions (continued)

2.d Volatile Organic Compound (VOC) Emission Limitation:

i. VOC emissions shall not exceed 6.97 lbs/hr.

ii. BACT for the VOC emissions from this emissions unit was determined to be the low VOC emission rate and compliance with the operational restrictions.

2.e Carbon Monoxide (CO) Emission Limitation:

i. CO emissions shall not exceed 25.34 lbs/hr.

ii. BACT for the CO emissions from this emissions unit was determined to be burner design.

2.f The hourly emission limitations established in PTI 14-1905 were based on the emissions unit's potentials to emit. Therefore, it is not necessary to develop any additional monitoring, record keeping or reporting requirements to ensure compliance with these emission limitations.

2.g The permittee has satisfied the "best available control techniques and operating practices" required pursuant to OAC rule 3745-21-08(B) by committing to comply with the best available control technology requirements established pursuant to 40 CFR Part 52.21 in Permit to Install 14-1905.

On November 5, 2002, OAC rule 3745-21-08 was revised to delete paragraph (B); therefore, paragraph (B) is no longer part of the State regulations. However, that rule revision has not yet been submitted to the U.S. EPA as a revision to Ohio's State Implementation Plan (SIP). Therefore, until the SIP revision occurs and the U.S. EPA approves the revisions to OAC rule 3745-21-08, the requirement to satisfy the "best available control techniques and operating practices" still exists as part of the federally-approved SIP for Ohio.

The permittee has satisfied the "latest available control techniques and operating practices" required pursuant to OAC rule 3745-23-06(B) by committing to comply with the best available control technology requirements established pursuant to 40 CFR Part 52.21 in Permit to Install 14-1905.

II. Operational Restrictions

1. The sulfur content of the fuel oil burned in this emissions unit shall not exceed 0.5%, by weight.

2. The total combined amount of fuel oil burned in emissions units B001 through B006 shall not exceed the amounts specified by the following equations:

For any 3-hour period:

gallons of fuel oil = 35078 / S

where: S = the sulfur content of the fuel oil, in percent, by weight
(e.g., if the fuel oil sulfur content is 0.5%, then S = 0.5)

For any 24-hour period:

gallons of fuel oil = 158228 / S

where: S = the sulfur content of the fuel oil, in percent, by weight
(e.g., if the fuel oil sulfur content is 0.5%, then S = 0.5)

3. The total combined operating hours for emissions units B001 through B006 shall not exceed 17,844 hours per rolling, 12-month period.

4. The minimum stack height for this emissions unit shall be at least 213 feet above the ground.

5. The permittee shall burn only natural gas, LPG, and/or fuel oil in this emissions unit.

III. Monitoring and/or Record Keeping Requirements

1. For each day during which the permittee burns a fuel other than natural gas, LPG, and/or fuel oil, the permittee shall maintain a record of the type and quantity of fuel burned in this emissions unit.

2. The permittee shall operate and maintain a continuous monitoring system to monitor and record the fuel consumption and the ratio of water-to-fuel being fired in this emissions unit. This system shall be accurate to within plus or minus 5% and shall be approved by the Administrator of the U.S. EPA.

3. The permittee shall monitor the sulfur content and nitrogen content of the fuel being fired in this emissions unit as specified below.

Sulfur Content:

For each shipment of oil received for burning in this emissions unit, the permittee shall maintain records of the total quantity of oil received and the permittee's or oil supplier's analyses for sulfur content (in %, by weight). A shipment may be comprised of multiple tank truck loads from the same supplier's batch, or may be represented by single or multiple pipeline deliveries from the same supplier's batch, and the quality of the oil for those loads or pipeline deliveries may be represented by a single batch analysis from the supplier.

The permittee shall collect and record the sulfur content of the natural gas and LPG being fired in this emissions unit on a quarterly basis in accordance with the approved custom schedule for this facility.

The permittee shall perform or require the supplier to perform the analyses for sulfur content and heat content in accordance with 40 CFR Part 60.335(d), 40 CFR Part 75, or the appropriate ASTM methods, or equivalent methods as approved by the Administrator of the U.S. EPA.

Should any sulfur analysis indicate noncompliance with 40 CFR Part 60.333 or the sulfur content limitation stated in section A.I. of this permit, the permittee shall notify Hamilton County Department of Environmental Services - Air Quality Division of the exceedance and the custom schedule shall be re-examined. During the re-examination period the permittee shall conduct daily sulfur monitoring and submit these analyses to Hamilton County Department of Environmental Services - Air Quality Division.

Nitrogen Content:

To compute the NOx emissions, the permittee shall use analytical methods and procedures that are accurate to within 5% and are approved by the Administrator of the U.S. EPA to determine the nitrogen content of the fuel being fired.

4. The permittee shall collect and record the following information on a monthly basis:

a. The total hours of operation for this emissions unit.

b. The total combined hours of operation for emissions units B001 through B006.

c. The rolling, 12-month summation of the total combined hours of operation for emissions units B001 through B006 (the summation of the current month's total combined hours of operation recorded in 4.b added to the previous 11 months total combined hours of operation).

III. Monitoring and/or Record Keeping Requirements (continued)

5. The permittee shall collect and record the following information:

a. The total combined number of gallons of fuel oil supplied to emissions units B001 through B006 for all 3-hour periods of operation.

b. The percent sulfur content, by weight, of the fuel oil supplied to emissions units B001 through B006 for all 3-hour periods of operation.

c. The total combined number of gallons of fuel oil supplied to emissions units B001 through B006 for all 24-hour periods of operation.

d. The percent sulfur content, by weight, of the fuel oil supplied to emissions units B001 through B006 for all 24-hour periods of operation.

e. The total combined SO2 emissions, in lbs, for emissions units B001 through B006 for all 3-hour periods of operation when burning fuel oil. (The SO2 emissions shall be calculated using the fuel oil usage and fuel oil sulfur content data above.)

f. The total combined SO2 emissions, in lbs, for emissions units B001 through B006 for all 24-hour periods of operation when burning fuel oil. (The SO2 emissions shall be calculated using the fuel oil usage and fuel oil sulfur content data above.)

g. Identification of each cold start-up for this emissions unit.

h. Identification of each shutdown for this emissions unit.

IV. Reporting Requirements

1. Pursuant to 40 CFR Parts 60.7 and 60.13(h), the permittee shall submit reports within 30 days following the end of each calendar quarter to the Hamilton County Department of Environmental Services - Air Quality Division documenting any 1-hour period during which the average water-to-fuel ratio, as measured by the continuous monitoring system, falls below the water-to-fuel ratio established during the most recent performance test that demonstrated that the emissions unit was in compliance with the applicable NOx emission limitations or any period during which the fuel-bound nitrogen of the fuel is greater than the maximum nitrogen content allowed by the fuel-bound nitrogen allowance used during the most recent performance test that demonstrated that the emissions unit was in compliance with the applicable NOx emission limitations. Each report shall include the average water-to-fuel ratio, average fuel consumption, ambient conditions, gas turbine load, and the nitrogen content of the fuel during the period of excess emissions. The graphs or figures developed under 40 CFR Part 60.335(a) shall also be submitted with each report.

The permittee shall submit reports within 30 days following the end of each calendar quarter to the Hamilton County Department of Environmental Services - Air Quality Division documenting any continuous water-to-fuel monitoring system downtime while the emissions unit was on line (date, time, duration and reason) along with any corrective action(s) taken. The permittee shall provide the emissions unit operating time during the reporting period and the date, time, reason and corrective action(s) taken for each time period of emissions unit and control equipment malfunctions. The total operating time of the emissions unit and the total operating time of the continuous monitoring system while the emissions unit was on line shall also be included in the quarterly report.

If there are no excess emissions during the calendar quarter, the permittee shall submit a statement to that effect along with the date, time, reason, and corrective action(s) taken for each time period of monitoring system malfunctions. The total operating time of the emissions unit and the total operating time of the continuous monitoring system while the emissions unit was on line also shall be included in the quarterly report. These quarterly excess emission reports shall be submitted by January 30, April 30, July 30, and October 30 of each year and shall address the data obtained during the previous calendar quarter.

IV. Reporting Requirements (continued)

Pursuant to 40 CFR Part 60.7, the permittee shall submit a summary of the excess emission report. The summary shall be submitted in accordance with 40 CFR Part 60.7(d) to the Hamilton County Department of Environmental Services - Air Quality Division within 30 days following the end of each calendar quarter in a manner prescribed by the Director.

2. The permittee shall submit quarterly reports that identify each period during which an exemption for ice-fog provided in 40 CFR Part 60.332(f) is in effect. The report shall include the ambient conditions existing during the period, the date and time the air pollution control system was deactivated, and the date and time when the air pollution control system was reactivated.

3. The permittee shall submit quarterly deviation (excursion) reports that identify the following:

a. Any exceedance of the 3-hour and/or 24-hour total combined fuel oil usage restrictions for emissions units B001 through B006 when burning fuel oil as calculated in section A.II.2.

b. Any exceedance of the 3-hour and/or 24-hour SO2 emission limitations when burning fuel oil for emissions units B001 through B006.

c. Any exceedance of the total combined operating hours restriction for emissions units B001 through B006.

d. Any exceedance of the 0.5%, by weight, fuel oil sulfur content restriction for this emissions unit.

e. Each day when a fuel other than natural gas, LPG, and/or fuel oil was burned in this emissions unit.

The quarterly deviation reports shall be submitted in accordance with the reporting requirements specified in Part I - General Term and Condition A.1.c.ii.

V. Testing Requirements

1. Emission Limitation:
Emissions of PE/PM10 shall not exceed 40.4 lbs/hr.

Applicable Compliance Method:
This emission limitation reflects the emissions unit's potential to emit. Compliance with this emission limitation may be demonstrated through the emission factors and equations found in Table 2.3 of the technical support document submitted 8/25/89 for PSD Permit to Install 14-1905. The PE/PM10 emission factor in Table 2.3 of Permit to Install 14-1905 is 5.10 grams of PE/PM10 per second when burning fuel oil, and 0.24 gram of PE/PM10 per second when burning natural gas or LPG.

If required, the permittee shall demonstrate compliance with the PE and PM10 emission limitation through emission tests performed in accordance with 40 CFR Part 60, Appendix A, Methods 1 through 5 while burning natural gas. Alternate U.S. EPA-approved test methods may be used with prior approval from the Ohio EPA.

2. Emission Limitation:
Visible PE from any combustion turbine stack shall not exceed 10% opacity, as a 6-minute average, except for cold start-up and shutdown periods.

Applicable Compliance Method:
If required, compliance with this emission limitation shall be demonstrated through visible emissions observations performed in accordance with 40 CFR Part 60, Appendix A, Method 9.

V. Testing Requirements (continued)

3. Emission Limitations:
NOx emissions shall not exceed 261.4 lbs/hr.

When burning natural gas, NOx emissions shall not exceed 42 ppm at 15% oxygen, on a dry basis.

When burning LPG or fuel oil, NOx emissions shall not exceed 65 ppm at 15% oxygen, on a dry basis.

Applicable Compliance Method:
The hourly NOx emission limitation reflects the emissions unit's potential to emit. Compliance with this emission limitation may be demonstrated through the emission factors and equations found in Table 2.3 of the technical support document submitted 8/25/89 for PSD Permit to Install 14-1905. The NOx emission factor in Table 2.3 of Permit to Install 14-1905 is 33.00 grams of NOx per second when burning fuel oil, and 32.50 grams of NOx per second when burning natural gas or LPG.

If required, the permittee shall demonstrate compliance with the hourly emission limitation through emission tests performed in accordance with 40 CFR Part 60, Appendix A, Methods 1 through 4 and 7 while burning natural gas. Alternate U.S. EPA-approved test methods may be used with prior approval from the Ohio EPA.

Compliance with the NOx concentration emission limitations may be demonstrated based upon the records required pursuant to Section A.III.2.

If required, the permittee shall demonstrate compliance with the NOx concentration emission limitations in accordance with the methods and procedures specified in 40 CFR Part 60.335(c).

4. Emission Limitations:
When burning fuel oil, SO2 emissions shall not exceed 516 lbs/hr from this emissions unit.

When burning fuel oil, the total combined SO2 emissions from emissions units B001 through B006 shall not exceed 4911 lbs per 3-hour period and 22,152 lbs per 24-hour period.

When burning natural gas or LPG, SO2 emissions shall not exceed 0.015%, by volume, at 15% oxygen on a dry basis from this emissions unit.

Applicable Compliance Method:
The hourly SO2 emission limitation reflects the emissions unit's potential to emit. Compliance with this emission limitation may be demonstrated through the emission factors and equations found in Table 2.3 of the technical support document submitted 8/25/89 for PSD Permit to Install 14-1905. The SO2 emission factor in Table 2.3 of Permit to Install 14-1905 is 65.13 grams of SO2 per second when burning fuel oil, and 0.00 gram of SO2 per second when burning natural gas or LPG.

If required, the permittee shall demonstrate compliance with the hourly emission limitation through emission tests performed in accordance with 40 CFR Part 60, Appendix A, Methods 1 through 4 and 6 while burning natural gas. Alternate U.S. EPA-approved test methods may be used with prior approval from the Ohio EPA.

If required, the permittee shall demonstrate compliance with the SO2 concentration emission limitation in accordance with the method and procedures specified in 40 CFR Part 60.335(c)(3).

Compliance with the total combined 3-hour and 24-hour SO2 emission limitations for emissions units B001 through B006 may be demonstrated based upon the records required pursuant to Section A.III.5.

V. Testing Requirements (continued)

5. Emission Limitation:
CO emissions shall not exceed 25.34 lbs/hr.

Applicable Compliance Method:
This emission limitation reflects the emissions unit's potential to emit. Compliance with this emission limitation may be demonstrated through the emission factors and equations found in Table 2.3 of the technical support document submitted 8/25/89 for PSD permit 14-1905. The CO emission factor in Table 2.3 of Permit to Install 14-1905 is 3.20 grams of CO per second when burning fuel oil, natural gas, or LPG.

If required, the permittee shall demonstrate compliance with this emission limitation through emission tests performed in accordance with 40 CFR Part 60, Appendix A, Methods 1 through 4 and 10 while burning natural gas. Alternate U.S. EPA-approved test methods may be used with prior approval from the Ohio EPA.

6. Emission Limitation:
VOC emissions shall not exceed 6.97 lbs/hr.

Applicable Compliance Method:
This emission limitation reflects the emissions unit's potential to emit. Compliance with this emission limitation may be demonstrated through the emission factors and equations found in Table 2.3 of the technical support document submitted 8/25/89 for PSD permit 14-1905. The VOC emission factor in Table 2.3 of Permit to Install 14-1905 is 0.88 gram of VOC per second when burning fuel oil, natural gas, or LPG.

If required, the permittee shall demonstrate compliance with this emission limitation through emission tests performed in accordance with 40 CFR Part 60, Appendix A, Methods 1 through 4 and 25 while burning natural gas. Alternate U.S. EPA-approved test methods may be used with prior approval from the Ohio EPA.

7. Upon initial use of fuel oil, the permittee shall conduct, or have conducted, emission testing for this emissions unit to demonstrate compliance with the applicable PE/PM10, NOx, SO2, VOC, and CO emission limitations in accordance with the following requirements:

The emission testing shall be conducted within 90 days of initiating fuel oil firing, unless an alternative schedule is submitted and approved by Hamilton County Department of Environmental Services-Air Quality Control Division. The frequency for future emission testing while burning fuel oil will be determined based upon the results of the initial emission tests and the procedures specified in Ohio EPA Engineering Guide 16.

Compliance with the applicable PE/PM10, NOx, SO2, VOC, and CO emission limitations shall be determined in accordance with the following:

for PE/PM10 - 40 CFR Part 60, Appendix A, Methods 1 through 5;
for NOx (hourly) - 40 CFR Part 60, Appendix A, Methods 1 through 4 and 7;
for NOx (concentration) - 40 CFR Part 60, Appendix A, Method 20
for SO2 - 40 CFR Part 60, Appendix A, Methods 1 through 4 and 6;
for VOC - 40 CFR Part 60, Appendix A, Methods 1 through 4 and 25; and
for CO - 40 CFR Part 60, Appendix A, Methods 1 through 4 and 10.

Alternate U.S. EPA-approved test methods may be used with prior approval from the Ohio EPA.

Testing for PE/PM10, NOx, and SO2 shall be performed on each emissions unit. Testing for CO and VOC shall be performed on one emissions unit that is representative of the permitted combustion turbine units (B001 through B006). Prior to performing CO and VOC testing, the permittee shall obtain agreement on the emissions unit to be tested as a representative unit from the Hamilton County Department of Environmental Services-Air Quality Control Division.

The tests shall be conducted while the emissions unit is operating at or near its maximum capacity.

V. Testing Requirements (continued)

Not later than 30 days prior to the proposed test date(s), the permittee shall submit an "Intent to Test" notification to the Hamilton County Department of Environmental Services. The "Intent to Test" notification shall describe in detail the proposed test methods and procedures, the emissions unit operating parameters, the time(s) and date(s) of the test(s), and the person(s) who will be conducting the test(s). Failure to submit such notification for review and approval prior to the test(s) may result in the Hamilton County Department of Environmental Services' refusal to accept the results of the emission test(s).

Personnel from the Hamilton County Department of Environmental Services and Ohio EPA shall be permitted to witness the test(s), examine the testing equipment, and acquire data and information necessary to ensure that the operation of the emissions unit and the testing procedures provide a valid characterization of the emissions from the emissions unit and/or the performance of the control equipment.

A comprehensive written report on the results of the emission test(s) shall be signed by the person or persons responsible for the tests and submitted to the Hamilton County Department of Environmental Services within 30 days following completion of the test(s). The permittee may request additional time for the submittal of the written report, where warranted, with prior approval from the Hamilton County Department of Environmental Services.

VI. Miscellaneous Requirements

None

B. State Enforceable Section

I. Applicable Emissions Limitations and/or Control Requirements

1. The specific operation(s), property, and/or equipment which constitute this emissions unit are listed in the following table along with the applicable rules and/or requirements and with the applicable emissions limitations and/or control measures. Emissions from this unit shall not exceed the listed limitations, and the listed control measures shall be employed. Additional applicable emissions limitations and/or control measures (if any) may be specified in narrative form following the table.

Operations, Property, and/or Equipment	Applicable Rules/ Requirements	Applicable Emissions Limitations/Control Measures

2. Additional Terms and Conditions

None

II. Operational Restrictions

None

III. Monitoring and/or Record Keeping Requirements

None

IV. Reporting Requirements

None

V. Testing Requirements

None

VI. Miscellaneous Requirements

None

Part III - Terms and Conditions for Emissions Units

Emissions Unit ID: Vaporizing Boiler # 1 (B013)

Activity Description: Cleaver Brooks model CB 700-500 propane vaporizing boiler

A. State and Federally Enforceable Section

I. Applicable Emissions Limitations and/or Control Requirements

1. The specific operation(s), property, and/or equipment which constitute this emissions unit are listed in the following table along with the applicable rules and/or requirements and with the applicable emissions limitations and/or control measures. Emissions from this unit shall not exceed the listed limitations, and the listed control measures shall be employed. Additional applicable emissions limitations and/or control measures (if any) may be specified in narrative form following the table.

Operations, Property, and/or Equipment	Applicable Rules/ Requirements	Applicable Emissions Limitations/Control Measures
21 MMBtu/hr liquid petroleum gas (LPG)-fired vaporizing boiler (non-steam generating)	40 CFR Part 52.21 and OAC rules 3745-31-11 through 3745-31-20 (PTI 14-1905)	See A.I.2.a through A.I.2.f and A.II.3 below.
	OAC rule 3745-31-05(A)(3) (PTI 14-1905)	Compliance with this rule also includes compliance with 40 CFR Part 52.21, OAC rules 3745-31-11 through 3745-31-20, and OAC rule 3745-17-07(A). See A.II.1 below.
	OAC rule 3745-17-07(A)	Visible particulate emissions shall not exceed 20% opacity as a 6-minute average, except as provided by rule.
	OAC rule 3745-17-10(B)	The particulate emission limitation specified in OAC rule 3745-17-10(B) is less stringent than the particulate emission limitation established in PTI 14-1905 pursuant to 40 CFR Part 52.21.
	OAC rules 3745-21-08(B) and 3745-23-06(B)	See A.I.2.g below.

2. Additional Terms and Conditions

2.a Particulate Emission Limitation:

i. Emissions of particulates and particulates less than 10 microns in diameter (PE/PM10) shall not exceed 0.27 lb/1000 gallons of LPG burned.

ii. Best available control technology (BACT) for the PE/PM10 emissions from this emissions unit was determined to be burner design, combustion control, and the use of LPG fuel.

2. Additional Terms and Conditions (continued)

2.b Nitrogen Oxides (NOx) Emission Limitation:

i. NOx emissions shall not exceed 12.4 lbs/1000 gallons of LPG burned.

ii. BACT for the NOx emissions from this emissions unit was determined to be a low NOx burner design.

2.c Carbon Monoxide (CO) Emission Limitation:

i. CO emissions shall not exceed 3.1 lbs/1000 gallons of LPG burned.

ii. BACT for the CO emissions from this emissions unit was determined to be burner design, combustion control, and the use of LPG fuel.

2.d Volatile Organic Compound (VOC) Emission Limitation:

i. VOC emissions shall not exceed 0.25 lb/1000 gallons of LPG burned.

ii. BACT for the VOC emissions from this emissions unit was determined to be burner design, combustion control, and the use of LPG fuel.

2.e Sulfur Dioxide (SO2) Emissions:

i. BACT for the SO2 emissions from this emissions unit was determined to be burner design, combustion control, and the use of LPG fuel.

ii. SO2 emission limitations were not established in PTI 14-1905 because emissions were negligible for this emissions unit.

2.f The pound(s) per 1000 gallons of LPG burned emission limitations established in PTI 14-1905 were based on the emissions unit's potentials to emit. Therefore, it is not necessary to develop any additional monitoring, record keeping or reporting requirements to ensure compliance with these emission limitations.

2.g The permittee has satisfied the "best available control techniques and operating practices" required pursuant to OAC rule 3745-21-08(B) by committing to comply with the best available control technology requirements established pursuant to 40 CFR Part 52.21 in Permit to Install 14-1905.

On November 5, 2002, OAC rule 3745-21-08 was revised to delete paragraph (B); therefore, paragraph (B) is no longer part of the State regulations. However, that rule revision has not yet been submitted to the U.S. EPA as a revision to Ohio's State Implementation Plan (SIP). Therefore, until the SIP revision occurs and the U.S. EPA approves the revisions to OAC rule 3745-21-08, the requirement to satisfy the "best available control techniques and operating practices" still exists as part of the federally-approved SIP for Ohio.

The permittee has satisfied the "latest available control techniques and operating practices" required pursuant to OAC rule 3745-23-06(B) by committing to comply with the best available control technology requirements established pursuant to 40 CFR Part 52.21 in Permit to Install 14-1905.

II. Operational Restrictions

1. The minimum stack height for this emissions unit shall be at least 80 feet above the ground.

2. The permittee shall burn only LPG in this emissions unit.

3. The total combined amount of LPG burned in emissions units B013 through B018 shall not exceed 4.9 million gallons per rolling, 12-month period.

III. Monitoring and/or Record Keeping Requirements

1. For each day during which the permittee burns a fuel other than LPG, the permittee shall maintain a record of the type and quantity of fuel burned in this emissions unit.

2. The permittee shall collect and record the following information on a monthly basis:

a. The total combined amount of LPG gas burned in emissions units B013 through B018.

b. The rolling, 12-month summation of the total combined amount of LPG gas burned in emissions units B013 through B018 (the summation of the current month's total combined amount of LPG gas burned recorded in line 2.a, added to the previous 11 months total combined amount of LPG gas burned).

IV. Reporting Requirements

1. The permittee shall submit quarterly deviation (excursion) reports that identify the following:

a. each day when a fuel other than LPG was burned in this emissions unit; and

b. any monthly record which shows an exceedance of the LPG usage restriction specified in Section A.II.3.

The quarterly deviation reports shall be submitted in accordance with the reporting requirements specified in Part I - General Term and Condition A.1.c.ii.

V. Testing Requirements

1. Emission Limitation:
PE/PM10 shall not exceed 0.27 lb/1000 gallons of LPG burned.

Applicable Compliance Method:
This emission limitation reflects the emissions unit's potential to emit. Compliance with this emission limitation may be demonstrated through the emission factors and equations found in Table 2.3 of the technical support document submitted 8/25/89 for PSD Permit to Install 14-1905. The PE/PM10 emission factor in Table 2.3 of Permit to Install 14-1905 is 0.015 gram of PE/PM10 per second when burning LPG.

If required, the permittee shall demonstrate compliance with this emission limitation through emission tests performed in accordance with 40 CFR Part 60, Appendix A, Methods 1 through 5. Alternate U.S. EPA-approved test methods may be used with prior approval from the Ohio EPA.

2. Emission Limitation:
NOx emissions shall not exceed 12.4 lbs/1000 gallons of LPG burned.

Applicable Compliance Method:
This emission limitation reflects the emissions unit's potential to emit. Compliance with this emission limitation may be demonstrated through the emission factors and equations found in Table 2.3 of the technical support document submitted 8/25/89 for PSD Permit to Install 14-1905. The NOx emission factor in Table 2.3 of Permit to Install 14-1905 is 0.43 gram of NOx per second when burning LPG.

If required, the permittee shall demonstrate compliance with this emission limitation through emission tests performed in accordance with 40 CFR Part 60, Appendix A, Methods 1 through 4 and 7. Alternate U.S. EPA-approved test methods may be used with prior approval from the Ohio EPA.

V. Testing Requirements (continued)

3. Emission Limitation:
CO emissions shall not exceed 3.1 lbs/1000 gallons of LPG burned.

Applicable Compliance Method:
This emission limitation reflects the emissions unit's potential to emit. Compliance with this emission limitation may be demonstrated through the emission factors and equations found in Table 2.3 of the technical support document submitted 8/25/89 for PSD permit 14-1905. The CO emission factor in Table 2.3 of Permit to Install 14-1905 is 0.108 gram of CO per second when burning LPG.

If required, the permittee shall demonstrate compliance with this emission limitation through emission tests performed in accordance with 40 CFR Part 60, Appendix A, Methods 1 through 4 and 10. Alternate U.S. EPA-approved test methods may be used with prior approval from the Ohio EPA.

4. Emission Limitation:
VOC emissions shall not exceed 0.25 lb/1000 gallons of LPG burned.

Applicable Compliance Method:
This emission limitation reflects the emissions unit's potential to emit. Compliance with this emission limitation may be demonstrated through the emission factors and equations found in Table 2.3 of the technical support document submitted 8/25/89 for PSD permit 14-1905. The VOC emission factor in Table 2.3 of Permit to Install 14-1905 is 0.009 gram of VOC per second when burning LPG.

If required, the permittee shall demonstrate compliance with this emission limitation through emission tests performed in accordance with 40 CFR Part 60, Appendix A, Methods 1 through 4 and 25. Alternate U.S. EPA-approved test methods may be used with prior approval from the Ohio EPA.

5. Emission Limitation:
Visible particulate emissions shall not exceed 20% opacity as a 6-minute average, except as provided by rule.

Applicable Compliance Method:
If required, compliance with this emission limitation shall be demonstrated through visible emissions observations performed in accordance with 40 CFR Part 60, Appendix A, Method 9 and the procedures specified in OAC rule 3745-17-03(B)(1).

VI. Miscellaneous Requirements

None

B. State Enforceable Section

I. Applicable Emissions Limitations and/or Control Requirements

1. The specific operation(s), property, and/or equipment which constitute this emissions unit are listed in the following table along with the applicable rules and/or requirements and with the applicable emissions limitations and/or control measures. Emissions from this unit shall not exceed the listed limitations, and the listed control measures shall be employed. Additional applicable emissions limitations and/or control measures (if any) may be specified in narrative form following the table.

Operations, Property, and/or Equipment	Applicable Rules/ Requirements	Applicable Emissions Limitations/Control Measures

2. Additional Terms and Conditions

None

II. Operational Restrictions

None

III. Monitoring and/or Record Keeping Requirements

None

IV. Reporting Requirements

None

V. Testing Requirements

None

VI. Miscellaneous Requirements

None

Part III - Terms and Conditions for Emissions Units

Emissions Unit ID: Vaporizing Boiler # 2 (B014)

Activity Description: Cleaver Brooks model CB 700-500 propane vaporizing boiler

A. State and Federally Enforceable Section

I. Applicable Emissions Limitations and/or Control Requirements

1. The specific operation(s), property, and/or equipment which constitute this emissions unit are listed in the following table along with the applicable rules and/or requirements and with the applicable emissions limitations and/or control measures. Emissions from this unit shall not exceed the listed limitations, and the listed control measures shall be employed. Additional applicable emissions limitations and/or control measures (if any) may be specified in narrative form following the table.

Operations, Property, and/or Equipment	Applicable Rules/ Requirements	Applicable Emissions Limitations/Control Measures
21 MMBtu/hr liquid petroleum gas (LPG)-fired vaporizing boiler (non-steam generating)	40 CFR Part 52.21 and OAC rules 3745-31-11 through 3745-31-20 (PTI 14-1905)	See A.I.2.a through A.I.2.f and A.II.3 below.
	OAC rule 3745-31-05(A)(3) (PTI 14-1905)	Compliance with this rule also includes compliance with 40 CFR Part 52.21, OAC rules 3745-31-11 through 3745-31-20, and OAC rule 3745-17-07(A). See A.II.1 below.
	OAC rule 3745-17-07(A)	Visible particulate emissions shall not exceed 20% opacity as a 6-minute average, except as provided by rule.
	OAC rule 3745-17-10(B)	The particulate emission limitation specified in OAC rule 3745-17-10(B) is less stringent than the particulate emission limitation established in PTI 14-1905 pursuant to 40 CFR Part 52.21.
	OAC rules 3745-21-08(B) and 3745-23-06(B)	See A.I.2.g below.

2. Additional Terms and Conditions

2.a Particulate Emission Limitation:

i. Emissions of particulates and particulates less than 10 microns in diameter (PE/PM10) shall not exceed 0.27 lb/1000 gallons of LPG burned.

ii. Best available control technology (BACT) for the PE/PM10 emissions from this emissions unit was determined to be burner design, combustion control, and the use of LPG fuel.

2. Additional Terms and Conditions (continued)

2.b Nitrogen Oxides (NOx) Emission Limitation:

i. NOx emissions shall not exceed 12.4 lbs/1000 gallons of LPG burned.

ii. BACT for the NOx emissions from this emissions unit was determined to be a low NOx burner design.

2.c Carbon Monoxide (CO) Emission Limitation:

i. CO emissions shall not exceed 3.1 lbs/1000 gallons of LPG burned.

ii. BACT for the CO emissions from this emissions unit was determined to be burner design, combustion control, and the use of LPG fuel.

2.d Volatile Organic Compound (VOC) Emission Limitation:

i. VOC emissions shall not exceed 0.25 lb/1000 gallons of LPG burned.

ii. BACT for the VOC emissions from this emissions unit was determined to be burner design, combustion control, and the use of LPG fuel.

2.e Sulfur Dioxide (SO2) Emissions:

i. BACT for the SO2 emissions from this emissions unit was determined to be burner design, combustion control, and the use of LPG fuel.

ii. SO2 emission limitations were not established in PTI 14-1905 because emissions were negligible for this emissions unit.

2.f The pound(s) per 1000 gallons of LPG burned emission limitations established in PTI 14-1905 were based on the emissions unit's potentials to emit. Therefore, it is not necessary to develop any additional monitoring, record keeping or reporting requirements to ensure compliance with these emission limitations.

2.g The permittee has satisfied the "best available control techniques and operating practices" required pursuant to OAC rule 3745-21-08(B) by committing to comply with the best available control technology requirements established pursuant to 40 CFR Part 52.21 in Permit to Install 14-1905.

On November 5, 2002, OAC rule 3745-21-08 was revised to delete paragraph (B); therefore, paragraph (B) is no longer part of the State regulations. However, that rule revision has not yet been submitted to the U.S. EPA as a revision to Ohio's State Implementation Plan (SIP). Therefore, until the SIP revision occurs and the U.S. EPA approves the revisions to OAC rule 3745-21-08, the requirement to satisfy the "best available control techniques and operating practices" still exists as part of the federally-approved SIP for Ohio.

The permittee has satisfied the "latest available control techniques and operating practices" required pursuant to OAC rule 3745-23-06(B) by committing to comply with the best available control technology requirements established pursuant to 40 CFR Part 52.21 in Permit to Install 14-1905.

II. Operational Restrictions

1. The minimum stack height for this emissions unit shall be at least 80 feet above the ground.

2. The permittee shall burn only LPG in this emissions unit.

3. The total combined amount of LPG burned in emissions units B013 through B018 shall not exceed 4.9 million gallons per rolling, 12-month period.

III. Monitoring and/or Record Keeping Requirements

1. For each day during which the permittee burns a fuel other than LPG, the permittee shall maintain a record of the type and quantity of fuel burned in this emissions unit.

2. The permittee shall collect and record the following information on a monthly basis:

a. The total combined amount of LPG gas burned in emissions units B013 through B018.

b. The rolling, 12-month summation of the total combined amount of LPG gas burned in emissions units B013 through B018 (the summation of the current month's total combined amount of LPG gas burned recorded in line 2.a, added to the previous 11 months total combined amount of LPG gas burned).

IV. Reporting Requirements

1. The permittee shall submit quarterly deviation (excursion) reports that identify the following:

a. each day when a fuel other than LPG was burned in this emissions unit; and

b. any monthly record which shows an exceedance of the LPG usage restriction specified in Section A.II.3.

The quarterly deviation reports shall be submitted in accordance with the reporting requirements specified in Part I - General Term and Condition A.1.c.ii.

V. Testing Requirements

1. Emission Limitation:
PE/PM10 shall not exceed 0.27 lb/1000 gallons of LPG burned.

Applicable Compliance Method:
This emission limitation reflects the emissions unit's potential to emit. Compliance with this emission limitation may be demonstrated through the emission factors and equations found in Table 2.3 of the technical support document submitted 8/25/89 for PSD Permit to Install 14-1905. The PE/PM10 emission factor in Table 2.3 of Permit to Install 14-1905 is 0.015 gram of PE/PM10 per second when burning LPG.

If required, the permittee shall demonstrate compliance with this emission limitation through emission tests performed in accordance with 40 CFR Part 60, Appendix A, Methods 1 through 5. Alternate U.S. EPA-approved test methods may be used with prior approval from the Ohio EPA.

2. Emission Limitation:
NOx emissions shall not exceed 12.4 lbs/1000 gallons of LPG burned.

Applicable Compliance Method:
This emission limitation reflects the emissions unit's potential to emit. Compliance with this emission limitation may be demonstrated through the emission factors and equations found in Table 2.3 of the technical support document submitted 8/25/89 for PSD Permit to Install 14-1905. The NOx emission factor in Table 2.3 of Permit to Install 14-1905 is 0.43 gram of NOx per second when burning LPG.

If required, the permittee shall demonstrate compliance with this emission limitation through emission tests performed in accordance with 40 CFR Part 60, Appendix A, Methods 1 through 4 and 7. Alternate U.S. EPA-approved test methods may be used with prior approval from the Ohio EPA.

V. Testing Requirements (continued)

3. Emission Limitation:
CO emissions shall not exceed 3.1 lbs/1000 gallons of LPG burned.

Applicable Compliance Method:
This emission limitation reflects the emissions unit's potential to emit. Compliance with this emission limitation may be demonstrated through the emission factors and equations found in Table 2.3 of the technical support document submitted 8/25/89 for PSD permit 14-1905. The CO emission factor in Table 2.3 of Permit to Install 14-1905 is 0.108 gram of CO per second when burning LPG.

If required, the permittee shall demonstrate compliance with this emission limitation through emission tests performed in accordance with 40 CFR Part 60, Appendix A, Methods 1 through 4 and 10. Alternate U.S. EPA-approved test methods may be used with prior approval from the Ohio EPA.

4. Emission Limitation:
VOC emissions shall not exceed 0.25 lb/1000 gallons of LPG burned.

Applicable Compliance Method:
This emission limitation reflects the emissions unit's potential to emit. Compliance with this emission limitation may be demonstrated through the emission factors and equations found in Table 2.3 of the technical support document submitted 8/25/89 for PSD permit 14-1905. The VOC emission factor in Table 2.3 of Permit to Install 14-1905 is 0.009 gram of VOC per second when burning LPG.

If required, the permittee shall demonstrate compliance with this emission limitation through emission tests performed in accordance with 40 CFR Part 60, Appendix A, Methods 1 through 4 and 25. Alternate U.S. EPA-approved test methods may be used with prior approval from the Ohio EPA.

5. Emission Limitation:
Visible particulate emissions shall not exceed 20% opacity as a 6-minute average, except as provided by rule.

Applicable Compliance Method:
If required, compliance with this emission limitation shall be demonstrated through visible emissions observations performed in accordance with 40 CFR Part 60, Appendix A, Method 9 and the procedures specified in OAC rule 3745-17-03(B)(1).

VI. Miscellaneous Requirements

None

B. State Enforceable Section

I. Applicable Emissions Limitations and/or Control Requirements

1. The specific operation(s), property, and/or equipment which constitute this emissions unit are listed in the following table along with the applicable rules and/or requirements and with the applicable emissions limitations and/or control measures. Emissions from this unit shall not exceed the listed limitations, and the listed control measures shall be employed. Additional applicable emissions limitations and/or control measures (if any) may be specified in narrative form following the table.

Operations, Property, and/or Equipment	Applicable Rules/ Requirements	Applicable Emissions Limitations/Control Measures

2. Additional Terms and Conditions

None

II. Operational Restrictions

None

III. Monitoring and/or Record Keeping Requirements

None

IV. Reporting Requirements

None

V. Testing Requirements

None

VI. Miscellaneous Requirements

None

Part III - Terms and Conditions for Emissions Units

Emissions Unit ID: Vaporizing Boiler # 3 (B015)

Activity Description: Cleaver Brooks model CB 700-500 propane vaporizing boiler

A. State and Federally Enforceable Section

I. Applicable Emissions Limitations and/or Control Requirements

1. The specific operation(s), property, and/or equipment which constitute this emissions unit are listed in the following table along with the applicable rules and/or requirements and with the applicable emissions limitations and/or control measures. Emissions from this unit shall not exceed the listed limitations, and the listed control measures shall be employed. Additional applicable emissions limitations and/or control measures (if any) may be specified in narrative form following the table.

Operations, Property, and/or Equipment	Applicable Rules/ Requirements	Applicable Emissions Limitations/Control Measures
21 MMBtu/hr liquid petroleum gas (LPG)-fired vaporizing boiler (non-steam generating)	40 CFR Part 52.21 and OAC rules 3745-31-11 through 3745-31-20 (PTI 14-1905)	See A.I.2.a through A.I.2.f and A.II.3 below.
	OAC rule 3745-31-05(A)(3) (PTI 14-1905)	Compliance with this rule also includes compliance with 40 CFR Part 52.21, OAC rules 3745-31-11 through 3745-31-20, and OAC rule 3745-17-07(A). See A.II.1 below.
	OAC rule 3745-17-07(A)	Visible particulate emissions shall not exceed 20% opacity as a 6-minute average, except as provided by rule.
	OAC rule 3745-17-10(B)	The particulate emission limitation specified in OAC rule 3745-17-10(B) is less stringent than the particulate emission limitation established in PTI 14-1905 pursuant to 40 CFR Part 52.21.
	OAC rules 3745-21-08(B) and 3745-23-06(B)	See A.I.2.g below.

2. Additional Terms and Conditions

2.a Particulate Emission Limitation:

i. Emissions of particulates and particulates less than 10 microns in diameter (PE/PM10) shall not exceed 0.27 lb/1000 gallons of LPG burned.

ii. Best available control technology (BACT) for the PE/PM10 emissions from this emissions unit was determined to be burner design, combustion control, and the use of LPG fuel.

2. Additional Terms and Conditions (continued)

2.b Nitrogen Oxides (NOx) Emission Limitation:

i. NOx emissions shall not exceed 12.4 lbs/1000 gallons of LPG burned.

ii. BACT for the NOx emissions from this emissions unit was determined to be a low NOx burner design.

2.c Carbon Monoxide (CO) Emission Limitation:

i. CO emissions shall not exceed 3.1 lbs/1000 gallons of LPG burned.

ii. BACT for the CO emissions from this emissions unit was determined to be burner design, combustion control, and the use of LPG fuel.

2.d Volatile Organic Compound (VOC) Emission Limitation:

i. VOC emissions shall not exceed 0.25 lb/1000 gallons of LPG burned.

ii. BACT for the VOC emissions from this emissions unit was determined to be burner design, combustion control, and the use of LPG fuel.

2.e Sulfur Dioxide (SO2) Emissions:

i. BACT for the SO2 emissions from this emissions unit was determined to be burner design, combustion control, and the use of LPG fuel.

ii. SO2 emission limitations were not established in PTI 14-1905 because emissions were negligible for this emissions unit.

2.f The pound(s) per 1000 gallons of LPG burned emission limitations established in PTI 14-1905 were based on the emissions unit's potentials to emit. Therefore, it is not necessary to develop any additional monitoring, record keeping or reporting requirements to ensure compliance with these emission limitations.

2.g The permittee has satisfied the "best available control techniques and operating practices" required pursuant to OAC rule 3745-21-08(B) by committing to comply with the best available control technology requirements established pursuant to 40 CFR Part 52.21 in Permit to Install 14-1905.

On November 5, 2002, OAC rule 3745-21-08 was revised to delete paragraph (B); therefore, paragraph (B) is no longer part of the State regulations. However, that rule revision has not yet been submitted to the U.S. EPA as a revision to Ohio's State Implementation Plan (SIP). Therefore, until the SIP revision occurs and the U.S. EPA approves the revisions to OAC rule 3745-21-08, the requirement to satisfy the "best available control techniques and operating practices" still exists as part of the federally-approved SIP for Ohio.

The permittee has satisfied the "latest available control techniques and operating practices" required pursuant to OAC rule 3745-23-06(B) by committing to comply with the best available control technology requirements established pursuant to 40 CFR Part 52.21 in Permit to Install 14-1905.

II. Operational Restrictions

1. The minimum stack height for this emissions unit shall be at least 80 feet above the ground.

2. The permittee shall burn only LPG in this emissions unit.

3. The total combined amount of LPG burned in emissions units B013 through B018 shall not exceed 4.9 million gallons per rolling, 12-month period.

III. Monitoring and/or Record Keeping Requirements

1. For each day during which the permittee burns a fuel other than LPG, the permittee shall maintain a record of the type and quantity of fuel burned in this emissions unit.

2. The permittee shall collect and record the following information on a monthly basis:

a. The total combined amount of LPG gas burned in emissions units B013 through B018.

b. The rolling, 12-month summation of the total combined amount of LPG gas burned in emissions units B013 through B018 (the summation of the current month's total combined amount of LPG gas burned recorded in line 2.a, added to the previous 11 months total combined amount of LPG gas burned).

IV. Reporting Requirements

1. The permittee shall submit quarterly deviation (excursion) reports that identify the following:

a. each day when a fuel other than LPG was burned in this emissions unit; and

b. any monthly record which shows an exceedance of the LPG usage restriction specified in Section A.II.3.

The quarterly deviation reports shall be submitted in accordance with the reporting requirements specified in Part I - General Term and Condition A.1.c.ii.

V. Testing Requirements

1. Emission Limitation:
PE/PM10 shall not exceed 0.27 lb/1000 gallons of LPG burned.

Applicable Compliance Method:
This emission limitation reflects the emissions unit's potential to emit. Compliance with this emission limitation may be demonstrated through the emission factors and equations found in Table 2.3 of the technical support document submitted 8/25/89 for PSD Permit to Install 14-1905. The PE/PM10 emission factor in Table 2.3 of Permit to Install 14-1905 is 0.015 gram of PE/PM10 per second when burning LPG.

If required, the permittee shall demonstrate compliance with this emission limitation through emission tests performed in accordance with 40 CFR Part 60, Appendix A, Methods 1 through 5. Alternate U.S. EPA-approved test methods may be used with prior approval from the Ohio EPA.

2. Emission Limitation:
NOx emissions shall not exceed 12.4 lbs/1000 gallons of LPG burned.

Applicable Compliance Method:
This emission limitation reflects the emissions unit's potential to emit. Compliance with this emission limitation may be demonstrated through the emission factors and equations found in Table 2.3 of the technical support document submitted 8/25/89 for PSD Permit to Install 14-1905. The NOx emission factor in Table 2.3 of Permit to Install 14-1905 is 0.43 gram of NOx per second when burning LPG.

If required, the permittee shall demonstrate compliance with this emission limitation through emission tests performed in accordance with 40 CFR Part 60, Appendix A, Methods 1 through 4 and 7. Alternate U.S. EPA-approved test methods may be used with prior approval from the Ohio EPA.

V. Testing Requirements (continued)

3. Emission Limitation:
CO emissions shall not exceed 3.1 lbs/1000 gallons of LPG burned.

Applicable Compliance Method:
This emission limitation reflects the emissions unit's potential to emit. Compliance with this emission limitation may be demonstrated through the emission factors and equations found in Table 2.3 of the technical support document submitted 8/25/89 for PSD permit 14-1905. The CO emission factor in Table 2.3 of Permit to Install 14-1905 is 0.108 gram of CO per second when burning LPG.

If required, the permittee shall demonstrate compliance with this emission limitation through emission tests performed in accordance with 40 CFR Part 60, Appendix A, Methods 1 through 4 and 10. Alternate U.S. EPA-approved test methods may be used with prior approval from the Ohio EPA.

4. Emission Limitation:
VOC emissions shall not exceed 0.25 lb/1000 gallons of LPG burned.

Applicable Compliance Method:
This emission limitation reflects the emissions unit's potential to emit. Compliance with this emission limitation may be demonstrated through the emission factors and equations found in Table 2.3 of the technical support document submitted 8/25/89 for PSD permit 14-1905. The VOC emission factor in Table 2.3 of Permit to Install 14-1905 is 0.009 gram of VOC per second when burning LPG.

If required, the permittee shall demonstrate compliance with this emission limitation through emission tests performed in accordance with 40 CFR Part 60, Appendix A, Methods 1 through 4 and 25. Alternate U.S. EPA-approved test methods may be used with prior approval from the Ohio EPA.

5. Emission Limitation:
Visible particulate emissions shall not exceed 20% opacity as a 6-minute average, except as provided by rule.

Applicable Compliance Method:
If required, compliance with this emission limitation shall be demonstrated through visible emissions observations performed in accordance with 40 CFR Part 60, Appendix A, Method 9 and the procedures specified in OAC rule 3745-17-03(B)(1).

VI. Miscellaneous Requirements

None

B. State Enforceable Section

I. Applicable Emissions Limitations and/or Control Requirements

1. The specific operation(s), property, and/or equipment which constitute this emissions unit are listed in the following table along with the applicable rules and/or requirements and with the applicable emissions limitations and/or control measures. Emissions from this unit shall not exceed the listed limitations, and the listed control measures shall be employed. Additional applicable emissions limitations and/or control measures (if any) may be specified in narrative form following the table.

Operations, Property, and/or Equipment	Applicable Rules/ Requirements	Applicable Emissions Limitations/Control Measures

2. Additional Terms and Conditions

None

II. Operational Restrictions

None

III. Monitoring and/or Record Keeping Requirements

None

IV. Reporting Requirements

None

V. Testing Requirements

None

VI. Miscellaneous Requirements

None

Part III - Terms and Conditions for Emissions Units

Emissions Unit ID: Vaporizing Boiler # 4 (B016)

Activity Description: Cleaver Brooks model CB 700-500 propane vaporizing boiler

A. State and Federally Enforceable Section

I. Applicable Emissions Limitations and/or Control Requirements

1. The specific operation(s), property, and/or equipment which constitute this emissions unit are listed in the following table along with the applicable rules and/or requirements and with the applicable emissions limitations and/or control measures. Emissions from this unit shall not exceed the listed limitations, and the listed control measures shall be employed. Additional applicable emissions limitations and/or control measures (if any) may be specified in narrative form following the table.

Operations, Property, and/or Equipment	Applicable Rules/ Requirements	Applicable Emissions Limitations/Control Measures
21 MMBtu/hr liquid petroleum gas (LPG)-fired vaporizing boiler (non-steam generating)	40 CFR Part 52.21 and OAC rules 3745-31-11 through 3745-31-20 (PTI 14-1905)	See A.I.2.a through A.I.2.f and A.II.3 below.
	OAC rule 3745-31-05(A)(3) (PTI 14-1905)	Compliance with this rule also includes compliance with 40 CFR Part 52.21, OAC rules 3745-31-11 through 3745-31-20, and OAC rule 3745-17-07(A). See A.II.1 below.
	OAC rule 3745-17-07(A)	Visible particulate emissions shall not exceed 20% opacity as a 6-minute average, except as provided by rule.
	OAC rule 3745-17-10(B)	The particulate emission limitation specified in OAC rule 3745-17-10(B) is less stringent than the particulate emission limitation established in PTI 14-1905 pursuant to 40 CFR Part 52.21.
	OAC rules 3745-21-08(B) and 3745-23-06(B)	See A.I.2.g below.

2. Additional Terms and Conditions

2.a Particulate Emission Limitation:

i. Emissions of particulates and particulates less than 10 microns in diameter (PE/PM10) shall not exceed 0.27 lb/1000 gallons of LPG burned.

ii. Best available control technology (BACT) for the PE/PM10 emissions from this emissions unit was determined to be burner design, combustion control, and the use of LPG fuel.

2. Additional Terms and Conditions (continued)

2.b Nitrogen Oxides (NOx) Emission Limitation:

i. NOx emissions shall not exceed 12.4 lbs/1000 gallons of LPG burned.

ii. BACT for the NOx emissions from this emissions unit was determined to be a low NOx burner design.

2.c Carbon Monoxide (CO) Emission Limitation:

i. CO emissions shall not exceed 3.1 lbs/1000 gallons of LPG burned.

ii. BACT for the CO emissions from this emissions unit was determined to be burner design, combustion control, and the use of LPG fuel.

2.d Volatile Organic Compound (VOC) Emission Limitation:

i. VOC emissions shall not exceed 0.25 lb/1000 gallons of LPG burned.

ii. BACT for the VOC emissions from this emissions unit was determined to be burner design, combustion control, and the use of LPG fuel.

2.e Sulfur Dioxide (SO2) Emissions:

i. BACT for the SO2 emissions from this emissions unit was determined to be burner design, combustion control, and the use of LPG fuel.

ii. SO2 emission limitations were not established in PTI 14-1905 because emissions were negligible for this emissions unit.

2.f The pound(s) per 1000 gallons of LPG burned emission limitations established in PTI 14-1905 were based on the emissions unit's potentials to emit. Therefore, it is not necessary to develop any additional monitoring, record keeping or reporting requirements to ensure compliance with these emission limitations.

2.g The permittee has satisfied the "best available control techniques and operating practices" required pursuant to OAC rule 3745-21-08(B) by committing to comply with the best available control technology requirements established pursuant to 40 CFR Part 52.21 in Permit to Install 14-1905.

On November 5, 2002, OAC rule 3745-21-08 was revised to delete paragraph (B); therefore, paragraph (B) is no longer part of the State regulations. However, that rule revision has not yet been submitted to the U.S. EPA as a revision to Ohio's State Implementation Plan (SIP). Therefore, until the SIP revision occurs and the U.S. EPA approves the revisions to OAC rule 3745-21-08, the requirement to satisfy the "best available control techniques and operating practices" still exists as part of the federally-approved SIP for Ohio.

The permittee has satisfied the "latest available control techniques and operating practices" required pursuant to OAC rule 3745-23-06(B) by committing to comply with the best available control technology requirements established pursuant to 40 CFR Part 52.21 in Permit to Install 14-1905.

II. Operational Restrictions

1. The minimum stack height for this emissions unit shall be at least 80 feet above the ground.

2. The permittee shall burn only LPG in this emissions unit.

3. The total combined amount of LPG burned in emissions units B013 through B018 shall not exceed 4.9 million gallons per rolling, 12-month period.

III. Monitoring and/or Record Keeping Requirements

1. For each day during which the permittee burns a fuel other than LPG, the permittee shall maintain a record of the type and quantity of fuel burned in this emissions unit.

2. The permittee shall collect and record the following information on a monthly basis:

a. The total combined amount of LPG gas burned in emissions units B013 through B018.

b. The rolling, 12-month summation of the total combined amount of LPG gas burned in emissions units B013 through B018 (the summation of the current month's total combined amount of LPG gas burned recorded in line 2.a, added to the previous 11 months total combined amount of LPG gas burned).

IV. Reporting Requirements

1. The permittee shall submit quarterly deviation (excursion) reports that identify the following:

a. each day when a fuel other than LPG was burned in this emissions unit; and

b. any monthly record which shows an exceedance of the LPG usage restriction specified in Section A.II.3.

The quarterly deviation reports shall be submitted in accordance with the reporting requirements specified in Part I - General Term and Condition A.1.c.ii.

V. Testing Requirements

1. Emission Limitation:
PE/PM10 shall not exceed 0.27 lb/1000 gallons of LPG burned.

Applicable Compliance Method:
This emission limitation reflects the emissions unit's potential to emit. Compliance with this emission limitation may be demonstrated through the emission factors and equations found in Table 2.3 of the technical support document submitted 8/25/89 for PSD Permit to Install 14-1905. The PE/PM10 emission factor in Table 2.3 of Permit to Install 14-1905 is 0.015 gram of PE/PM10 per second when burning LPG.

If required, the permittee shall demonstrate compliance with this emission limitation through emission tests performed in accordance with 40 CFR Part 60, Appendix A, Methods 1 through 5. Alternate U.S. EPA-approved test methods may be used with prior approval from the Ohio EPA.

2. Emission Limitation:
NOx emissions shall not exceed 12.4 lbs/1000 gallons of LPG burned.

Applicable Compliance Method:
This emission limitation reflects the emissions unit's potential to emit. Compliance with this emission limitation may be demonstrated through the emission factors and equations found in Table 2.3 of the technical support document submitted 8/25/89 for PSD Permit to Install 14-1905. The NOx emission factor in Table 2.3 of Permit to Install 14-1905 is 0.43 gram of NOx per second when burning LPG.

If required, the permittee shall demonstrate compliance with this emission limitation through emission tests performed in accordance with 40 CFR Part 60, Appendix A, Methods 1 through 4 and 7. Alternate U.S. EPA-approved test methods may be used with prior approval from the Ohio EPA.

V. Testing Requirements (continued)

3. Emission Limitation:
CO emissions shall not exceed 3.1 lbs/1000 gallons of LPG burned.

Applicable Compliance Method:
This emission limitation reflects the emissions unit's potential to emit. Compliance with this emission limitation may be demonstrated through the emission factors and equations found in Table 2.3 of the technical support document submitted 8/25/89 for PSD permit 14-1905. The CO emission factor in Table 2.3 of Permit to Install 14-1905 is 0.108 gram of CO per second when burning LPG.

If required, the permittee shall demonstrate compliance with this emission limitation through emission tests performed in accordance with 40 CFR Part 60, Appendix A, Methods 1 through 4 and 10. Alternate U.S. EPA-approved test methods may be used with prior approval from the Ohio EPA.

4. Emission Limitation:
VOC emissions shall not exceed 0.25 lb/1000 gallons of LPG burned.

Applicable Compliance Method:
This emission limitation reflects the emissions unit's potential to emit. Compliance with this emission limitation may be demonstrated through the emission factors and equations found in Table 2.3 of the technical support document submitted 8/25/89 for PSD permit 14-1905. The VOC emission factor in Table 2.3 of Permit to Install 14-1905 is 0.009 gram of VOC per second when burning LPG.

If required, the permittee shall demonstrate compliance with this emission limitation through emission tests performed in accordance with 40 CFR Part 60, Appendix A, Methods 1 through 4 and 25. Alternate U.S. EPA-approved test methods may be used with prior approval from the Ohio EPA.

5. Emission Limitation:
Visible particulate emissions shall not exceed 20% opacity as a 6-minute average, except as provided by rule.

Applicable Compliance Method:
If required, compliance with this emission limitation shall be demonstrated through visible emissions observations performed in accordance with 40 CFR Part 60, Appendix A, Method 9 and the procedures specified in OAC rule 3745-17-03(B)(1).

VI. Miscellaneous Requirements

None

B. State Enforceable Section

I. Applicable Emissions Limitations and/or Control Requirements

1. The specific operation(s), property, and/or equipment which constitute this emissions unit are listed in the following table along with the applicable rules and/or requirements and with the applicable emissions limitations and/or control measures. Emissions from this unit shall not exceed the listed limitations, and the listed control measures shall be employed. Additional applicable emissions limitations and/or control measures (if any) may be specified in narrative form following the table.

Operations, Property, and/or Equipment	Applicable Rules/ Requirements	Applicable Emissions Limitations/Control Measures

2. Additional Terms and Conditions

None

II. Operational Restrictions

None

III. Monitoring and/or Record Keeping Requirements

None

IV. Reporting Requirements

None

V. Testing Requirements

None

VI. Miscellaneous Requirements

None

Part III - Terms and Conditions for Emissions Units

Emissions Unit ID: Vaporizing Boiler # 5 (B017)

Activity Description: Cleaver Brooks model CB 700-500 propane vaporizing boiler

A. State and Federally Enforceable Section

I. Applicable Emissions Limitations and/or Control Requirements

1. The specific operation(s), property, and/or equipment which constitute this emissions unit are listed in the following table along with the applicable rules and/or requirements and with the applicable emissions limitations and/or control measures. Emissions from this unit shall not exceed the listed limitations, and the listed control measures shall be employed. Additional applicable emissions limitations and/or control measures (if any) may be specified in narrative form following the table.

Operations, Property, and/or Equipment	Applicable Rules/ Requirements	Applicable Emissions Limitations/Control Measures
21 MMBtu/hr liquid petroleum gas (LPG)-fired vaporizing boiler (non-steam generating)	40 CFR Part 52.21 and OAC rules 3745-31-11 through 3745-31-20 (PTI 14-1905)	See A.I.2.a through A.I.2.f and A.II.3 below.
	OAC rule 3745-31-05(A)(3) (PTI 14-1905)	Compliance with this rule also includes compliance with 40 CFR Part 52.21, OAC rules 3745-31-11 through 3745-31-20, and OAC rule 3745-17-07(A). See A.II.1 below.
	OAC rule 3745-17-07(A)	Visible particulate emissions shall not exceed 20% opacity as a 6-minute average, except as provided by rule.
	OAC rule 3745-17-10(B)	The particulate emission limitation specified in OAC rule 3745-17-10(B) is less stringent than the particulate emission limitation established in PTI 14-1905 pursuant to 40 CFR Part 52.21.
	OAC rules 3745-21-08(B) and 3745-23-06(B)	See A.I.2.g below.

2. Additional Terms and Conditions

2.a Particulate Emission Limitation:

i. Emissions of particulates and particulates less than 10 microns in diameter (PE/PM10) shall not exceed 0.27 lb/1000 gallons of LPG burned.

ii. Best available control technology (BACT) for the PE/PM10 emissions from this emissions unit was determined to be burner design, combustion control, and the use of LPG fuel.

2. Additional Terms and Conditions (continued)

2.b Nitrogen Oxides (NOx) Emission Limitation:

i. NOx emissions shall not exceed 12.4 lbs/1000 gallons of LPG burned.

ii. BACT for the NOx emissions from this emissions unit was determined to be a low NOx burner design.

2.c Carbon Monoxide (CO) Emission Limitation:

i. CO emissions shall not exceed 3.1 lbs/1000 gallons of LPG burned.

ii. BACT for the CO emissions from this emissions unit was determined to be burner design, combustion control, and the use of LPG fuel.

2.d Volatile Organic Compound (VOC) Emission Limitation:

i. VOC emissions shall not exceed 0.25 lb/1000 gallons of LPG burned.

ii. BACT for the VOC emissions from this emissions unit was determined to be burner design, combustion control, and the use of LPG fuel.

2.e Sulfur Dioxide (SO2) Emissions:

i. BACT for the SO2 emissions from this emissions unit was determined to be burner design, combustion control, and the use of LPG fuel.

ii. SO2 emission limitations were not established in PTI 14-1905 because emissions were negligible for this emissions unit.

2.f The pound(s) per 1000 gallons of LPG burned emission limitations established in PTI 14-1905 were based on the emissions unit's potentials to emit. Therefore, it is not necessary to develop any additional monitoring, record keeping or reporting requirements to ensure compliance with these emission limitations.

2.g The permittee has satisfied the "best available control techniques and operating practices" required pursuant to OAC rule 3745-21-08(B) by committing to comply with the best available control technology requirements established pursuant to 40 CFR Part 52.21 in Permit to Install 14-1905.

On November 5, 2002, OAC rule 3745-21-08 was revised to delete paragraph (B); therefore, paragraph (B) is no longer part of the State regulations. However, that rule revision has not yet been submitted to the U.S. EPA as a revision to Ohio's State Implementation Plan (SIP). Therefore, until the SIP revision occurs and the U.S. EPA approves the revisions to OAC rule 3745-21-08, the requirement to satisfy the "best available control techniques and operating practices" still exists as part of the federally-approved SIP for Ohio.

The permittee has satisfied the "latest available control techniques and operating practices" required pursuant to OAC rule 3745-23-06(B) by committing to comply with the best available control technology requirements established pursuant to 40 CFR Part 52.21 in Permit to Install 14-1905.

II. Operational Restrictions

1. The minimum stack height for this emissions unit shall be at least 80 feet above the ground.

2. The permittee shall burn only LPG in this emissions unit.

3. The total combined amount of LPG burned in emissions units B013 through B018 shall not exceed 4.9 million gallons per rolling, 12-month period.

III. Monitoring and/or Record Keeping Requirements

1. For each day during which the permittee burns a fuel other than LPG, the permittee shall maintain a record of the type and quantity of fuel burned in this emissions unit.

2. The permittee shall collect and record the following information on a monthly basis:

a. The total combined amount of LPG gas burned in emissions units B013 through B018.

b. The rolling, 12-month summation of the total combined amount of LPG gas burned in emissions units B013 through B018 (the summation of the current month's total combined amount of LPG gas burned recorded in line 2.a, added to the previous 11 months total combined amount of LPG gas burned).

IV. Reporting Requirements

1. The permittee shall submit quarterly deviation (excursion) reports that identify the following:

a. each day when a fuel other than LPG was burned in this emissions unit; and

b. any monthly record which shows an exceedance of the LPG usage restriction specified in Section A.II.3.

The quarterly deviation reports shall be submitted in accordance with the reporting requirements specified in Part I - General Term and Condition A.1.c.ii.

V. Testing Requirements

1. Emission Limitation:
PE/PM10 shall not exceed 0.27 lb/1000 gallons of LPG burned.

Applicable Compliance Method:
This emission limitation reflects the emissions unit's potential to emit. Compliance with this emission limitation may be demonstrated through the emission factors and equations found in Table 2.3 of the technical support document submitted 8/25/89 for PSD Permit to Install 14-1905. The PE/PM10 emission factor in Table 2.3 of Permit to Install 14-1905 is 0.015 gram of PE/PM10 per second when burning LPG.

If required, the permittee shall demonstrate compliance with this emission limitation through emission tests performed in accordance with 40 CFR Part 60, Appendix A, Methods 1 through 5. Alternate U.S. EPA-approved test methods may be used with prior approval from the Ohio EPA.

2. Emission Limitation:
NOx emissions shall not exceed 12.4 lbs/1000 gallons of LPG burned.

Applicable Compliance Method:
This emission limitation reflects the emissions unit's potential to emit. Compliance with this emission limitation may be demonstrated through the emission factors and equations found in Table 2.3 of the technical support document submitted 8/25/89 for PSD Permit to Install 14-1905. The NOx emission factor in Table 2.3 of Permit to Install 14-1905 is 0.43 gram of NOx per second when burning LPG.

If required, the permittee shall demonstrate compliance with this emission limitation through emission tests performed in accordance with 40 CFR Part 60, Appendix A, Methods 1 through 4 and 7. Alternate U.S. EPA-approved test methods may be used with prior approval from the Ohio EPA.

V. Testing Requirements (continued)

3. Emission Limitation:
CO emissions shall not exceed 3.1 lbs/1000 gallons of LPG burned.

Applicable Compliance Method:
This emission limitation reflects the emissions unit's potential to emit. Compliance with this emission limitation may be demonstrated through the emission factors and equations found in Table 2.3 of the technical support document submitted 8/25/89 for PSD permit 14-1905. The CO emission factor in Table 2.3 of Permit to Install 14-1905 is 0.108 gram of CO per second when burning LPG.

If required, the permittee shall demonstrate compliance with this emission limitation through emission tests performed in accordance with 40 CFR Part 60, Appendix A, Methods 1 through 4 and 10. Alternate U.S. EPA-approved test methods may be used with prior approval from the Ohio EPA.

4. Emission Limitation:
VOC emissions shall not exceed 0.25 lb/1000 gallons of LPG burned.

Applicable Compliance Method:
This emission limitation reflects the emissions unit's potential to emit. Compliance with this emission limitation may be demonstrated through the emission factors and equations found in Table 2.3 of the technical support document submitted 8/25/89 for PSD permit 14-1905. The VOC emission factor in Table 2.3 of Permit to Install 14-1905 is 0.009 gram of VOC per second when burning LPG.

If required, the permittee shall demonstrate compliance with this emission limitation through emission tests performed in accordance with 40 CFR Part 60, Appendix A, Methods 1 through 4 and 25. Alternate U.S. EPA-approved test methods may be used with prior approval from the Ohio EPA.

5. Emission Limitation:
Visible particulate emissions shall not exceed 20% opacity as a 6-minute average, except as provided by rule.

Applicable Compliance Method:
If required, compliance with this emission limitation shall be demonstrated through visible emissions observations performed in accordance with 40 CFR Part 60, Appendix A, Method 9 and the procedures specified in OAC rule 3745-17-03(B)(1).

VI. Miscellaneous Requirements

None

B. State Enforceable Section

I. Applicable Emissions Limitations and/or Control Requirements

1. The specific operation(s), property, and/or equipment which constitute this emissions unit are listed in the following table along with the applicable rules and/or requirements and with the applicable emissions limitations and/or control measures. Emissions from this unit shall not exceed the listed limitations, and the listed control measures shall be employed. Additional applicable emissions limitations and/or control measures (if any) may be specified in narrative form following the table.

Operations, Property, and/or Equipment	Applicable Rules/ Requirements	Applicable Emissions Limitations/Control Measures

2. Additional Terms and Conditions

None

II. Operational Restrictions

None

III. Monitoring and/or Record Keeping Requirements

None

IV. Reporting Requirements

None

V. Testing Requirements

None

VI. Miscellaneous Requirements

None

Part III - Terms and Conditions for Emissions Units

Emissions Unit ID: Vaporizing Boiler # 6 (B018)

Activity Description: Cleaver Brooks model CB 700-500 propane vaporizing boiler

A. State and Federally Enforceable Section

I. Applicable Emissions Limitations and/or Control Requirements

1. The specific operation(s), property, and/or equipment which constitute this emissions unit are listed in the following table along with the applicable rules and/or requirements and with the applicable emissions limitations and/or control measures. Emissions from this unit shall not exceed the listed limitations, and the listed control measures shall be employed. Additional applicable emissions limitations and/or control measures (if any) may be specified in narrative form following the table.

Operations, Property, and/or Equipment	Applicable Rules/ Requirements	Applicable Emissions Limitations/Control Measures
21 MMBtu/hr liquid petroleum gas (LPG)-fired vaporizing boiler (non-steam generating)	40 CFR Part 52.21 and OAC rules 3745-31-11 through 3745-31-20 (PTI 14-1905)	See A.I.2.a through A.I.2.f and A.II.3 below.
	OAC rule 3745-31-05(A)(3) (PTI 14-1905)	Compliance with this rule also includes compliance with 40 CFR Part 52.21, OAC rules 3745-31-11 through 3745-31-20, and OAC rule 3745-17-07(A). See A.II.1 below.
	OAC rule 3745-17-07(A)	Visible particulate emissions shall not exceed 20% opacity as a 6-minute average, except as provided by rule.
	OAC rule 3745-17-10(B)	The particulate emission limitation specified in OAC rule 3745-17-10(B) is less stringent than the particulate emission limitation established in PTI 14-1905 pursuant to 40 CFR Part 52.21.
	OAC rules 3745-21-08(B) and 3745-23-06(B)	See A.I.2.g below.

2. Additional Terms and Conditions

2.a Particulate Emission Limitation:

i. Emissions of particulates and particulates less than 10 microns in diameter (PE/PM10) shall not exceed 0.27 lb/1000 gallons of LPG burned.

ii. Best available control technology (BACT) for the PE/PM10 emissions from this emissions unit was determined to be burner design, combustion control, and the use of LPG fuel.

2. Additional Terms and Conditions (continued)

2.b Nitrogen Oxides (NOx) Emission Limitation:

i. NOx emissions shall not exceed 12.4 lbs/1000 gallons of LPG burned.

ii. BACT for the NOx emissions from this emissions unit was determined to be a low NOx burner design.

2.c Carbon Monoxide (CO) Emission Limitation:

i. CO emissions shall not exceed 3.1 lbs/1000 gallons of LPG burned.

ii. BACT for the CO emissions from this emissions unit was determined to be burner design, combustion control, and the use of LPG fuel.

2.d Volatile Organic Compound (VOC) Emission Limitation:

i. VOC emissions shall not exceed 0.25 lb/1000 gallons of LPG burned.

ii. BACT for the VOC emissions from this emissions unit was determined to be burner design, combustion control, and the use of LPG fuel.

2.e Sulfur Dioxide (SO2) Emissions:

i. BACT for the SO2 emissions from this emissions unit was determined to be burner design, combustion control, and the use of LPG fuel.

ii. SO2 emission limitations were not established in PTI 14-1905 because emissions were negligible for this emissions unit.

2.f The pound(s) per 1000 gallons of LPG burned emission limitations established in PTI 14-1905 were based on the emissions unit's potentials to emit. Therefore, it is not necessary to develop any additional monitoring, record keeping or reporting requirements to ensure compliance with these emission limitations.

2.g The permittee has satisfied the "best available control techniques and operating practices" required pursuant to OAC rule 3745-21-08(B) by committing to comply with the best available control technology requirements established pursuant to 40 CFR Part 52.21 in Permit to Install 14-1905.

On November 5, 2002, OAC rule 3745-21-08 was revised to delete paragraph (B); therefore, paragraph (B) is no longer part of the State regulations. However, that rule revision has not yet been submitted to the U.S. EPA as a revision to Ohio's State Implementation Plan (SIP). Therefore, until the SIP revision occurs and the U.S. EPA approves the revisions to OAC rule 3745-21-08, the requirement to satisfy the "best available control techniques and operating practices" still exists as part of the federally-approved SIP for Ohio.

The permittee has satisfied the "latest available control techniques and operating practices" required pursuant to OAC rule 3745-23-06(B) by committing to comply with the best available control technology requirements established pursuant to 40 CFR Part 52.21 in Permit to Install 14-1905.

II. Operational Restrictions

1. The minimum stack height for this emissions unit shall be at least 80 feet above the ground.

2. The permittee shall burn only LPG in this emissions unit.

3. The total combined amount of LPG burned in emissions units B013 through B018 shall not exceed 4.9 million gallons per rolling, 12-month period.

III. Monitoring and/or Record Keeping Requirements

1. For each day during which the permittee burns a fuel other than LPG, the permittee shall maintain a record of the type and quantity of fuel burned in this emissions unit.

2. The permittee shall collect and record the following information on a monthly basis:

a. The total combined amount of LPG gas burned in emissions units B013 through B018.

b. The rolling, 12-month summation of the total combined amount of LPG gas burned in emissions units B013 through B018 (the summation of the current month's total combined amount of LPG gas burned recorded in line 2.a, added to the previous 11 months total combined amount of LPG gas burned).

IV. Reporting Requirements

1. The permittee shall submit quarterly deviation (excursion) reports that identify the following:

a. each day when a fuel other than LPG was burned in this emissions unit; and

b. any monthly record which shows an exceedance of the LPG usage restriction specified in Section A.II.3.

The quarterly deviation reports shall be submitted in accordance with the reporting requirements specified in Part I - General Term and Condition A.1.c.ii.

V. Testing Requirements

1. Emission Limitation:
PE/PM10 shall not exceed 0.27 lb/1000 gallons of LPG burned.

Applicable Compliance Method:
This emission limitation reflects the emissions unit's potential to emit. Compliance with this emission limitation may be demonstrated through the emission factors and equations found in Table 2.3 of the technical support document submitted 8/25/89 for PSD Permit to Install 14-1905. The PE/PM10 emission factor in Table 2.3 of Permit to Install 14-1905 is 0.015 gram of PE/PM10 per second when burning LPG.

If required, the permittee shall demonstrate compliance with this emission limitation through emission tests performed in accordance with 40 CFR Part 60, Appendix A, Methods 1 through 5. Alternate U.S. EPA-approved test methods may be used with prior approval from the Ohio EPA.

2. Emission Limitation:
NOx emissions shall not exceed 12.4 lbs/1000 gallons of LPG burned.

Applicable Compliance Method:
This emission limitation reflects the emissions unit's potential to emit. Compliance with this emission limitation may be demonstrated through the emission factors and equations found in Table 2.3 of the technical support document submitted 8/25/89 for PSD Permit to Install 14-1905. The NOx emission factor in Table 2.3 of Permit to Install 14-1905 is 0.43 gram of NOx per second when burning LPG.

If required, the permittee shall demonstrate compliance with this emission limitation through emission tests performed in accordance with 40 CFR Part 60, Appendix A, Methods 1 through 4 and 7. Alternate U.S. EPA-approved test methods may be used with prior approval from the Ohio EPA.

V. Testing Requirements (continued)

3. Emission Limitation:
CO emissions shall not exceed 3.1 lbs/1000 gallons of LPG burned.

Applicable Compliance Method:
This emission limitation reflects the emissions unit's potential to emit. Compliance with this emission limitation may be demonstrated through the emission factors and equations found in Table 2.3 of the technical support document submitted 8/25/89 for PSD permit 14-1905. The CO emission factor in Table 2.3 of Permit to Install 14-1905 is 0.108 gram of CO per second when burning LPG.

If required, the permittee shall demonstrate compliance with this emission limitation through emission tests performed in accordance with 40 CFR Part 60, Appendix A, Methods 1 through 4 and 10. Alternate U.S. EPA-approved test methods may be used with prior approval from the Ohio EPA.

4. Emission Limitation:
VOC emissions shall not exceed 0.25 lb/1000 gallons of LPG burned.

Applicable Compliance Method:
This emission limitation reflects the emissions unit's potential to emit. Compliance with this emission limitation may be demonstrated through the emission factors and equations found in Table 2.3 of the technical support document submitted 8/25/89 for PSD permit 14-1905. The VOC emission factor in Table 2.3 of Permit to Install 14-1905 is 0.009 gram of VOC per second when burning LPG.

If required, the permittee shall demonstrate compliance with this emission limitation through emission tests performed in accordance with 40 CFR Part 60, Appendix A, Methods 1 through 4 and 25. Alternate U.S. EPA-approved test methods may be used with prior approval from the Ohio EPA.

5. Emission Limitation:
Visible particulate emissions shall not exceed 20% opacity as a 6-minute average, except as provided by rule.

Applicable Compliance Method:
If required, compliance with this emission limitation shall be demonstrated through visible emissions observations performed in accordance with 40 CFR Part 60, Appendix A, Method 9 and the procedures specified in OAC rule 3745-17-03(B)(1).

VI. Miscellaneous Requirements

None

B. State Enforceable Section

I. Applicable Emissions Limitations and/or Control Requirements

1. The specific operation(s), property, and/or equipment which constitute this emissions unit are listed in the following table along with the applicable rules and/or requirements and with the applicable emissions limitations and/or control measures. Emissions from this unit shall not exceed the listed limitations, and the listed control measures shall be employed. Additional applicable emissions limitations and/or control measures (if any) may be specified in narrative form following the table.

Operations, Property, and/or Equipment	Applicable Rules/ Requirements	Applicable Emissions Limitations/Control Measures

2. Additional Terms and Conditions

None

II. Operational Restrictions

None

III. Monitoring and/or Record Keeping Requirements

None

IV. Reporting Requirements

None

V. Testing Requirements

None

VI. Miscellaneous Requirements

None

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6560-50-P

ENVIRONMENTAL PROTECTION AGENCY

40 CFR Part 63

[OAR-2002-0058; FRL-]

RIN 2060-AG69

National Emission Standards for Hazardous Air Pollutants for Industrial, Commercial, and Institutional Boilers and Process Heaters

AGENCY: Environmental Protection Agency (EPA).

ACTION: Final rule.

SUMMARY: The EPA is promulgating national emission standards for hazardous air pollutants (NESHAP) for industrial, commercial, and institutional boilers and process heaters. The EPA has identified industrial, commercial, and institutional boilers and process heaters as major sources of hazardous air pollutants (HAP) emissions. The final rule will implement section 112(d) of the Clean Air Act (CAA) by requiring all major sources to meet HAP emissions standards reflecting the application of the maximum achievable control technology (MACT). The final rule is expected to reduce HAP emissions by 50,600 to 58,000 tons per year (tpy).

The HAP emitted by facilities in the boiler and process heater source category include arsenic, cadmium, chromium, hydrogen chloride (HCl), hydrogen fluoride, lead, manganese,

mercury, nickel, and various organic HAP. Exposure to these substances has been demonstrated to cause adverse health effects such as irritation to the lung, skin, and mucus membranes, effects on the central nervous system, kidney damage, and cancer. These adverse health effects associated with the exposure to these specific HAP are further described in this preamble. In general, these findings only have been shown with concentrations higher than those typically in the ambient air.

The final rule contains numerous compliance provisions including health-based compliance alternatives for the hydrogen chloride and total selected metals emission limits.

EFFECTIVE DATE: [INSERT THE DATE 60 DAYS AFTER DATE OF PUBLICATION OF THE FINAL RULE IN THE FEDERAL REGISTER]

ADDRESSES: The official public docket is the collection of materials that is available for public viewing at the Office of Air and Radiation Docket and Information Center (Air Docket) in the EPA Docket Center, Room B-102, 1301 Constitution Avenue, NW, Washington, DC.

FOR FURTHER INFORMATION CONTACT: For information concerning applicability and rule determinations, contact your State or local representative or appropriate EPA Regional Office representative. For information concerning rule development, contact Jim Eddinger, Combustion Group,

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Emission Standards Division (C439-01), U.S. EPA, Research Triangle Park, North Carolina 27711, telephone number (919) 541-5426, fax number (919) 541-5450, electronic mail address eddinger.jim@epa.gov.

SUPPLEMENTARY INFORMATION: Regulated Entities. Categories and entities potentially regulated by this action include:

Category	NAICS Code	SIC Code	Examples of potentially regulated entities
Any industry using a boiler or process heater as defined in the final rule	211	13	Extractors of crude petroleum and natural gas
	321	24	Manufacturers of lumber and wood products
	322	26	Pulp and paper mills
	325	28	Chemical manufacturers
	324	29	Petroleum refineries, and manufacturers of coal products
	316, 326, 339	30	Manufacturers of rubber and miscellaneous plastic products
	331	33	Steel works, blast furnaces
	332	34	Electroplating, plating, polishing, anodizing, and coloring
	336	37	Manufacturers of motor vehicle parts and accessories
	221	49	Electric, gas, and sanitary services

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622	80	Health services
611	82	Educational services

This table is not intended to be exhaustive, but rather provides a guide for readers regarding entities likely to be regulated by this action. This table lists examples of the types of entities EPA is now aware could potentially be regulated by this action. Other types of entities not listed could also be affected. To determine whether your facility, company, business, organization, etc., is regulated by this action, you should examine the applicability criteria in §63.7485 of the final rule. If you have any questions regarding the applicability of this action to a particular entity, consult the person listed in the preceding FOR FURTHER INFORMATION CONTACT section.

Docket. The EPA has established an official public docket for this action under Docket ID No. OAR-2003-0058 and Docket ID No. A-96-47. The official public docket consists of the documents specifically referenced in this action, any public comments received, and other information related to this action. All items may not be listed under both docket numbers, so interested parties should inspect both docket numbers to ensure that they have received all materials relevant to the final rule. Although a part of the official docket, the public docket does not include Confidential

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Business Information (CBI) or other information whose disclosure is restricted by statute. The official public docket is the collection of materials that is available for public viewing at the Office of Air and Radiation Docket and Information Center (Air Docket) in the EPA Docket Center, Room B102, 1301 Constitution Ave., NW, Washington, DC. The EPA Docket Center Public Reading Room is open from 8:30 a.m. to 4:30 p.m., Monday through Friday, excluding legal holidays. The telephone number for the Reading Room is (202) 566-1744, and the telephone number for the Air and Radiation Docket is (202) 566-1742. A reasonable fee may be charged for copying docket materials.

Electronic Access. You may access this Federal Register document electronically through the EPA Internet under the "Federal Register" listings at http://www.epa.gov/fedrgstr/.

An electronic version of the public docket is available through EPA's electronic public docket and comment system, EPA Dockets. You may use EPA Dockets at http://www.epa.gov/edocket/ to view public comments, access the index listing of the contents of the official public docket, and to access those documents in the public docket that are available electronically. Once in the system, select "search," then key in the appropriate docket identification number.

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Worldwide Web (WWW). In addition to being available in the docket, an electronic copy of the final rule is also available on the WWW through the Technology Transfer Network (TTN). Following signature, a copy of the final rule will be posted on the TTN policy and guidance page for newly proposed or promulgated rules at the following address: http://www.epa.gov/ttn/oarpg. The TTN provides information and technology exchange in various areas of air pollution control. If more information regarding the TTN is needed, call the TTN HELP line at (919) 541-5384.

Judicial Review. Under section 307(b)(1) of the CAA, judicial review of the NESHAP is available by filing a petition for review in the U.S. Court of Appeals for the District of Columbia Circuit by [INSERT THE DATE 60 DAYS AFTER PUBLICATION OF THE FINAL RULE IN THE FEDERAL REGISTER]. Only those objections to the final rule that were raised with reasonable specificity during the period for public comment may be raised during judicial review. Under section 307(b)(2) of the CAA, the requirements that are the subject of the final rule may not be challenged later in civil or criminal proceedings brought by EPA to enforce these requirements.

Background Information Document. The EPA proposed the NESHAP for industrial, commercial, and institutional boilers

and process heaters on January 13, 2003 (68 FR 1660) and received 218 comment letters on the proposal. A memorandum "National Emission Standards for Hazardous Air Pollutants for Industrial, Commercial, and Institutional Boilers and Process Heaters, Summary of Public Comments and Responses," containing EPA's responses to each public comment is available in Docket No. OAR-2002-0058.

Outline. The information presented in this preamble is organized as follows:

I. Background Information
A. What is the statutory authority for the final rule?
B. What criteria are used in the development of NESHAP?
C. How was the final rule developed?
D. What is the relationship between the final rule and other combustion rules?
E. What are the health effects of pollutants emitted from industrial, commercial, and institutional boilers and process heaters?
II. Summary of the Final Rule
A. What source categories and subcategories are affected by the final rule?
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C. What pollutants are emitted and controlled?
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E. What are the emission limitations and work practice standards?
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G. What are the continuous compliance requirements?
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I. What are the health-based compliance alternatives and how do I demonstrate eligibility?
III. What are the significant changes since proposal?
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B. Sources Not Covered by the NESHAP
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Emission Limits or Work Practice Requirements
F. Carbon Monoxide Work Practice Emission Levels and Requirements
G. Fuel Analysis Option
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I. Opacity Limit
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IV. What are the responses to significant comments?
A. Applicability
B. Format
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E. MACT Floor
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V. Impacts of the Final Rule
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B. What are the water and solid waste impacts?
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F. What are the social costs and benefits of the final rule?
VI. Statutory and Executive Order Reviews
A. Executive Order 12866: Regulatory Planning and Review
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D. Unfunded Mandates Reform Act of 1995
E. Executive Order 13132: Federalism
F. Executive Order 13175: Consultation and Coordination with Indian Tribal Governments
G. Executive Order 13045: Protection of Children from Environmental Health Risks and Safety Risks
H. Executive Order 13211: Actions Concerning Regulations that Significantly Affect Energy Supply, Distribution, or Use
I. National Technology Transfer and Advancement Act
J. Congressional Review Act

I. Background Information

A. What is the statutory authority for the final rule?

Section 112 of the CAA requires us to list categories

and subcategories of major sources and area sources of HAP and to establish NESHAP for the listed source categories and subcategories. Industrial boilers, commercial and institutional boilers, and process heaters were listed on July 16, 1992 (57 FR 31576). Major sources of HAP are those that have the potential to emit greater than 10 tpy of any one HAP or 25 tpy of any combination of HAP.

B. What criteria are used in the development of NESHAP?

Section 112(c)(2) of the CAA requires that we establish NESHAP for control of HAP from both existing and new major sources, based upon the criteria set out in CAA section 112(d). The CAA requires the NESHAP to reflect the maximum degree of reduction in emissions of HAP that is achievable, taking into consideration the cost of achieving the emission reduction, any non-air quality health and environmental impacts, and energy requirements. This level of control is commonly referred to as the MACT.

The minimum control level allowed for NESHAP (the minimum level of stringency for MACT) is the "MACT floor," as defined under section 112(d)(3) of the CAA. The MACT floor for existing sources is the emission limitation achieved by the average of the best-performing 12 percent of existing sources for categories and subcategories with 30 or more sources, or the average of the best-performing five

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sources for categories or subcategories with fewer than 30 sources. For new sources, the MACT floor cannot be less stringent than the emission control achieved in practice by the best-controlled similar source.

C. How was the final rule developed?

We proposed standards for industrial, commercial, and institutional boilers and process heaters on January 13, 2003 (68 FR 1660). Public comments were solicited at the time of proposal. The public comment period lasted from January 13, 2003, to March 14, 2003.

We received a total of 218 public comment letters on the proposed rule. Comments were submitted by industry trade associations, owners/operators of boilers and process heaters, State regulatory agencies and their representatives, and environmental groups. Today's final rule reflects our consideration of all of the comments and additional information received. Major public comments on the proposed rules, along with our responses to those comments, are summarized in this preamble.

D. What is the relationship between the final rule and other combustion rules?

The final rule regulates source categories covering industrial boilers, institutional and commercial boilers, and process heaters. These source categories potentially

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include combustion units that are already regulated by other MACT standards. Therefore, we are excluding from the final rule any combustion units that are already or will be subject to regulation under another MACT standard under 40 CFR part 63.

Combustion units that are regulated by other standards and are therefore excluded from the final rule include solid waste incineration units covered by section 129 of the CAA; boilers or process heaters required to have a permit under section 3005 of the Solid Waste Disposal Act or covered by the hazardous waste combustor NESHAP in 40 CFR part 63, subpart EEE[1]; and recovery boilers or furnaces covered by 40 CFR part 63, subpart MM.

With regards to solid waste incineration units covered by section 129 of the CAA, EPA solicited on February 17, 2004 (69 FR 7390) public comments on the definition of "commercial and industrial solid waste incineration unit" for the purpose of determining which combustion sources to regulate under section 129 and which to regulate under section 112 (e.g., boilers and process heaters). As stated above, combustion units covered under section 129 are not subject to the final rule.

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[1]Please note that boilers that burn small quantities of hazardous waste under the exemptions provided by 40 CFR 266.108 are subject to today's final rule.

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Electric utility steam generating units are not subject to the final rule. An electric utility steam generating unit is a fossil fuel-fired combustion unit of more than 25 megawatts 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 megawatts electrical output to any utility power distribution system for sale is considered an electric utility steam generating unit. Non-fossil fuel-fired utility boilers and electric utility steam generating units less than 25 megawatts are covered by the final rule.

In 1986, EPA codified the NSPS for industrial boilers (40 CFR part 60, subparts Db and Dc) and revised portions of them in 1999. The NSPS regulates emissions of particulate matter (PM), sulfur dioxide, and nitrogen oxides from boilers constructed after June 19, 1984. Sources subject to the NSPS are also subject to the final rule because the final rule regulates sources of hazardous air pollutants while the NSPS does not. However, in developing the final rule for industrial, commercial, and institutional boilers and process heaters, EPA minimized the monitoring requirements, testing requirements, and recordkeeping requirements to avoid duplicating requirements.

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Because of the broad applicability of the final rule due to the definition of a process heater, certain process heaters could appear to fit the applicability of another existing MACT rule. We have, therefore, included in the list of combustion units not subject to the final rule refining kettles subject to the secondary lead MACT rule (40 CFR part 63, subpart X); ethylene cracking furnaces covered by 40 CFR part 63, subpart YY; and blast furnace stoves described in the EPA document entitled "National Emission Standards for Hazardous Air Pollutants for Integrated Iron and Steel Plants - Background Information for Proposed Standards" (EPA-453/R-01-005).

E. <u>What are the health effects of pollutants emitted from industrial, commercial, and institutional boilers and process heaters</u>?

The final rule protects air quality and promotes the public health by reducing emissions of some of the HAP listed in section 112(b)(1) of the CAA. As noted above, emissions data collected during development of the proposed rule show that HCl emissions represent the predominant HAP emitted by industrial boilers. Industrial boilers emit lesser amounts of hydrogen fluoride, chlorine, metals (arsenic, cadmium, chromium, mercury, manganese, nickel, and lead), and organic HAP emissions. Although numerous organic

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HAP may be emitted from industrial boilers and process heaters, only a few account for essentially all the mass of organic HAP emissions. These organic HAP are: formaldehyde, benzene, and acetaldehyde.

Exposure to high levels of these HAP is associated with a variety of adverse health effects. These adverse health effects include chronic health disorders (e.g., irritation of the lung, skin, and mucus membranes, effects on the central nervous system, and damage to the kidneys), and acute health disorders (e.g., lung irritation and congestion, alimentary effects such as nausea and vomiting, and effects on the kidney and central nervous system). We have classified three of the HAP as human carcinogens and five as probable human carcinogens. Our screening assessment for respiratory HAP and for central nervous system (CNS) HAP, using health protective assumptions, indicates that manganese and chlorine are the only boiler-related HAP that are reasonably expected to approach health based criteria concentrations at receptor locations at or beyond facility boundaries. Emissions of all other HAP modeled on an individual basis appears to be insignificant relative to the concentration that would produce the health effects that they represent. The maximal hazard index (HI) for summation of the HAP modeled in the screening assessment

for respiratory effects, including chlorine, was less than 3. The maximal HI for summation of the HAP modeled in the screening assessment for CNS effects, including manganese, was less than 3. Therefore, effects noted below for HAP at high concentrations are not expected to occur prior or after regulation as a result of emissions from these facilities, and are provided to illustrate the nature of the contaminant's effects at high dose. A screening assessment was also conducted for acute effects, and no exceedances were seen. Therefore, potential acute effects are not discussed below. However, to the extent the adverse effects do occur, the final rule will reduce emissions and subsequent exposures.

Acetaldehyde

Acetaldehyde is ubiquitous in the environment and may be formed in the body from the breakdown of ethanol (ethyl alcohol). In humans, symptoms of chronic (long-term) exposure to acetaldehyde resemble those of alcoholism. Long-term inhalation exposure studies in animals reported effects on the nasal epithelium and mucous membranes, and increased kidney weight. The EPA has classified acetaldehyde as a probable human carcinogen (Group B2) based on animal studies that have shown nasal tumors in rats and laryngeal tumors in hamsters.

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Arsenic

Chronic (long-term) inhalation exposure to inorganic arsenic in humans is associated with irritation of the skin and mucous membranes. Human data suggest a relationship between inhalation exposure for women working at or living near metal smelters and an increased risk of reproductive effects. Inorganic arsenic exposure in humans by the inhalation route has been shown to be strongly associated with lung cancer, while ingestion of inorganic arsenic in humans has been linked to a form of skin cancer and also to bladder, liver, and lung cancer. The EPA has classified inorganic arsenic as a Group A, human carcinogen.

Benzene

Chronic (long-term) inhalation exposure has caused various disorders in the blood, including reduced numbers of red blood cells. Increased incidence of leukemia (cancer of the tissues that form white blood cells) has been observed in humans occupationally exposed to benzene. The EPA has classified benzene as a Group A, known human carcinogen.

Beryllium

Chronic (long-term) inhalation exposure of humans to high levels of beryllium has been reported to cause chronic beryllium disease (berylliosis), in which granulomatous (noncancerous) lesions develop in the lung. Inhalation

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exposure to high levels of beryllium has been demonstrated to cause lung cancer in rats and monkeys. Human studies are limited, but suggest a causal relationship between beryllium exposure and an increased risk of lung cancer. We have classified beryllium as a Group B1, probable human carcinogen, when inhaled; data are inadequate to determine whether beryllium is carcinogenic when ingested.

Cadmium

Chronic (long-term) inhalation or oral exposure to cadmium leads to a build-up of cadmium in the kidneys that can cause kidney disease. Cadmium has been shown to be a developmental toxicant at high doses in animals, resulting in fetal malformations and other effects, but no conclusive evidence exists in humans. Animal studies have demonstrated an increase in lung cancer from long-term inhalation exposure to cadmium. The EPA has classified cadmium as a Group B1, probable carcinogen.

Chlorine

Chlorine is a commonly used household cleaner and disinfectant. Chlorine is an irritant to the eyes, the upper respiratory tract, and lungs. Chronic (long-term) exposure to chlorine gas in workers has resulted in respiratory effects, including eye and throat irritation and airflow obstruction. No information is available on the

carcinogenic effects of chlorine in humans from inhalation exposure. A National Toxicology Program (NTP) study showed no evidence of carcinogenic activity in male rats or male and female mice, and equivocal evidence in female rats, from ingestion of chlorinated water. The EPA has not classified chlorine for potential carcinogenicity.

Chromium

Chromium may be emitted by industrial boilers in two forms, trivalent chromium (chromium III) or hexavalent chromium (chromium VI). The respiratory tract is the major target organ for chromium VI toxicity for inhalation exposures. Bronchitis, decreased pulmonary function, pneumonia, and other respiratory effects have been noted from chronic high dose exposure in occupational settings to chromium VI. Limited human studies suggest that chromium VI inhalation exposure may be associated with complications during pregnancy and childbirth, while animal studies have not reported reproductive effects from inhalation exposure to chromium VI. Human and animal studies have clearly established that inhaled chromium VI is a carcinogen, resulting in an increased risk of lung cancer. The EPA has classified chromium VI as a Group A, human carcinogen.

Chromium III is less toxic than chromium VI. The respiratory tract is also the major target organ for

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chromium III toxicity, similar to chromium VI. Chromium III is an essential element in humans, with a daily intake of 50 to 200 micrograms per day recommended for an adult. The body can detoxify some amount of chromium VI to chromium III. The EPA has not classified chromium III with respect to carcinogenicity.

Formaldehyde

Exposure to formaldehyde irritates the eyes, nose, and throat. Reproductive effects, such as menstrual disorders and pregnancy problems, have been reported in female workers exposed to high levels of formaldehyde. Limited human studies have reported an association between formaldehyde exposure and lung and nasopharyngeal cancer. Animal inhalation studies have reported an increased incidence of nasal squamous cell cancer. The EPA considers formaldehyde a probable human carcinogen (Group B2).

Hydrogen chloride

Hydrogen chloride, also called hydrochloric acid, is corrosive to the eyes, skin, and mucous membranes at high concentration. Chronic (long-term) occupational exposure to high levels of hydrochloric acid has been reported to cause gastritis, bronchitis, and dermatitis in workers. Prolonged exposure to lower concentrations may also cause dental discoloration and erosion. No information is available on

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the reproductive or developmental effects of hydrochloric acid in humans. In rats exposed to high levels of hydrochloric acid by inhalation, altered estrus cycles have been reported in females and increased fetal mortality and decreased fetal weight have been reported in offspring. The EPA has not classified hydrochloric acid for carcinogenicity.

Hydrogen fluoride

Chronic (long-term) exposure to fluoride at low levels has a beneficial effect of dental cavity prevention and may also be useful for the treatment of osteoporosis. Exposure to higher levels of fluoride may cause dental fluorosis. One study reported menstrual irregularities in women occupationally exposed to fluoride. The EPA has not classified hydrogen fluoride for carcinogenicity.

Lead

Lead can cause a variety of effects at low dose levels. Chronic (long-term) exposure to high levels of lead in humans results in effects on the blood, central nervous system (CNS), blood pressure, and kidneys. Children are particularly sensitive to the chronic effects of lead, with slowed cognitive development, reduced growth and other effects reported. Reproductive effects, such as decreased sperm count in men and spontaneous abortions in women, have

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been associated with lead exposure. The developing fetus is at particular risk from maternal lead exposure, with low birth weight and slowed postnatal neurobehavioral development noted. Human studies are inconclusive regarding lead exposure and cancer, while animal studies have reported an increase in kidney cancer from high-dose lead exposure by the oral route. The EPA has classified lead as a Group B2, probable human carcinogen.

Manganese

Health effects in humans have been associated with both deficiencies and excess intakes of manganese. Chronic (long-term) exposure to low levels of manganese in the diet is considered to be nutritionally essential in humans, with a recommended daily allowance of 2 to 5 milligrams per day (mg/d). Chronic exposure to high levels of manganese by inhalation in humans results primarily in CNS effects. Visual reaction time, hand steadiness, and eye-hand coordination were affected in chronically-exposed workers. Impotence and loss of libido have been noted in male workers afflicted with manganism attributed to high-dose inhalation exposures. The EPA has classified manganese in Group D, not classifiable as to carcinogenicity in humans.

Mercury

Mercury exists in three forms: elemental mercury,

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inorganic mercury compounds (primarily mercuric chloride), and organic mercury compounds (primarily methyl mercury). Each form exhibits different health effects. Various major sources may release elemental or inorganic mercury; environmental methyl mercury is typically formed by biological processes after mercury has precipitated from the air.

Chronic (long-term) exposure to elemental mercury in humans also affects the CNS, with effects such as increased excitability, irritability, excessive shyness, and tremors. The EPA has not classified elemental mercury with respect to cancer.

The major effect from chronic exposure to inorganic mercury is kidney effects. Reproductive and developmental animal studies have reported effects such as alterations in testicular tissue, increased embryo resorption rates, and abnormalities of development. Mercuric chloride (an inorganic mercury compound) exposure has been shown to result in tumors in experimental animals. The EPA has classified mercuric chloride as a Group C, possible human carcinogen.

Nickel

Nickel is an essential element in some animal species, and it has been suggested it may be essential for human

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nutrition. Nickel dermatitis, consisting of itching of the fingers, hand and forearms, is the most common effect in humans from chronic (long-term) skin contact with nickel. Respiratory effects have also been reported in humans from inhalation exposure to nickel. No information is available regarding the reproductive or developmental effects of nickel in humans, but animal studies have reported such effects, although a consistent dose-response relationship has not been seen. Nickel forms released from industrial boilers include soluble nickel compounds, nickel subsulfide, and nickel carbonyl. Human and animal studies have reported an increased risk of lung and nasal cancers from exposure to nickel refinery dusts and nickel subsulfide. Animal studies of soluble nickel compounds (i.e., nickel carbonyl) have reported lung tumors. The EPA has classified nickel refinery subsulfide as Group A, human carcinogens and nickel carbonyl as a Group B2, probable human carcinogen.

Selenium

Selenium is a naturally occurring substance that is toxic at high concentrations but is also a nutritionally essential element. Studies of humans chronically (long-term) exposed to high levels of selenium in food and water have reported discoloration of the skin, pathological deformation and loss of nails, loss of hair, excessive tooth

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decay and discoloration, lack of mental alertness, and listlessness. The consumption of high levels of selenium by pigs, sheep, and cattle has been shown to interfere with normal fetal development and to produce birth defects. Results of human and animal studies suggest that supplementation with some forms of selenium may result in a reduced incidence of several tumor types. One selenium compound, selenium sulfide, is carcinogenic in animals exposed orally. We have classified elemental selenium as a Group D, not classifiable as to human carcinogenicity, and selenium sulfide as a Group B2, probable human carcinogen.

II. Summary of the Final Rule

A. What source categories and subcategories are affected by the final rule?

The final rule affects industrial boilers, institutional and commercial boilers, and process heaters. In the final rule, process heater means an enclosed device using controlled flame, that is not a boiler, and the unit's primary purpose is to transfer heat indirectly to a process material (liquid, gas, or solid) or to heat a transfer material for use in a process unit, instead of generating steam. Process heaters are devices in which the combustion gases do not directly come into contact with process materials. Process heaters do not include units used for

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comfort heat or space heat, food preparation for on-site consumption, or autoclaves. 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. Waste heat boilers are excluded from the definition of boiler. A waste heat boiler (or heat recovery steam generator) means a device, without controlled flame combustion, that recovers normally unused energy and converts it to usable heat. Waste heat boilers incorporating duct or supplemental burners that are designed to supply 50 percent or more of the total rated heat input capacity of the waste heat boiler are considered boilers and not waste heat boilers. Emissions from a combustion unit with a waste heat boiler are regulated by the applicable standards for the particular type of combustion unit. For example, emissions from a commercial or industrial solid waste incineration unit, or other incineration unit with a waste heat boiler are regulated by standards established under section 129 of the CAA.

Hot water heaters also are not regulated under the final rule. A hot water heater is a closed vessel, with a capacity of no more than 120 U.S. gallons, in which water is heated by combustion of gaseous or liquid fuel and is withdrawn for use external to the vessel at pressures not

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exceeding 160 pounds per square inch gauge and water temperatures not exceeding 210 degree Fahrenheit (99 degrees Celsius).

Temporary boilers also are not regulated under the final rule. A temporary boiler is any gaseous or liquid fuel-fired boiler that is designed, and is capable of, being carried or moved from one location to another, and remains at any one location for less than 180 consecutive days. Additionally, any new temporary boiler that replaces an existing temporary boiler and is intended to perform the same or similar function will be included in the determination of the consecutive 180-day time period.

Boilers or process heaters that are used specifically for research and development are not regulated under the final rule. However, units that only provide steam to a process at a research and development facility are still subject to the final rule.

B. What is the affected source?

In the final rule, the affected source is defined as follows: (1) the collection of all existing industrial, commercial, or institutional boilers and process heaters within a subcategory located at a major source; or (2) each new or reconstructed industrial, commercial or institutional boiler and process heater located at a major source.

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The affected source does not include combustion units that are subject to another standard under 40 CFR part 63, or covered by other standards listed in this preamble.

C. What pollutants are emitted and controlled?

Boilers and process heaters can emit a wide variety of HAP, depending on the material burned. Because of the large number of HAP potentially present in emissions and the disparity in the quantity and quality of the emissions information available, we use several surrogates to control multiple HAP in the final rule. This will reduce the burden of implementation and compliance on both regulators and the regulated community.

We grouped the HAP into four common categories: mercury, non-mercury metallic HAP, inorganic HAP, and organic HAP. In general, the pollutants within each group have similar characteristics and can be controlled with the same techniques.

Next, we identified compounds that could be used as surrogates for all the compounds in each pollutant category. For the non-mercury metallic HAP, we chose to use PM as a surrogate. Most, if not all, non-mercury metallic HAP emitted from combustion sources will appear on the flue gas fly-ash. Therefore, the same control techniques that would be used to control the fly-ash PM will control non-mercury

metallic HAP. Particulate matter was also chosen instead of specific metallic HAP because all fuels do not emit the same type and amount of metallic HAP but most generally emit PM. The use of PM as a surrogate will also eliminate the cost of performance testing to comply with numerous standards for individual metals.

However, we are sensitive to the fact that some sources burn fuels containing very little metals, but would have sufficient PM emissions to require control under the PM provisions of the proposed rule. In such cases, PM would not be an appropriate surrogate for metallic HAP. Therefore, in the final rule, an alternative metals emission limit is included. A source may choose to comply with the alternative metals emissions limit instead of the PM limit to meet the final rule.

For inorganic HAP, we chose to use HCl as a surrogate. The emissions test information available indicate that the primary inorganic HAP emitted from boilers and process heaters are acid gases, with HCl present in the largest amounts. Other inorganic compounds emitted are found in much smaller quantities. Also, control technologies that would reduce HCl would also control other inorganic compounds that are acid gases. Thus, the best controls for HCl would also be the best controls for other inorganic HAP

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that are acid gases. Therefore, HCl is a good surrogate for inorganic HAP because controlling HCl will result in a corresponding control of other inorganic HAP emissions.

For organic HAP, we chose to use carbon monoxide (CO) as a surrogate to represent the variety of organic compounds, including dioxins, emitted from the various fuels burned in boilers and process heaters. Because CO is a good indicator of incomplete combustion, there is a direct correlation between CO emissions and the formation of organic HAP emissions. Monitoring equipment for CO is readily available, which is not the case for organic HAP. Also, it is significantly easier and less expensive to measure and monitor CO emissions than to measure and monitor emissions of each individual organic HAP. Therefore, using CO as a surrogate for organic HAP is a reasonable approach because minimizing CO emissions will result in minimizing organic HAP emissions.

D. Does the final rule apply to me?

The final rule applies to you if you own or operate a boiler or process heater located at a major source meeting the requirements in this preamble.

E. What are the emission limitations and work practice standards?

You must meet the emission limits and work practice

standards for the subcategories in Table 1 of this preamble for each of the pollutants listed. Emission limits and work practice standards were developed for new and existing sources; and for large, small, and limited use solid, liquid, and gas fuel-fired units. Large units are those watertube boilers and process heaters with heat input capacities greater than 10 million British thermal units per hour (MMBtu/hr). Small units are any firetube boilers or any boiler and process heater with heat input capacities less than or equal to 10 MMBtu/hr. Limited use units are those large units with capacity utilizations less than or equal to 10 percent as required in a federally enforceable permit.

If your new or existing boiler or process heater is permitted to burn a solid fuel (either as a primary fuel or a backup fuel), or any combination of solid fuel with liquid or gaseous fuel, the unit is in one of the solid subcategories. If your new or existing boiler or process heater burns a liquid fuel, or a liquid fuel in combination with a gaseous fuel, the unit is in one of the liquid subcategories, except if the unit burns liquid only during periods of gas curtailment. If your new or existing boiler or process heater burns a gaseous fuel not combined with any liquid or solid fuels, or burns liquid fuel only during

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periods of gas curtailment or gas supply emergencies, the unit is in the gaseous subcategory.

Table 1. EMISSION LIMITS AND WORK PRACTICE STANDARDS FOR BOILERS AND PROCESS HEATERS (pounds per million British thermal units (lb/MMBtu))

Source	Subcategory	Particulate Matter (PM)	or	Total Selected Metals	Hydrogen Chloride (HCl)	Mercury (Hg)	Carbon Monoxide (CO)(ppm
New Boiler or Process Heater	Solid Fuel, Large Unit	0.025	or	0.0003	0.02	0.000003	400 (@7%oxygen)
	Solid Fuel, Small Unit	0.025	or	0.0003	0.02	0.000003	--
	Solid Fuel, Limited Use	0.025	or	0.0003	0.02	0.000003	400 (@7%oxygen)
	Liquid Fuel, Large Unit	0.03		--	0.0005	--	400 (@3%oxygen)
	Liquid Fuel, Small Unit	0.03		--	0.0009	--	--
	Liquid Fuel, Limited Use	0.03		--	0.0009	--	400 (@3%oxygen)
	Gaseous Fuel Large Unit	--		--	--	--	400 (@3%oxygen)

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	Gaseous Fuel Small Unit	--	--	--	--	--
	Gaseous Fuel Limited Use	--	--	--	--	400 (@3%oxygen)
Existing Boiler or Process Heater	Solid Fuel, Large Unit	0.07 or	0.001	0.09	0.000009	--
	Solid Fuel, Small Unit	--	--	--	--	--
	Solid Fuel, Limited Use	0.21 or	0.004	--	--	--
	Liquid Fuel, Large Unit	--	--	--	--	--
	Liquid Fuel, Small Unit	--	--	--	--	--
	Liquid Fuel, Limited Use	--	--	--	--	--
	Gaseous Fuel	--	--	--	--	--

For solid fuel-fired boilers or process heaters, sources may choose one of two emission limit options: (1) existing and new affected units may choose to limit PM emissions to the level listed in Table 1 of this preamble,

or (2) existing and new affected units may choose to limit total selected metals emissions to the level listed in Table 1 of this preamble. Sources meeting the emission limits must also meet operating limits.

We have provided several compliance alternatives in the final rule. Sources may choose to demonstrate compliance based on the fuel pollutant content. Sources are also allowed to demonstrate compliance for existing large solid fuel units using emissions averaging.

F. What are the testing and initial compliance requirements?

As the owner or operator of a new or existing boiler or process heater, you must conduct performance tests (i.e. stack testing) or an initial fuel analysis to demonstrate compliance with any applicable emission limits. The applicable emission limits and, therefore, the required performance tests and fuel analysis are different depending on the subcategory classification of the unit. Existing units in the small solid fuel subcategory and existing units in any of the liquid or gaseous fuel subcategories do not have applicable emission limits and, therefore, are not required to conduct stack tests or fuel analyses. Other units are required to conduct the following compliance tests or fuel analyses where applicable:

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(1) Conduct initial and annual stack tests to determine compliance with the PM emission limits using EPA Method 5 or Method 17 in appendix A to part 60 of this chapter.

(2) Affected sources in the solid fuel subcategories may choose to comply with an alternative total selected metals emission limit instead of PM. Sources would conduct initial and annual stack tests to determine compliance with the total selected metals emission limit using EPA Method 29 in appendix A to part 60 of this chapter.

(3) Conduct initial and annual stack tests to determine compliance with the mercury emission limits using EPA Method 29 in appendix A to part 60 of this chapter or the ASTM D6784-02.

(4) Conduct initial and annual stack tests to determine compliance with the HCl emission limits using EPA Method 26 in appendix A to part 60 of this chapter (for boilers without wet scrubbers) or EPA Method 26A in appendix A to part 60 of this chapter (for boilers with wet scrubbers).

(5) For new boilers and process heaters in any of the limited use subcategories and new boilers and process heaters in any of the large subcategories with heat input capacities greater than 10 MMBtu/hr but less than 100

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MMBtu/hr, conduct initial and annual stack tests to determine compliance with the CO work practice limit using EPA Method 10, 10A, or 10B in appendix A to part 60 of this chapter.

(6) Use EPA Method 19 in appendix A to part 60 of this chapter to convert measured concentration values to pound per million British thermal units (Btu) values.

(7) For new units in any of the liquid fuel subcategories that do not burn residual oil, instead of conducting an initial and annual compliance test you may submit a signed statement in the Notification of Compliance Status report that indicates that you only burn liquid fossil fuels other than residual oil.

(8) For affected sources that choose to meet the emission limits based on fuel analysis, conduct the fuel analysis using method ASTM D5865-01ael or ASTM E711-87 to determine heat content; ASTM D3684-01 (for coal), SW-846-7471A (for solid samples) or SW-846-7470A (for liquid samples) to determine mercury levels; SW-846-6010B or ASTM D3683-94 (for coal) or ASTM E885-88 (for biomass) to determine total selected metals concentration; SW-846-9250 or ASTM E776-87 (for biomass) to determine chlorine concentration; and ASTM D3173 or ASTM E871 to determine moisture content.

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As part of the initial compliance demonstration, you must monitor specified operating parameters during the initial performance tests that demonstrate compliance with the PM (or metals), mercury, and HCl emission limits. You must calculate the average parameter values measured during each test run over the 3-run performance test. The minimum or maximum of the three average values (depending on the parameter measured) for each applicable parameter establishes the site-specific operating limit. The applicable operating parameters for which operating limits must be established are based on the emissions limits applicable to your unit as well as the types of add-on controls on the unit. A summary of the operating limits that must be established for the various types of controls are as follows:

(1) For boilers and process heaters without wet scrubbers that must comply with the mercury emission limit and either a PM emission limit or a total selected metals emission limit, you must meet an opacity limit of 20 percent for existing sources (based on 6-minute averages), except for one 6-minute period per hour of not more than 27 percent, or 10 percent for new sources (based on 1-hour block averages). Or, if the unit is controlled with a fabric filter, instead of meeting an opacity operating

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limit, you may elect to operate the fabric filter using a bag leak detection system such that corrective actions are initiated within 1 hour of a bag leak detection system alarm and you operate and maintain the fabric filter such that the alarm is not engaged for more than 5 percent of the total operating time in a 6-month reporting period. If you can demonstrate compliance with the PM, mercury, or metals limits but cannot demonstrate compliance with the opacity operating limit, then you can establish a site-specific maximum opacity operating limit using data from a continuous opacity monitoring system and calculated from the average opacity for each individual test run.

(2) For boilers and process heaters without wet or dry scrubbers that must comply with an HCl emission limit, you must determine the average chloride content level in the input fuel(s) during the HCl performance test. This is your maximum chloride input operating limit.

(3) For boilers and process heaters with wet scrubbers that must comply with a mercury, PM (or total selected metals) and/or an HCl emission limit, you must measure pressure drop and liquid flow rate of the scrubber during the performance test and calculate the average value for each test run. The minimum test run average establishes your site-specific pressure drop and liquid flow rate

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operating levels. If different average parameter levels are measured during the mercury, PM (or metals) and HCl tests, the highest of the minimum test run average values establishes your site-specific operating limit. If you are complying with an HCl emission limit, you must measure pH during the performance test for HCl and determine the average for each test run and the minimum value for the performance test. This establishes your minimum pH operating limit.

(4) For boilers and process heaters with dry scrubbers that must comply with an HCl emission limit, you must measure the sorbent injection rate during the performance test for mercury and HCl and calculate the average for each test run. The minimum test run average during the performance test establishes your site-specific minimum sorbent injection rate operating limit.

(5) For boilers and process heaters with fabric filters in combination with wet scrubbers that must comply with a mercury emission limit, PM (or total selected metals) emission limit and/or an HCl emission limit, you must measure the pH, pressure drop, and liquid flowrate of the wet scrubber during the performance test and calculate the average value for each test run. The minimum test run average establishes your site-specific pH, pressure drop,

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and liquid flowrate operating limits for the wet scrubber. Furthermore, the fabric filter must be operated such that the bag leak detection system alarm does not sound more than 5 percent of the operating time during any 6-month period.

(6) For boilers and process heaters with electrostatic precipitators (ESP) in combination with wet scrubbers that must comply with a mercury, PM (or total selected metals) and/or an HCl emission limit, you must measure the pH, pressure drop, and liquid flow rate of the wet scrubber during the HCl performance test, and you must measure the voltage and secondary current of the ESP collection plates or total power input during the mercury and PM (or metals) performance test. Calculate the average value of these parameters for each test run. The minimum test run averages establish your site-specific minimum pH, pressure drop, and liquid flowrate operating limit for the wet scrubber and the minimum voltage and current operating limits for the ESP.

(7) For boilers and process heaters that choose to comply with the alternative total selected metals emission limit instead of PM, you must determine the total selected metals content of the inlet fuels that were burned during the total selected metals performance test. This value is your maximum fuel inlet metals content operating limit.

(8) For boilers and process heaters that burn a

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mixture of multiple fuels, you must determine the mercury content of the inlet fuels that were burned during the mercury performance test. This value is your maximum fuel inlet mercury operating limit. Units burning only a single fuel type (not including start-up fuels) do not need to determine, by fuel analysis, the fuel inlet operating limit when conducting performance tests.

(9) For new boilers and process heaters in any of the large subcategories and with heat input capacities greater or equal to 100 MMBtu/hr, you must monitor CO to demonstrate that average CO emissions, on a 30-day rolling average, are at or below an exhaust concentration of 400 parts per million (ppm) by volume on a dry basis corrected to 3 percent oxygen for units in the liquid subcategories and corrected to 7 percent for units in the solid subcategories. For new boilers and process heaters in any of the limited use subcategories or with heat input capacities less than 100 MMBtu/hr, you must conduct initial test of CO emissions to demonstrate compliance with the CO work practice limit.

The final rule also provides you another compliance alternative. You may demonstrate compliance by emissions averaging for existing large solid fuel boilers in States that choose to allow emissions averaging in their operating permit program.

G. What are the continuous compliance requirements?

To demonstrate continuous compliance with the emission limitations, you must monitor and comply with the applicable site-specific operating limits established during the performance tests or fuel analysis. Upon detecting an excursion or exceedance, you must restore operation of the unit to its normal or usual manner of operation as expeditiously as practicable in accordance with good air pollution control practices for minimizing emissions. The response shall include minimizing the period of any startup, shutdown or malfunction and taking any necessary corrective actions to restore normal operation and prevent the likely recurrence of the cause of an excursion or exceedance. Such actions may include initial inspections and evaluation, recording that operations returned to normal without operator action, or any necessary follow-up actions to return operation to below the work practice standard.

(1) For boilers and process heaters without wet scrubbers that must comply with a mercury emission limit and either a PM emission limit or a total selected metals emission limit, you must continuously monitor opacity and maintain the opacity at or below the maximum opacity operating limit for new and existing sources. Or, if the unit is controlled with a fabric filter, instead of

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continuous monitoring opacity, the fabric filter may be continuously operated such that the bag leak detection system alarm does not sound more than 5 percent of the operating time during any 6-month period.

(2) For boilers and process heaters without wet or dry scrubbers that must comply with an HCl emission limit, you must maintain monthly records of fuel use that demonstrate that you have burned no new fuel types or new mixtures such that you have maintained the fuel HCl content level at or below your site-specific maximum HCl input operating limit. If you plan to burn a new fuel type or a new mixture than what was burned during the initial performance test, then you must re-calculate the maximum HCl input anticipated from the new fuels based on supplier data or your own fuel analysis. If the results of re-calculating the HCl input exceeds the average HCl content level established during the initial test, then you must conduct a new performance test to demonstrate continuous compliance with the HCl emission limit.

(3) For boilers and process heaters with wet scrubbers that must comply with a mercury, PM (or total selected metals) and/or an HCl emission limit, you must monitor pressure drop and liquid flow rate of the scrubber and maintain the 3-hour block averages at or above the operating

limits established during the performance test. You must monitor the pH of the scrubber and maintain the 3-hour block average at or above the operating limit established during the performance test to demonstrate continuous compliance with the HCl emission limits.

(4) For boilers and process heaters with dry scrubbers that must comply with a PM (or total selected metals) or mercury emission limit, and/or an HCl emission limit, you must continuously monitor the sorbent injection rate and maintain it at or above the operating limits established during the HCl performance test.

(5) For boilers and process heaters with fabric filters in combination with wet scrubbers, you must monitor the pH, pressure drop, and liquid flowrate of the wet scrubber and maintain the levels at or above the operating limits established during the HCl performance test. You must also maintain the operation of the fabric filter such that the bag leak detection system alarm does not sound more than 5 percent of the operating time during any 6-month period.

(6) For boilers and process heaters with ESP in combination with wet scrubbers that must comply with a mercury, PM and/or an HCl emission limit, you must monitor the pH, pressure drop, and liquid flow rate of the wet

scrubber and maintain the 3-hour block averages at or above the operating limits established during the HCl performance test. Also, you must monitor the voltage and secondary current of the ESP collection plates or total power input and maintain the 3-hour block averages at or above the operating limits established during the mercury or PM (or metals) performance test.

(7) For boilers and process heaters that choose to comply with the alternative total selected metals limit instead of PM emission limit, you must maintain monthly fuel records that demonstrate that you burned no new fuel type or new mixtures such that the total selected metals content of the inlet fuel was maintained at or below your maximum fuel inlet metals content operating limit set during the metals performance test. If you plan to burn a new fuel type or new mixture, then you must re-calculate the maximum metals input anticipated from the new fuels based on supplier data or own fuel analysis. If the results of re-calculating the metals input exceeds the average metals content level established during the initial test, then you must conduct a new performance test to demonstrate continuous compliance with the alternate selected metals emission limit.

(8) For boilers and process heaters that must comply with the mercury emission limit, you must maintain monthly

fuel records that demonstrate that you burned no new fuel type or new mixture such that the total selected mercury content of the inlet fuel was maintained at or below your maximum fuel inlet metals content operating limit set during the mercury performance test. If you plan to burn a new fuel type or new mixture than what was burned during the initial performance test, then you must re-calculate the maximum mercury input anticipated from the new fuels based on supplier data or own fuel analysis. If the results of re-calculating the mercury input exceeds the average mercury content level established during the initial test, then you must conduct a new performance test to demonstrate continuous compliance with the mercury emission limit.

(9) For boilers and process heaters that choose to comply with any emission limit based on fuel analysis, you must maintain monthly fuel records to demonstrate that the content of fuel is maintained below the appropriate applicable emission limit.

(10) For new boilers and process heaters in any of the large subcategories with heat input capacities greater or equal to 100 MMBtu/hr, you must continuously monitor CO and maintain the 30-day rolling average CO emissions at or below 400 ppm by volume on a dry basis (corrected to 3 percent oxygen for units in the liquid or gaseous subcategories, and

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7 percent for units in the solid fuel subcategories) to demonstrate compliance with the work practice standards at all times except during startup, shutdown, and malfunction and when the unit is operating less than 50 percent of the rated capacity.

If a control device other than the ones specified in this section is used to comply with the final rule, you must establish site-specific operating limits and establish appropriate continuous monitoring requirements, as approved by the EPA Administrator.

If you choose to comply using emissions averaging, you must demonstrate on a monthly basis that mercury, metals, PM, and HCl emission limits can be met over a 12-month period.

H. <u>What are the notification, recordkeeping and reporting requirements</u>?

If your boiler or process heater is in the existing large gaseous fuel subcategory, or existing limited use gaseous fuel subcategory, or existing large liquid fuel subcategory, or existing limited use liquid fuel subcategory, or a new small liquid fuel unit that only burn gaseous fuels or distillate oil, you only have to submit the initial notification report. If your boiler or process heater is in the existing small gaseous, liquid, or solid

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fuel subcategories or new small gaseous fuel subcategory, you are not required to keep any records or submit any reports.

If your boiler or process heater is in any other subcategory, then you must keep the following records:

(1) All reports and notifications submitted to comply with the final rule.

(2) Continuous monitoring data as required in the final rule.

(3) Each instance in which you did not meet each emission limit work practice and operating limit, including periods of startup, shutdown, and malfunction (i.e., deviations from the final rule).

(4) Monthly hours of operation by each source that is in a limited use subcategory.

(5) Monthly fuel use by each boilers and process heaters subject to an emission limit including a description of the type(s) of fuel(s) burned, amount of each fuel type burned, and units of measure

(6) Calculations and supporting information of chloride fuel input, as required in the final rule.

(7) Calculations and supporting information of total selected metals and mercury fuel input, as required in the final rule, if applicable.

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(8) A copy of the results of all performance tests, fuel analysis, opacity observations, performance evaluations, or other compliance demonstrations conducted to demonstrate initial or continuous compliance with the final rule.

(9) A copy of any federally enforceable permit that limits the annual capacity factor of the source to less than or equal to 10 percent.

(10) A copy of your site-specific startup, shutdown, and malfunction plan.

(11) A copy of your site-specific monitoring plan developed for the final rule, if applicable.

(12) A copy of your site-specific fuel analysis plan developed for the final rule, if applicable.

(13) A copy of the emissions averaging plan, if applicable.

You must submit the following reports and notifications:

(1) Notifications required by the General Provisions.

(2) Initial Notification no later than 120 calendar days after you become subject to the final rule.

(3) Notification of Intent to conduct performance tests and/or compliance demonstration at least 30 calendar days before the performance test and/or compliance

demonstration is scheduled.

(4) Notification of Compliance Status 60 calendar days following completion of the performance test and/or compliance demonstration.

(5) Notification of intent to demonstrate compliance by emissions averaging.

(6) Notification of intent to demonstrate eligibility for either health-based compliance alternative.

(7) Compliance reports semi-annually.

I. <u>What are the health-based compliance alternatives, and how do I demonstrate eligibility?</u>

<u>HCl Compliance Alternative</u>

As an alternative to the requirement for each large solid fuel-fired boiler to demonstrate compliance with the HCl emission limit in the final rule, you may demonstrate compliance with a health-based HCl equivalent allowable emission limit.

The procedures for demonstrating eligibility for the HCl compliance alternative (as outlined in appendix A of the final rule) are:

(1) You must include in your demonstration every emission point covered under the final rule.

(2) You must conduct HCl and chlorine emissions tests for every emission point covered under the final rule.

(3) You must determine the total maximum hourly mass HCl-equivalent emission rate for your affected source by summing the maximum hourly emission rates of HCl and chlorine for each of the affected units at your facility covered under the final rule.

(4) Use the look-up table in the appendix A of the final rule to determine if your facility is in compliance with the health-based HCl-equivalent emission limit.

(5) Select the maximum allowable HCl-equivalent emission rate from the look-up table in appendix A of the final rule for your affected source using the average stack height of your emission units covered under the final rule as your stack height and the minimum distance between any affected emission point and the property boundary as your property boundary.

(6) Your facility is in compliance if your maximum HCl-equivalent emission rate does not exceed the value specified in the look-up table in appendix A of the final rule.

(7) As an alternative to using the look-up table, you may conduct a site-specific compliance demonstration (as outlined in appendix A of the final rule) which demonstrates that the subpart DDDDD units at your facility are not expected to cause an individual chronic inhalation exposure

from HCl and chlorine which can exceed a Hazard Index (HI) value of 1.0.

Total Selected Metals Compliance Alternative

In lieu of complying with the emission standard for total selected metals (TSM) in the final rule based on the sum of emissions for the eight selected metals, you may demonstrate eligibility for complying with the TSM standard based on excluding manganese emissions from the summation of TSM emissions for the affected source unit(s).

The procedures for demonstrating eligibility for the TSM compliance alternative (as outlined in appendix A of the final rule) are:

(1) You must include in your demonstration every emission point covered under the final rule that emits manganese.

(2) You must conduct manganese emissions tests for every emission point covered under the final rule that emits manganese.

(3) You must determine the total maximum hourly manganese emission rate from your affected source by summing the maximum hourly manganese emission rates for each of the affected units at your facility covered under the final rule.

(4) Use the look-up table in appendix A of the final

rule to determine if your facility is eligible for complying with the alternative TSM limit based on the sum of emissions for seven metals (excluding manganese) for the affected source units.

(5) Select the maximum allowable manganese emission rate from the look-up table in appendix A of the final rule for your affected source using the average stack height of your emission units covered under the final rule as your stack height and the minimum distance between any of those emission points and the property boundary as your property boundary.

(6) Your facility is eligible if your maximum manganese emission rate does not exceed the value specified in the look-up table in appendix A of the final rule.

(7) As an alternative to using look-up table to determine if your facility is eligible for the TSM compliance alternative, you may conduct a site-specific compliance demonstration (as outlined in appendix A of the final rule) which demonstrates that the subpart DDDDD units at your facility are not expected to cause an individual chronic inhalation exposure from manganese which can exceed a Hazard Quotient (HQ) value of 1.0.

If you elect to demonstrate eligibility for either of the health-based compliance alternatives, you must submit

certified documentation supporting compliance with the procedures at least 1 year before the compliance date.

You must submit supporting documentation including documentation of all maximum capacities, existing control devices used to reduce emissions, stack parameters, and property boundary distances to each affected source of HCl-equivalent and/or manganese emissions.

You must keep records of the information used in developing the eligibility demonstration for your affected source.

To be eligible for either health-based compliance alternative, the parameters that defined your affected source as eligible for the health-based compliance alternatives (including, but not limited to, fuel type, type of control devices, process parameters reflecting the emission rates used for your eligibility demonstration) must be incorporated as Federally enforceable limits into your title V permit. If you do not meet these criteria, then your affected source is subject to the applicable emission limits, operating limits, and work practice standards in the final rule.

If you intend to change key parameters (including distance of stack to the property boundary) that may result in lower allowable health-based emission limits, you must

recalculate the limits under the provisions of this section, and submit documentation supporting the revised limits prior to initiating the change to the key parameter.

If you intend to install a new solid fuel-fired boiler or process heater or change any existing emissions controls that may result in increasing HCl-equivalent and/or manganese emissions, you must recalculate the total maximum hourly HCl-equivalent and/or manganese emission rate from your affected source, and submit certified documentation supporting continued eligibility under the revised information prior to initiating the new installation or change to the emissions controls.

III. What are the significant changes since proposal?

A. Definition of Affected Source

The definition of affected source in §63.7490 has been revised to be: (1) the collection of all existing industrial, commercial, or institutional boilers or process heaters within a subcategory located at a major source; and/or (2) each new or reconstructed industrial, commercial, or institutional boiler or process heater located at a major source.

B. Sources Not Covered by the NESHAP

The applicability section of the final rule (§63.7490(c)) has been written to clarify that the following

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are not subject to the final rule: blast furnace stoves, any boiler or process heater specifically listed as an affected source in another MACT standard, temporary boilers, and blast furnace gas fuel-fired boilers and process heaters.

C. Emission Limits

The emission limit for mercury in the existing large solid fuel subcategories has been written as 0.000009 lb/MMBtu (from 0.000007 lb/MMBtu at proposal).

D. Definitions Added and Revised

The EPA has written the definitions of large, limited use, and small gaseous subcategories to include gaseous fuel-fired boilers and process heaters that burn liquid fuel during periods of gas curtailment or gas supply emergencies.

The final rule also includes a definition of fuel type which is used in the fuel analysis compliance options. Fuel type means each category of fuels that share a common name of classification. Examples include, but are not limited to: bituminous coal, subbituminous coal, lignite, anthracite, biomass, construction/demolition material, salt water laden wood, creosote treated wood, tires, and residual oil. Individual fuel types received from different suppliers are not considered new fuel types except for construction/demolition material.

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Construction/demolition material means waste building material that result from the construction or demolition operations on houses and commercial and industrial buildings.

Unadulterated wood, component of biomass, means wood or wood products that have not been painted, pigment-stained, or pressure treated with compounds such as chromate copper arsenate, pentachlorophenol, and creosote. Plywood, particle board, oriented strand board, and other types of wood products bound by glues and resins are included in this definition.

We have included a definition for temporary boiler to mean any gaseous or liquid fuel-fired boiler that is designed, and is capable of, being carried or moved from one location to another. A temporary boiler that remains at a location for more than 180 consecutive days is no longer considered to be a temporary boiler. Any temporary boiler that replaces a temporary boiler at a location and is intended to perform the same or similar function will be included in calculating the consecutive time period.

The final rule also contains a definition written for waste heat boiler that identifies waste heat boilers incorporating duct or supplemental burners that are designed to supply 50 percent or more of the total rated heat input

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capacity of the waste heat boiler as not being waste heat boilers, but are considered boilers and subject to the final rule.

E. Requirements for Sources in Subcategories Without Emission Limits or Work Practice Requirements

In the final rule, we have clarified that sources in the existing large and limited use gaseous fuel subcategories, existing large and limited use liquid fuel subcategories, new small gaseous fuel subcategory and new small liquid fuel subcategory are only subject to the initial notification requirements in §63.9(b) of subpart A of this part and are not required to submit as startup, shutdown, and malfunction (SSM) plan as part of their initial notification. We have written the final rule to state that sources in the existing small gaseous fuel, liquid fuel, and solid fuel subcategories are not subject to any requirements in the final rule or of subpart A of this part.

F. Carbon Monoxide Work Practice Emission Levels and Requirements

The final rule provides revisions to the CO work practice emission levels. For new sources in the solid fuel subcategory, the work practice standard has been written to be corrected to 7 percent oxygen rather than 3 percent.

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Units in the gaseous and liquid fuel subcategories still have to correct to 3 percent oxygen.

The final rule also allows sources with heat input capacities greater than 10 MMBtu/hr but less that 100 MMBtu/hr to conduct initial and annual compliance tests to demonstrate compliance with the CO limit. Sources greater than 100 MMBtu/hr must still demonstrate compliance using CO continuous emission monitors (CEMS).

The final rule also does not allow you to calculate data average using data recorded during periods where your boiler or process heater is operating at less than 50 percent of its rated capacity, monitoring malfunctions, associated repairs, out-of-control periods, or required quality assurance or control activities. You must use all data collected during all other periods in assessing compliance.

G. Fuel Analysis Option

We have clarified the fuel analysis options in the final rule. You are not required to conduct performance tests for hydrogen chloride, mercury, or total selected metals if you demonstrate compliance with the hydrogen chloride, mercury, or total selected metals limits based on the fuel pollutant content. Your operating limit is then the emission limit of the applicable pollutant. You are not

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required to conduct emission tests.

If you demonstrate compliance with the HCl, mercury, or TSM limit by performance tests, then your operating limits are the operating limits of the control device (if used) and the fuel pollutant content of the fuel type/mixture burned. Units burning multiple fuel types are required to determine by fuel analysis, the fuel pollutant content of the fuel/mixture burned during the performance test.

The final rule specifies the testing and initial and continuous compliance requirements to be used when complying with the fuel analysis options. Fuel analysis tests for total chloride, gross calorific value, mercury, metal analysis, sample collection, and sample preparation are included in the final rule.

We have written the requirement to remove the need for conducting additional tests if you receive fuel from a new supplier. You are required to conduct another performance test, if you demonstrated compliance through performance testing, only when you burn a new fuel type or mixture and the results of recalculating the fuel pollutant content are higher than the level established during the initial performance test.

H. Emissions Averaging

We have included a compliance alternative in the final

rule to allow emissions averaging between existing large solid fuel boilers. Compliance must be demonstrated on a 12-month rolling average basis, determined at the end of every month. If you elect to comply with the emissions averaging compliance alternative, you must use equations provided in the final rule to demonstrate that particulate matter or TSM, HCl, or mercury from all applicable units do not exceed the emission limits specified in the final rule. If you use this option, you must also develop and submit an implementation plan no later than 6 months before the date that the facility intends to demonstrate compliance.

I. Opacity Limit

At proposal, we required sources meeting the PM and mercury limits to determine site-specific opacity operating limits based on levels during the initial performance test. To demonstrate continuous compliance with the opacity limit, the opacity operating limits have been established to be 20 percent (based on 6-minute averages) except for one 6-minute period per hour of not more than 27 percent for existing sources and 10 percent (based on 1-hour block averages) for new sources.

J. Operating Limit Determination

The final rule defines maximum and minimum operating parameters that must be met. For sources complying with the

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alternative opacity requirement of establishing opacity limits during the initial performance test, the maximum opacity operating limit is 110 percent of the highest test-run average opacity measured according to the final rule during the most recent performance test demonstrating compliance with the applicable emission limit. For sources meeting the standards using scrubbers or ESP, the minimum pressure drop, scrubber effluent pH, scrubber flow rate, sorbent flow rate, voltage or amperage means 90 percent of the lowest test run average pressure drop, scrubber effluent pH, scrubber flow rate, sorbent flow rate, voltage or amperage measured according to the most recent performance test demonstrating compliance with the applicable emission limits.

The final rule clarifies that operation above the established maximum or below the established minimum operating parameters constitute a deviation of established operating parameters.

K. Revision of Compliance Dates

In §63.7510, we have also written the date by which you have to complete a compliance demonstration to be 180 days after the compliance date instead of at the compliance date.

IV. What are the responses to significant comments?

We received 218 public comment letters on the proposed

rule. Complete summaries of all the comments and responses are found in the Response-to-Comments document (see SUPPLEMENTARY INFORMATION section).

A. Applicability

Comment: Many commenters requested that EPA exempt units that are not subject to emission limits or work practice requirements from monitoring, recordkeeping, and reporting requirements.

Response: Sources in subcategories that do not have any emission limitations and work practices are not required to keep records or reports other than the initial notification. This is appropriate because no reports other than the initial notification would apply to these units. The SSM plan is not necessary nor required for these units because §63.6(e)(3) of subpart A of this part requires an affected source to develop an SSM plan for control equipment used to comply with the relevant standard. The proposed rule was not intended to require monitoring, recordkeeping, and reporting (including startup, shutdown, and malfunction plans), other than the initial notification for sources not subject to an emission limit. We have clarified this decision in the final rule. We have also determined that existing small units and new small gaseous fuel units, which are not subject to emission limits or work practices in this

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standard, and which are also not subject to such requirements in any other Federal regulation, should also not have to provide an initial notification. These small sources are generally gas-fired and since they have minimal emissions, they are usually considered as insignificant emission units by State permitting agencies.

Comment: Several commenters requested that EPA specifically exclude portable/transportable units from the final rule. The commenters stated that facilities periodically use these units to supply or supplement other site steam supplies when there is a mechanical problem that takes a unit out of service or during planned outages. The commenters added that because they are used on a limited basis, portable units are not fully integrated with site control systems and most portable/transportable units are owned by a rental company and may not be operated by the facility owner/operator.

Response: We agree with the commenters that temporary/portable units are used only on a limited basis and are not integrated into a facility's control system. These units are gas or oil fired units. Units in the existing gaseous or liquid subcategories are not subject to emission limits or work practice standards. Consequently, we have decided that temporary/portable units are not

subject to the final rule. We have added a definition for temporary boiler to mean any gaseous or liquid fuel-fired boiler that is designed, and is capable of, being carried or moved from one location to another. A temporary boiler that remains at a location for more than 180 consecutive days is no longer considered to be a temporary boiler. Any temporary boiler that replaces a temporary boiler at a location and is intended to perform the same or similar function will be included in calculating the consecutive time period. We chose the 180-day time frame because that is the length of time a new source has after startup to conduct the initial performance test.

Comment: Several commenters requested EPA provide a lower size cut-off for the small unit subcategory. Several commenters argued that the benefits from requiring smaller units to install controls would be minimal given the overall monitoring, recordkeeping, and reporting burden. Several commenters also requested lower size cutoffs to make the final rule similar to others established by EPA (e.g, NSPS Nitrogen Oxide (NOx) SIP Call). Several commenters noted several recent court decisions in which the court has decided that a de minimis exemption is appropriate since the regulation of small sources would yield a gain of trivial or no value yet would impose significant regulatory burden. A

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wide range of lower size cutoffs were suggested. However, one commenter said that EPA should not develop de minimis exemptions. The commenter noted that de minimis exemptions do not spare EPA's resources for use on other purposes and are not justified by reductions in industry burden or inconvenience. The commenter noted that EPA did not establish any administrative record justifying the de minimis exemption.

Response: We have reviewed the commenters arguments and all the data provided in the comment letters. There is no justification for developing a lower size cut-off or de minimis level. We would also note the designation of large and small subcategories was not based solely on size of the unit. Large and small subcategories were developed because small units less than 10 MMBtu/hr heat input typically use a combustor design that is not common in larger units. Large boilers generally use the watertube combustor design. The design of the boiler or process heater will influence the completeness of the combustion process which will influence the formation of organic HAP emissions. Additionally, the vast majority of small units use natural gas as fuel. The EPA chose to develop large and small subcategories to account for these differences and their affect on the type of emissions. The cut-off between the large and small

subcategories of 10 MMBtu/hr was based on typical sizes for fire tube units, and also when considering cut-offs in State and Federal rules. Lastly, we would like to note that the final rule does not impose any requirements for existing units in any of the small subcategories.

Comment: Many commenters asked EPA to clarify which sources are not covered by the final rule.

Response: We have included an extensive list of sources that are not subject to the final rule. The final rule clarifies that boilers and process heaters that are included as part of the affected source in any other NESHAP are not subject to the NESHAP for industrial boilers and process heaters. However, we do not exclude boilers and process heaters that are used as control devices unless they are specifically considered part of any other NESHAP's definition of affected source. Incinerators, thermal oxidizers, and flares do not generally fall under the definition of a boiler or process heater and would not be subject to the final rule. The final rule excludes waste heat boilers and waste heat boilers with supplemental firing, as long as the supplemental firing does not provide more than 50 percent of the waste heat boiler's heat input. If your waste heat boiler does receive 50 percent of its total heat input from supplemental firing, it would be

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subject to the NESHAP for industrial boilers unless it is subject to any other NESHAP. We specifically exclude comfort heaters from the final rule. However, this exclusion does not include boilers used to make steam or heated water for comfort heat. If your boiler meets the definition of a hot water heater, then it would not be subject to the final rule. However, if the temperature, pressure, or capacity specifications of your boiler exceed the criteria specified for hot water heaters, then your boiler would be subject to the final rule. We recognize the unique properties of blast furnace gas having high CO concentrations and none to almost no organic compounds. Consequently, we agree that for these sources CO is not a surrogate for organic HAP emissions since CO is the primary component of blast furnace gas and virtually no organic HAP are generated in its combustion. As a result, we exclude from the final rule units that receive 90 percent or more of their total heat input from blast furnace gas. In addition, research and development (R&D) operations are not subject to the final rule. However, units that only provide steam to a process or for heating at a research and development facility are still subject to the final rule. This should address the commenters' concern over overlapping applicability.

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Comment: Several commenters suggested that EPA revise the proposed definition of affected source to be consistent with the definition of affected source in the General Provisions. The definition in the rule as proposed is much more narrow than that in the General Provisions, even though the General Provisions states that each standard will redefine affected source based on published justification as to why the definition would result in significant administration, practical or implementation problems. The commenters argued that EPA failed to provide justification for the proposed definition of affected source, which is narrower than the definition of affected source in the General Provisions.

Response: We agree with the commenters and in the final rule have incorporated the broader definition of affected source from the revised General Provisions. The General Provisions define the affected source as "the collection of equipment, activities, or both within a single contiguous area and under common control that is included in a section 112(c) source category or subcategory . . . " Therefore, the definition of existing affected source in the final rule is the collection of existing industrial, commercial, or institutional boilers and process heaters within a subcategory located at a major source of HAP

emissions.

B. Format

Comment: Several commenters opposed using one or more surrogates for the HAP regulated. Some commenters stated that EPA must set emission standards for each HAP emitted by this category. One commenter explained that the use of surrogates is acceptable if: (1) the surrogates reflect the actual emissions of the represented pollutants, (2) the emission limit set for the surrogate is consistent with the emission limit calculated for the represented pollutants, and (3) the surrogates have substantially the same properties as the represented pollutants and is controlled by the same mechanism. Based on these criteria, the commenter argued that EPA's selection of surrogates is inadequate. One commenter specifically contended that CO is not an adequate surrogate for dioxin because dioxin emissions are affected by the temperature of the emissions, how quickly the temperature is lowered, and the levels of chlorine in the materials that are being combusted and control devices. Other commenters supported the use of surrogates to represent the HAP list.

Response: As discussed in the proposal preamble, the use of surrogates for the HAP regulated is appropriate. Because of the large number of HAP potentially present, the

disparity in the quality and quantity of the emissions information available, particularly for different fuel types, we chose to group HAP into four categories: mercury, non-mercury metallic HAP, inorganic HAP, and organic HAP. In general, the pollutants within each group have similar characteristics and can be controlled with the same techniques. We then chose compounds that could be used as surrogates for all the compounds in each pollutant category. We have used surrogates in previous NESHAP as a technique to reduce the performance testing costs, and thus the use of surrogates is appropriate in the final rule.

For inorganic HAP, we chose to use HCl as a surrogate. The emissions test information available to us indicated that the primary inorganic HAP emitted from boilers and process heaters is HCl. Much smaller amounts of hydrogen fluoride and chlorine are emitted. Control technologies that would reduce HCl would also control other inorganic HAP. Additionally, we had limited emissions information for other inorganic HAP. By focusing on HCl, we have achieved control of the largest emitted and most widely emitted HAP, and control of HCl would also constitute control of other inorganic HAP.

For non-mercury metallic HAP, we chose to use PM as a surrogate. Most, if not all, non-mercury metallic HAP

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emitted from combustion sources will appear on the flue gas fly-ash. Therefore, the same control technology that would be used to control fly-ash PM will control non-mercury metallic HAP. A review of data in the emission database for PM control devices having both inlet and outlet emissions results shows control efficiencies for each non-mercury metallic HAP similar to PM. Particulate matter was also chosen instead of a specific metallic HAP because all fuels do not emit the same type and amount of metallic HAP, but most generally emit PM that includes some amount and combination of metallic HAP. We maintain that particulate matter reflects the emissions of non-mercury metallic HAP as these compounds usually comprise a percentage of the emitted particulate matter. Since the NESHAP program is technology-based, the technologies that have been developed and implemented to control particulate matter, also control non-mercury metallic HAP. Furthermore, since non-mercury metallic HAP is a component of particulate matter, we can use particulate matter as a surrogate for the purposes of the final rule.

While we did use PM as a surrogate for non-mercury metallic HAP, we also provided an alternative total selected metals emission limit based on the sum of the emissions of the eight most common and largest emitted metallic HAP

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compounds from boilers and process heaters. Again, a total selected metals number was used instead of limits for each individual metallic HAP because sufficient information was not available for each metallic HAP for every fuel type. However, a total metals number could be calculated for every fuel type.

We realize that mercury emissions can exist in different forms depending on combustion conditions and concentrations of other compounds. That is why we have mercury as a separate pollutant category in the final rule and do not provide for a surrogate.

For organic HAP, we chose to use CO as a surrogate to represent the variety of organic compounds emitted from the various fuels burned. Both organic HAP and CO emissions are the result of incomplete combustion of the fuel. Because CO is a good indicator of incomplete combustion, there is a direct correlation between CO emissions and minimizing organic HAP emissions. The extent to which CO and HAP emissions are related can also depend on site-specific operating conditions for each boiler or process heater. This site-specific nature may result in various degrees of correlation between CO and organic HAP emissions, but it is proven that reductions in CO emissions result in a reduction of organic HAP emissions. The control methods for both CO

and organic HAP are the same, i.e., complete combustion. This result would not have been different if MACT floor analyses were conducted for specific organic HAP or for a surrogate compound such as CO. For boilers and process heaters, we have determined that CO is a reasonable indicator of incomplete combustion. Also, we did not set emission limits for each specific organic HAP because we lacked sufficient information for many of the organic HAP for all the fuels combusted. We acknowledge that there are many factors that affect the formation of dioxin, but we also recognize that dioxin can be formed in both the combustion unit and downstream in the associated PM control device. Minimizing organic HAP emissions can limit the formation of dioxin in the combustion unit. We reviewed all the good combustion practice (GCP) information available in the boiler population database and determined that no floor level of control exists, except for limiting CO emissions, such that GCP could be incorporated into the standard. One control technique, controlling inlet temperature to the PM control device, that has demonstrated controlling downstream formation of dioxins in other source categories (e.g., municipal waste combustors) was analyzed for industrial boilers. In all cases, no increase in dioxins emissions were indicated across the PM control device even at high

inlet temperatures. However, we requested comment on controls that would achieve reductions of organic HAP, including any additional data that might be available. The EPA did not receive any additional supporting information or data. Additionally, more stringent options beyond the floor level of control were evaluated, but were determined to be too costly and emissions reductions associated with the options could not be evaluated because no information was available that indicated a relationship between the GCP and emission reduction of organics (including dioxin).

C. Compliance Schedule

Comment: Many commenters requested that EPA provide an additional year to comply with the final rule. Commenters explained that the time lines associated with permitting, capital appropriation, project bid, and construction activities are significant and that the 3-year deadline would not provide adequate time for the estimated 3,730 existing units at affected sources to be retrofitted as necessary to meet the new MACT standards. The commenters added that sources subject to the final rule would also be competing with sources that are subject to other combustion rules for the same vendors.

Response: The EPA disagrees with the commenters that the 3-year compliance deadline is too short considering the

number of sources that will be competing for the resources and materials from engineering consultants, equipment vendors, construction contractors, financial institutions, and other critical suppliers. The EPA recognizes the possibility that these same consultants, vendors, etc., may also be used to comply with the utility MACT standard. However, we know that many sources will not need to install controls. As a result, since not everyone will need more than 3 years to actually install controls, the final rule does not allow an extra year for existing sources to comply with the final rule. Section 112(i)(3)(B) of the CAA allows EPA or the permit authority, on a case-by-case basis, to grant an extension permitting an existing source up to 1 additional year to comply with standards if such additional period is necessary for the installation of controls. This provision is sufficient for those sources where the 3-year deadline would not provide adequate time to retrofit as necessary to comply with the requirements of the standard. We anticipate that a number of units will seek and be granted the 1-year extension since construction of needed control devices could be constrained by the potential impacts on delays in obtaining funding and potential labor and equipment shortages.

D. Subcategorization

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Comment: Two commenters said that EPA does not have the authority to develop subcategories for the purpose of reducing compliance costs or weakening the standard. The commenters also noted that costs should not be considered in subcategorizing and establishing the MACT floor. One commenter explained that EPA has failed to present a persuasive rationale for the establishment of new or different subcategories, such as a wood-fired unit subcategory and noted that EPA cannot subcategorize based on fuel type, cost, level of emissions reductions, control technology applicability or effectiveness, achievability of emissions reductions, or health risks. The commenter argued that EPA cannot subcategorize to reduce cost because that would change CAA section 112 standards into a cost-benefit program and that is not legally defensible. The commenter noted that the D.C. Circuit court recently held that, when confronted with the cost argument, costs are not relevant when determining MACT floors.

Response: If the commenters are referring to the request for comment regarding further subcategorizations than what was proposed, the EPA agrees that there is no justification for any further subcategories. The final rule maintains the subcategories presented in the proposed rule. If the commenters are referring to subcategories presented

in the proposed rule, section 112(d)(1) of the CAA states "the Administrator may distinguish among classes, types, and sizes of sources within a category or subcategory" in establishing emission standards. Thus, we have discretion in determining appropriate subcategories based on classes, types, and sizes of sources. We used this discretion in developing subcategories for the industrial, commercial, and institutional boilers and process heaters source category. Through subcategorization, we are able to define subsets of similar emission sources within a source category if differences in emissions characteristics, processes, air pollution control device (APCD) viability, or opportunities for pollution prevention exist within the source category. We first subcategorized boilers and process heaters based on the physical state of the fuel (solid, liquid, or gaseous), which will affect the type of pollutants emitted and controls applicable, and the design and operation of the boiler, which influences the formation of organic HAP emissions. We then further subcategorized boilers and process heaters based on size. Our distinctions are based on technological differences in the equipment. For example, small units are package units typically having capacities less than 10 million Btu per hour heat input and use a combustor design which is not common in large units. A

review of the information gathered on boilers also shows that a number of units operate as backup, emergency, or peaking units that operate infrequently. The boiler database indicates that these infrequently operated units typically operate 10 percent of the year or less. These limited use boilers, when called upon to operate, must respond without failure and without lengthy periods of startup. Since their use and operation are different compared to typical industrial, commercial, and institutional boilers, we decided that such limited use units should have their own subcategory.

Neither the subcategories or MACT floor analysis was conducted considering costs, either in the proposed rule or in the final rule.

Comment: Many commenters requested EPA to develop a separate subcategory for small municipal electric utilities. Reasons for creating a subcategory for small electrical utility steam generating units included: (1) EPA has authority to establish such a subcategory of sources to be regulated under CAA section 112 and is meant to address control costs and feasibility, (2) past EPA practice supports subcategorization in this instance, (3) differences between municipal utility boilers and non-utility boilers justify subcategorization, and (4) EPA cannot properly

account for cost and energy concerns mandated in the MACT standard setting process without subcategorization for municipal utility boilers. The commenters added that the unique physical attributes of municipally-owned utilities, as well as their significant and direct impact on municipal tax base, support a separate subcategorization.

Response: The EPA sees no technical or legal justification for creating a separate subcategory for municipal utilities. Boilers at municipal utilities fire the same type of fuels, have the same type of combustor designs, and can use the same type of controls as other units in the large subcategory. Consequently, the subcategories that are in the final rule are the same as at proposal. We would also like to clarify that subcategories were developed based on combustor design and not on industrial sector. Also, had we gone beyond-the-floor, we would have considered cost in the final determination. Since we did not go beyond-the-floor level of control, cost did not play a role in the analysis.

Comment: Many commenters requested EPA add a subcategory for medium sized boilers and process heaters.

Response: The EPA does not see justification for creating a separate subcategory for medium sized units. The designation of large and small subcategories was not based

solely on size of the unit. Large and small subcategories were developed because small units less than 10 MMBtu/hr heat input typically use a combustor design that is not common in larger units. Large boilers generally use the watertube combustor design. The design of the boiler or process heater will influence the completeness of the combustion process which will influence the formation of organic HAP emissions. The EPA developed large and small subcategories to account for these differences and their affect on the type of emissions. The proposed size break between the large and small subcategories of 10 MMBtu/hr was based on typical sizes for firetube and cast iron units and considering cut-offs in State and Federal permitting requirements and rules. The EPA does not view medium sized boilers as being different than larger boilers. Combustor designs, applicable air pollution control devices, fuels used, and operation are similar for large and medium. While actual pollution controls used and monitoring equipment may be different, the CAA does not allow EPA to subcategorize on these parameters.

Section 112(d)(1) of the CAA allows EPA to distinguish among classes, types, and size in establishing MACT standards. As indicated above, at proposal, the size break selected between large and small units of 10 MMBtu/hr was

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based on typical sizes for fire tube units and also considering cut-offs in State and Federal permitting requirements and emission rules. Based on comments, we have examined information in the docket regarding the population and characteristics of industrial, commercial, and institutional boilers. It is correct that boilers below 10 MMBtu/hr are generally not required to be permitted and are either firetube or cast iron boilers. Based on review of the thousands of responses received on an information collection request (ICR) conducted during the rulemaking process, it is obvious and appropriate that the distinction between small and large units needs to include size. It is apparent from the ICR responses that facilities know the size of their units but do not generally know the exact type of the units. Many responses indicated that the boiler was both firetube and watertube. Many more responses did not list the boiler type at all. Therefore, the inclusion of size in the definition of small and large subcategories is appropriate.

Based on review of the 1979 EPA document on boiler population and the ICR survey database, the appropriate size break between small and large type units is 10 MMBtu/hr. In the EPA document, 99 percent of the boilers listed as being below 10 MMbtu/hr are either firetube or cast iron. Since

these trends are from a 25 year old report, we analyzed our ICR survey database which confirmed these findings.

E. MACT Floor

Comment: Several commenters supported EPA's finding that the MACT floor level for existing gas and liquid fuel-fired units is no emissions reductions. Other commenters contended that EPA has legal authority to set the MACT floor as "no emissions control" for particular HAP categories. A commenter noted that EPA has a clear statutory obligation to set emission standards for each listed HAP. One commenter specifically challenged EPA's determination that "no control" is the MACT floor for organic pollutants. The commenter noted that the U.S. Court of Appeals for the D.C. Circuit had squarely held, in the National Lime case, that EPA was not allowed to make a "no control" determination for a pollutant emitted by a listed category of sources.

Response: First, the MACT floor methodology we use is consistent with D.C. Circuit's holding in the National Lime case. The D.C. Circuit held that by focusing only on technology EPA ignored the directive in CAA section 112(d)(2) to consider pollution-reducing measures including process changes and substitution of materials.

The EPA has ample legal authority to set the MACT floor at "no emissions reductions." This is because the statute

requires EPA to set standards that are duplicable by others. In the National Lime case, the court threw out EPA's determination of a no control floor because it was based only on a control technology approach. The court stated that EPA must look at what the best performers achieve, regardless of how they achieve it. Therefore, our determination that the MACT floor for certain subcategories or HAP is "no emissions reductions" is lawful because we determined that the best-performing sources were not achieving emissions reductions through the use of an emission control system and there were no other appropriate methods by which boilers and process heaters could reduce HAP emissions. Furthermore, setting emissions standards on the basis of actual emissions data alone where facilities have no way of controlling their HAP emissions would contravene the plain statutory language as well as Congressional intent that affected sources not be forced to shut down.

The EPA agrees with the commenter that all factors which might control HAP emissions must be considered in making a floor determination for each subcategory. However, EPA disagrees that it must express the floor as a quantitative emission level in those instances where the source on which the floor determination is based has not

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adopted or implemented any measure that would reduce emissions.

A detailed discussion of the MACT floor methodology is presented in the memorandum "MACT Floor Analysis for New and Existing Sources in the Industrial, Commercial, and Institutional Boilers and Process Heaters Source Categories" in the docket. In summary, we considered several approaches to identifying MACT floor for existing industrial, commercial, and institutional boilers and process heaters. Based on recent court decisions, in most cases the most acceptable approach for determining the MACT floor is likely to involve primarily the consideration of available emissions test data. However, after review of the available HAP emission test data, we determined that it was inappropriate to use this MACT floor approach to establish emission limits for boilers and process heaters. The main problem with using only the HAP emissions data is that, based on the test data alone, uncontrolled units (or units with low efficiency add-on controls) were frequently identified as being among the best performing 12 percent of sources in a subcategory, while many units with high efficiency controls were not. However, these uncontrolled or poorly controlled units are not truly among the best controlled units in the category. Rather, the emissions

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from these units are relatively low because of particular characteristics of the fuel that they burn, that can not reasonably be replicated by other units in the category or subcategory. A review of fuel analyses indicate that the concentration of HAP (metals, HCl, mercury) vary greatly, not only between fuel types, but also within each fuel type. Therefore, a unit without any add-on controls, but burning a fuel containing lower amounts of HAP, can have emission levels that are lower than the emissions from a unit with the best available add-on controls. If only the available HAP emissions data are used, the resulting MACT floor levels would, in most cases, be unachievable for many, if not most, existing units, even those that employ the most effective available emission control technology. Another problem with using only emissions data is that there is very limited or no HAP emissions information available to the Agency for the subcategories. This is consistent with the fact that units in these source categories have not historically been required to test for HAP emissions.

We also considered using HAP emission limits contained in State regulations and permits as a surrogate for actual emission data in order to identify the emissions levels from the best performing units in the category for purposes of establishing MACT standards. However, we found no State

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regulations or State permits which specifically limit HAP emissions from these sources.

Consequently, we concluded that the most appropriate approach for determining MACT floors for boilers and process heaters is to look at the control options used by the units within each subcategory in order to identify the best performing units. Information was available regarding the emission control options employed by the population of boilers identified by the EPA. We considered several possible control techniques (i.e., factors that influence emissions), including fuel substitution, process changes and work practices, and add-on control technologies.

We first considered whether fuel switching would be an appropriate control option for sources in each subcategory. We considered the feasibility of both fuel switching to other fuels used in the subcategory and to fuels from other subcategories. This consideration included determining whether switching fuels would achieve lower HAP emissions. A second consideration was whether fuel switching could be technically achieved by boilers and process heaters in the subcategory considering the existing design of boilers and process heaters. We also considered the availability of various types of fuel. After considering these factors, we determined that fuel switching was not an appropriate

control technology for purposes of determining the MACT floor level of control for any subcategory. This decision was based on the overall effect of fuel switching on HAP emissions, technical and design considerations, and concerns about fuel availability.

We also concluded that process changes or work practices were not appropriate criteria for identifying the MACT floor level of control for units in the boilers and process heaters category. The HAP emissions from boilers and process heaters are either fuel dependent (i.e., mercury, metals, and inorganic HAP) or combustion related (i.e., organic HAP). Fuel dependent HAP are typically controlled by removing them from the flue gas after combustion. Therefore, they are not affected by the operation of the boiler or process heater. Consequently, process changes would be ineffective in reducing these fuel-related HAP emissions.

On the other hand, organic HAP can be formed from incomplete combustion of the fuel. Good combustion practice (GCP), in terms of boilers and process heaters, could be defined as the system design and work practices expected to minimize organic HAP emissions. While few sources in EPA's database specifically reported using good combustion practices, the data that we have suggests that boilers and

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process heaters within each subcategory might use any of a wide variety of different work practices, depending on the characteristics of the individual unit. The lack of information, and lack of a uniform approach to assuring combustion efficiency, is not surprising given the extreme diversity of boilers and process heaters, and given the fact that no applicable Federal standards, and most applicable State standards, do not include work practice requirements for boilers and process heaters. Even those States that do have such requirements do not require the same work practices. For example, CO emissions are generally a good indicator of incomplete combustion, and, therefore, low CO emissions might reflect good combustion practices. (As discussed in the proposal, CO is considered a surrogate for organic HAP emissions.) Therefore, we considered whether existing CO emission limits might be used to establish good combustion practice standards for boilers and process heaters. We reviewed State regulations applicable to boilers and process heaters, and then for each subcategory we matched the applicability of State CO emission limits with information on the locations and characteristics of the boilers and process heaters in the population database. Ultimately, we found that very few units (less than 6 percent) in any subcategory were subject to CO emission

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limits. We concluded that this information did not allow EPA to identify a level of performance that was representative of good combustion across the various units in any subcategory. Therefore, we did not establish a CO emission limit, as a surrogate for organic HAP emissions, as a part of the MACT floor for existing units. However, we have considered the appropriateness of such requirements in the context of evaluation possible beyond-the-floor options.

In general, boilers and process heaters are designed for good combustion. Facilities have an economic incentive to ensure that fuel is not wasted, and the combustion device operates properly and is appropriately maintained. In fact, existing boilers and process heaters are used typically as high efficiency control devices to control (reduce) emission streams containing organic HAP compounds from various process operations. Therefore, EPA's inability to establish a combustion practice requirement as part of the MACT floor for existing sources in this category should not reduce the incentive for owners and operators to run their boilers and process heaters at top efficiency.

As a result of the evaluation of the feasibility of establishing emission limits based on control techniques such as fuel switching and good combustion practices, we concluded that add-on control technology should be the

primary factor for purposes of identifying the best controlled units within each subcategory of boilers and process heaters. We identified the types of air pollution control techniques currently used. We ranked those controls according to their effectiveness in removing the different HAP categories of pollutants; including metallic HAP and PM, inorganic HAP such as acid gases, mercury, and organic HAP. We then listed all the boilers and process heaters in the population database in order of decreasing control device effectiveness within each subcategory for each pollutant type. Then we identified the top 12 percent of units within each category based on this ranking, and determined what kind of emission control technology, or combination of technologies, the units in the top 12 percent employed. Finally, we looked at the emissions test data from boilers and process heaters that used the same control technology, or technologies, as the units in the top 12 percent to estimate the average emissions limitation achieved by the these units.

This approach reasonably ensures that the emission limit selected as the MACT floor adequately represents the average level of control actually achieved by units in the top 12 percent. The analysis of the measured emissions from units representative of the top 12 percent is reasonably

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designed to provide a meaningful estimate of the average performance, or central tendency, of the best controlled 12 percent of units in a given subcategory. For existing subcategories where less than 12 percent of units in the subcategory use any type of control technology, we looked to see if we could estimate the central tendency of the best controlled units by looking at the unit occupying the median point in the top 12 percent (the unit at the 94th percentile). If the median unit of the top 12 percent is using some control technology, we might use the measured emission performance of that individual unit as the basis for estimating an appropriate average level of control of the top 12 percent. For subcategories were less than 6 percent of the units in a HAP grouping used controls or limited emissions, the median unit for that HAP grouping reflects no emissions reductions. Therefore, in these circumstances, EPA has appropriately established the MACT floor emission levels for these sources as no emission reduction.

Comment: Many commenters opposed EPA using emissions data from units in the large subcategory to develop emission limits for units in the small or limited use subcategories. Some commenters stated that it was not appropriate to assume that emissions rates achievable by large units are

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achievable by small units, even the best controlled units. Other commenters argued that the use of large unit data in MACT determinations for other subcategories would defeat the purpose of the subcategorization and violate the requirements of CAA section 112 because the use of this data does not represent sources in the relevant category or subcategory.

Response: The EPA disagrees with the commenters and maintains that it has conducted the MACT floor analysis appropriately. Section 112(d) of the CAA requires us to establish emission limits for new sources based on the performance of the best-controlled similar source. The CAA does not specify that the similar source must be within the same source category or subcategory. To the contrary, our interpretation of section 112(d) is that we are obligated to consider similar sources from other source categories or subcategories in determining the best-controlled similar source for establishing MACT for new sources.

For new limited use and small units, we concluded that the best-controlled similar sources are found in the large subcategory. First, EPA determined the control technology used by the best controlled sources in the subcategory. For example, only units in the population database less than 10 MMBtu/hr (and not in the limited use subcategory) were used

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to determine the MACT floor control technology for units in the small subcategories. Second, EPA used information in the emissions test database to establish the emission level associated with the MACT floor control technology. The emissions test database did not contain test data for limited use or small boilers and process heaters. Section 112(d) of the CAA requires EPA to use information from similar sources to set the MACT floor. Such sources may not be in the same subcategory. Although the units in the small and limited use subcategories are different enough to warrant their own subcategory (i.e., different purposes and operation), emissions of the specific types of HAP for which limits are being proposed are expected to be related more to the type of fuel burned and the type of control used, than to unit operation. Consequently, EPA determined that emissions information from large fuel-fired units could be used to establish MACT floor levels for the small and limited use subcategories because the fuels and controls are similar. The proposal preamble requested additional information from commenters to refine/revise the approach if necessary. No commenters provided emissions information for limited use or small subcategory boilers or process heaters.

Comment: Several commenters requested that EPA account for variability in fuel composition as MACT floors are

established and to provide adequate allowances for inherent fuel supply variability. Some commenters argued that there is no flexibility in the rule to account for this variability and noted that coal composition can vary by location and also within an individual seam.

Response: As described in the memorandum "Revised MACT Floor Analysis for the Industrial, Commercial, and Institutional Boilers and Process Heater National Emission Standards for Hazardous Air Pollutants Based on Public Comments" in the docket, the calculation of numerical emission limits was a two-step analysis. The first step involved calculating a numerical average of the appropriate subset of emission test data. The second step involved generating and applying an appropriate variability factor to account for unavoidable variations in emissions due to uncontrollable variations in fuel characteristics and ordinary operational variability. Accounting for variability is appropriate in order to generate a more accurate estimation of the actual, long term, performance of a source (e.g., the source occupying the median point in the top 12 percent). An emission test provides a momentary snapshot, not an estimation of continuous performance. In order to translate the former into the latter, we must account for that ordinary and unavoidable variability that

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the source is like to experience over time. This give us a more reasonable estimate of the actual level of emissions control that the unit is achieving. The EPA contends that by considering the variability of emissions information, we have indirectly incorporated variability in fuel, operating conditions, and sampling and analytical conditions because these parameters vary from emission tests conducted from one unit to another, and even within each test set of three measurements at a single unit. The most elementary measure of variation is range. Range is defined as the difference between the largest and smallest values. This is the variability methodology used in the proposed rule. That is, for each unit with multiple emissions tests conducted over time, the variability was calculated by dividing the highest three-run test result by the lowest three-run test result. The overall variability was calculated by averaging all the individual unit variability factors. This overall variability factor was multiplied by the overall average emission level to derive a MACT floor limit representative of the average emission limitation achieved by the top 12 percent of units. This approach adequately accounts for inherent fuel supply variability. Based on comments, EPA did conduct a more robust statistical analysis (*t*-test) of the mercury emissions data used in the MACT floor analysis

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to identify the 97.5th percent confidence limit. This analysis provided similar results to the variability analysis conducted in the proposed rule. Consequently, EPA decided not to change its variability methodology. A detailed discussion of the statistical analysis conducted is provided in the memorandum "Statistical Analysis of Mercury Test Data Variability in Response to Public Comments on Determination of the MACT Floor for Mercury Emissions" in the docket.

Comment: Several commenters supported EPA's finding that the MACT floor level of control for existing gaseous and liquid fuel units is no control. Other commenters noted that EPA has a clear statutory obligation to set emission standards for each listed HAP (the commenter cited legal briefs). One commenter specifically challenged EPA's determination of the MACT floor for organic pollutants. The commenter explained that EPA should rank the units for which emissions data is available according to the best performing units, not based on the add-on control level of 6 percent of the total population. The commenter noted that the U.S. Court of Appeals for the D.C. Circuit had squarely held, in the National Lime case, that EPA was not allowed to make a "no control" determination for a pollutant emitted by a listed category of sources.

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Response: The EPA agrees that all factors which might control HAP emissions must be considered in making a floor determination for each subcategory. However, EPA disagrees that it must express the floor as a quantitative emission level in those instances where the sources on which the floor determination is based has not adopted or implemented any measure that would reduce emissions. For several subcategories and certain HAP, EPA has not identified any adjustments or other operational modifications that would materially reduce emissions by these units, and EPA had determined that no add-on controls are presently in use. In these circumstances, EPA has established appropriately the MACT floors for these sources as no emission reduction.

Comment: One commenter pointed out that the variability factor used to make the calculated MACT floor less stringent is not allowed by section 112 of the CAA. The commenter mentioned that the variability factors are not consistent, as one factor considers the fuel variability and the other factor considers the test data variability.

Response: Section 112(d)(2) of the CAA requires that emissions standards promulgated shall require the maximum degree of reductions in emissions that the EPA Administrator, taking into consideration the costs of achieving such emission reduction, determines is achievable

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for new and existing sources in the subcategory to which such emission standards applies. Accounting for variability is appropriate in order to generate a more accurate estimation of the actual, long term, performance of a source (e.g., the source occupying the median point in the top 12 percent). An emission test provides a momentary snapshot, not an estimation of continuous performance. In order to translate the former into the latter, we must account for that ordinary and unavoidable variability that the source is like to experience over time. This give us a more reasonable estimate of the actual level of emissions control that the unit is achieving. As such, due to variations in fuel burned, and ordinary operational variability any emission limit set from a point source measurement alone may not be indicative of normal emissions or operations of the unit. Attempting to base a standard (either a floor standard, or a beyond-the-floor standard) solely on point measurements would lead to unachievable standards for all sources. Limits set by EPA must be achieved at all times, and it is important that the MACT floor limit adequately account for the normal and unavoidable variability in the process and in the operation of the control device.

Variability was assessed two ways. For existing subcategories, variability in emissions information was used

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to develop variability factors for all subcategories where emissions information was available. Variability in fuel content was used only in situations regarding determining the achievable MACT floor level for new sources from the emission test result on the best controlled similar source. This approach is appropriate since the main uncertainty associated with the emission test result from the best controlled similar source is fuel variability. Corresponding fuel analysis results were not available for the emissions test results from the best controlled similar source. Whereas, the average emission level of the best 12 percent of the units has, besides fuel variability, the uncertainty associated with operational and design variability of the various control devices installed on units that represent the best 12 percent of the units. For example, available fuel analysis information shows that mercury content of coal varies by a factor of 12.54. Dividing the highest mercury emission test result by the lowest mercury test results from coal-fired units included in units that represent the best 12 percent results in a variability factor of 20. Therefore, we concluded that fuel availability was inherently considered in the MACT floor analysis approach used for existing subcategories.

Comment: Many commenters requested that EPA revise the

MACT floor methodology for mercury emission limits. The commenters contended that the variability factor was calculated inappropriately. Other commenters stated that EPA should account for variability in fuel composition in the MACT floor analysis. Other commenters expressed concern that the floor level of control was based on fabric filters, which has not been proven at all sources to reduce mercury.

Response: As discussed in the proposal preamble, the MACT floor analysis for mercury was based on a two step process. First the percentage of units with control technologies that could achieve mercury emissions reductions was determined using the boiler population databases. If the control technology analysis indicated that at least 12 percent of sources in the subcategory used a control device that could achieve mercury emissions reductions, then the control technology present at the median (6th percentile) was identified as the MACT floor control technology. The MACT floor level of control for mercury was identified as a fabric filter. The control effectiveness of fabric filters was based on emissions information for utility boilers that indicated that mercury emissions reductions were being achieved with this technology. In this case, we could use control efficiency information from another similar source category to supplement the information available in this

source category because of the similarity in fuel burned, combustor type, and control methodology and operation. We maintain that fabric filters are still the appropriate level of control for the MACT floor.

Second, the emission limit associated with the MACT floor control technology was calculated using emissions information for units in the subcategory, whenever possible. For most of the subcategories developed, emissions information was adequate. Only for the emission limit for new source liquids and the variability factor for new source solids was fuel pollutant content incorporated into the MACT floor analyses. The mercury fuel content of coal from the utility industry was used in developing the variability factors for new solid fired units. This was done because mercury emissions are dependent on the quantity of mercury in the fuel burned. Coal available to utilities and industrial boilers and process heaters is expected to be similar, and coal is the solid fuel that is routinely used in such units that has generally the greatest degree of HAP variability. We maintain that the utility database used at proposal to develop the variability factor for new sources was adequate in establishing the MACT floor emission limit.

The EPA recognizes that the mercury emissions database for industrial boilers is limited. However, EPA is directed

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by the CAA to develop standards for sources using whatever data is available. Prior to proposal and during the Industrial Combustion Coordinated Rulemaking (ICCR) process, EPA conducted a thorough search for HAP emission test reports. This search was supported by industry, trade groups, and States. For criteria pollutants, such as PM, substantial emission information was available and gathered. For mercury and other HAP, this was not the case. Industrial boilers have not generally been required to test for HAP emissions. In the proposed rule, EPA requested commenters to provide additional emissions information. However, only one source provided any additional mercury emissions data. This information (test results from three additional coal-fired industrial boilers) was used to revise the mercury emission limit for existing sources. We also reviewed the mercury emission database used to develop the MACT floor emission limit for existing sources. After review, we determined that a revision to the variability factor was appropriate. The additional data and the revised variability factor was used to re-calculate the mercury emission limit to be 0.000009 lb/MMBtu (from 0.000007 lb/MMBtu at proposal). A detailed discussion of the revised MACT floor analysis conducted is provided in the memorandum "Revised MACT Floor Analysis for the Industrial, Commercial,

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and Institutional Boilers and Process Heaters National Emission Standards for Hazardous Air Pollutants Based on Public Comments" in the docket.

Variability of the emissions data were incorporated into the final emission limits. The EPA contends that by considering the variability of emissions information, we have indirectly incorporated variability in fuel, operating conditions, and sampling and analytical conditions because these parameters vary from emission tests conducted from one unit to another, and even within one unit. The EPA does not consider it appropriate or feasible to incorporate variability from a multitude of parameters because such information is not available and cannot be correlated to the emissions information in the emissions test database. For the final rule, EPA did conduct a statistical analysis of the data to identify the 97.5th percent confidence interval. This analysis provided similar results to the variability analysis conducted in the proposed rule. Consequently, EPA decided not to change its variability methodology. A detailed discussion of the statistical analysis conducted is provided in the memorandum "Statistical Analysis of Mercury Test Data Variability in Response to Public Comments on Determination of the MACT Floor for Mercury Emissions" in the docket.

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Comment: Several commenters contended that the California standards which the CO requirements are based on do not require CO CEMS, but require initial compliance testing and periodic subsequent performance testing.

Response: The commenters are correct that the California CO regulations do not require CO CEMS. The regulations do provide sources with the option of conducting annual testing or installing CO CEMS to demonstrate compliance with the CO emission limit. Because the regulations that were the basis of the MACT floor do not provide specifics on which boilers should conduct annual testing and which should use CO CEMS, we reviewed the cost information provided by the commenters to make this determination. In considering the additional cost information and reviewing the cost information used in the proposed rule, the EPA decided that changes to the CO compliance requirements were warranted. The final rule requires that new units with heat input capacities less than 100 MMBtu/hr conduct initial and annual performance tests for CO emissions. New units with heat input capacities greater or equal to 100 MMBtu/hr are still required to install, operate, and maintain a CO CEMS.

Regardless of whether the California regulations do or do not require CO CEMS, we would have reviewed the need for

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continuous monitoring and operating limits in order to ensure the most accurate indication of proper operation of the control system. The purpose of all of the minimum operating parameter limits in the standard is to ensure continuous compliance by ensuring that the air pollution control equipment is operating as they were during the latest performance test demonstrating compliance with the emission limits. The operating parameters are established as "minimum" to provide enforceable boundaries in their operation. Operating outside the bounds of the minimum parameters may lead to increased air emissions.

The EPA would also like to clarify that operation above the CO limit constitutes a deviation of the work practice standard. However, the determination of what deviations constitute violations of the standard is up to the discretion of the entity responsible for enforcement of the standards.

F. Beyond the MACT Floor

Comment: Many commenters contended that carbon injection should have been required as a beyond-the-floor option. Other commenters supported EPA's decision to not require any controls beyond-the-floor.

Response: For the final rule, EPA maintains that options beyond the MACT floor are not appropriate for the

standard. The EPA is required by the CAA to set the standard at a minimum on the best controlled 12 percent of sources (for existing units) or best controlled similar source (for new units). The CAA also requires EPA to consider costs and non-air quality impacts and energy requirements when considering more stringent requirements than the MACT floor. As documented in the memorandum "Methodology for Estimating Costs and Emissions Impacts for Industrial, Commercial, and Institutional Boilers and Process Heaters National Emission Standards for Hazardous Air Pollutants" in the docket, EPA did consider the cost and emission impacts of a variety of regulatory options more stringent than the MACT floor for each subcategory. The EPA recognizes that for some subcategories, more stringent controls than the MACT floor can be applied and achieve additional emissions reductions. However, EPA also determined that the cost impacts of such controls were very high. Considering both the costs and emissions reductions, EPA determined that it would be infeasible to require any options more stringent than the floor level.

For the final rule, EPA maintains that carbon injection should not be required as an above the floor technology. As discussed in the proposal preamble, we identified one existing industrial boiler that was using carbon injection.

The emissions data that we obtained from the boiler indicated that this carbon injection unit was not achieving mercury emissions reductions. This result led us to conclude that it was not the new source floor level of control. However, there may have been other reasons for the ineffectiveness of this system (e.g., low inlet mercury levels, insufficient carbon injection rate, ESP instead of fabric filter for PM control). Therefore, we considered carbon injection as a beyond-the-floor option, but decided that while this control technique has been used in other source categories, there is no demonstrated evidence that it would work for industrial boilers and process heaters because the type of mercury emitted and properties of the emission streams are sufficiently different for boilers and process heaters and other source categories.

G. Work Practice Requirements

Comment: Many commenters requested EPA consider exceedences of the CO limit to be a trigger for corrective action rather than a violation.

Response: In the final rule, we have clarified that an exceedence of the CO limit constitutes a deviation of the work practice standard. An observed exceedence of a monitoring parameter is not an automatic violation. You are required to report any deviation from an applicable emission

limitation (including operating limit). We will review the information in your report along with other available information to determine if the deviation constitutes a violation. The determination of what emission or operating limit deviation constitutes violations of the standard is up to the discretion of the entity responsible for enforcement of the standard.

H. Compliance

Comment: Many commenters requested that EPA simplify and write the fuel monitoring requirements to not require retesting of fuel for changes in fuel supplier.

Response: We agree that the fuel monitoring requirements in the proposal needed to be clarified and explained further. Therefore, we have clarified the fuel analysis options in the final rule. If you elect to demonstrate compliance with the HCl, mercury, or total selected metals limit by using fuel which has a statistically lower pollutant content than the emission limit, then your operating limit is the emission limit of the applicable pollutant. Under this option, you are not required to conduct performance tests (i.e. stack tests).

If you demonstrate compliance with the HCl, mercury, or total selected metals limit by using fuel with a statistically higher pollutant content than the applicable

emission limit, but performance tests demonstrate that you can meet the emission limits, then your operating limits are the operating limits of the control device (if used) and the fuel pollutant content of the fuel type/mixture burned.

The final rule specifies the testing methodology and procedures and the initial and continuous compliance requirements to be used when complying with the fuel analysis options. Fuel analysis tests for total chloride, gross calorific value, mercury, metal analysis, sample collection, and sample preparation are included in the final rule.

If you elect to comply based on fuel analysis, you are required to statistically analyze, using the z-test, the data to determine the 90th percentile confidence level. It is the 90th percentile confidence level that is required to be used to determine compliance with the applicable emission limit. The statistical approach is required to assist in ensuring continuous compliance by statistically accounting for the inherent variability in the fuel type.

You are required to recalculate the fuel pollutant content only if you burn a new fuel type or fuel mixture. You are required to conduct another performance test if you demonstrate compliance through performance testing, you burn a new fuel type or mixture, and the results of recalculating

the fuel pollutant content are higher than the level established during the initial performance test

Comment: Many commenters requested EPA consider exceedences of parametric limits to be a trigger for corrective action rather than a violation.

Response: In the final rule, we have clarified than an exceedence of the parametric limits constitute a deviation of the operating limits. An observed exceedence of a monitoring parameter is not an automatic violation. You are required to report any deviation from an applicable emission limitation (including operating limit). We will review the information in your report along with other available information to determine if the deviation constitutes a violation. The determination of what emission or operating limit deviation constitutes violations of the standard is up to the discretion of the entity responsible for enforcement of the standard.

Comment: Many commenters requested EPA revise the opacity requirements. Commenters objected to the provision in the proposed NESHAP that would establish an opacity "operating limit" based on the initial performance test. Some commenters contended that EPA has provided no data or references demonstrating a relationship between opacity and particulate, total metals, or mercury emissions. Other

commenters argued that the proposed opacity limit approach for dry control devices is unworkable due to the inherent inability of continuous opacity monitors (COMS) to accurately measure opacity at levels less than 10 percent. Some commenters argued that the performance and opacity achieved during the initial test may not be representative of the unit's performance. Other commenters explained that equipment condition, fuel and operating variations, and other uncontrollable parameters may result in varying emissions and emissions control equipment efficiencies over time. Commenters suggested requiring the NSPS limits for opacity rather than setting opacity based on the initial compliance test.

Response: We have reviewed the information provided by the commenters, and agree that the opacity operating limit requirements in the proposed rule are not appropriate for this source category. Because of the variability in fuels burned, the combination of fuels burned, and the typical operation of boilers and process heaters, we have decided that an opacity limit set based on the initial performance test may not be representative of the units typical performance.

We have revised the opacity operating limit provision by requiring existing units to maintain opacity to less than

or equal to 20 percent (based on 6-minute averages) except for one 6-minute period per hour of not more than 27 percent. This is the opacity limit contained in the current NSPS for industrial boilers, which has a similar PM emission limit as the final rule. Therefore, it was determined that it was appropriate to include a similar opacity level as the control device operating limit for existing units. New sources can maintain their opacity operating limit to less than or equal to 10 percent (based on 1-hour block averages). This level appears to be the lowest opacity level currently applicable to industrial boilers in State regulations.

Comment: Several commenters objected to the requirement to conduct performance testing at worst case conditions. The commenters found this requirement to be unrealistic because stack testing must be scheduled well in advance and worst-case conditions depend on fuel, load, and many other variables, making it impossible to assure that the testing will occur during worst-case conditions. Two commenters contended there can be no guarantee that mineral properties for a fuel source at the time of the baseline test can be guaranteed beyond the content identified during purchase contract negotiations with a fuel supplier. Two commenters suggested that EPA define what worst case

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conditions are because sources do not have the experience to determine worst-case representative process conditions.

Response: We agree that more direction and clarification is needed regarding testing at worst case conditions. We have modified fuel sampling requirements and performance testing fuel use requirements to simplify compliance. During performance testing, sources are required to burn the type of fuel or mixture of fuel types that have the highest concentration of regulated HAP. This, in combination with revised fuel sampling requirements (e.g., based on fuel type and not on supplier, etc), will simplify the determination of the fuel blend during the performance test. Sources are also required to conduct performance tests under representative full load operating conditions.

Comment: Several commenters objected to the requirement for annual performance tests because they felt that it is overly burdensome given the ongoing compliance demonstrations required by the NESHAP. Several commenters suggested that initial performance testing should be required with subsequent performance testing occurring every 3 to 5 years. Some commenters stated that 5-year test intervals are consistent with title V permits and have been allowed in other MACT standards (e.g. Hazardous Waste

Combustors).

Response: We have worked to minimize the testing and monitoring requirements of the final rule while retaining the ability to ensure compliance with the emission limits and work practice requirements. We are providing an option for sources to conduct performance testing once every 3 years if they conduct successful performance testing for 3 consecutive years. We are also allowing sources to demonstrate compliance with the HCl, mercury, and total selected metals emission limits through fuel testing if they do not need emission control devices to achieve the standard.

I. Emissions Averaging

In the proposal preamble, we solicited comments on an emissions averaging or bubbling compliance alternative, as part of the EPA's general policy of encouraging the use of flexible compliance approaches where they can be properly monitored and enforced, and whether EPA should include emissions averaging in the final rule. Emissions averaging can provide sources the flexibility to comply in the least costly manner while still maintaining regulation that is workable and enforceable. We requested comment on an averaging approach for determining compliance with the non-mercury metallic HAP, HCl, mercury, and/or PM standards for

existing sources. We indicated that averaging would allow owners and operators to submit non-mercury metals, mercury, HCl, and/or PM emissions limits to the EPA Administrator for approval for each existing boiler in the averaging group such that if these emission limits are met, the total emissions from all existing boilers in the averaging group are less than or equal to emission limits (for non-mercury metals, mercury, HCl, or PM) applicable to units in the particular subcategory. We indicated also that averaging would not be applicable to new sources and could only be used between boilers and process heaters in the same subcategory. Also, owners or operators of existing sources subject to the Industrial Boiler New Source Performance Standards NSPS (40 CFR part 60, subparts Db and Dc) would be required to continue to meet the PM emission standard of that NSPS regardless of whether or not they are averaging.

Emissions averaging has been incorporated into the final rule as an alternative means of complying with the final rule. Emissions averaging allows an individual affected unit emitting above the allowable emission limit required by the final rule to comply with that emission limit by averaging its emissions with other affected units at the same facility emitting below the allowable emission limit required by the final rule.

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Comment: Many commenters supported including averaging in the final rule. Commenters cited numerous reasons, including cost effectiveness, energy efficiency, greater flexibility in compliance, and greater environmental benefit. Commenters also cited 40 CFR part 63, subpart MM, Pulping Chemical Recovery Combustion MACT as a precedent for including emissions averaging in MACT standards. Two commenters disagreed with allowing emissions averaging, stating that it would complicate compliance determinations, does not fit within the CAA mandate, and is inconsistent with the purpose of CAA section 112. Many of those commenters who supported emissions averaging recommended additional flexibility, such as including new units, and bubbling across subcategories.

Response: The final rule includes an emissions averaging compliance alternative because emissions averaging represents an equivalent, more flexible, and less costly alternative to controlling certain emission points to MACT levels. We have concluded that a limited form of averaging could be implemented and not lessen the stringency of the standard. We agree with the commenters that some type of emissions averaging would provide flexibility in compliance, cost and energy savings to owners and operators. We also recognize that we must ensure that any emissions averaging

option can be implemented and enforced, will be clear to sources, and most importantly, will achieve no less emissions reductions than unit by unit implementation of the MACT requirements.

The final rule is not the first NESHAP to include provisions permitting emission averaging. In general, EPA has concluded that it is permissible to establish within a NESHAP a unified compliance regimen that permits averaging across affected units subject to the standard under certain conditions. Averaging across affected units is permitted only if it can be demonstrated that the total quantity of any particular HAP that may be emitted by that portion of a contiguous major source that is subject to the NESHAP will not be greater under the averaging mechanism than it would be if each individual affected unit complied separately with the applicable standard. Under this rigorous test, the practical outcome of averaging is equivalent in every respect to compliance by the discrete units, and the statutory policy embodied in the MACT floor provisions is, therefore, fully effectuated.

The EPA has generally imposed certain limits on the scope and nature of emissions averaging programs. These limits include: (1) no averaging between different types of pollutants, (2) no averaging between sources that are not

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part of the same major source, (3) no averaging between sources within the same major source that are not subject to the same NESHAP, and (4) no averaging between existing sources and new sources.

The final rule fully satisfies each of these criteria. Accordingly, EPA has concluded that the averaging of emissions across affected units permitted by the final rule is consistent with the CAA. In addition, EPA notes that the provision in the final rule that requires each facility that intends to utilize emission averaging to submit an emission averaging plan provides additional assurance that the necessary criteria will be followed. In this emission averaging plan, the facility must include the identification of (1) all units in the averaging group, (2) the control technology installed, (3) the process parameter that will be monitored, (4) the specific control technology or pollution prevention measure to be used, (5) the test plan for the measurement of particulate matter (or selected total metals), hydrogen chloride, or mercury emissions, and (6) the operating parameters to be monitored for each control device. Upon receipt, the regulatory authority will not approve an emission averaging plan containing averaging between emissions of different types of pollutants or between sources in different subcategories.

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The final rule excludes new affected sources from the emissions averaging provision. New sources have historically been held to a stricter standard than existing sources because it is most cost effective to integrate state-of-the-art controls into equipment design and to install the technology during construction of new sources. One reason we allow emissions averaging is to give existing sources flexibility to achieve compliance at diverse points with varying degrees of add-on control already in place in the most cost-effective and technically reasonable fashion. This concern does not apply to new sources which can be designed and constructed with compliance in mind.

Only existing large solid fuel units, as defined in the final rule, can be included in the emissions averaging compliance alternative. Of the nine subcategories established for existing sources, existing large solid fuel units is the only subcategory for which multiple HAP emissions limits apply. For the existing small solid fuel subcategory and the six existing gaseous and liquid fuel subcategories, no HAP emissions limits are included in the final rule and, thus, it would not be appropriate to allow these units to average emissions. As for the existing limited use solid fuel subcategory, since these units, as defined in the final rule, operated on a limited basis

(capacity factor of less than 10 percent) and are subject only to a less stringent PM emissions limit (as a surrogate for non-mercury metals), it would be inappropriate to allow these units to average emissions.

With concern about the equivalency of emissions reductions from averaging and non-averaging in mind, the EPA Administrator is also imposing under the emission averaging provision caps on the current emissions from each of the sources in the averaging group. The emissions for each unit in the averaging group would be capped at the emission level being achieved on the effective date of the final rule. These caps would ensure that emissions do not increase above the emission levels that sources currently are designed, operated, and maintained to achieve. In the absence of performance tests, in documenting these caps, these sources will documented the type, design, and operating specification of control devices installed on the effective date of the final rule to ensure that existing controls are not removed or lessen. By including this provision in the final rule, the EPA Administrator has taken yet another step to assist in ensuring that emission averaging results in environmental benefits equivalent or better over what would have happened without emission averaging.

The inclusion of emissions averaging into rules and the

decision on how to design an emission averaging approach for a particular source category must be evaluated for each source category.

J. Risk-based Approach

Comment: Multiple commenters supported EPA's incorporation of risk-based concepts into the MACT Program. One commenter stated that providing risk-based applicability criteria for sources whose HAP emissions do not pose a significant risk is appropriate. Several commenters stated that there is clear legal authority in the CAA to construct NESHAP based on risk, and such an approach is very appropriate in the case of the Industrial Boiler MACT. The commenter also noted that the regulatory framework exists within their State to implement such an approach. Several commenters added that risk-based alternatives will function as indirect emission limits that must be maintained by the facilities to assure that the criteria are met, and, thus, such alternatives for low-risk facilities are supportable by EPA's authority under section 112(d)(4) and 112(c)(9) of the CAA and EPA's inherent de minimis authority. Another commenter asserted that there are ways to structure the rule to focus on facilities that pose significant risks and avoid imposition of high costs on facilities that pose little risk. An appropriate approach would be to allow individual

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facilities to conduct a risk assessment to show that they pose insignificant risks to the public. However, one commenter stated that it is not appropriate for State and local programs to determine which facilities should be exempted from MACT. Several commenters supported a risk-based compliance alternative for HCl.

Response: The EPA has determined that it can establish applicable health-based emission standards for HCl and manganese for affected sources in this category pursuant to its authority under section 112(d)(4) of the CAA. As a result, EPA has included such standards in the final rule as alternative compliance requirements. Under this approach, affected sources can choose to comply with either the MACT-based emission limits or the health-based emission limits. Sources which choose to comply with the health-based emission limit(s) will remain subject to those limits, but will need to comply with testing, monitoring and reporting requirements commensurate with the compliance option they have chosen. Such health-based standards are consistent with both the commenters' support for an approach that minimizes the impact on low-risk facilities and EPA's statutory mandate under section 112.

Section 112(d)(4) of the CAA authorizes EPA to consider established health thresholds, with an ample margin of

safety, when promulgating emission standards under section 112. Hydrogen chloride and Mn are two pollutants for which health thresholds have been established. Issues concerning our legal authority to establish health-based emission standards under section 112(d)(4) are discussed in detail below.

We are not using CAA section 112(c)(9) for the final rule, and there is no delisting of categories or subcategories, as would be consistent with section 112(c)(9).

The criteria defining how affected sources demonstrate that they meet the threshold emissions levels for the health-based compliance alternative(s) is included in appendix A to the final rule. The criteria in appendix A to the final rule were developed for and apply only to the Boiler and process heater source category and are not applicable to other source categories. The final rule provides two ways that an affected source may demonstrate compliance with the health-based emission limits. The first option is through the use of lookup tables which allow facilities to determine, using a limited number of site-specific input parameters, whether emissions from boilers and process heaters might cause a hazard index (HI) limit for non-carcinogens to be exceeded. The second option is a

modeling approach which allows those facilities that do not match the site-specific input parameters on which the lookup tables are based to demonstrate compliance with the health-based emission limits by modeling using site-specific information.

The affected source will have to demonstrate that it meets the criteria established by today's final rule and then assume Federally enforceable limitations, as described in appendix A of the final rule, that ensure their specified HAP emissions do not subsequently increase to exceed levels reflected in their demonstrations.

Comment: Multiple commenters are opposed to the risk-based exemptions. Some noted that the proposal to include risk-based exemptions is critically flawed and opposes adoption of the risk-based exemptions.

One commenter stated that the inclusion of case-by-case risk-based exemptions into the first phase of the MACT program will negate the legislative mandate and jeopardize the effectiveness of the national air toxics program to adequately protect public health and the environment and to establish a level playing field. The commenter was very concerned that EPA referenced a fundamentally flawed interpretation of CAA section 112(d)(4) written by an industry (AF&PA) subject to regulation. Of particular

concern was AF&PA's unprecedented proposal to include "de minimis exemptions" and "cost" in the MACT standard process.

One commenter stated that the use of risk-based concepts to evade MACT applicability is contrary to the intent of the CAA and is based on a flawed interpretation of section 112(d)(4) of the CAA. The commenter added that the CAA requires a technology-based floor level of control and does not provide exclusions for risk or secondary impacts from applying the MACT floor.

One commenter stated that in separate rulemakings and lawsuits, EPA has adopted legal positions and policies that refute and contradict the very risk-based and cost-based approaches contained in the proposals. In these other arenas, the commenter contended that EPA has properly rejected risk assessment to alter the establishment of MACT standards. The EPA also has properly rejected cost in determining MACT floors and in denying a basis for avoiding the MACT floor.

Several commenters stated that the preamble discussion of the risk-based approaches is not sufficient to allow for complete public comment and, therefore, it would not be appropriate for EPA to go directly to a final rule (without reproposal) with any of the approaches outlined in the proposal.

Response: We are not identifying and deleting a subcategory of sources in this source category pursuant to the authority of CAA section 112(c)(9). Legal issues associated with the health-based provisions are addressed below and in the comment/response memorandum.

As discussed above, we are, however, including in the final rule alternative health-based emission standards for HCl and TSM based on our authority under CAA section 112(d)(4). Section 112(d)(4) authorizes EPA to consider health thresholds, with an ample margin of safety, in establishing emission standards. The analysis necessary to do this can generally be characterized as a risk analysis. Thus, we disagree with the commenter that we must wait for implementation of CAA section 112(f) before utilizing risk analysis.

Comment: Many commenters stated that the proposal to include risk-based exemptions is contrary to the 1990 CAA Amendments (CAAA) which calls for MACT standards based on technology rather than risk as a first step. They added that congress incorporated the residual risk program under CAA section 112(f) to follow the MACT standards (not to replace them). The commenters added that the need for the technology-based approach has been recently reinforced by the results of the National Air Toxics Assessment (NATA),

which indicates that exposure to air toxics is very high throughout the country in urban and remote areas. Several commenters added that risk-based approaches will be used separately to augment and improve technology-based standards that do not adequately provide protection to the public. One commenter added that they have been unable to substantiate the basis for EPA's support of the regulatory relief sought by industry through risk-based exemptions and that, in fact, the use of risk assessment at this stage of the MACT program is directly opposed to title III of the CAA.

Response: We disagree that inclusion of health-based compliance alternatives, in the form of emission standards based on the authority of section 112(d)(4) of the CAA, in the final rule is contrary to the 1990 CAAA. The final rule is a technology-based standard developed using the procedures dictated by section 112 of the CAA. The only difference between the final rule and other MACT is that we used our discretion under section 112(d)(4) to base appropriate parts of the final rule on established health thresholds, with an ample margin of safety. The final rule is particularly well-suited for a health-based compliance alternative, established pursuant to the criteria set forth in section 112(d)(4). In addition to the fact that there

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are established health thresholds for HCl and manganese, EPA has determined that many of the facilities in this source category do not emit these pollutants in amounts that pose a significant risk to the surrounding population. Those sources that can demonstrate that the emissions of acid gases and manganese meet the threshold emission levels will be in compliance with the MACT. The criteria are based on health-protective estimates of risk and the threshold emission levels will provide ample protection of human health and the environment.

Inclusion of health-based compliance alternatives in the final rule does not alter the MACT program. Rather, it merely represents EPA availing itself, in appropriate circumstances, of the authority Congress granted it in section 112(d)(4) of the CAA. We recognize that such provisions are only appropriate for certain HAP, and our decision-making process required source category-specific input from stakeholders.

Although the NATA modeling study may show measurable concentrations of toxic air pollution across the country, these data do not suggest that EPA should not establish health-based emission standards pursuant to its authority under CAA section 112(d)(4) when it determines that it is appropriate to do so. The alternative health-based emission

standards included in the final rule will ensure that affected sources which choose to comply with those standards do not emit HCl and/or manganese at levels that are harmful to public health.

Comment: Many commenters stated that the proposal to allow risk-based exemptions would divert back to the time-consuming NESHAP development process that existed prior to the CAAA of 1990. The commenters asserted that under this process, which began with a risk assessment step, only eight NESHAP were promulgated during a 20-year period. The commenters continued that if the proposed approaches are inserted into upcoming standards, the commenters fear the MACT program (which is already far behind schedule) would be further delayed. One commenter supported EPA efforts to determine alternative MACT setting methodologies but strongly recommended that these be pursued separately from the final rule. The commenter contended that this will provide for timely issuance of final RICE and Boiler/Process Heater MACT rules relative to the settlement deadline. Two commenters stated that delays could be exacerbated by litigation following legal challenges to the rules, and such delays would trigger the MACT hammer, which would unnecessarily burden the State and local agencies and the industries. The commenters concluded that further delay is

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unacceptable. The commenters did not want to be in a position of implementing the CAA section 112(j) program and urged EPA to not delay the issuance of any MACT standard. The commenters noted that according to a recently proposed EPA rule regarding section 112(j), the regulated community and State and local agencies would have to proceed with part 2 permit applications, followed by case-by-case MACT, if EPA misses the newly agreed-upon MACT deadlines by as little as 2 months. This would be time consuming, costly, and burdensome for both regulators and the regulated community.

Response: We disagree that allowing health-based compliance alternatives in the final rule will alter the MACT program or affect the schedule for promulgation of the remaining MACT standards. We do not anticipate any further delays in completing the remaining MACT standards. The setting of alternative health-based emission standards in the final rule affects only the final rule.

The approach taken in the final rule is particularly well-suited to acid gases and manganese, which are the only pollutants included in the health-based compliance alternatives. For many facilities, these pollutants are currently emitted in amounts that do not expose anyone in surrounding population to concentrations above the established health thresholds. As a result, emissions of

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HCl and/or manganese at these facilities do not pose a significant risk to the surrounding population. Only those Boiler facilities that demonstrate that their emissions are below the health-based emission standard(s), are eligible for the compliance alternatives.

Including health-based compliance alternatives for boiler sources does not mean that EPA will automatically provide such alternatives for other industries. Rather, as has been the case throughout the MACT rule development process, EPA will undertake in each individual rule to determine whether it is appropriate to exercise its discretion to use its authority under CAA section 112(d)(4) in developing applicable emission standards. Furthermore, EPA has no intentions of re-opening previously promulgated NESHAP in light of decisions made specific to the Boilers source category. The Boilers NESHAP is being promulgated by the February 2004 court-ordered deadline.

Comment: Many commenters stated that the risk-based proposal removes the level-playing field that would result from the proper implementation of technology-based MACT standards. The commenters added that establishing a baseline level of control is essential to prevent industry from moving to areas of the country that have the least stringent air toxics programs, which was one of the primary

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goals of developing a uniform national air toxics program under section 112 of the 1990 CAA amendments. The risk-based approaches would jeopardize future reductions of HAP in a uniform and consistent manner across the nation.

Response: Providing health-based compliance alternatives for sources that can meet them in the final rule will assure the application of a uniform set of requirements across the nation. The final rule and its criteria for demonstrating eligibility for the health-based compliance alternatives apply uniformly to boilers across the nation in the large solid fuel-fired subcategories. The final rule establishes a two baseline levels of emission reduction for HCl and manganese, one based on a traditional MACT analysis and the other based on EPA's evaluation of the health threat posed by emissions of these two pollutants. All Boiler facilities must meet one of these baseline levels, and all facilities with boilers in the applicable subcategories have the same opportunity to demonstrate that they can meet the alternative health-based emission standards. The criteria for qualifying to comply with the alternative health-based emission standards are not dependent on local air toxics programs. Therefore, concerns regarding facilities moving to areas of the country with less-stringent air toxics programs should be alleviated.

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Comment: Multiple commenters stated that section 112(d)(4) of the CAA provides EPA with authority to exclude sources that emit threshold pollutants from regulation. The commenters indicated that section 112(d)(4) allows for discretion in developing MACT standards for HAP with health thresholds. The commenters added that the use of section 112(d)(4) authority also is supported by CAA's legislative history, which emphasizes that Congress included section 112(d)(4) in the CAA to prevent unnecessary regulation of source categories.

One commenter pointed out that Congress does not differentiate between technology-based "emission standards" set under CAA section 112(d)(3) versus "health threshold" based "emission standards" set under CAA section 112(d)(4). Instead, the statute explicitly treats emission standards promulgated under section 112(d)(3) and 112(d)(4) as equivalent by not distinguishing between those emission standards under the residual risk provisions of CAA section 112(f). One commenter added that EPA is permitted to establish alternative standards as long as it ensures that ambient concentrations are less than the health thresholds plus a margin of safety and the emissions do not cause adverse environmental effects. Multiple commenters pointed out that EPA has exercised such authority and cited the

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NESHAP for Chemical Recovery Combustion Sources at Kraft, Soda, Sulfite, and Stand-Alone Semichemical Pulp Mills. In addition, the commenters added that in that NESHAP, EPA identified circumstances in which they would decline to exercise 112(d)(4) authority–where significant or widespread environmental harm would occur as a result of emissions from the category and the estimated health thresholds are subject to substantial scientific uncertainty. The commenters concluded that EPA determined that these considerations were not relevant to emissions from the pulp and paper source category, and the commenters stated that the same is true for their source categories and that the same treatment is warranted for many facilities within the source categories. The commenters noted that facilities that cannot meet the risk criteria would remain subject to the MACT requirements.

One commenter added that the risk-based approaches are squarely in line with the plain meaning of section CAA 112(d)(4). The commenters cited the Senate report (Sen Rep. No. 228, 101st Congress, 1st Sess 175-6 (1990)) showed that Congress contemplated that sources within the same category or subcategory would be subject to varied regulatory requirements, depending on the risk they pose to public health. The commenters added that nothing in the statutory definition of "emission standard" suggests that the term is

limited to a requirement for the installation of control technology. The commenters added that the risk-based compliance alternatives would meet this requirement because they would apply to an entire source category or subcategory. The EPA could create a subcategory for low-risk sources and tailor an emission standard to this subcategory, or apply to all sources in the category a NESHAP containing multiple compliance options, one or more being risk-based.

Multiple commenters stated that the plain meaning of CAA section 112(d)(4) does not allow EPA to make MACT standards for individual sources. Two commenters noted that section 112(d)(4) states that "with respect to pollutants for which a health threshold has been established, the EPA Administrator may consider such threshold level, with ample margin of safety, when establishing emission standards under this subsection."

Several commenters contended that EPA has misinterpreted the provision in CAA section 112(d)(4) in that section 112(d)(4) does not state that EPA can use applicability thresholds "in lieu of" the CAA section 112(d)(3) MACT floor requirements. The commenter interpreted section 112(d)(4) to state that health based thresholds can be considered when establishing the degree of

the MACT floor requirements, but it should not be used to supplant the requirements established pursuant to section 112(d)(3).

Many commenters stated that the legislative history of CAA section 112(d)(4) clearly rejects EPA's proposed facility-by-facility MACT exemptions. The commenters noted that Congress considered and rejected the applicability cutoffs upon which EPA now solicits comment. The commenters noted that the House version of the 1990 Amendments allowed States to issue permits that exempted a source from compliance with MACT rules if the source presented sufficient evidence to demonstrate negligible risk, and the Senate version of the 1990 Amendments contained no such provision. In conference, Congress considered both the House and Senate versions and rejected the House bill's exemption for specific facilities in favor of the Senate bill's language.

Response: The EPA has properly exercised the authority granted to it pursuant to CAA section 112(d)(4) of the CAA in establishing health-based emission standards for HCl and manganese which are applicable to the large solid fuel-fired subcategory. Section 112(d)(4) authorizes it to by-pass the mandate in section 112(d)(3) in appropriate circumstances. Those circumstances are present in the large solid fuel-

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fired Boiler subcategories.

Section 112(d)(4) of the CAA provides EPA with authority, at its discretion, to develop health-based emission standards for HAP "for which a health threshold has been established," provided that the standard reflects the health threshold "with an ample margin of safety." (The full text of the section 112(d)(4): "[with respect to pollutants for which a health threshold has been established, the Administrator may consider such threshold level, within an ample margin of safety, when establishing emission standards under this subsection.")

Both the plain language of CAA section 112(d)(4) and the legislative history cited above indicate that EPA has the discretion under section 112(d)(4) to develop health-based standards for some source categories emitting threshold pollutants, and that those standards may be less stringent than the corresponding "floor"-based MACT standard would be. The EPA's use of such standards is not limited to situations where every source in the category or subcategory can comply with them. As is the case with technology-based standards, a particular source's ability to comply with a health-based standard will depend on its individual circumstances, as will what it must do to achieve compliance.

In developing health-based emission standards under CAA section 112(d)(4), EPA seeks to assure that those standards ensure that the concentration of the particular HAP to which an individual exposed at the upper end of the exposure distribution is exposed does not exceed the health threshold. The upper end of the exposure distribution is calculated using the "high end exposure estimate," defined as "a plausible estimate of individual exposure for those persons at the upper end of the exposure distribution, conceptually above the 90th percentile, but not higher than the individual in the population who has the highest exposure" (EPA Exposure Assessment Guidelines, 57 FR 22888, May 29, 1992). Assuring protection to persons at the upper end of the exposure distribution is consistent with the "ample margin of safety" requirement in section 112(d)(4).

We agree that section 112(d)(4) is appropriate for establishing emission standards for HCl and manganese applicable to the large solid fuel-fired subcategories, and, therefore, we have established such standards as an alternate compliance requirement for affected sources in those subcategories. Affected sources in the large solid fuel-fired subcategories which believe that they can demonstrate compliance with one or both of the health-based emission standards may choose to comply with those standards

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in lieu of the otherwise applicable MACT-based standard.

For purposes of the final rule, we are not considering background HAP emissions in developing the section CAA 112(d)(4) compliance alternatives. As we indicated in the Residual Risk Report to Congress, however, the Agency intends to consider facility-wide HAP emissions in future CAA section 112(f) residual risk actions.

Comment: Many commenters contended that the proposal will place a very intensive resource demand on State and local agencies to review source's risk assessments, and State/local agencies may not have expertise in risk assessment methodology or the resources needed to verify information (e.g., emissions data and stack parameters) submitted with each risk assessment.

Other commenters stated that a risk-based program can be structured and implemented in a manner that does not adversely impact limited State resources. One commenter asserted that EPA should work closely with States and industry to implement the risk-based approach in a non-burdensome manner. Another commenter stated that the risk-based approaches, like other MACT standards, would simply be incorporated into each State's existing title V program. The commenter concluded that because the title V framework already exists, the addition of a risk-based MACT

standard would not require States to overhaul existing permitting programs. Another commenter contended that the final MACT rule itself should set forth the applicability criteria - including the threshold levels of exposure - that sources must meet to qualify for a risk-based determination. Each source would have the burden of demonstrating that its exposures are below this limit and, therefore, the States would not be required to develop their own risk assessment guidance or to conduct source-specific risk assessments.

Response: The health-based emission limits for HCl and TSM which EPA has adopted in the final rule should not impose significant resource burdens on States. Further, the required compliance demonstration methodology is structured in such a way as to avoid the need for States to have significant expertise in risk assessment methodology. We have considered the commenters' concerns in developing the criteria defining eligibility for these compliance alternatives, and the approach that is included in the final rule provides clear, flexible requirements and enforceable compliance parameters. The final rule provides two ways that a facility may demonstrate eligibility for complying with the alternative health-based emission standard. First, look-up tables, which are included as Tables 2 (HCl) and 3 (manganese) in appendix A of the final rule, allow

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facilities to determine, using a limited number of site-specific input parameters, whether emissions from their sources might cause a hazard index limit (hazard quotient in the case of manganese) to be exceeded. If a facility cannot demonstrate eligibility using a look-up table, a modeling approach can be followed. Appendix A to the final rule presents the criteria for performing this modeling.

Regarding commenters' concerns with looking for a threshold level for carcinogens, the compliance alternatives only apply to HCl and manganese, which are not currently expected to be carcinogens. Also, the concern expressed by a commenter about exempting a facility based on limited emission data if EPA established a subcategory listing low-risk sources is not relevant here, because we have not used CAA section 112(c)(9) authority to establish a low-risk subcategory for the Industrial/Commercial/Institutional Boilers and Process Heaters source category. With respect to guidance for performing site-specific modeling, all of the procedures for performing such modeling are available in peer-reviewed scientific literature and, therefore, no additional guidance needs to be developed.

Only a portion of the major facilities in the large solid fuel-fired boilers and process heaters subcategory will submit eligibility demonstrations for the compliance

alternatives. Of this portion of major sources, most will be able to demonstrate eligibility based on simple analyses (e.g., using the look-up tables provided in appendix A of the final rule). However, it is likely that some facilities will require more detailed modeling. The criteria for demonstrating eligibility for the compliance alternatives are clearly spelled out in the final rule. Because these requirements are clearly spelled out and because any standards or requirements created under CAA section 112 are considered applicable requirements under 40 CFR part 70, the compliance alternatives would be incorporated into title V programs, and States would not have to overhaul existing permitting programs.

Finally, with respect to the burden associated with ongoing assurance that facilities which opt to do so continue to comply with the health-based compliance alternatives, the burden to States will be minimal. In accordance with the provisions of title V of the CAA and part 70 of 40 CFR (collectively "title V"), the owner or operator of any affected source opting to comply with the health-based emission standards will be required to certify compliance with those standards on an annual basis. Additionally, before changing key parameters that may impact an affected source's ability to continue to meet one or both

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of the health-based emission standards, the affected source is required to evaluate its ability to continue to comply with the health-based emission standard(s) and submit documentation to the permitting authority supporting continued eligibility for the compliance alternative.

The promulgation of specific alternative health-based emission limits and a uniform methodology for demonstrating compliance with those alternatives alleviates any concern regarding the public process required in reviewing/approving the proposed approaches and making substantial changes to existing regulations. It also addresses concerns regarding the costs and resources associated with assuring adequate public participation in the process of reviewing site-specific risk analyses.

To ensure that affected sources which choose to comply with the alternative health-based emission standards continue to comply with those standards after the initial compliance demonstration, specified assessment parameters (e.g.,HCl and/or manganese emission rate, boiler heat output, etc.) must be included in their title V permit as enforceable requirements. Draft permits and permit applications must be made available to the public from the State or local agency responsible for issuing the permit, or in the case where EPA is issuing the permit, from the EPA

regional office. Members of the public may request that the State or local agency include them on their public notice mailing list, thus providing the public the opportunity to review the appropriateness of these requirements. Every proposed title V permit has a 30-day public comment period and a 45-day EPA review period. If EPA does not object to the permit, any member of the public may petition EPA to object to the permit within 60 days of the end of the EPA review period.

Comment: A commenter contended that exempting HCl emissions from control is inappropriate, particularly since EPA proposed HCl as a surrogate measure for all the inorganic HAP emitted by this source category. Hence, an exemption that excluded HCl emission points from control requirements would also exclude emissions of all the other inorganic HAP that would likely include hydrogen cyanide and hydrogen fluoride.

Response: Facilities attempting to utilize the health-based compliance alternative for HCl will not be required to evaluate emissions of other inorganic HAP except for chlorine. We conducted an assessment of boiler emissions and determined that, of the acid gas HAP controlled by scrubbing technology, chlorine is responsible for the great majority of risk and HCl is responsible for the next largest

portion of the total risk. The contributions of other HAP, including hydrogen fluoride, to the total risk were negligible. Therefore, facilities attempting to demonstrate eligibility for the health-based compliance alternative for HCl, either by conducting a lookup table analysis or by conducting a site-specific compliance demonstration, must include emission rates of chlorine and HCl from their boilers. We do not expect hydrogen cyanide emissions from boilers covered under the final rule.

Comment: Commenters stated that the proposal does not address ecological risk that may result from uncontrolled HAP emissions, especially in those areas with sensitive habitats but few people nearby to be exposed and that EPA provided inadequate discussion of how environmental risks will be evaluated.

Response: To identify HAP with potential to cause multimedia and/or environmental effects, the EPA has identified HAP with significant potential to persist in the environment and to bioaccumulate. This list does not include HCl or manganese which are the only HAP with health-based compliance alternatives in the final rule. Additionally, a screening level analysis conducted by the EPA indicates that acute impacts of these HAP from industrial boiler facilities are highly unlikely. For these

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reasons we do not believe that emissions of HCl or manganese from industrial boiler facilities will pose a significant risk to the environment and facilities attempting to comply with the health-based alternatives for these HAP are not required to perform an ecological assessment.

V. Impacts of the Final Rule

A. What are the air impacts?

Nationwide emissions of selected HAP (i.e., HCl, hydrogen fluoride, lead, and nickel) will be reduced by 58,500 tpy for existing units and 73 tpy for new units. Depending on the number of facilities demonstrating eligibility for the health-based compliance alternatives, the total HAP reduction for existing units could be 50,600 tpy. Emissions of HCl will be reduced by 42,000 tpy for existing units and 72 tpy for new units. Depending on the number of facilities demonstrating eligibility for the health-based compliance alternatives, the total HCl emissions reduction for existing units could be 36,400 tpy. Emissions of mercury will be reduced by 1.9 tpy for existing units and 0.006 tpy for new units. Emissions of PM will be reduced by 565,000 tpy for existing units and 480 tpy for new units. Depending on the number of facilities demonstrating eligibility for the health-based compliance alternatives, the total PM emissions reduction for existing

units could be 547,000 tpy. Emissions of total selected nonmercury metals (i.e., arsenic, beryllium, cadmium, chromium, lead, manganese, nickel, and selenium) will be reduced by 1,100 tpy for existing units and will be reduced by 1.4 tpy for new units. Depending on the number of facilities demonstrating eligibility for the health-based compliance alternatives, the total nonmercury metals emissions reduction for existing units could be 950 tpy. In addition, emissions of sulfur dioxide (SO_2) are established to be reduced by 113,000 tpy for existing sources and 110 tpy for new sources. Depending on the number of facilities demonstrating eligibility for the health-based compliance alternatives, the total SO_2 emissions reduction for existing units could be 49,000 tpy.

As noted above, use of the health-based compliance alternatives by eligible facilities will affect reductions in HAP, PM (and total non-mercury metals that are generally controlled along with PM), and SO_2. Nevertheless, our analysis indicates that the difference in emissions of HCl and manganese with and without the compliance alternatives will not affect health risks because the compliance alternative is available only to those facilities that demonstrate that their emissions pose little risks. Emissions of PM and SO_2 will still be reduced by the

implementation of other provisions of the Clean Air Act, such as attainment of the health-based National Ambient Air Quality Standards, which include mechanisms to control such emissions.

A discussion of the methodology used to estimate emissions and emissions reductions is presented in "Estimation of Baseline Emissions and Emissions Reductions for Industrial, Commercial, and Institutional Boilers and Process Heaters" in the docket. To estimate the potential impacts of the health-based compliance alternatives, we performed a preliminary "rough" assessment of the large solid fuel subcategory to determine the extent to which facilities might become eligible for the health-based compliance alternatives. Based on the results of this rough assessment, 448 coal-fired boilers could potentially be eligible for the HCl compliance alternative and 386 biomass-fired boilers could be potentially eligible for the TSM compliance alternative.

B. What are the water and solid waste impacts?

The EPA estimates the additional water usage that would result from the MACT floor level of control to be 110 million gallons per year for existing sources and 0.6 million gallons per year for new sources. In addition to the increased water usage, an additional 3.7 million gallons

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per year of wastewater will be produced for existing sources and 0.6 million gallons per year for new sources. The costs of treating the additional wastewater are $18,000 for existing sources and $2,300 for new sources, in advance of any facility demonstrating eligibility for the health-based compliance alternatives. These costs are accounted for in the control costs estimates.

The EPA estimates the additional solid waste that would result from the MACT floor level of control to be 102,000 tpy for existing sources and 1 tpy for new sources. The estimated costs of handling the additional solid waste generated are $1.5 million for existing sources and $17,000 for new sources, in advance of any facility demonstrating eligibility for the health-based compliance alternatives. These costs are also accounted for in the control costs estimates.

A discussion of the methodology used to estimate impacts is presented in "Estimation of Impacts for Industrial, Commercial, and Institutional Boilers and Process Heaters NESHAP" in the docket.

C. <u>What are the energy impacts</u>?

The EPA expects an increase of approximately 1,130 million kilowatt hours (kWh) in national annual energy usage as a result of the final rule, in advance of any facility

demonstrating eligibility for the health-based compliance alternatives. Of this amount, 1,120 million kWh is estimated from existing sources and 13 million kWh is estimated from new sources. The increase results from the electricity required to operate control devices installed to meet the final rule, such as wet scrubbers and fabric filters.

D. What are the control costs?

To estimate the national cost impacts of the final rule for existing sources, EPA developed several model boilers and process heaters and determined the cost of control equipment for these model boilers. The EPA assigned a model boiler or heater to each existing unit in the database based on the fuel, size, design, and current controls. The analysis considered all air pollution control equipment currently in operation at existing boilers and process heaters. Model costs were then assigned to all existing units that could not otherwise meet the proposed emission limits. The resulting total national cost impact of the final rule is $1,790 million in capital expenditures and $860 million per year in total annual costs. Depending on the number of facilities demonstrating eligibility for the health-based compliance alternatives, these costs could be $1,440 million in capital expenditures and $690 million per

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year in total annual costs. The total capital and annual costs include costs for testing, monitoring, and recordkeeping and reporting. Costs include testing and monitoring costs, but not recordkeeping and reporting costs.

Using Department of Energy projections on fuel expenditures, EPA estimated the number of additional boilers that could be potentially constructed. The resulting total national cost impact of the final rule in the 5th year is $58 million in capital expenditures and $18.6 million per year in total annual costs, in advance of any facility demonstrating eligibility for the health-based provisions. Costs are mainly for testing and monitoring.

A discussion of the methodology used to estimate cost impacts is presented in "Methodology and Results of Estimating the Cost of Complying with the Industrial, Commercial, and Institutional Boiler and Process Heater NESHAP" in the docket.

E. What are the economic impacts?

The economic impact analysis shows that the expected price increase for output in the 40 affected industries would be no more than 0.04 percent as a result of the final rule for industrial boilers and process heaters. The expected change in production of affected output is a reduction of only 0.03 percent or less in the same

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industries. In addition, impacts to affected energy markets show that prices of petroleum, natural gas, electricity and coal should increase by no more than 0.05 percent as a result of implementation of the final rule, and output of these types of energy should decrease by no more than 0.01 percent. These impacts are generated in advance of any facility demonstrating eligibility for the health-based compliance alternatives. Depending on the number of affected facilities demonstrating eligibility for the health-based compliance alternatives, these impacts on product prices could fall to a 0.03 percent increase, and a decrease in output of the energy types mentioned previously of less than 0.01 percent. Therefore, it is likely that there is no adverse impact expected to occur for those industries that produce output affected by the final rule, such as lumber and wood products, chemical manufacturers, petroleum refining, and furniture manufacturing.

F. <u>What are the social costs and benefits of the final rule</u>?

Our assessment of costs and benefits of the final rule is detailed in the "Regulatory Impact Analysis for the Final Industrial, Commercial, and Institutional Boilers and Process Heaters MACT." The Regulatory Impact Analysis (RIA) is located in the Docket.

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It is estimated that 3 years after implementation of the final rule, HAP will be reduced by 58,500 tpy (53,200 megagrams per year (Mg/yr)) due to reductions in arsenic, beryllium, HCl, and several other HAP from existing affected emission sources. Of these reductions, 42,000 tpy (38,200 Mg/yr) are of HCl. In addition to these reductions, there are 73 tpy (66 Mg/yr) of HAP reductions expected from new sources. Of these reductions, virtually all of them are of HCl. The health effects associated with these HAP are discussed earlier in this preamble. While it is beneficial to society to reduce these HAP, we are unable to quantify and provide a monetized estimate of the benefits at this time.

Despite our inability to quantify and provide monetized benefit estimates from HAP reductions, it is possible to derive rough estimates for one of the more important benefit categories, i.e., the potential number of cancer cases avoided and cancer risk reduced as a result of the imposition of the MACT level of control on this source category. Our analysis suggests that imposition of the MACT level of control would reduce cancer cases at worst case baseline assumptions by possibly tens of cases per year, on average, starting some years after implementation of the final rule. This risk reduction estimate is uncertain, is

likely to overestimate benefits, and should be regarded as an extremely rough estimate. Furthermore, the estimate should be viewed in the context of the full spectrum of unquantified noncancer effects associated with the HAP reductions. Noncancer effects associated with the HAP are presented earlier in this preamble.

The control technologies used to reduce the level of HAP emitted from affected sources are also expected to reduce emissions of PM (PM_{10},$PM_{2.5}$), and sulfur dioxide (SO_2). It is estimated that PM_{10} emissions reductions total approximately 562,000 tpy (510,000 Mg/yr), $PM_{2.5}$ emissions reductions total approximately 159,000 tpy (145,000 Mg/yr), and SO_2 emissions reductions total approximately 113,000 tpy (102,670 Mg/yr). These estimated reductions occur from existing sources in operation 3 years after the implementation of the requirements of the final rule and are expected to continue throughout the life of the sources.

In general, exposure to high concentrations of PM may aggravate existing respiratory and cardiovascular disease including asthma, bronchitis and emphysema, especially in children and the elderly. SO_2 is also a contributor to acid deposition, or acid rain, which causes acidification of lakes and streams and can damage trees, crops, historic buildings and statues. Exposure to $PM_{2.5}$ can lead to

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decreased lung function, and alterations in lung tissue and structure and in respiratory tract defense mechanisms which may then lead to, increased respiratory symptoms and disease, or in more severe cases, premature death or increased hospital admissions and emergency room visits. Children, the elderly, and people with cardiopulmonary disease, such as asthma, are most at risk from these health effects. Fine PM can also form a haze that reduces the visibility of scenic areas, can cause acidification of water bodies, and have other impacts on soil, plants, and materials. As SO_2 emissions transform into PM, they can lead to the same health and welfare effects listed above.

For PM_{10} and $PM_{2.5}$ (including SO_2 contributions to ambient concentrations of $PM_{2.5}$), we provide a monetary estimate for the benefits associated with the reduction in emissions associated with the final rule. To do so, we conducted an air quality assessment to determine the change in ambient concentrations of PM_{10} and $PM_{2.5}$ that result from reductions of PM and SO_2 at existing affected facilities. Unfortunately, our data are not able to define the exact location of the reductions for every affected boiler and process heater. Because of this limitation, the benefits assessment is conducted in two phases. First, an air quality analysis was conducted for emissions reductions from

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those emissions sources that have an known link to a specific control device, which represents approximately 50 percent of the total emissions reductions mentioned above. Using this subset of information, we determined the air quality change nationwide. The results of the air quality assessment served as input to a model that estimates the total monetary value of benefits of the health effects listed above. Total benefits associated with this portion of the analysis (in phase one) are $8.2 billion in the year 2005 (presented in 1999 dollars).

In the second phase of our analysis, for those emissions reductions from affected sources that do not have a known link to a specific control device, the results of the air quality analysis in phase one serve as a reasonable approximation of air quality changes to transfer to the remaining emissions reductions of the final rule. Because there is not a reasonable way to apportion the total benefits of the combined impact of the PM and SO_2 reductions from the air quality and benefit analyses completed above, we performed two additional air quality analyses. One analysis was performed to evaluate the impact on air quality of the PM reductions alone (holding SO_2 unchanged), and one to evaluate the impact on air quality from the SO_2 reductions alone (holding PM unchanged). With independent

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PM and SO_2 air quality assessments, we can determine the total benefit associated with each component of total pollutant reductions. The total benefit associated with the PM and SO_2 reductions with unspecified location (in phase two) are $7.9 billion.

The benefit estimates derived from the air quality modeling in the first phase of our analysis uses an analytical structure and sequence similar to that used in the benefits analyses for the proposed Nonroad Diesel rule and proposed Integrated Air Quality Rule (IAQR) and in the "section 812 studies" analysis of the total benefits and costs of the Clean Air Act. We used many of the same models and assumptions used in the Nonroad Diesel and IAQR analyses as well as other Regulatory Impact Analyses (RIAs) prepared by the Office of Air and Radiation. By adopting the major design elements, models, and assumptions developed for the section 812 studies and other RIAs, we have largely relied on methods which have already received extensive review by the independent Science Advisory Board (SAB), the National Academies of Sciences, by the public, and by other federal agencies.

The benefits transfer method used in the second phase of the analysis is similar to that used to estimate benefits at the proposal of the rule, and in the proposed the

Reciprocating Internal Combustion Engines NESHAP. A similar method has also been used in recent benefits analyses for the proposed Nonroad Large Spark-Ignition Engines and Recreational Engines standards (67 FR 68241, November 8, 2002).

The sum of benefits from the two phases of analysis provide an estimate of the total benefits of the rule. Total benefits of the final rule are approximately $16.3 billion (1999$). This economic benefit is associated with approximately 2,270 avoided premature mortalities, 5,100 avoided cases of chronic bronchitis, thousands of avoided hospital and emergency room visits for respiratory and cardiovascular diseases, tens of thousands of avoided days with respiratory symptoms, and millions of avoided work loss and restricted activity days. This estimate is generated in advance of any facility demonstrating eligibility for the health-based compliance alternatives.

Every benefit-cost analysis examining the potential effects of a change in environmental protection requirements is limited, to some extent, by data gaps, limitations in model capabilities (such as geographic coverage), and uncertainties in the underlying scientific and economic studies used to configure the benefit and cost models. Deficiencies in the scientific literature often result in

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the inability to estimate changes in health and environmental effects. Deficiencies in the economics literature often result in the inability to assign economic values even to those health and environmental outcomes that can be quantified. While these general uncertainties in the underlying scientific and economics literatures are discussed in detail in the RIA and its supporting documents and references, the key uncertainties which have a bearing on the results of the benefit-cost analysis of today's action are the following:

1. The exclusion of potentially significant benefit categories (e.g., health and ecological benefits of reduction in hazardous air pollutants emissions);

2. Errors in measurement and projection for variables such as population growth;

3. Uncertainties in the estimation of future year emissions inventories and air quality;

4. Uncertainties associated with the extrapolation of air quality monitoring data to some unmonitored areas required to better capture the effects of the standards on the affected population;

5. Variability in the estimated relationships of health and welfare effects to changes in pollutant concentrations; and

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6. Uncertainties associated with the benefit transfer approach.

7. Uncertainties in the size of the effect estimates linking air pollution and health endpoints,

8. Uncertainties about relative toxicity of different components within the complex mixture.

Despite these uncertainties, we believe the benefit-cost analysis provides a reasonable indication of the expected economic benefits of the final rule under a given set of assumptions.

Based on estimated compliance costs (control + administrative costs associated with Paperwork Reduction Act requirements associated with the rule and predicted changes in the price and output of electricity), the estimated annualized social costs of the Industrial, Commercial, and Institutional Boilers and Process Heaters NESHAP are $863 million (1999$). Depending on the number of affected facilities demonstrating eligibility for the health-based compliance alternatives, these annualized social costs could fall to $746 million. Social costs are different from compliance costs in that social costs take into account the interactions between affected producers and the consumers of affected products in response to the imposition of the compliance costs.

As explained above, we estimate $16.3 billion in benefits from the final rule, compared to $863 million in costs. It is important to put the results of this analysis in the proper context. The large benefit estimate is not attributable to reducing human and environmental exposure to the HAPs that are reduced by this rule. It arises from ancillary reductions in PM and SO_2 that result from controls aimed at complying with the NESHAP. Although consideration of ancillary benefits is reasonable, we note that these benefits are not uniquely attributable to the regulation. The Agency believes nonetheless that the key rationale for controlling arsenic, beryllium, HCl, and the other HAPs associated with this rule is to reduce public and environmental exposure to these HAPs, thereby reducing risk to public health and wildlife. Although the available science does not support quantification of these benefits at this time, the Agency believes the qualitative benefits are large enough to justify substantial investment in these emission reductions.

It should be recognized, however, that this analysis does not account for many of the potential benefits that may result from these actions. Thus, our estimate of total benefits also includes a "B" to represent those additional health and environmental benefits which could not be

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expressed in quantitative incidence and/or economic value terms. The net benefits would be greater if all the benefits of the other pollutant reductions could be quantified. Notable omissions to the net benefits include all benefits of HAP reductions, including reduced cancer incidences, toxic morbidity effects, and cardiovascular and CNS effects, and all welfare effects from reduction of ambient PM and SO_2. A full appreciation of the overall economic consequences of the industrial boiler and process heater standards requires consideration of all benefits and costs expected to result from the final rule, not just those benefits and costs that could be expressed here in dollar terms. A full listing of the benefit categories that could not be quantified or monetized in our base estimate are provided in Table 2 of this preamble.

TABLE 2.—UNQUANTIFIED BENEFIT CATEGORIES

	Unquantified benefit categories associated with HAP	Unquantified benefit categories associated with PM

Health Categories	— Airway responsiveness — Pulmonary inflammation — Increases susceptibility to respiratory infection — Acute inflammation and respiratory cell damage — Chronic respiratory damage/Premature aging of lungs — Emergency room visits for asthma	— Changes in pulmonary function. — Morphological changes. Altered host defense mechanisms — Other chronic respiratory disease — Emergency room visits for asthma — Emergency visits for non-asthma respiratory and cardiovascular causes — Lower and upper respiratory systems — Acute bronchitis — Shortness of breath — Increased school absence rates — Materials damage — Damage to ecosystems (e.g., acid sulfate deposition). — Nitrates in drinking water — Visibility in recreational and residential areas
Welfare Categories	— Ecosystem and vegetation effects — Damage to urban ornamentals (e.g. grass, flowers, shrubs, and trees in urban areas) — Commercial field crops — Fruit and vegetable crops — Reduced yields of tree seedlings, commercial and non-commercial forests — Damage to ecosystems — Materials damage	

Using the results of the benefit analysis, we can use benefit-cost comparison (or net benefits) as another tool to evaluate the reallocation of society's resources needed to address the pollution externality created by the operation of industrial boilers and process heaters. The additional costs of internalizing the pollution produced at major sources of emissions from industrial boilers and process

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heaters are compared to the improvement in society's well-being from a cleaner and healthier environment. Comparing benefits of the final rule to the costs imposed by alternative ways to control emissions optimally identifies a strategy that results in the highest net benefit to society. In the final rule, we include only one option, the minimal level of control mandated by the CAA, or the MACT floor. Other alternatives that lead to higher levels of control (or beyond-the-floor alternatives) lead to higher estimates of benefits net of costs, but also lead to additional economic impacts, including more substantial impacts to small entities. For more details, please refer to the RIA for the final rule.

Based on estimated compliance costs associated with the final rule and the predicted change in prices and production in the affected industries, the estimated annualized social costs of the final rule are $863 million (1999 dollars). This estimate of social cost is generated in advance of any facility demonstrating eligibility for the health-based compliance alternatives. Depending on the number of affected facilities demonstrating eligibility for the health-based compliance alternatives, these annualized social costs could fall to $746 million. Social costs are different from compliance costs in that social costs take

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into account the interactions of consumers and producers of affected products in response to the imposition of the compliance costs. Therefore, the Agency's estimate of monetized benefits net of costs is $15.4 billion + B (1999 dollars) in 2005.

VI. Administrative and Executive Order Reviews

A. Executive Order 12866: Regulatory Planning and Review

Under Executive Order 12866 (58 FR 51735, October 4, 1993), the EPA must determine whether a regulatory action is "significant" and, therefore, subject to review by the OMB and the requirements of the Executive Order. The Executive Order defines "significant regulatory action" as one that is likely to result in a rule that may:

(1) Have an annual effect on the economy of $100 million or more or adversely affect in a material way the economy, a sector of the economy, productivity, competition, jobs, the environment, public health or safety, or State, local, or tribal governments or communities;

(2) create a serious inconsistency or otherwise interfere with an action taken or planned by another agency;

(3) materially alter the budgetary impact of entitlements, grants, user fees, or loan programs, or the rights and obligation of recipients thereof; or

(4) raise novel legal or policy issues arising out of

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legal mandates, the President's priorities, or the principles set forth in the Executive Order.

Pursuant to the terms of Executive Order 12866, the EPA has determined that the final rule is a "significant regulatory action" because it has an annual effect on the economy of over $100 million. As such, the final rule was submitted to OMB for review.

B. Paperwork Reduction Act

The information collection requirements in the final rule have been submitted for approval to the Office of Management and Budget (OMB) under the Paperwork Reduction Act, 44 U.S.C. 3501 et seq. The information collection requirements are not enforceable until OMB approves them.

The information requirements are based on notification, recordkeeping, and reporting requirements in the NESHAP General Provisions (40 CFR part 63, subpart A), which are mandatory for all operators subject to national emission standards. These recordkeeping and reporting requirements are specifically authorized by section 114 of the CAA (42 U.S.C. 7414). All information submitted to EPA pursuant to the recordkeeping and reporting requirements for which a claim of confidentiality is made is safeguarded according to Agency policies set forth in 40 CFR part 2, subpart B.

The final rule requires maintenance inspections of the

control devices, but does not require any notifications or reports beyond those required by the General Provisions. The recordkeeping requirements require only the specific information needed to determine compliance.

The annual monitoring, reporting, and recordkeeping burden for this collection (averaged over the first 3 years after the effective date of the final rule) is estimated to be $91 million. This includes 1.2 million labor hours per year at a total labor cost of $67 million per year, and total non-labor capital costs of $24 million per year. This estimate includes a one-time performance test, semiannual excess emission reports, maintenance inspections, notifications, and recordkeeping. The total burden for the Federal government (averaged over the first 3 years after the effective date of the final rule) is estimated to be 346,000 hours per year at a total labor cost of $14 million per year. Table 4 of this preamble shows the average annualized burden for monitoring, reporting, and recordkeeping for each subcategory.

TABLE 4. SUMMARY OF THE AVERAGE REPORTING AND RECORDKEEPING COSTS

Subcategory	Total Labor Costs ($)	Total Capital Costs ($)	Total Costs ($)
Large Solid Fuel Units	56,253,000	12,488,000	68,741,000

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Limited Use Solid Fuel Units	2,565,000	2,267,000	4,832,000
Small Solid Fuel Units	627,000	111,000	738,000
Large Liquid Fuel Units	498,000	491,000	989,000
Limited Use Liquid Fuel Units	214,000	264,000	478,000
Small Liquid Fuel Units	442,000	0	442,000
Large Gaseous Fuel Units	3,673,000	6,615,000	10,288,000
Limited Use Gaseous Fuel Units	663,000	1,209,000	1,872,000
Small Gaseous Fuel Units	2,413,000	0	2,413,000

Burden means the total time, effort, or financial resources expended by persons to generate, maintain, retain, or disclose or provide information to or for a Federal agency. This includes the time needed to review instructions; develop, acquire, install, and utilize technology and systems for the purposes of collecting, validating, and verifying information, processing and maintaining information, and disclosing and providing information; adjust the existing ways to comply with any previously applicable instructions and requirements; train personnel to be able to respond to a collection of

information; search data sources; complete and review the collection of information; and transmit or otherwise disclose the information.

An agency may not conduct or sponsor, and a person is not required to respond to, a collection of information unless it displays a currently valid OMB control number. The OMB control numbers for EPA's regulations are listed in 40 CFR part 9. When this ICR is approved by OMB, the Agency will publish a technical amendment to 40 CFR part 9 in the Federal Register to display the OMB control number for the approved information collection requirements contained in this final rule.

The EPA requested comments on the need for this information, the accuracy of the provided burden estimates, and any suggested methods for minimizing respondent burden, including through the use of automated collection techniques.

C. Regulatory Flexibility Act

The EPA has determined that it is not necessary to prepare a regulatory flexibility analysis in connection with the final rule. We have also determined that the final rule will not have a significant impact on a substantial number of small entities.

For purposes of assessing the impacts of the final rule

on small entities, small entity is defined as:

(1) A small business according to Small Business Administration size standards by the North American Industry Classification System (NAICS) category of the owning entity. The range of small business size standards for the 40 affected industries ranges from 500 to 1,000 employees, except for petroleum refining and electric utilities. In these latter two industries, the size standard is 1,500 employees and a mass throughput of 75,000 barrels/day or less, and 4 million kilowatt-hours of production or less, respectively;

(2) a small governmental jurisdiction that is a government of a city, county, town, school district or special district with a population of less than 50,000; and

(3) a small organization that is any not-for-profit enterprise that is independently owned and operated and is not dominant in its field.

After considering the economic impact of the final rule on small entities, we have determined that the final rule will not have a significant economic impact on a substantial number of small entities. Based on SBA size definitions for the affected industries and reported sales and employment data, EPA identified 185 of the 576 entities, or 32 percent, owning affected facilities as small entities.

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Although small entities represent 32 percent of the entities within the source category, they are expected to incur only 4 percent of the total compliance costs of $862.7 million (1998 dollars). There are only ten small entities with compliance costs equal to or greater than 3 percent of their sales. In addition, there are only 24 small entities with cost-to-sales ratios between 1 and 3 percent.

An economic impact analysis was performed to estimate the changes in product price and production quantities for the final rule. As mentioned in the summary of economic impacts earlier in this preamble, the estimated changes in prices and output for affected entities is no more than 0.05 percent. For more information, consult the docket for the final rule.

It should be noted that these small entity impacts are in advance of any facility demonstrating eligibility for the health-based compliance alternatives. Depending on the number of affected facilities demonstrating eligibility for the health-based compliance alternatives, the estimated small entity impacts could fall to eight small entities with compliance costs equal to or greater than 3 percent of their sales, and 14 small entities with compliance costs between 1 and 3 percent of their sales.

The final rule will not have a significant economic

impact on a substantial number of small entities as a result of several decisions EPA made regarding the development of the rule, which resulted in limiting the impact of the rule on small entities. First, as mentioned earlier in this preamble, EPA identified small units (heat input of 10 MMBtu/hr or less) and limited use boilers (operate less than 10 percent of the time) as separate subcategories different from large units. Many small and limited use units are located at small entities. As also discussed earlier, the results of the MACT floor analysis for these subcategories of existing sources was that no MACT floor could be identified except for the limited use solid fuel subcategory, which is less stringent than the MACT floor for large units. Furthermore, the results of the beyond-the-floor analysis for these subcategories indicated that the costs would be too high to consider them feasible options. Consequently, the final rule contains no emission limitations for any of the existing small and limited use subcategories except the existing limited use solid fuel subcategory. In addition, the alternative metals emission limit resulted in minimizing the impacts on small entities since some of the potential entities burning a fuel containing very little metals are small entities.

D. Unfunded Mandates Reform Act of 1995

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Title II of the Unfunded Mandates Reform Act of 1995 (UMRA), Public Law 104-4, establishes requirements for Federal agencies to assess the effects of their regulatory actions on State, local, and tribal governments and the private sector. Under section 202 of the UMRA, we generally must prepare a written statement, including a cost-benefit analysis, for proposed and final rules with "Federal mandates" that may result in expenditures to State, local, and tribal governments, in the aggregate, or to the private sector, of $100 million or more in any 1 year. Before promulgating a rule for which a written statement is needed, section 205 of the UMRA generally requires us to identify and consider a reasonable number of regulatory alternatives and adopt the least costly, most cost-effective or least burdensome alternative that achieves the objectives of the rule. The provisions of section 205 do not apply when they are inconsistent with applicable law. Moreover, section 205 allows us to adopt an alternative other than the least costly, most cost-effective or least burdensome alternative if the EPA Administrator publishes with the final rule an explanation why that alternative was not adopted. Before we establish any regulatory requirements that may significantly or uniquely affect small governments, including tribal governments, we must develop a small government agency plan

under section 203 of the UMRA. The plan must provide for notifying potentially affected small governments, enabling officials of affected small governments to have meaningful and timely input in the development of regulatory promulgation with significant Federal intergovernmental mandates, and informing, educating, and advising small governments on compliance with the regulatory requirements.

We determined that the final rule contains a Federal mandate that may result in expenditures of $100 million or more for State, local, and Tribal governments, in the aggregate, or the private sector in any 1 year. Accordingly, we have prepared a written statement (titled "Unfunded Mandates Reform Act Analysis for the Industrial Boilers and Process Heaters NESHAP)" under section 202 of the UMRA, which is summarized below.

Statutory Authority

As discussed in this preamble, the statutory authority for the final rulemaking is section 112 of the CAA. Title III of the CAA Amendments was enacted to reduce nationwide air toxic emissions. Section 112(b) of the CAA lists the 188 chemicals, compounds, or groups of chemicals deemed by Congress to be HAP. These toxic air pollutants are to be regulated by NESHAP.

Section 112(d) of the CAA directs us to develop NESHAP,

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which require existing and new major sources to control emissions of HAP using MACT based standards. The final rule applies to all industrial, commercial, and institutional boilers and process heaters located at major sources of HAP emissions.

In compliance with section 205(a) of the UMRA, we identified and considered a reasonable number of regulatory alternatives. Additional information on the costs and environmental impacts of these regulatory alternatives is presented in the docket.

The regulatory alternative upon which the final rule is based represents the MACT floor for industrial boilers and process heaters and, as a result, it is the least costly and least burdensome alternative.

Social Costs and Benefits

The regulatory impact analysis prepared for the final rule including the EPA's assessment of costs and benefits, is detailed in the "Regulatory Impact Analysis for the Industrial Boilers and Process Heaters MACT" in the docket. Based on estimated compliance costs associated with the final rule and the predicted change in prices and production in the affected industries, the estimated social costs of the final rule are $863 million (1999 dollars). Depending on the number of affected facilities demonstrating

eligibility for the health-based compliance alternatives, these annualized social costs could fall to $746 million.

It is estimated that 5 years after implementation of the final rule, HAP will be reduced by 58,500 tpy due to reductions in arsenic, beryllium, dioxin, hydrochloric acid, and several other HAP from industrial boilers and process heaters. Studies have determined a relationship between exposure to these HAP and the onset of cancer, however, there are some questions remaining on how cancers that may result from exposure to these HAP can be quantified in terms of dollars. Therefore, the EPA is unable to provide a monetized estimate of the benefits of the HAP reduced by the final rule at this time. However, there are significant reductions in PM and in SO_2 that occur. Reductions of 560,000 tons of PM with a diameter of less than or equal to 10 micrometers (PM_{10}), 159,000 tons of PM with a diameter of less than or equal to 2.5 micrometers ($PM_{2.5}$), and 112,000 tons of SO_2 are expected to occur. These reductions occur from existing sources in operation 5 years after the implementation of the regulation and are expected to continue throughout the life of the affected sources. The major health effect that results from these PM and SO_2 emissions reductions is a reduction in premature mortality. Other health effects that occur are reductions in chronic

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bronchitis, asthma attacks, and work-lost days (i.e., days when employees are unable to work).

While we are unable to monetize the benefits associated with the HAP emissions reductions, we are able to monetize the benefits associated with the PM and SO_2 emissions reductions. For SO_2 and PM, we estimated the benefits associated with health effects of PM, but were unable to quantify all categories of benefits (particularly those associated with ecosystem and environmental effects). Unquantified benefits are noted with "B" in the estimates presented below. Our primary estimate of the monetized benefits in 2005 associated with the implementation of the proposed alternative is $16.3 billion + B (1999 dollars). This estimate is about $15.3 billion + B (1999 dollars) higher than the estimated social costs shown earlier in this section. These benefit estimates are in advance of any facility demonstrating eligibility for the health-based compliance alternatives. Depending on the number of affected facilities demonstrating eligibility for the health-based compliance alternatives, the benefit estimate presuming the health-based compliance alternatives is $14.5 billion + B, which is $1.7 billion lower than the estimate for the final rule. This estimate is $13.8 billion + B higher than the estimated social costs presuming the health-based compliance

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alternatives. The general approach to calculating monetized benefits is discussed in more detail earlier in this preamble. For more detailed information on the benefits estimated for the final rule, refer to the RIA in the docket.

Future and Disproportionate Costs

The Unfunded Mandates Act requires that we estimate, where accurate estimation is reasonably feasible, future compliance costs imposed by the rule and any disproportionate budgetary effects. Our estimates of the future compliance costs of the final rule are discussed previously in this preamble.

We do not feel that there will be any disproportionate budgetary effects of the final rule on any particular areas of the country, State or local governments, types of communities (e.g., urban, rural), or particular industry segments. This is true for the 257 facilities owned by 54 different government bodies, and this is borne out by the results of the "Economic Impact Analysis of the Industrial Boilers and Process Heaters NESHAP," the results of which are discussed previously in this preamble.

Effects on the National Economy

The Unfunded Mandates Act requires that we estimate the effect of the final rule on the national economy. To the

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extent feasible, we must estimate the effect on productivity, economic growth, full employment, creation of productive jobs, and international competitiveness of the U.S. goods and services, if we determine that accurate estimates are reasonably feasible and that such effect is relevant and material.

The nationwide economic impact of the final rule is presented in the "Economic Impact Analysis for the Industrial Boilers and Process Heaters MACT" in the docket. This analysis provides estimates of the effect of the final rule on some of the categories mentioned above. The results of the economic impact analysis are summarized previously in this preamble. The results show that there will be little impact on prices and output from the affected industries, and little impact on communities that may be affected by the final rule. In addition, there should be little impact on energy markets (in this case, coal, natural gas, petroleum products, and electricity). Hence, the potential impacts on the categories mentioned above should be minimal.

Consultation with Government Officials

The Unfunded Mandates Act requires that we describe the extent of the EPA's prior consultation with affected State, local, and tribal officials, summarize the officials'

comments or concerns, and summarize our response to those comments or concerns. In addition, section 203 of the UMRA requires that we develop a plan for informing and advising small governments that may be significantly or uniquely impacted by a rule. Although the final rule does not significantly affect any State, local, or Tribal governments, we have consulted with State and local air pollution control officials. We also have held meetings on the final rule with many of the stakeholders from numerous individual companies, environmental groups, consultants and vendors, labor unions, and other interested parties. We have added materials to the docket to document these meetings.

In addition, we have determined that the final rule contains no regulatory requirements that might significantly or uniquely affect small governments. While some small governments may have some sources affected by the final rule, the impacts are not expected to be significant. Therefore, the final rule is not subject to the requirements of section 203 of the UMRA. However, EPA did complete a report containing analyses called for in the UMRA as a response to comments from many municipal utilities regarding the final rule and its potential impacts. This report, "Unfunded Mandates Reform Act Analysis for the Industrial

Boilers and Process Heaters NESHAP," is in the docket.

E. Executive Order 13132: Federalism

Executive Order 13132 requires EPA to develop an accountable process to ensure "meaningful and timely input by State and local officials in the development of regulatory policies that have federalism implications." "Policies that have federalism implications" are defined in the Executive Order to include regulations that have "substantial direct effects on the States, on the relationship between the national government and the States, or on the distribution of power and responsibilities among the various levels of government.

The final rule does not have federalism implications. It will not have substantial direct effects on the States, on the relationship between the national government and the States, or on the distribution of power and responsibilities among the various levels of government, as specified in Executive Order 13132.

The agency is required by section 112 of the CAA, to establish the standards in the final rule. The final rule primarily affects private industry, and does not impose significant economic costs on State or local governments. The final rule does not include an express provision preempting State or local regulations. Thus, the

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requirements of section 6 of the Executive Order do not apply to the final rule.

Although section 6 of Executive Order 13132 does not apply to the final rule, we consulted with representatives of State and local governments to enable them to provide meaningful and timely input into the development of the final rule. This consultation took place during the ICCR Federal Advisory Committee Act (FACA) committee meetings where members representing State and local governments participated in developing recommendations for EPA's combustion-related rulemakings, including the final rule. The concerns raised by representatives of State and local governments were considered during the development of the final rule.

In the spirit of Executive Order 13132, and consistent with EPA policy to promote communications between EPA and State and local governments, EPA specifically solicited comment on the final rule from State and local officials.

F. Executive Order 13175: Consultation and Coordination with Indian Tribal Governments

Executive Order 13175 (65 FR 67249, November 9, 2000) requires EPA to develop an accountable process to ensure "meaningful and timely input by tribal officials in the development of regulatory policies that have tribal

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implications." The final rule does not have tribal implications, as specified in Executive Order 13175.

The final rule does not significantly or uniquely affect the communities of Indian tribal governments. We do not know of any industrial-commercial-institutional boilers or process heaters owned or operated by Indian tribal governments. However, if there are any, the effect of these rules on communities of tribal governments would not be unique or disproportionate to the effect on other communities. Thus, Executive Order 13175 does not apply to the final rule. The EPA specifically solicited additional comment on the final rule from tribal officials, but received none.

G. Executive Order 13045: Protection of Children from Environmental Health Risks and Safety Risks

Executive Order 13045 (62 FR 19885, April 23, 1997) applies to any regulation that: (1) is determined to be "economically significant" as defined under Executive Order 12866, and (2) concerns an environmental health or safety risk that we have reason to believe may have a disproportionate effect on children.

If the regulatory action meets both criteria, the EPA must evaluate the environmental health or safety effects of the planned regulation on children, and explain why the

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planned regulation is preferable to other potentially effective and reasonably feasible alternatives considered by the EPA.

The EPA interprets Executive Order 13045 as applying only to those regulatory actions that are based on health or safety risks, such that the analysis required under section 5-501 of the Executive Order has the potential to influence the regulation. The final rule is not subject to Executive Order 13045 because it is based on technology performance and not on health or safety risks.

H. Executive Order 13211: Actions Concerning Regulations that Significantly Affect Energy Supply, Distribution, or Use

Executive Order 13211 (66 FR 28355, May 22, 2001) provides that agencies shall prepare and submit to the Administrator of the Office of Information and Regulatory Affairs, Office of Management and Budget, a Statement of Energy Effects for certain actions identified as "significant energy actions." Section 4(b) of Executive Order 13211 defines "significant energy actions" as "any action by an agency (normally published in the Federal Register) that promulgates or is expected to lead to the promulgation of a final rule or regulation, including notices of inquiry, advance notices of final rulemaking, and

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notices of final rulemaking: (1)(i) That is a significant regulatory action under Executive Order 12866 or any successor order, and (ii) is likely to have a significant adverse effect on the supply, distribution, or use of energy; or (2) that is designated by the Administrator of the Office of Information and Regulatory Affairs as a "significant energy action." The final rule is not a "significant energy action" because it is not likely to have a significant adverse effect on the supply, distribution, or use of energy. The basis for the determination is as follows.

The reduction in petroleum product output, which includes reductions in fuel production, is estimated at only 0.001 percent, or about 68 barrels per day based on 2000 U.S. fuel production nationwide. That is a minimal reduction in nationwide petroleum product output. The reduction in coal production is estimated at only 0.014 percent, or about 3.5 million tpy (or less than 1,000 tons per day) based on 2000 U.S. coal production nationwide. The combination of the increase in electricity usage estimated with the effect of the increased price of affected output yields an increase in electricity output estimated at only 0.012 percent, or about 0.72 billion kilowatt-hours per year based on 2000 U.S. electricity production nationwide. All

energy price changes estimated show no increase in price more than 0.05 percent nationwide, and a similar result occurs for energy distribution costs. We also expect that there will be no discernable impact on the import of foreign energy supplies, and no other adverse outcomes are expected to occur with regards to energy supplies. All of the results presented above account for the pass through of costs to consumers, as well as the cost impact to producers. For more information on the estimated energy effects, please refer to the economic impact analysis for the final rule. The analysis is available in the public docket. It should be noted that these energy impact estimates are in advance of any facility demonstrating eligibility for the health-based compliance alternatives.

Depending on the number of affected facilities demonstrating eligibility for the health-based compliance alternatives, the reduction in petroleum product output, which includes reductions in fuel production, could fall to 65 barrels per day, or only 0.001 percent. The reduction in coal production could fall to only 0.010 percent, or about 2.5 million tpy based on 2000 U.S. coal production nationwide. The combination of the increase in electricity usage estimated with the effect of the increased price of affected output could yield an increase in electricity

output could fall to only 0.0067 percent, or about 0.40 billion kilowatt-hours per year based on 2000 U.S. electricity production nationwide. All energy price changes estimated could now fall to increases of no more than 0.04 percent nationwide, and a similar result occurs for energy distribution costs. There should be no discernable impact on import of foreign energy supplies, and no other adverse outcomes are expected to occur with regards to energy supplies. All of the results presented with presumption of the health-based compliance alternatives also account for the pass through of costs to consumers as well as the cost impact to producers.

Therefore, we conclude that the final rule when implemented is not likely to have a significant adverse effect on the supply, distribution, or use of energy.

I. National Technology Transfer and Advancement Act

Section 12(d) of the National Technology Transfer and Advancement Act (NTTAA) of 1995 (Public Law No. 104-113; 15 U.S.C. 272 note) directs the EPA to use voluntary consensus standards in their regulatory and procurement activities unless to do so would be inconsistent with applicable law or otherwise impractical. Voluntary consensus standards are technical standards (e.g., materials specifications, test methods, sampling procedures, business

practices) developed or adopted by one or more voluntary consensus bodies. The NTTAA directs EPA to provide Congress, through annual reports to the OMB, with explanations when an agency does not use available and applicable voluntary consensus standards.

The final rule involves technical standards. The EPA cites the following standards in the final rule: EPA Methods 1, 2, 2F, 2G, 3A, 3B, 4, 5, 5D, 17, 19, 26, 26A, 29 of 40 CFR part 60. Consistent with the NTTAA, EPA conducted searches to identify voluntary consensus standards in addition to these EPA methods. No applicable voluntary consensus standards were identified for EPA Methods 2F, 2G, 5D, and 19. The search and review results have been documented and are placed in the docket for the final rule.

The three voluntary consensus standards described below were identified as acceptable alternatives to EPA test methods for the purposes of the final rule.

The voluntary consensus standard ASME PTC 19-10-1981-Part 10, "Flue and Exhaust Gas Analyses," is cited in the final rule for its manual method for measuring the oxygen, carbon dioxide, and carbon monoxide content of exhaust gas. This part of ASME PTC 19-10-1981-Part 10 is an acceptable alternative to Method 3B.

The voluntary consensus standard ASTM D6522-00,

"Standard Test Method for the Determination of Nitrogen Oxides, Carbon Monoxide, and Oxygen Concentrations in Emissions from Natural Gas-Fired Reciprocating Engines, Combustion Turbines, Boilers and Process Heaters Using Portable Analyzers" is an acceptable alternative to EPA Method 3A for identifying carbon monoxide and oxygen concentrations for the final rule when the fuel is natural gas.

The voluntary consensus standard ASTM Z65907, "Standard Method for Both Speciated and Elemental Mercury Determination," is an acceptable alternative to EPA Method 29 (portion for mercury only) for the purpose of the final rule. This standard can be used in the final rule to determine the mercury concentration in stack gases for boilers with rated heat input capacities of greater than 250 MMBtu per hour.

In addition to the voluntary consensus standards EPA uses in the final rule, the search for emissions measurement procedures identified 15 other voluntary consensus standards. The EPA determined that 13 of these 15 standards identified for measuring emissions of the HAP or surrogates subject to the emission standards were impractical alternatives to EPA test methods for the purposes of the final rule. Therefore, EPA does not intend to adopt these

standards for this purpose. (See Docket ID No. OAR-2002-0058 for further information on the methods.)

Two of the 15 voluntary consensus standards identified in this search were not available at the time the review was conducted for the purposes of the final rule because they are under development by a voluntary consensus body: ASME/BSR MFC 13M, "Flow Measurement by Velocity Traverse," for EPA Method 2 (and possibly 1); and ASME/BSR MFC 12M, "Flow in Closed Conduits Using Multiport Averaging Pitot Primary Flowmeters," for EPA Method 2.

Section 63.7520 and Tables 4A through 4D of the final rule list the EPA testing methods. Under §63.7(f) and §63.8(f) of subpart A, 40 CFR part 63, of the General Provisions, a source may apply to EPA for permission to use alternative test methods or alternative monitoring requirements in place of any of the EPA testing methods, performance specifications, or procedures.

J. Congressional Review Act

The Congressional Review Act, 5 U.S.C. 801, et seq., as added by the Small Business Regulatory Enforcement Fairness Act of 1996, generally provides that before a rule may take effect, the agency promulgating the rule must submit a rule report, which includes a copy of the rule, to each House of the Congress and to the Comptroller General of the United

States. The EPA will submit a report containing the final rule and other required information to the United States Senate, the United States House of Representatives, and the Comptroller General of the United States prior to publication of the final rule in the Federal Register. A major rule cannot take effect until 60 days after it is published in the Federal Register. This action is a "major rule" as defined by 5 U.S.C. section 804(2). The rule will be effective on [INSERT DATE 60 DAYS AFTER DATE OF PUBLICATION OF FINAL RULE IN THE FEDERAL REGISTER].

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List of Subjects in 40 CFR part 63

Environmental protection, Administrative practice and procedure, Air pollution control, Hazardous substances, Intergovernmental relations, Reporting and recordkeeping requirements.

_____
Dated: February 26, 2004

/s/
_____
Michael O. Leavitt,
Administrator.

For the reasons stated in the preamble, title 40, chapter I, part 63 of the Code of Federal Regulations is amended as follows:

Part 63--[AMENDED]

1. The authority citation for part 63 continues to read as follows:

Authority: 42 U.S.C. 7401, et seq.

SUBPART A –[AMENDED]

2. Section 63.14 is amended by adding paragraphs (b)(30) through (46) and paragraph (i)(4). The additions read as follows:

§63.14 Incorporation by Reference.

* * * * *

(b) * * *

(30) ASTM Method D388-99e1, Standard Classification of Coals by Rank, IBR approved for §63.7575.

(31) ASTM D396-02a, Standard Specification for Fuel Oils, IBR approved for §63.7575.

(32) ASTM D1835-03a, Standard Specification for Liquified Petroleum (LP) Gases, IBR approved for §63.7575.

(33) ASTM D2013-01, Standard Practice for Preparing Coal Samples for Analysis, IBR approved for Table 6 to Subpart DDDDD of Part 63 — Requirements for Fuel Analysis Testing.

(34) ASTM D2234/D2234M-03, Standard Practice for Collection of a Gross Sample of Coal, IBR approved for Table 6 to Subpart DDDDD of Part 63 — Requirements for Fuel Analysis Testing.

(35) ASTM D3173-02, Standard Test Method for Moisture in the Analysis Sample of Coal and Coke, IBR approved for Table 6 to Subpart DDDDD of Part 63 — Requirements for Fuel Analysis Testing.

(36) ASTM D3683-94 (2000), Standard Test Method for Trace Elements in Coal and Coke Ash Absorption, IBR approved for Table 6 to Subpart DDDDD of Part 63 — Requirements for Fuel Analysis Testing.

(37) ASTM D3684-01, Standard Test Method for Total Mercury in Coal by the Oxygen Bomb Combustion/Atomic Absorption Method, IBR approved for Table 6 to Subpart DDDDD of Part 63 — Requirements for Fuel Analysis Testing.

(38) ASTM D5198-92 (2003), Standard Practice for Nitric Acid Digestion of Solid Waste, IBR approved for Table 6 to Subpart DDDDD of Part 63 — Requirements for Fuel Analysis Testing.

(39) ASTM D5865-03a, Standard Test Method for Gross Calorific Value of Coal and Coke, IBR approved for Table 6 to Subpart DDDDD of Part 63 — Requirements for Fuel Analysis Testing.

(40) ASTM D6323-98 (2003), Standard Guide for Laboratory Subsampling of Media Related to Waste Management Activities, IBR approved for Table 6 to Subpart DDDDD of Part 63 — Requirements for Fuel Analysis Testing.

(41) ASTM D6522-00, Standard Test Method for Determination of Nitrogen Oxides, Carbon Monoxide, and Oxygen Concentrations in Emissions from Natural Gas-Fired Reciprocating Engines, Combustion Turbines, Boilers, and Process Heaters Using Portable Analyzers, IBR approved for Table 5 to Subpart DDDDD of Part 63 — Requirements for Performance Tests.

(42) ASTM D6784-02, Standard Test Method for Elemental, Oxidized, Particle-Bound and Total Mercury in Flue Gas Generated from Coal-Fired Stationary Sources (Ontario Hydro Method), IBR approved for Table 5 to Subpart DDDDD of Part 63 — Requirements for Performance Tests.

(43) ASTM E711-87 (1996), Standard Test Method for Gross Calorific Value of Refuse-Derived Fuel by the Bomb Calorimeter, IBR approved for Table 6 to Subpart DDDDD of Part 63 — Requirements for Fuel Analysis Testing.

(44) ASTM E776-87 (1996), Standard Test Method for Forms of Chlorine in Refuse-Derived Fuel, IBR approved for Table 6 to Subpart DDDDD of Part 63 — Requirements for Fuel Analysis Testing.

(45) ASTM E871-82 (1998), Standard Method of Moisture Analysis of Particulate Wood Fuels, IBR approved for Table 6 to Subpart DDDDD of Part 63 — Requirements for Fuel Analysis Testing.

(46) ASTM E885-88 (1996), Standard Test Methods for Analyses of Metals in Refuse-Derived Fuel by Atomic Absorption Spectroscopy, IBR approved for Table 6 to Subpart DDDDD of Part 63 — Requirements for Fuel Analysis Testing.

* * * * *

(i) * * *

(4) ASME PTC 19.10-1981, Flue and Exhaust Gas Analyses - Part 10, IBR approved for Table 5 to Subpart DDDDD of Part 63 - Performance Testing Requirements.

3. Part 63 is amended by adding subpart DDDDD to read as follows:

Subpart DDDDD--National Emission Standards for Hazardous Air Pollutants for Industrial, Commercial, and Institutional Boilers and Process Heaters

Sec.

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63.7490 What is the affected source of this subpart?
63.7491 Are any boilers or process heaters not subject to this subpart?
63.7495 When do I have to comply with this subpart?

Emission Limits and Work Practice Standards

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63.7500 What emission limits, work practice standards, and operating limits must I meet?

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Appendix

Appendix A to Subpart DDDDD - Methodology and Criteria for Demonstrating Eligibility for the Health-Based Compliance Alternatives Specified for the Large Solid Fuel Subcategory

What this Subpart Covers

<u>§63.7480 What is the purpose of this subpart?</u>

This subpart establishes national emission limits and work practice standards for hazardous air pollutants (HAP) emitted from industrial, commercial, and institutional

boilers and process heaters. This subpart also establishes requirements to demonstrate initial and continuous compliance with the emission limits and work practice standards.

§63.7485 Am I subject to this subpart?

You are subject to this subpart if you own or operate an industrial, commercial, or institutional boiler or process heater as defined in §63.7575 that is located at, or is part of, a major source of HAP as defined in §63.2 or §63.760 (40 CFR part 63, subpart HH, National Emission Standards for Hazardous Air Pollutants from Oil and Natural Gas Production Facilities), except as specified in §63.7491.

§63.7490 What is the affected source of this subpart?

(a) This subpart applies to new, reconstructed, or existing affected sources as described in paragraphs (a)(1) and (2) of this section.

(1) The affected source of this subpart is the collection of all existing industrial, commercial, and institutional boilers and process heaters within a subcategory located at a major source 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 located at a major source as

defined in §63.7575.

(b) A boiler or process heater is new if you commence construction of the boiler or process heater after January 13, 2003, 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 January 13, 2003, 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.

§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 (o) of this section are not subject to this subpart.

(a) A municipal waste combustor covered by 40 CFR part 60, subpart AAAA, subpart BBBB or subpart Cb.

(b) A hospital/medical/infectious waste incinerator covered by 40 CFR part 60, subpart Ce or subpart Ec.

(c) An electric utility steam generating unit that is a fossil fuel-fired combustion unit of more than 25 megawatts 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 megawatts electrical output to any utility power distribution system for sale is considered an electric utility steam generating unit.

(d) A boiler or process heater required to have a permit under section 3005 of the Solid Waste Disposal Act or covered by 40 CFR part 63, subpart EEE (e.g., hazardous waste boilers).

(e) A commercial and industrial solid waste incineration unit covered by 40 CFR part 60, subpart CCCC or subpart DDDD.

(f) A recovery boiler or furnace covered by 40 CFR part 63, subpart MM.

(g) A boiler or process heater that is used specifically for research and development. This does not include units that only provide heat or steam to a process at a research and development facility.

(h) A hot water heater as defined in this subpart.

(i) A refining kettle covered by 40 CFR part 63, subpart X.

(j) An ethylene cracking furnace covered by 40 CFR part 63, subpart YY.

(k) Blast furnace stoves as described in the EPA document, entitled "National Emission Standards for Hazardous Air Pollutants (NESHAP) for Integrated Iron and Steel Plants - Background Information for Proposed Standards," (EPA-453/R-01-005).

(l) Any boiler and process heater specifically listed as an affected source in another standard(s) under 40 CFR part 63.

(m) Any boiler and process heater specifically listed as an affected source in another standard(s) established under section 129 of the Clean Air Act (CAA).

(n) Temporary boilers as defined in this subpart.

(o) Blast furnace gas fuel-fired boilers and process heaters as defined in this subpart.

§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 [INSERT THE DATE OF PUBLICATION OF THE FINAL RULE IN THE FEDERAL REGISTER] 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 [INSERT THE DATE 3 YEARS AFTER PUBLICATION OF THE FINAL RULE IN THE FEDERAL REGISTER].

(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 facility must be in compliance with this subpart upon startup.

(2) Any existing boiler or process heater at the existing facility must be in compliance with this subpart within 3 years after the facility 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.

Emission Limits and Work Practice Standards

<u>§63.7499 What are the subcategories of boilers and process heaters</u>?

(a) The subcategories of boilers and process heaters are large solid fuel, limited use solid fuel, small solid fuel, large liquid fuel, limited use liquid fuel, small liquid fuel, large gaseous fuel, limited use gaseous fuel, and small gaseous fuel. Each subcategory is defined in §63.7575.

(b) If you change an existing boiler or process heater in the large solid fuel subcategory such that its applicable subcategory also changes, and the change does not meet the definition of reconstruction as defined in subpart A of this part, you may choose to meet the applicable emission limits for the original large solid fuel subcategory.

§63.7500 What emission limits, work practice standards, and operating limits must I meet?

(a) You must meet the requirements in paragraphs (a)(1) and (2) of this section.

(1) You must meet each emission limit and work practice standard in Table 1 to this subpart that applies to your boiler or process heater, except as provided under §63.7507.

(2) You must meet each operating limit in Tables 2 through 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 Tables 2 through 4 to this subpart, or you wish to establish and monitor an alternative operating limit and alternative monitoring parameters, you must apply to the United States Environmental Protection Agency (EPA) Administrator for approval of alternative monitoring under §63.8(f).

(b) As provided in §63.6(g), EPA may approve use of an

alternative to the work practice standards in this section.

General Compliance Requirements

§63.7505 What are my general requirements for complying with this subpart?

(a) You must be in compliance with the emission limits (including operating limits) and the work practice standards in this subpart at all times, except during periods of startup, shutdown, and malfunction.

(b) 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)(i).

(c) You can demonstrate compliance with any applicable emission limit using fuel analysis if the emission rate calculated according to §63.7530(d) is less than the applicable emission limit. Otherwise, you must demonstrate compliance using performance testing.

(d) If you demonstrate compliance with any applicable emission limit through performance testing, you must develop a site-specific monitoring plan according to the requirements in paragraphs (d)(1) through (4) of this section. This requirement also applies to you if you petition the EPA Administrator for alternative monitoring parameters under §63.8(f).

(1) For each continuous monitoring system (CMS)

required in this section, you must develop and submit to the EPA Administrator for approval a site-specific monitoring plan that addresses paragraphs (d)(1)(i) through (iii) of this section. You must submit this site-specific monitoring plan at least 60 days before your initial performance evaluation of your CMS.

(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).

(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), (3), and (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), (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 or work practice standard, you must develop and implement a written startup, shutdown, and malfunction plan (SSMP) according to the provisions in §63.6(e)(3).

<u>§63.7506 Do any boilers or process heaters have limited requirements</u>?

(a) New or reconstructed boilers and process heaters in one of the liquid fuel subcategories (the large liquid fuel subcategory, the limited use liquid fuel subcategory, or the small liquid fuel subcategory) that burn only fossil fuels and other gases and do not burn any residual oil are subject to the emission limits and applicable work practice standards in Table 1 to this subpart. You are not required to conduct a performance test to demonstrate compliance with the emission limits. You are not required to set and

maintain operating limits to demonstrate continuous compliance with the emission limits. However, you must meet the requirements in paragraphs (a)(1) and (2) of this section.

(1) To demonstrate initial compliance, you must include a signed statement in the Notification of Compliance Status report required in §63.7545(e) that indicates you burn only liquid fossil fuels other than residual oils, either alone or in combination with gaseous fuels.

(2) To demonstrate continuous compliance with the applicable emission limits, you must also keep records that demonstrate that you burn only liquid fossil fuels other than residual oils, either alone or in combination with gaseous fuels. You must also include a signed statement in each semiannual compliance report required in §63.7550 that indicates you burned only liquid fossil fuels other than residual oils, either alone or in combination with gaseous fuels, during the reporting period.

(b) The affected boilers and process heaters listed in paragraphs (b)(1) through (3) of this section are subject to only the initial notification requirements in §63.9(b) (i.e., they are not subject to the emission limits, work practice standards, performance testing, monitoring, SSMP, site-specific monitoring plans, recordkeeping and reporting requirements of this subpart or any other requirements in

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subpart A of this part).

(1) Existing large and limited use gaseous fuel units.

(2) Existing large and limited use liquid fuel units.

(3) New small liquid fuel units that burn only gaseous fuels or distillate oil. New small liquid fuel boilers and process heaters that commence burning of any other type of liquid fuel must comply with all applicable requirements of this subpart and subpart A of this part upon startup of burning the other type of liquid fuel.

(c) The affected boilers and process heaters listed in paragraphs (c)(1) through (4) of this section are not subject to the initial notification requirements in §63.9(b) and are not subject to any requirements in this subpart or in subpart A of this part (i.e., they are not subject to the emission limits, work practice standards, performance testing, monitoring, SSM plans, site-specific monitoring plans, recordkeeping and reporting requirements of this subpart, or any other requirements in subpart A of this part.

(1) Existing small solid fuel boilers and process heaters.

(2) Existing small liquid fuel boilers and process heaters.

(3) Existing small gaseous fuel boilers and process

heaters.

(4) New small gaseous fuel units.

§63.7507 What are the health-based compliance alternatives for the hydrogen chloride (HCl) and total selected metals (TSM) standards?

(a) As an alternative to the requirement for large solid fuel boilers located at a single facility to demonstrate compliance with the HCl emission limit in Table 1 to this subpart, you may demonstrate eligibility for the health-based compliance alternative for HCl emissions under the procedures prescribed in appendix A to this subpart.

(b) In lieu of complying with the TSM emission standards in Table 1 to this subpart based on the sum of emissions for the eight selected metals, you may demonstrate eligibility for complying with the TSM emission standards in Table 1 based on the sum of emissions for seven selected metals (by excluding manganese emissions from the summation of TSM emissions) under the procedures prescribed in appendix A of this subpart.

Testing, Fuel Analyses, and Initial Compliance Requirements

§63.7510 What are my initial compliance requirements and by what date must I conduct them?

(a) For affected sources that elect to demonstrate compliance with any of the emission limits of this subpart

through performance testing, your initial compliance requirements include conducting performance tests according to §63.7520 and Table 5 to this subpart, conducting 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, establishing operating limits according to §63.7530 and Table 7 to this subpart, and conducting CMS performance evaluations according to §63.7525.

(b) For affected sources that elect to demonstrate compliance with the emission limits 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.

(c) For affected sources that have an applicable work practice standard, your initial compliance requirements depend on the subcategory and rated capacity of your boiler or process heater. If your boiler or process heater is in any of the limited use subcategories or has a heat input capacity less than 100 MMBtu per hour, your initial compliance demonstration is conducting a performance test for carbon monoxide according to Table 5 to this subpart. If your boiler or process heater is in any of the large

subcategories and has a heat input capacity of 100 MMBtu per hour or greater, your initial compliance demonstration is conducting a performance evaluation of your continuous emission monitoring system for carbon monoxide according to §63.7525(a).

(d) For existing affected sources, you must demonstrate initial compliance 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.

(e) If your new or reconstructed affected source commenced construction or reconstruction between January 13, 2003 and [INSERT THE DATE OF PUBLICATION OF THE FINAL RULE IN THE FEDERAL REGISTER], you must demonstrate initial compliance with either the proposed emission limits and work practice standards or the promulgated emission limits and work practice standards no later than 180 days after [INSERT THE DATE 180 DAYS AFTER PUBLICATION OF THE FINAL RULE IN THE FEDERAL REGISTER] or within 180 days after startup of the source, whichever is later, according to §63.7(a)(2)(ix).

(f) If your new or reconstructed affected source commenced construction or reconstruction between January 13, 2003, and [INSERT THE DATE OF PUBLICATION OF THE FINAL RULE IN THE FEDERAL REGISTER], and you chose to comply with the

proposed emission limits and work practice standards when demonstrating initial compliance, you must conduct a second compliance demonstration for the promulgated emission limits and work practice standards within 3 years after [INSERT THE DATE 3 YEARS AFTER PUBLICATION OF THE FINAL RULE IN THE FEDERAL REGISTER] or within 3 years after startup of the affected source, whichever is later.

(g) If your new or reconstructed affected source commences construction or reconstruction after [INSERT THE DATE OF PUBLICATION OF THE FINAL RULE IN THE FEDERAL REGISTER], you must demonstrate initial compliance with the promulgated emission limits and work practice standards no later than 180 days after startup of the source.

<u>§63.7515 When must I conduct subsequent performance tests or fuel analyses?</u>

(a) You must conduct all applicable performance tests according to §63.7520 on an annual basis, unless you follow the requirements listed in paragraphs (b) through (d) of this section. Annual performance tests must be completed between 10 and 12 months after the previous performance test, unless you follow the requirements listed in paragraphs (b) through (d) of this section.

(b) You can conduct performance tests less often for a given pollutant if your performance tests for the pollutant

(particulate matter, HCl, mercury, or TSM) for at least 3 consecutive years show that you comply with the emission limit. In this case, you do not have to conduct a performance test for that pollutant for the next 2 years. You must conduct a performance test during the third year and no more than 36 months after the previous performance test.

(c) If your boiler or process heater continues to meet the emission limit for particulate matter, HCl, mercury, or TSM, you may choose to conduct performance tests for these pollutants every third year, but each such performance test must be conducted no more than 36 months after the previous performance test.

(d) If a performance test shows noncompliance with an emission limit for particulate matter, HCl, mercury, or TSM, you must conduct annual performance tests for that pollutant until all performance tests over a consecutive 3-year period show compliance.

(e) If you have an applicable work practice standard for carbon monoxide and your boiler or process heater is in any of the limited use subcategories or has a heat input capacity less than 100 MMBtu per hour, you must conduct annual performance tests for carbon monoxide according to §63.7520. Each annual performance test must be conducted

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between 10 and 12 months after the previous performance test.

(f) You must conduct a fuel analysis according to §63.7521 for each type of fuel burned no later than 5 years after the previous fuel analysis for each fuel type. 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.

(g) You must report the results of performance tests and fuel analyses within 60 days after the completion of the performance tests or fuel analyses. This report should also verify that the operating limits for your affected source have not changed or provide documentation of revised operating parameters established according to §63.7530 and Table 7 to this subpart, as applicable. The reports for all subsequent performance tests and fuel analyses should include all applicable information required in §63.7550.

<u>§63.7520 What performance tests and procedures must I use?</u>

(a) You must conduct all performance tests according to §63.7(c), (d), (f), and (h). You must also develop a site-specific test plan according to the requirements in §63.7(c) if you elect to demonstrate compliance through performance testing.

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(b) You must conduct each performance test according to the requirements in Table 5 to this subpart.

(c) New or reconstructed boilers or process heaters in one of the liquid fuel subcategories that burn only fossil fuels and other gases and do not burn any residual oil must demonstrate compliance according to §63.7506(a).

(d) 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 the maximum normal operating load while burning the type of fuel or mixture of fuels that have the highest content of chlorine, mercury, and total selected metals, and you must demonstrate initial compliance and establish your operating limits based on these tests. These requirements could result in the need to conduct more than one performance test.

(e) You may not conduct performance tests during periods of startup, shutdown, or malfunction.

(f) 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.

(g) 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 of appendix A to part 60 of this chapter to convert the measured particulate

matter concentrations, the measured HCl concentrations, the measured TSM concentrations, and the measured mercury concentrations that result from the initial performance test to pounds per million Btu heat input emission rates using F-factors.

§63.7521 What fuel analyses and procedures must I use?

(a) You must conduct fuel analyses according to the procedures in paragraphs (b) through (e) of this section and Table 6 to this subpart, as applicable.

(b) You must develop and submit a site-specific fuel analysis plan to the EPA Administrator for review and approval according to the following procedures and requirements in paragraphs (b)(1) and (2) of this section.

(1) You must submit the fuel analysis plan no later than 180 days before the date that you intend to demonstrate compliance.

(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 fuel type, the notification of whether you or a fuel supplier will be conducting the fuel analysis.

(iii) For each 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 fuel type, the analytical methods, with the expected minimum detection levels, to be used for the measurement of selected total metals, 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 will be used.

(vi) If you will be using fuel analysis from a fuel supplier in lieu of site-specific sampling and analysis, the fuel supplier must use the analytical methods required by Table 6 to this subpart.

(c) At a minimum, you must obtain three composite fuel samples for each fuel type according to the procedures in paragraph (c)(1) or (2) of this section.

(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

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from the full cross-section of the stopped belt to obtain a minimum two pounds of sample. Collect all the material (fines and coarse) in the full cross-section. Transfer the sample to a clean plastic bag.

(ii) Each composite sample will consist of a minimum of three samples collected at approximately equal intervals during the testing period.

(2) If sampling from a fuel pile or truck, collect fuel samples according to paragraphs (c)(2)(i) through (iii) of this section.

(i) For each composite sample, select a minimum of five sampling locations uniformly spaced over the surface of the pile.

(ii) At each sampling site, dig into the pile to a depth of 18 inches. Insert a clean flat square shovel into the hole and withdraw a sample, making sure that large pieces do not fall off during sampling.

(iii) Transfer all samples to a clean plastic bag for further processing.

(d) Prepare each composite sample according to the procedures in paragraphs (d)(1) through (7) of this section.

(1) Throughly mix and pour the entire composite sample over a clean plastic sheet.

(2) Break sample pieces larger than 3 inches into

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smaller sizes.

(3) Make a pie shape with the entire composite sample and subdivide it into four equal parts.

(4) Separate one of the quarter samples as the first subset.

(5) If this subset is too large for grinding, repeat the procedure in paragraph (d)(3) of this section with the quarter sample and obtain a one-quarter subset from this sample.

(6) Grind the sample in a mill.

(7) 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) Determine the concentration of pollutants in the fuel (mercury, chlorine, and/or total selected metals) 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.

<u>§63.7522 Can I use emission averaging to comply with this subpart?</u>

(a) As an alternative to meeting the requirements of §63.7500, if you have more than one existing large solid fuel boiler located at your facility, you may demonstrate

compliance by emission averaging according to the procedures in this section in a State that does not choose to exclude emission averaging.

(b) For each existing large solid fuel boiler 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 [INSERT DATE 60 DAYS AFTER DATE OF PUBLICATION OF THE FINAL RULE IN THE FEDERAL REGISTER] 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 [INSERT DATE 60 DAYS AFTER DATE OF PUBLICATION OF THE FINAL RULE IN THE FEDERAL REGISTER].

(c) You may average particulate matter or TSM, HCl, and mercury emissions from existing large solid fuel boilers to demonstrate compliance with the limits in Table 1 to this subpart if you satisfy the requirements in paragraphs (d), (e), and (f) of this section.

(d) The weighted average emissions from the existing large solid fuel boilers participating in the emissions averaging option must be in compliance with the limits in Table 1 to this subpart at all times following the compliance date specified in §63.7495.

(e) You must demonstrate initial compliance according

to paragraphs (e)(1) or (2).

(1) You must use equation 1 of this section to demonstrate that the particulate matter or TSM, HCl, and mercury emissions from all existing large solid fuel boilers participating in the emissions averaging option do not exceed the emission limits in Table 1 to this subpart.

$$AveWeightedEmissions = \sum_{i=1}^{n} (Er \times Hm) \div \sum_{i=1}^{n} Hm \qquad \text{(Eq. 1)}$$

Where:

AveWeighted Emissions	=	Average weighted emissions for particulate matter or TSM, HCl, or mercury, in units of pounds per million Btu of heat input;
Er	=	Emission rate (as calculated according to Table 5 to this subpart) or fuel analysis (as calculated by the applicable equation in §63.7530(d)) for boiler, i, for particulate matter or TSM, HCl, or mercury, in units of pounds per million Btu of heat input;
Hm	=	Maximum rated heat input capacity of boiler, i, in units of million Btu per hour;
n	=	Number of large solid fuel boilers participating in the emissions averaging option.

(2) If you are not capable of monitoring heat input, you can use equation 2 of this section as an alternative to

using equation 1 of this section to demonstrate that the particulate matter or TSM, HCl, and mercury emissions from all existing large solid fuel boilers participating in the emissions averaging option do not exceed the emission limits in Table 1 to this subpart.

$$AveWeightedEmissions = \sum_{i=1}^{n} (Er \times Sm \times Cf) \div \sum_{i=1}^{n} Sm \times Cf \qquad \text{(Eq. 2)}$$

Where:

AveWeighted Emissions	=	Average weighted emission level for PM or TSM, HCl, or mercury, in units of pounds per million Btu of heat input.
Er	=	Emission rate (as calculated according to Table 5 to this subpart) or fuel analysis (as calculated by the applicable equation in §63.7530(d)) for boiler, i, for particulate matter or TSM, HCl, or mercury, in units of pounds per million Btu of heat input.
Sm	=	Maximum steam generation by boiler, i, in units of pounds.
Cf	=	Conversion factor, calculated from the most recent compliance test, in units of million Btu of heat input per pounds of steam generated.

(f) You must demonstrate continuous compliance on a 12-month rolling average basis determined at the end of every month (12 times per year) according to paragraphs (f)(1) and

(2). The first 12-month rolling-average period begins on the compliance date specified in §63.7495.

(1) For each calendar month, you must use equation 3 of this section to calculate the 12-month rolling average weighted emission limit using the actual heat capacity for each existing large solid fuel boiler participating in the emissions averaging option.

$$AveWeightedEmissions = \sum_{i=1}^{n} (Er \times Hb) \div \sum_{i=1}^{n} Hb \qquad \text{(Eq. 3)}$$

Where:

AveWeighted Emissions	=	12-month rolling average weighted emission level for particulate matter or TSM, HCl, or mercury, in units of pounds per million Btu of heat input.
Er	=	Emission rate, calculated during the most recent compliance test,(as calculated according to Table 5 to this subpart) or fuel analysis (as calculated by the applicable equation in §63.7530(d)) for boiler, i, for particulate matter or TSM, HCl, or mercury, in units of pounds per million Btu of heat input.
Hb	=	The average heat input for each calendar month of boiler, i, in units of million Btu
n	=	Number of large solid fuel boilers participating in the emissions averaging option.

(2) If you are not capable of monitoring heat input,

you can use equation 4 of this section as an alternative to using equation 3 of this section to calculate the 12-month rolling average weighted emission limit using the actual steam generation from the large solid fuel boilers participating in the emissions averaging option.

$$AveWeightedEmissions = \sum_{i=1}^{n} (Er \times Sa \times Cf) \div \sum_{i=1}^{n} Sa \times Cf \qquad \text{(Eq. 4)}$$

Where:

AveWeighted Emissions	=	12-month rolling average weighted emission level for PM or TSM, HCl, or mercury, in units of pounds per million Btu of heat input.
Er	=	Emission rate, calculated during the most recent compliance test(as calculated according to Table 5 to this subpart) or fuel analysis (as calculated by the applicable equation in §63.7530(d)) for boiler, i, for particulate matter or TSM, HCl, or mercury, in units of pounds per million Btu of heat input.
Sa	=	Actual steam generation for each calender month by boiler, i, in units of pounds.
Cf	=	Conversion factor, as calculated during the most recent compliance test,in units of million Btu of heat input per pounds of steam generated.

(g) You must develop and submit an implementation plan for emission averaging to the applicable regulatory

authority for review and approval according to the following procedures and requirements in paragraphs (f)(1) through (4).

(1) You must submit the implementation plan no later than 180 days before the date that the facility intends to demonstrate compliance using the emission averaging option.

(2) You must include the information contained in paragraphs (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 large solid fuel boilers in the averaging group, including for each either the applicable HAP emission level or the control technology installed on;

(ii) The process parameter (heat input or steam generated) that will be monitored for each averaging group of large solid fuel boilers;

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

(iv) The test plan for the measurement of particulate

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matter (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 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 applicable regulatory authority, 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 conditions.

(3) Upon receipt, the regulatory authority 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 (f)(2) of this section; and

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

(4) The applicable regulatory authority 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 large solid fuel boiler.

<u>§63.7525 What are my monitoring, installation, operation, and maintenance requirements?</u>

(a) If you have an applicable work practice standard for carbon monoxide, and your boiler or process heater is in any of the large subcategories and has a heat input capacity of 100 MMBtu per hour or greater, you must install, operate, and maintain a continuous emission monitoring system (CEMS) for carbon monoxide according to the procedures in paragraphs (a)(1) through (6) of this section by the compliance date specified in §63.7495.

(1) Each CEMS must be installed, operated, and maintained according to Performance Specification (PS) 4A of 40 CFR part 60, appendix B, and according to the site-specific monitoring plan developed according to §63.7505(d).

(2) You must conduct a performance evaluation of each CEMS according to the requirements in §63.8 and according to PS 4A of 40 CFR part 60, appendix B.

(3) Each CEMS must complete a minimum of one cycle of operation (sampling, analyzing, and data recording) for each successive 15-minute period.

(4) The CEMS data must be reduced as specified in §63.8(g)(2).

(5) You must calculate and record a 30-day rolling average emission rate on a daily basis. A new 30-day rolling average emission rate is calculated as the average of all of the hourly CO emission data for the preceding 30 operating days.

(6) For purposes of calculating data averages, you must not use data recorded during periods of monitoring malfunctions, associated repairs, out-of-control periods, required quality assurance or control activities, or when your boiler or process heater is operating at less than 50 percent of its rated capacity. You must use all the data collected during all other periods in assessing compliance.

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Any period for which the monitoring system is out of control and data are not available for required calculations constitutes a deviation from the monitoring requirements.

(b) If you have an applicable opacity operating limit, you must install, operate, certify and maintain each continuous opacity monitoring system (COMS) according to the procedures in paragraphs (b)(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 PS 1 of 40 CFR part 60, appendix B.

(2) You must conduct a performance evaluation of each COMS according to the requirements in §63.8 and according to PS 1 of 40 CFR part 60, appendix B.

(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). 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.

(7) You must determine and record all the 6-minute averages (and 1-hour block averages as applicable) collected for periods during which the COMS is not out of control.

(c) If you have an operating limit that requires the use of a CMS, you must install, operate, and maintain each continuous parameter monitoring system (CPMS) according to the procedures in paragraphs (c)(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 for each successive 15-minute period. You must have a minimum of four successive cycles of operation to have a valid hour of data.

(2) Except for monitoring malfunctions, associated repairs, and required quality assurance or control activities (including, as applicable, calibration checks and required zero and span adjustments), you must conduct all monitoring in continuous operation at all times that the

unit 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.

(3) For purposes of calculating data averages, you must not use data recorded during monitoring malfunctions, associated repairs, out of control periods, or required quality assurance or control activities. You must use all the data collected during all other periods in assessing compliance. Any period for which the monitoring system is out-of-control and data are not available for required calculations constitutes a deviation from the monitoring requirements.

(4) Determine the 3-hour block average of all recorded readings, except as provided in paragraph (c)(3) of this section.

(5) Record the results of each inspection, calibration, and validation check.

(d) If you have an operating limit that requires the use of a flow measurement device, you must meet the requirements in paragraphs (c) and (d)(1) through (4) of this section.

(1) Locate the flow sensor and other necessary

equipment in a position that provides a representative flow.

(2) Use a flow sensor with a measurement sensitivity of 2 percent of the flow rate.

(3) Reduce swirling flow or abnormal velocity distributions due to upstream and downstream disturbances.

(4) Conduct a flow sensor calibration check at least semiannually.

(e) If you have an operating limit that requires the use of a pressure measurement device, you must meet the requirements in paragraphs (c) and (e)(1) through (6) of this section.

(1) Locate the pressure sensor(s) in a position that provides a representative measurement of the pressure.

(2) Minimize or eliminate pulsating pressure, vibration, and internal and external corrosion.

(3) Use a gauge with a minimum tolerance of 1.27 centimeters of water or a transducer with a minimum tolerance of 1 percent of the pressure range.

(4) Check pressure tap pluggage daily.

(5) Using a manometer, check gauge calibration quarterly and transducer calibration monthly.

(6) Conduct calibration checks any time the sensor exceeds the manufacturer’s specified maximum operating pressure range or install a new pressure sensor.

(f) If you have an operating limit that requires the use of a pH measurement device, you must meet the requirements in paragraphs (c) and (f)(1) through (3) of this section.

(1) Locate 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) Check the pH meter's calibration on at least two points every 8 hours of process operation.

(g) If you have an operating limit that requires the use of equipment to monitor voltage and secondary current (or total power input) of an electrostatic precipitator (ESP), you must use voltage and secondary current monitoring equipment to measure voltage and secondary current to the ESP.

(h) If you have an operating limit that requires the use of equipment to monitor sorbent injection rate (e.g., weigh belt, weigh hopper, or hopper flow measurement device), you must meet the requirements in paragraphs (c) and (h)(1) through (3) of this section.

(1) Locate the device in a position(s) that provides a representative measurement of the total sorbent injection rate.

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(2) Install and calibrate the device in accordance with manufacturer’s procedures and specifications.

(3) At least annually, calibrate the device in accordance with the manufacturer’s procedures and specifications.

(i) If you 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 a bag leak detection system as specified in paragraphs (i)(1) through (8) of this section.

(1) You must install and operate a bag leak detection system for each exhaust stack of the fabric filter.

(2) Each bag leak detection system must be installed, operated, calibrated, and maintained in a manner consistent with the manufacturer’s written specifications and recommendations and in accordance with the guidance provided in EPA-454/R-98-015, September 1997.

(3) The bag leak detection system must be certified by the manufacturer to be capable of detecting particulate matter emissions at concentrations of 10 milligrams per actual cubic meter or less.

(4) The bag leak detection system sensor must provide output of relative or absolute particulate matter loadings.

(5) The bag leak detection system must be equipped

with a device to continuously record the output signal from the sensor.

(6) The bag leak detection system must be equipped with an alarm system that will sound automatically when an increase in relative particulate matter emissions over a preset level is detected. The alarm must be located where it is easily heard by plant operating personnel.

(7) For positive pressure fabric filter systems that do not duct all compartments of cells to a common stack, a bag leak detection system must be installed in each baghouse compartment or cell.

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

<u>§63.7530 How do I demonstrate initial compliance with the emission limits and work practice standards?</u>

(a) You must demonstrate initial compliance with each emission limit and work practice standard that applies to you by either conducting initial performance tests and establishing operating limits, as applicable, according to §63.7520, paragraph (c) of this section, and Tables 5, 7 and 8 to this subpart OR conducting initial fuel analyses to determine emission rates and establishing operating limits, as applicable, according to §63.7521, paragraph (d) of this

section, and Tables 6 and 8 to this subpart.

(b) New or reconstructed boilers or process heaters in one of the liquid fuel subcategories that burn only fossil fuels and other gases and do not burn any residual oil must demonstrate compliance according to §63.7506(a).

(c) If you demonstrate compliance through performance testing, you must establish each site-specific operating limit in Tables 2 through 4 to this subpart that applies to you according to the requirements in §63.7520, Table 7 to this subpart, and paragraph (c)(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 (c)(1) through (3) of this section, as applicable.

(1) You must establish the maximum chlorine fuel input (Cl_{input}) during the initial performance testing according to the procedures in paragraphs (c)(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 performance testing for HCl, you must determine the fraction of the total heat input for each fuel type burned (Q_i) based on the fuel mixture that has the

highest content of chlorine, and the average chlorine concentration of each fuel type burned ©$_i$).

(iii) You must establish a maximum chlorine input level using Equation 5 of this section.

$$Cl_{input} = \sum_{i=1}^{n} \left[(C_i)(Q_i) \right] \qquad \text{(Eq. 5)}$$

Where:

Cl_{input}	=	Maximum amount of chlorine entering the boiler or process heater through fuels burned in units of pounds per million Btu.
C_i	=	Arithmetic average concentration of chlorine in fuel type, i, analyzed according to §63.7521, in units of pounds per million Btu
Q_i	=	Fraction of total heat input from fuel type, i, based on the fuel mixture that has the highest content of chlorine. If you do not burn multiple fuel types during the performance testing, it is not necessary to determine the value of this term. Insert a value of "1" for Q_i
n	=	Number of different fuel types burned in your boiler or process heater for the mixture that has the highest content of chlorine.

(2) If you choose to comply with the alternative TSM emission limit instead of the particulate matter emission limit, you must establish the maximum TSM fuel input level (TSM_{input}) during the initial performance testing according to the procedures in paragraphs (c)(2)(i) through (iii) of this section.

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(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 performance testing for TSM, you must determine the fraction of total heat input from each fuel burned (Qi) based on the fuel mixture that has the highest content of total selected metals, and the average TSM concentration of each fuel type burned (Mi).

(iii) You must establish a baseline TSM input level using Equation 6 of this section.

$$TSM_{input} = \sum_{i=1}^{n} \left[(M_i)(Q_i) \right] \qquad \text{(Eq. 6)}$$

Where:

TSM_{input}	=	Maximum amount of TSM entering the boiler or process heater through fuels burned in units of pounds per million Btu;
M_i	=	Arithmetic average concentration of TSM in fuel type, i, analyzed according to §63.7521, in units of pound per million Btu;
Q_i	=	Fraction of total heat input from based fuel type, i, based on the fuel mixture that has the highest content of TSM. If you do not burn multiple fuel types during the performance test, it is not necessary to determine the value of this term. Insert a value of "1" for Q_i;
n	=	Number of different fuel types burned in your boiler or process heater for the mixture that has the highest content of TSM.

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(3) You must establish the maximum mercury fuel input level ($Mercury_{input}$) during the initial performance testing using the procedures in paragraphs (c)(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 mercury.

(ii) During the compliance demonstration for mercury, you must determine the fraction of total heat input for each fuel burned (Q_i) based on the fuel mixture that has the highest content of mercury, and the average mercury concentration of each fuel type burned (HG_i).

(iii) You must establish a maximum mercury input level using Equation 7 of this section.

$$Mercury_{input} = \sum_{i=1}^{n} \left[(HG_i)(Q_i) \right] \qquad \text{(Eq. 7)}$$

Where:

$Mercury_{input}$	=	Maximum amount of mercury entering the boiler or process heater through fuels burned in units of pounds per million Btu;
HG_i	=	Arithmetic average concentration of mercury in fuel type, i, analyzed according to §63.7521, in units of pound per million Btu;
Q_i	=	Fraction of total heat input from fuel type, i, based on the fuel mixture that has the highest mercury content. If you do not

		burn multiple fuel types during the performance test, it is not necessary to determine the value of this term. Insert a value of "1" for Q_i;
n	=	Number of different fuel types burned in your boiler or process heater for the mixture that has the highest content of mercury.

(4) You must establish parameter operating limits according to paragraphs (c)(4)(i) through (iv) of this section.

(i) For a wet scrubber, you must establish the minimum scrubber effluent pH, liquid flowrate, and pressure drop as defined in §63.7575, as your operating limits during the three-run performance test. If you use a wet scrubber and you conduct separate performance tests for particulate matter, HCl, and mercury emissions, you must establish one set of minimum scrubber effluent pH, liquid flowrate, 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 flowrate and pressure drop operating limits at the highest minimum values established during the performance tests.

(ii) For an electrostatic precipitator, you must establish the minimum voltage and secondary current (or total power input), as defined in §63.7575, as your

operating limits during the three-run performance test.

(iii) For a dry scrubber, you must establish the minimum sorbent injection rate, as defined in §63.7575, as your operating limit during the three-run performance test.

(iv) The operating limit for boilers or process heaters with fabric filters that choose to 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 alarm does not sound more than 5 percent of the operating time during a 6-month period.

(d) 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 (d)(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 z-statistic

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test described in Equation 8 of this section.

$$P_{90} = \text{mean} + (SD * t) \qquad \text{(Eq. 8)}$$

Where:

P_{90} = 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 pollutant concentration in the fuel samples analyzed according to §63.7521, in units of pounds per million Btu;

t = t distribution critical value for 90th percentile (0.1) probability for the appropriate degrees of freedom (number of samples minus one) as obtained from a 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 9 of this section must be less than the applicable emission limit for HCl.

$$HCl = \sum_{i=1}^{n} \left[(C_{i90})\,(Q_i)\,(1.028) \right] \qquad \text{(Eq. 9)}$$

Where:

HCl = HCl emission rate from the boiler or process heater in units of pounds per million Btu;

C_{i90} = 90th percentile confidence level concentration of chlorine in fuel type, i, in

units of pounds per million Btu as calculated according to Equation 8 of this section;

Q_i = 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 Q_i;

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 TSM, the TSM emission rate that you calculate for your boiler or process heater using Equation 10 of this section must be less than the applicable emission limit for TSM.

$$TSM = \sum_{i=1}^{n} \left[(M_{i90})(Q_i) \right] \qquad \text{(Eq. 10)}$$

Where:

TSM = TSM emission rate from the boiler or process heater in units of pounds per million Btu;

M_{i90} = 90th percentile confidence level concentration of TSM in fuel, i, in units of pound per million Btu as calculated according to Equation 8 of this section;

Qi = Fraction of total heat input from fuel type, i, based on the fuel mixture that has the highest content of total selected metals. 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 Q_i;

n = Number of different fuel types burned in your boiler or process heater for the mixture that has the highest content of TSM.

(5) 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 11 of this section must be less than the applicable emission limit for mercury.

$$\text{Mercury} = \sum_{i=1}^{n} \left[(HG_{i90})(Q_i) \right] \qquad \text{(Eq. 11)}$$

Where:

Mercury	=	Mercury emission rate from the boiler or process heater in units of pounds per million Btu;
HG_{i90}	=	90th percentile confidence level concentration of mercury in fuel, i, in units of pound per million Btu as calculated according to Equation 8 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 Q_i;
n	=	Number of different fuel types burned in your boiler or process heater for the mixture that has the highest mercury content.

(e) You must submit the Notification of Compliance Status containing the results of the initial compliance demonstration according to the requirements in §63.7545(e).

Continuous Compliance Requirements

<u>§63.7535 How do I monitor and collect data to demonstrate</u>

continuous compliance?

(a) You must monitor and collect data according to this section and the site-specific monitoring plan required by §63.7505(d).

(b) Except for monitor malfunctions, associated repairs, and required quality assurance or control activities (including, as applicable, calibration checks and required zero and span adjustments), you must monitor continuously (or collect data at all required intervals) at all times that the affected source is operating.

(c) You may not use data recorded during monitoring malfunctions, associated repairs, or required quality assurance or control activities in data averages and calculations used to report emission or operating levels. You must use all the data collected during all other periods in assessing the operation of the control device and associated control system. Boilers and process heaters that have an applicable carbon monoxide work practice standard and are required to install and operate a CEMS, may not use data recorded during periods when the boiler or process heater is operating at less than 50 percent of its rated capacity.

§63.7540 How do I demonstrate continuous compliance with the emission limits and work practice standards?

(a) You must demonstrate continuous compliance with each emission limit, operating limit, and work practice standard in Tables 1 through 4 to this subpart that applies to you according to the methods specified in Table 8 to this subpart and paragraphs (a)(1) through (10) of this section.

(1) Following the date on which the initial performance test is completed or is required to be completed under §§63.7 and 63.7510, whichever date comes first, you must not operate above any of the applicable maximum operating limits or below any of the applicable minimum operating limits listed in Tables 2 through 4 to this subpart at all times except during periods of startup, shutdown and malfunction. Operating limits do not apply during performance tests. Operation above the established maximum or below the established minimum operating limits shall constitute a deviation of established operating limits.

(2) 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 either result in lower emissions of TSM, HCl, and mercury, than the applicable emission limit for each pollutant (if you demonstrate compliance through fuel analysis), or result in lower fuel

input of TSM, chlorine, and mercury than the maximum values calculated during the last performance tests (if you demonstrate compliance through performance testing).

(3) If you demonstrate compliance with an applicable HCl emission limit through fuel analysis and you plan to burn a new type of fuel, you must recalculate the HCl emission rate using Equation 5 of §63.7530 according to paragraphs (a)(3)(i) through (iii) of this section.

(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 5 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 type or a new mixture of fuels, you must recalculate the maximum chlorine input using Equation 1 of §63.7530. If the results of recalculating the

maximum chlorine input using Equation 1 of §63.7530 are higher 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(c).

(5) If you demonstrate compliance with an applicable TSM emission limit through fuel analysis, and you plan to burn a new type of fuel, you must recalculate the TSM emission rate using Equation 6 of §63.7530 according to the procedures specified in paragraphs (a)(5)(i) through (iii) of this section.

(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 6 of §63.7530. The recalculated TSM emission rate must be less than the applicable emission limit.

(6) 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 2 of §63.7530. If the results of recalculating the maximum total selected metals input using Equation 2 of §63.7530 are higher than the maximum TSM 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(c).

(7) 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 7 of §63.7530 according to the procedures specified in paragraphs (a)(7)(i) through (iii) of this section.

(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 7 of §63.7530. The recalculated mercury emission rate must be less than the applicable emission limit.

(8) 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 3 of §63.7530. If the results of recalculating the maximum mercury input using Equation 3 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(c).

(9) 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 alarm and complete corrective actions according to your SSMP, and operate and maintain the fabric filter system such that the alarm does not sound 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 alarm, the time corrective action was initiated and completed, and a brief description of the cause of the alarm and the corrective action taken. You must also record the percent of the operating time during each 6-month period that the alarm sounds. In calculating this operating time percentage, if inspection of the fabric filter demonstrates that no corrective action is required, no alarm time is counted. If corrective action is required, each alarm shall be counted as a minimum of 1 hour. If you take longer than 1 hour to initiate corrective action, the alarm time shall be counted as the actual amount of time taken to initiate corrective action.

(10) If you have an applicable work practice standard for carbon monoxide, and you are required to install a CEMS according to §63.7525(a), then you must meet the requirements in paragraphs (a)(10)(i) through (iii) of this section.

(i) You must continuously monitor carbon monoxide according to §§63.7525(a) and 63.7535.

(ii) Maintain a carbon monoxide emission level below your applicable carbon monoxide work practice standard in Table 1 to this subpart at all times except during periods of startup, shutdown, malfunction, and when your boiler or process heater is operating at less than 50 percent of rated capacity.

(iii) Keep records of carbon monoxide levels according to §63.7555(b).

(b) You must report each instance in which you did not meet each emission limit, operating limit, and work practice standard in Tables 1 through 4 to this subpart that apply to you. You must also report each instance during a startup, shutdown, or malfunction when you did not meet each applicable emission limit, operating limit, and work practice standard. These instances are deviations from the emission limits and work practice standards in this subpart. These deviations must be reported according to the requirements in §63.7550.

(c) During periods of startup, shutdown, and malfunction, you must operate in accordance with the SSMP as required in §63.7505(e).

(d) Consistent with §§63.6(e)and 63.7(e)(1),

deviations that occur during a period of startup, shutdown, or malfunction are not violations if you demonstrate to the EPA Administrator's satisfaction that you were operating in accordance with your SSMP. The EPA Administrator will determine whether deviations that occur during a period of startup, shutdown, or malfunction are violations, according to the provisions in §63.6(e).

§63.7541 How do I demonstrate continuous compliance under the emission 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 (4) of this section.

(1) For each calendar month, demonstrate compliance with the average weighted emissions limit for the existing large solid fuel boilers participating in the emissions averaging option as determined in §63.7522(f) and (g);

(2) For each existing solid fuel boiler participating in the emissions averaging option that is equipped with a dry control system, maintain opacity at or below the applicable limit;

(3) For each existing solid fuel boiler participating in the emissions averaging option that is equipped with a wet scrubber, maintain the 3-hour average parameter values

at or below the operating limits established during the most recent performance test; and

(4) For each existing solid fuel boiler participating in the emissions averaging option that has an approved alternative operating plan, maintain the 3-hour average parameter values at or below the operating limits established in the most recent performance test.

(b) Any instance where the owner or operator fails to comply with the continuous monitoring requirements in paragraphs (a)(1) through (4) of this section, except during periods of startup, shutdown, and malfunction, is a deviation.

Notification, Reports, and Records

§63.7545 What notifications must I submit and when?

(a) You must submit all of the notifications in §§63.7(b) and (c), 63.8 (e), (f)(4) and (6), and 63.9 (b) through (h) that apply to you by the dates specified.

(b) As specified in §63.9(b)(2), if you startup your affected source before [INSERT THE DATE OF PUBLICATION OF THE FINAL RULE IN THE FEDERAL REGISTER], you must submit an Initial Notification not later than 120 days after [INSERT THE DATE OF PUBLICATION OF THE FINAL RULE IN THE FEDERAL REGISTER]. The Initial Notification must include the information required in paragraphs (b)(1) and (2) of this

section, as applicable.

(1) If your affected source has an annual capacity factor of greater than 10 percent, your Initial Notification must include the information required by §63.9(b)(2).

(2) If your affected source has a federally enforceable permit that limits the annual capacity factor to less than or equal to 10 percent such that the unit is in one of the limited use subcategories (the limited use solid fuel subcategory, the limited use liquid fuel subcategory, or the limited use gaseous fuel subcategory), your Initial Notification must include the information required by §63.9(b)(2) and also a signed statement indicating your affected source has a federally enforceable permit that limits the annual capacity factor to less than or equal to 10 percent.

(c) As specified in §63.9(b)(3), if you startup your new or reconstructed affected source on or after [INSERT THE DATE OF PUBLICATION OF THE FINAL RULE IN THE FEDERAL REGISTER], you must submit an Initial Notification not later than 120 days after you become subject to this subpart. The Initial Notification must include the information required in paragraphs (c)(1) and (2) of this section, as applicable.

(1) If your affected source has an annual capacity factor of greater than 10 percent, your Initial Notification

must include the information required by §63.9(b).

(2) If your affected source has a federally enforceable permit that limits the annual capacity factor to less than or equal to 10 percent such that the unit is in one of the limited use subcategories, your Initial Notification must include the information required by §63.9(b) and a signed statement indicating your affected source has a federally enforceable permit that limits the annual capacity factor to less than or equal to 10 percent.

(d) If you are required to conduct a performance test you must submit a Notification of Intent to conduct a performance test at least 30 days before the performance test is scheduled to begin as required in §63.7(b)(1).

(e) If you are required to conduct an initial compliance demonstration as specified in §63.7530(a), you must submit a Notification of Compliance Status according to §63.9(h)(2)(ii). For each initial compliance demonstration, 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 the performance test and/or other initial compliance demonstrations according to §63.10(d)(2). The Notification of Compliance Status report must contain all the information specified in paragraphs (e)(1) through (9),

as applicable.

(1) A description of the affected source(s) including identification of which subcategory the source is in, the capacity of the source, a description of the add-on controls used on the source description of the fuel(s) burned, and justification for the fuel(s) burned during the performance test.

(2) Summary of the results of all performance tests, fuel analyses, and calculations conducted to demonstrate initial compliance including all established operating limits.

(3) Identification of whether you are complying with the particulate matter emission limit or the alternative total selected metals emission limit.

(4) Identification of whether you plan to demonstrate compliance with each applicable emission limit through performance testing or fuel analysis.

(5) Identification of whether you plan to demonstrate compliance by emissions averaging.

(6) A signed certification that you have met all applicable emission limits and work practice standards.

(7) A summary of the carbon monoxide emissions monitoring data and the maximum carbon monoxide emission levels recorded during the performance test to show that you

have met any applicable work practice standard in Table 1 to this subpart.

(8) If your new or reconstructed boiler or process heater is in one of the liquid fuel subcategories and burns only liquid fossil fuels other than residual oil either alone or in combination with gaseous fuels, you must submit a signed statement certifying this in your Notification of Compliance Status report.

(9) If you had a deviation from any emission limit or work practice standard, 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.

§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 by the date in Table 9 to this subpart and according to the requirements in paragraphs (b)(1) through (5) of this section.

(1) The first compliance report must cover the period beginning on the compliance date that is specified for your affected source in §63.7495 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.

(2) The first 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 first calendar half after the compliance date that is specified for your source in §63.7495.

(3) Each subsequent compliance report must cover the semiannual reporting period from January 1 through June 30 or the semiannual reporting period from July 1 through December 31.

(4) Each subsequent compliance report must be postmarked or 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 affected source that is subject to permitting regulations pursuant to 40 CFR part 70 or 40 CFR part 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 (4) of this section.

(c) The compliance report must contain the information required in paragraphs (c)(1) through (11) of this section.

(1) Company name and address.

(2) 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.

(3) Date of report and beginning and ending dates of the reporting period.

(4) The total fuel use by each affected source subject to an emission limit, for each calendar month within the semiannual reporting period, including, but not limited to, a description of the fuel and the total fuel usage amount with units of measure.

(5) A summary of the results of the annual performance tests and documentation of any operating limits that were reestablished during this test, if applicable.

(6) A signed statement indicating that you burned no new types of fuel. Or, if you did burn a new type of fuel, you must submit the calculation of chlorine input, using Equation 1 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 5 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, you must submit the calculation of TSM input, using Equation 2 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 6 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). If you burned a new type of fuel, you must submit the calculation of mercury input, using Equation 3 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 7 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

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analysis).

(7) If you wish to burn a new type of fuel and you can not demonstrate compliance with the maximum chlorine input operating limit using Equation 1 of §63.7530, the maximum TSM input operating limit using Equation 2 of §63.7530, or the maximum mercury input operating limit using Equation 3 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.

(8) The hours of operation for each boiler and process heater that is subject to an emission limit for each calendar month within the semiannual reporting period. This requirement applies only to limited use boilers and process heaters.

(9) If you had a startup, shutdown, or malfunction during the reporting period and you took actions consistent with your SSMP, the compliance report must include the information in §63.10(d)(5)(i).

(10) If there are no deviations from any emission limits or operating limits in this subpart that apply to you, and there are no deviations from the requirements for work practice standards in this subpart, a statement that there were no deviations from the emission limits, operating limits, or work practice standards during the reporting

period.

(11) If there were 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 periods during which the CMSs were out of control during the reporting period.

(d) For each deviation from an emission limit or operating limit in this subpart and for each deviation from the requirements for work practice standards in this subpart that occurs at an affected source where you are not using a CMSs to comply with that emission limit, operating limit, or work practice standard, the compliance report must contain the information in paragraphs (c)(1) through (10) of this section and the information required in paragraphs (d)(1) through (4) of this section. This includes periods of startup, shutdown, and malfunction.

(1) The total operating time of each affected source during the reporting period.

(2) A description of the deviation and which emission limit, operating limit, or work practice standard from which you deviated.

(3) Information on the number, duration, and cause of deviations (including unknown cause), as applicable, and the corrective action taken.

(4) A copy of the test report if the annual performance test showed a deviation from the emission limit for particulate matter or the alternative TSM limit, a deviation from the HCl emission limit, or a deviation from the mercury emission limit.

(e) For each deviation from an emission limitation and operating limit or work practice standard in this subpart occurring at an affected source where you are using a CMS to comply with that emission limit, operating limit, or work practice standard, you must include the information in paragraphs (c)(1) through (10) of this section and the information required in paragraphs (e)(1) through (12) of this section. This includes periods of startup, shutdown, and malfunction and any deviations from your site-specific monitoring plan as required in §63.7505(d).

(1) The date and time that each malfunction 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, and whether each deviation occurred during a period

of startup, shutdown, or 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 startup, shutdown, control equipment problems, process problems, other known causes, and other unknown causes.

(7) A summary of the total duration of CMSs 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) An identification of each parameter that was monitored at the affected source for which there was a deviation, including opacity, carbon monoxide, and operating parameters for wet scrubbers and other control devices.

(9) A brief description of the source for which there was a deviation.

(10) A brief description of each CMS for which there was a deviation.

(11) The date of the latest CMS certification or audit

for the system for which there was a deviation.

(12) 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) Each affected source that has obtained a title V operating permit pursuant to 40 CFR part 70 or 40 CFR part 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 9 to this subpart along with, or as part of, the semiannual monitoring report required by 40 CFR 70.6(a)(3)(iii)(A) or 40 CFR 71.6(a)(3)(iii)(A), and the compliance report includes all required information concerning deviations from any emission limit, operating limit, or work practice requirement in this subpart, submission of the compliance report satisfies any obligation to report the same deviations in the semiannual monitoring report. However, submission of a compliance report does not otherwise affect any obligation the affected source may have to report deviations from permit requirements to the permit authority.

(g) If you operate a new gaseous fuel unit that is subject to the work practice standard specified in Table 1

to this subpart, and you intend to use a fuel other than natural gas or equivalent to fire the affected unit, you must submit a notification of alternative fuel use within 48 hours of the declaration of a period of natural gas curtailment or supply interruption, as defined in §63.7575. The notification must include the information specified in paragraphs (g)(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.

§63.7555 What records must I keep?

(a) You must keep records according to paragraphs (a)(1) through (3) 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) The records in §63.6(e)(3)(iii) through (v) related to startup, shutdown, and malfunction.

(3) Records of performance tests, fuel analyses, or other compliance demonstrations, performance evaluations, and opacity observations as required in §63.10(b)(2)(viii).

(b) For each CEMS, CPMS, and COMS, you must keep records according to paragraphs (b)(1) through (5) of this section.

(1) Records described in §63.10(b)(2)(vi) 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, and whether the deviation occurred during a period of startup, shutdown, or malfunction or during another period.

(c) You must keep the records required in Table 8 to this subpart including records of all monitoring data and

calculated averages for applicable operating limits such as opacity, pressure drop, carbon monoxide, and pH to show continuous compliance with each emission limit, operating limit, and work practice standard that applies to you.

(d) For each boiler or process heater subject to an emission limit, you must also keep the records in paragraphs (d)(1) through (5) 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) You must keep records of monthly hours of operation by each boiler or process heater. This requirement applies only to limited-use boilers and process heaters.

(3) A copy of all calculations and supporting documentation of maximum chlorine fuel input, using Equation 1 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 5 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 TSM fuel input, using Equation 2 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 6 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.

(5) A copy of all calculations and supporting documentation of maximum mercury fuel input, using Equation

3 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 7 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.

(e) If your boiler or process heater is subject to an emission limit or work practice standard in Table 1 to this subpart and has a federally enforceable permit that limits the annual capacity factor to less than or equal to 10 percent such that the unit is in one of the limited use subcategories, you must keep the records in paragraphs (e)(1) and (2) of this section.

(1) A copy of the federally enforceable permit that limits the annual capacity factor of the source to less than

or equal to 10 percent.

(2) Fuel use records for the days the boiler or process heater was operating.

§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 for at least 2 years after the date of each occurrence, measurement, maintenance, corrective action, report, or record, according to §63.10(b)(1). You can keep the records off site for the remaining 3 years.

Other Requirements and Information

§63.7565 What parts of the General Provisions apply to me?

Table 10 to this subpart shows which parts of the General Provisions in §§63.1 through 63.15 apply to you.

§63.7570 Who implements and enforces this subpart?

(a) This subpart can be implemented and enforced by U.S. EPA, or a delegated authority such as your State, local, or tribal agency. If the EPA Administrator has

delegated authority to your State, local, or tribal agency, then that agency (as well as the U.S. EPA) has the authority to implement and enforce this subpart. You should contact your EPA Regional Office to find out if this subpart is delegated to your State, local, or tribal agency.

(b) In delegating implementation and enforcement authority of this subpart to a State, local, or tribal agency under 40 CFR part 63, subpart E, the authorities listed in paragraphs (b)(1) through (5) of this section are retained by the EPA Administrator and are not transferred to the State, local, or tribal agency, however, the U.S. EPA retains oversight of this subpart and can take enforcement actions, as appropriate.

(1) Approval of alternatives to the non-opacity emission limits and work practice standards in §63.7500(a) through (c) under §63.6(g).

(2) Approval of alternative opacity emission limits in §63.7500(a) under §63.6(h)(9).

(3) Approval of major change to test methods in Table 5 to this subpart under §63.7(e)(2)(ii) and (f) and as defined in §63.90.

(4) Approval of major change to monitoring under §63.8(f) and as defined in §63.90.

(5) Approval of major change to recordkeeping and

reporting under §63.10(f) and as defined in §63.90.

§63.7575 What definitions apply to this subpart?

Terms used in this subpart are defined in the CAA, in §63.2 (the General Provisions), and in this section as follows:

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.

Bag leak detection system means an instrument that is 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.

Biomass fuel means unadulterated wood as defined in this subpart, wood residue, and wood products (e.g., trees, tree stumps, tree limbs, bark, lumber, sawdust, sanderdust, chips, scraps, slabs, millings, and shavings); animal litter; 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.

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 heat input (based on an annual average) 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. Waste heat boilers are excluded from this definition.

Coal means all solid fuels classifiable as anthracite, bituminous, sub-bituminous, or lignite by the American Society for Testing and Materials in ASTM D388-99e1, "Standard Specification for Classification of Coals by Rank," coal refuse, and petroleum coke. Synthetic fuels derived from coal for the purpose of creating useful heat including but not limited to, solvent-refined coal, coal-oil mixtures, and coal-water mixtures, for the purposes of this subpart. 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, research centers, institutions of higher education, hotels, and laundries to provide electricity, steam, and/or hot water.

Construction/demolition material means waste building material that result from the construction or demolition operations on houses and commercial and industrial buildings.

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 limit, operating limit, 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

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(3) Fails to meet any emission limit, operating limit, or work practice standard in this subpart during startup, shutdown, or malfunction, regardless or whether or not such failure is permitted by this subpart.

A deviation is not always a violation. The determination of whether a deviation constitutes a violation of the standard is up to the discretion of the entity responsible for enforcement of the standards.

Distillate oil means fuel oils, including recycled oils, that comply with the specifications for fuel oil numbers 1 and 2, as defined by the American Society for Testing and Materials in ASTM D396-02a, "Standard Specifications for Fuel Oils."

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 in fluidized bed boilers and process heaters are included in this definition.

Electric utility steam generating unit means a fossil fuel-fired combustion unit of more than 25 megawatts 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

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potential electric output capacity and more than 25 megawatts electrical output to any utility power distribution system for sale is considered an electric utility steam generating unit.

Electrostatic precipitator 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.

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.

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

Firetube boiler means a boiler in which hot gases of combustion pass through the tubes and water contacts the outside surfaces of the tubes.

Fuel type means each category of fuels that share a common name or classification. Examples include, but are not limited to, bituminous coal, subbituminous coal,

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lignite, anthracite, biomass, construction/demolition material, salt water laden wood, creosote treated wood, tires, residual oil. Individual fuel types received from different suppliers are not considered new fuel types except for construction/demolition material.

Fossil fuel means natural gas, petroleum, coal, and any form of solid, liquid, or gaseous fuel derived from such materials.

Gaseous fuel includes, but is not limited to, natural gas, process gas, landfill gas, coal derived gas, refinery gas, and biogas. Blast furnace gas is 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, or exhaust gases from other sources such as gas turbines, internal combustion engines, kilns, etc.

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 or liquid fuel and is withdrawn for use external to the vessel at pressures not exceeding 160 psig, including the apparatus by which the heat is generated and all controls and devices necessary to prevent water temperatures from exceeding 210°F (99°C).

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Industrial boiler means a boiler used in manufacturing, processing, mining, and refining or any other industry to provide steam, hot water, and/or electricity.

Large gaseous fuel subcategory includes any watertube boiler or process heater that burns gaseous fuels not combined with any solid fuels, burns liquid fuel only during periods of gas curtailment or gas supply emergencies, has a rated capacity of greater than 10 MMBtu per hour heat input, and has an annual capacity factor of greater than 10 percent.

Large liquid fuel subcategory includes any watertube boiler or process heater that does not burn any solid fuel and burns any liquid fuel either alone or in combination with gaseous fuels, has a rated capacity of greater than 10 MMBtu per hour heat input, and has an annual capacity factor of greater than 10 percent. Large gaseous fuel boilers and process heaters that burn liquid fuel during periods of gas curtailment or gas supply emergencies are not included in this definition.

Large solid fuel subcategory includes any watertube boiler or process heater that burns any amount of solid fuel either alone or in combination with liquid or gaseous fuels, has a rated capacity of greater than 10 MMBtu per hour heat input, and has an annual capacity factor of greater than 10

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percent.

Liquid fossil fuel means petroleum, distillate oil, residual oil and any form of liquid fuel derived from such material.

Liquid fuel includes, but is not limited to, distillate oil, residual oil, waste oil, and process liquids.

Limited use gaseous fuel subcategory includes any watertube boiler or process heater that burns gaseous fuels not combined with any liquid or solid fuels, burns liquid fuel only during periods of gas curtailment or gas supply emergencies, has a rated capacity of greater than 10 MMBtu per hour heat input, and has a federally enforceable annual average capacity factor of equal to or less than 10 percent.

Limited use liquid fuel subcategory includes any watertube boiler or process heater that does not burn any solid fuel and burns any liquid fuel either alone or in combination with gaseous fuels, has a rated capacity of greater than 10 MMBtu per hour heat input, and has a federally enforceable annual average capacity factor of equal to or less than 10 percent. Limited use gaseous fuel boilers and process heaters that burn liquid fuel during periods of gas curtailment or gas supply emergencies are not included in this definition.

Limited use solid fuel subcategory includes any

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watertube boiler or process heater that burns any amount of solid fuel either alone or in combination with liquid or gaseous fuels, has a rated capacity of greater than 10 MMBtu per hour heat input, and has a federally enforceable annual average capacity factor of equal to or less than 10 percent.

Minimum pressure drop means 90 percent of the lowest test-run 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 90 percent of the lowest test-run average effluent pH measured at the outlet of 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 flow rate means 90 percent of the lowest test-run average flow rate measured according to Table 7 to this subpart during the most recent performance test demonstrating compliance with the applicable emission limit.

Minimum sorbent flow rate means 90 percent of the lowest test-run average sorbent (or activated carbon) flow rate measured according to Table 7 to this subpart during the most recent performance test demonstrating compliance

with the applicable emission limits.

Minimum voltage or amperage means 90 percent of the lowest test-run average voltage or amperage 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) Liquid petroleum gas, as defined by the American Society for Testing and Materials in ASTM D1835-03a, "Standard Specification for Liquid Petroleum Gases."

Opacity means the degree to which emissions reduce the transmission of light and obscure the view of an object in the background.

Particulate matter means any finely divided solid or liquid material, other than uncombined water, as measured by the test methods specified under this subpart, or an alternative method.

Period of natural gas curtailment or supply interruption means a period of time during which the supply

of natural gas to an affected facility is halted for reasons beyond the control of the facility. An increase in the cost or unit price of natural gas does not constitute a period of natural gas curtailment or supply interruption.

Process heater means an enclosed device using controlled flame, that is not a boiler, 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 for use in a process unit, instead of generating steam. Process heaters are devices in which the combustion gases do not directly come into contact with process materials. Process heaters do not include units used for comfort heat or space heat, food preparation for on-site consumption, or autoclaves.

Residual oil means crude oil, and all fuel oil numbers 4, 5 and 6, as defined by the American Society for Testing and Materials in ASTM D396-02a, "Standard Specifications for Fuel Oils."

Responsible official means responsible official as defined in 40 CFR 70.2.

Small gaseous fuel subcategory includes any firetube boiler that burns gaseous fuels not combined with any solid fuels and burns liquid fuel only during periods of gas curtailment or gas supply emergencies, and any boiler or

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process heater that burns gaseous fuels not combined with any solid fuels, burns liquid fuel only during periods of gas curtailment or gas supply emergencies, and has a rated capacity of less than or equal to 10 MMBtu per hour heat input.

Small liquid fuel subcategory includes any firetube boiler that does not burn any solid fuel and burns any liquid fuel either alone or in combination with gaseous fuels, and any boiler or process heater that does not burn any solid fuel and burns any liquid fuel either alone or in combination with gaseous fuels, and has a rated capacity of less than or equal to 10 MMBtu per hour heat input. Small gaseous fuel boilers and process heaters that burn liquid fuel during periods of gas curtailment or gas supply emergencies are not included in this definition.

Small solid fuel subcategory includes any firetube boiler that burns any amount of solid fuel either alone or in combination with liquid or gaseous fuels, and any other boiler or process heater that burns any amount of solid fuel either alone or in combination with liquid or gaseous fuels and has a rated capacity of less than or equal to 10 MMBtu per hour heat input.

Solid fuel includes, but is not limited to, coal, wood, biomass, tires, plastics, and other nonfossil solid

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materials.

Temporary boiler means any gaseous or liquid fuel boiler that is designed to, and is capable of, being carried or moved from one location to another. A temporary boiler that remains at a location for more than 180 consecutive days is no longer considered to be a temporary boiler. Any temporary boiler that replaces a temporary boiler at a location and is intended to perform the same or similar function will be included in calculating the consecutive time period.

Total selected metals means the combination of the following metallic HAP: arsenic, beryllium, cadmium, chromium, lead, manganese, nickel and selenium.

Unadulterated wood means wood or wood products that have not been painted, pigment-stained, or pressure treated with compounds such as chromate copper arsenate, pentachlorophenol, and creosote. Plywood, particle board, oriented strand board, and other types of wood products bound by glues and resins are included in this definition.

Watertube boiler means a boiler in which water passes through the tubes and hot gases of combustion pass over the outside surfaces of the tubes.

Waste heat boiler means a device that recovers normally unused energy and converts it to usable heat. Waste heat

boilers incorporating duct or supplemental burners that are designed to supply 50 percent or more of the total rated heat input capacity of the waste heat boiler are not considered waste heat boilers, but are considered boilers. Waste heat boilers are also referred to as heat recovery steam generators.

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 and/or to absorb and neutralize acid gases, such as hydrogen chloride.

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 CAA.

Tables to Subpart DDDDD of Part 63

Table 1 to Subpart DDDDD of Part 63 — Emission Limits and Work Practice Standards

As stated in §63.7500, you must comply with the following applicable emission limits:

If your boiler or process heater is in this subcategory...	**For the following pollutants...**	**You must meet the following emission limits and work practice standards...**
1. New or reconstructed large	a. Particulate Matter (OR	0.025 lb per MMBtu of heat input; or

solid fuel	Total Selected Metals) b. Hydrogen Chloride c. Mercury d. Carbon Monoxide	(0.0003 lb per MMBtu/hr of heat input) 0.02 lb per MMBtu of heat input 0.000003 lb per MMBtu of heat input 400 ppm by volume on a dry basis corrected to 7 percent oxygen (30-day rolling average for units 100 MMBtu/hr or greater, 3-run average for units less than 100 MMBtu/hr)
2. New or reconstructed limited use solid fuel	a. Particulate Matter (OR Total Selected Metals) b. Hydrogen Chloride c. Mercury d. Carbon Monoxide	0.025 lb per MMBtu of heat input; or (0.0003 lb per MMBtu/hr of heat input) 0.02 lb per MMBtu of heat input 0.000003 lb per MMBtu of heat input 400 ppm by volume on a dry basis corrected to 7 percent oxygen (3-run average)
3. New or reconstructed small solid fuel	a. Particulate Matter (OR Total Selected Metals) b. Hydrogen Chloride c. Mercury	0.025 lb per MMBtu of heat input; or (0.0003 lb per MMBtu/hr of heat input) 0.02 lb per MMBtu of heat input 0.000003 lb per MMBtu of heat input

4. New or reconstructed large liquid fuel	a. Particulate Matter b. Hydrogen Chloride c. Carbon Monoxide	0.03 lb per MMBtu of heat input 0.0005 lb per MMBtu of heat input 400 ppm by volume on a dry basis corrected to 3 percent oxygen (30-day rolling average for units 100 MMBtu/hr or greater, 3-run average for units less than 100 MMBtu/hr)
5. New or reconstructed limited use liquid fuel	a. Particulate Matter b. Hydrogen Chloride c. Carbon Monoxide	0.03 lb per MMBtu of heat input 0.0009 lb per MMBtu of heat input 400 ppm by volume on a dry basis corrected to 3 percent oxygen (3-run average)
6. New or reconstructed small liquid fuel	a. Particulate Matter b. Hydrogen Chloride	0.03 lb per MMBtu of heat input 0.0009 lb per MMBtu of heat input
7. New or reconstructed large gaseous fuel	Carbon Monoxide	400 ppm by volume on a dry basis corrected to 3 percent oxygen (30-day rolling average for units 100 MMBtu/hr or greater, 3-run average for units less than 100 MMBtu/hr)
8. New or reconstructed limited use gaseous fuel	Carbon Monoxide	400 ppm by volume on a dry basis corrected to 3 percent oxygen (3-run average)

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9. Existing large solid fuel	a. Particulate Matter (OR Total Selected Metals) b. Hydrogen Chloride c. Mercury	0.07 lb per MMBtu of heat input (0.001 lb per MMBtu/hr of heat input) 0.09 lb per MMBtu of heat input 0.000009 lb per MMBtu of heat input
10. Existing limited use solid fuel	Particulate Matter (OR Total Selected Metals)	0.21 lb per MMBtu of heat input (0.004 lb per MMBtu/hr of heat input)

Table 2 to Subpart DDDDD of Part 63 — Operating Limits for Boilers and Process Heaters with Particulate Matter Emission Limits

As stated in §63.7500, you must comply with the applicable operating limits:

If you demonstrate compliance with applicable particulate matter emission limits using...	**You must meet these operating limits...**
1. Wet scrubber control	a. Maintain the minimum pressure drop and liquid flow-rate at or above the operating levels established during the performance test according to §63.7530(c) and Table 7 to this subpart that demonstrated compliance with the applicable emission limit for particulate matter.
2. Fabric filter control	a. Install and operate a bag leak detection system

	according to §63.7525 and operate the fabric filter such that the bag leak detection system alarm does not sound more than 5 percent of the operating time during each 6-month period; OR b. This option is for boilers and process heaters that operate dry control systems. Existing boilers and process heaters must maintain opacity to less than or equal to 20 percent (6-minute average) except for one 6-minute period per hour of not more than 27 percent. New boilers and process heaters must maintain opacity to less than or equal to 10 percent opacity (1-hour block average).
3. Electrostatic precipitator control	a. This option is for boilers and process heaters that operate dry control systems. Existing boilers and process heaters must maintain opacity to less than or equal to 20 percent (6-minute average) except for one 6-minute period per hour of not more than 27 percent. New boilers and process heaters must maintain opacity to less than or equal to 10 percent opacity (1-hour block average).; OR

	b. This option is only for boilers and process heaters that operate additional wet control systems. Maintain the minimum voltage and secondary current or total power input of the electrostatic precipitator at or above the operating limits established during the performance test according to §63.7530(c) and Table 7 to this subpart that demonstrated compliance with the applicable emission limit for particulate matter.
4. Any other control type	This option is for boilers and process heaters that operate dry control systems. Existing boilers and process heaters must maintain opacity to less than or equal to 20 percent (6-minute average) except for one 6-minute period per hour of not more than 27 percent. New boilers and process heaters must maintain opacity to less than or equal to 10 percent opacity (1-hour block average).

Table 3 to Subpart DDDDD of Part 63 — Operating Limits for Boilers and Process Heaters With Mercury Emission Limits and Boilers and Process Heaters That Choose to Comply With the Alternative Total Selected Metals Emission Limits

As stated in §63.7500, you must comply with the applicable operating limits:

If you demonstrate compliance with applicable mercury and/or total selected metals emission limits using...	**You must meet these operating limits...**
1. Wet scrubber control	Maintain the minimum pressure drop and liquid flow-rate at or above the operating levels established during the performance test according to §63.7530(c) and Table 7 to this subpart that demonstrated compliance with the applicable emission limits for mercury and/or total selected metals.
2. Fabric filter control	a. Install and operate a bag leak detection system according to §63.7525 and operate the fabric filter such that the bag leak detection system alarm does not sound more than 5 percent of the operating time during a 6-month period; OR b. This option is for boilers and process heaters that operate dry control systems. Existing sources must maintain opacity to less than or equal to 20 percent (6-minute average) except for one 6-minute period per hour of not more than 27 percent. New sources must maintain opacity to less than or equal to 10 percent opacity (1-hour block average).
3. Electrostatic precipitator control	a. This option is for boilers and process

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	heaters that operate dry control systems. Existing sources must maintain opacity to less than or equal to 20 percent (6-minute average) except for one 6-minute period per hour of not more than 27 percent. New sources must maintain opacity to less than or equal to 10 percent opacity (1-hour block average); OR b. This option is only for boilers and process heaters that operate additional wet control systems. Maintain the minimum voltage and secondary current or total power input of the electrostatic precipitator at or above the operating limits established during the performance test according to §63.7530(c) and Table 7 to this subpart that demonstrated compliance with the applicable emission limits for mercury and/or total selected metals.
4. Dry scrubber or carbon injection control	Maintain the minimum sorbent or carbon injection rate at or above the operating levels established during the performance test according to §63.7530(c) and Table 7 to this subpart that demonstrated compliance with the applicable emission limit for mercury.

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5. Any other control type	This option is only for boilers and process heaters that operate dry control systems. Existing sources must maintain opacity to less than or equal to 20 percent (6-minute average) except for one 6-minute period per hour of not more than 27 percent. New sources must maintain opacity to less than or equal to 10 percent opacity (1-hour block average).
6. Fuel analysis	Maintain the fuel type or fuel mixture such that the mercury and/or total selected metals emission rates calculated according to §63.7530(d)(4) and/or (5) is less than the applicable emission limits for mercury and/or total selected metals.

Table 4 to Subpart DDDDD of Part 63 — Operating Limits for Boilers and Process Heaters with Hydrogen Chloride Emission Limits

As stated in §63.7500, you must comply with the following applicable operating limits:

If you demonstrate compliance with applicable hydrogen chloride emission limits using...	**You must meet these operating limits...**

1. Wet scrubber control	Maintain the minimum scrubber effluent pH, pressure drop, and liquid flow-rate at or above the operating levels established during the performance test according to §63.7530(c) and Table 7 to this subpart that demonstrated compliance with the applicable emission limit for hydrogen chloride.
2. Dry scrubber control	Maintain the minimum sorbent injection rate at or above the operating levels established during the performance test according to §63.7530(c) and Table 7 to this subpart that demonstrated compliance with the applicable emission limit for hydrogen chloride.
3. Fuel analysis	Maintain the fuel type or fuel mixture such that the hydrogen chloride emission rate calculated according to §63.7530(d)(3) is less than the applicable emission limit for hydrogen chloride.

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 test for existing, new or reconstructed affected sources:

To conduct a performance test for the following pollutant...	**You must...**	**Using...**
1. Particulate Matter	a. Select sampling ports location and the number of	Method 1 in appendix A to part 60 of this chapter.

	traverse points. b. Determine velocity and volumetric flow-rate of the stack gas. c. Determine oxygen and carbon dioxide concentrations of the stack gas. d. Measure the moisture content of the stack gas e. Measure the particulate matter emission concentration f. Convert emissions concentration to lb per MMBtu emission rates.	Method 2, 2F, or 2G in appendix A to part 60 of this chapter. Method 3A or 3B in appendix A to part 60 of this chapter or ASME PTC 19, Part 10(1981). Method 4 in appendix A to part 60 of this chapter. Method 5 or 17 (positive pressure fabric filters must use Method 5D) in appendix A to part 60 of this chapter. Method 19 F-factor methodology in appendix A to part 60 of this chapter.
2. Total selected metals	a. Select sampling ports location and the number of traverse points. b. Determine velocity and volumetric flow-rate of the stack gas. c. Determine oxygen and carbon dioxide	Method 1 in appendix A to part 60 of this chapter. Method 2, 2F, or 2G in appendix A to part 60 of this chapter. Method 3A or 3B in appendix A to part 60 of this chapter

	concentrations of the stack gas.	or ASME PTC 19, Part 10(1981).
	d. Measure the moisture content of the stack gas	Method 4 in appendix A to part 60 of this chapter.
	e. Measure the total selected metals emission concentration	Method 29 in appendix A to part 60 of this chapter.
	f. Convert emissions concentration to lb per MMBtu emission rates.	Method 19 F-factor methodology in appendix A to part 60 of this chapter.

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3. Hydrogen chloride	a. Select sampling ports location and the number of traverse points.	Method 1 in appendix A to part 60 of this chapter.
	b. Determine velocity and volumetric flow-rate of the stack gas.	Method 2, 2F, or 2G in appendix A to part 60 of this chapter.
	c. Determine oxygen and carbon dioxide concentrations of the stack gas.	Method 3A or 3B in appendix A to part 60 of this chapter or ASME PTC 19, Part 10(1981).
	d. Measure the moisture content of the stack gas	Method 4 in appendix A to part 60 of this chapter.
	e. Measure the hydrogen chloride emission concentration	Method 26 or 26A in appendix A to part 60 of this chapter.
	f. Convert emissions concentration to lb per MMBtu emission rates.	Method 19 F-factor methodology in appendix A to part 60 of this chapter.

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4. Mercury	a. Select sampling ports location and the number of traverse points.	Method 1 in appendix A to part 60 of this chapter.
	b. Determine velocity and volumetric flow-rate of the stack gas.	Method 2, 2F, or 2G in appendix A to part 60 of this chapter.
	c. Determine oxygen and carbon dioxide concentrations of the stack gas.	Method 3A or 3B in appendix A to part 60 of this chapter or ASME PTC 19, Part 10(1981).
	d. Measure the moisture content of the stack gas	Method 4 in appendix A to part 60 of this chapter.
	e. Measure the mercury emission concentration	Method 29 in appendix A to part 60 of this chapter or Method 101A in appendix B to part 61 of this chapter or ASTM Method D6784-02.
	f. Convert emissions concentration to lb per MMBtu emission rates.	Method 19 F-factor methodology in appendix A to part 60 of this chapter.

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5. Carbon Monoxide	a. Select the sampling ports location and the number of traverse points.	Method 1 in appendix A to part 60 of this chapter.
	b. Determine velocity and volumetric flow-rate of the stack gas.	Method 2, 2F, or 2G in appendix A to part 60 of this chapter.
	c. Determine oxygen and carbon dioxide concentrations of the stack gas.	Method 3A or 3B in appendix A to part 60 of this chapter or ASME PTC 19, Part 10(1981).
	d. Measure the moisture content of the stack gas.	Method 4 in appendix A to part 60 of this chapter.
	e. Measure the carbon monoxide emission concentration.	Method 10, 10A, or 10 B in appendix A to part 60 of this chapter.
	f. Convert emissions concentration to lb per MMBtu emission rates.	Method 19 F-factor methodology in appendix A to part 60 of this chapter.

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:

To conduct a fuel analysis for the following pollutant...	**You must...**	**Using...**
1. Mercury	a. Collect fuel	Procedure in

	samples.	§63.7521(c) or ASTM D2234M-03 (for coal) or ASTM D6323-98 (2003) (for biomass) or equivalent.
	b. Composite fuel samples.	Procedure in §63.7521(d) or equivalent.
	c. Prepare composited fuel samples.	SW-846-3050B (for solid samples) or SW-846-3020A (for liquid samples) or ASTM D2013-01 (for coal) or ASTM D5198-92 (2003) (for biomass) or equivalent.
	d. Determine heat content of the fuel type.	ASTM D5865-03a (for coal) or ASTM E711-87 (1996) (for biomass) or equivalent.
	e. Determine moisture content of the fuel type.	ASTM D3173-02 or ASTM E871-82 (1998) or equivalent.
	f. Measure mercury concentration in fuel sample.	ASTM D3684-01 (for coal) or SW-846-7471A (for solid samples) or SW-846 7470A (for liquid samples).
	g. Convert concentrations in into units of pounds of pollutant per MMBtu of heat content.	

2. Total selected metals	a. Collect fuel samples.	Procedure in §63.7521(c) or ASTM D2234M-03 (for coal) or ASTM D6323-98 (2003) (for biomass) or equivalent.
	b. Composite fuel samples.	Procedure in §63.7521(d) or equivalent.
	c. Prepare composited fuel samples	SW-846-3050B (for solid samples) or SW-846-3020A (for liquid samples) or ASTM D2013-01 (for coal) or ASTM D5198-92 (2003)(for biomass) or equivalent.
	d. Determine heat content of the fuel type.	ASTM D5865-03a (for coal) or ASTM E 711-87 (for biomass) or equivalent.
	e. Determine moisture content of the fuel type.	ASTM D3173-02 or ASTM E871 or equivalent.
	f. Measure total selected metals concentration in fuel sample.	SW-846-6010Bor ASTM D3683-94 (2000) (for coal) or ASTM E885-88 (1996) (for biomass).
	g. Convert concentrations into units of pounds of pollutant per MMBtu of heat content.	
3.Hydrogen chloride	a. Collect fuel samples.	Procedure in §63.7521(c) or ASTM D2234M-03 (for coal) or ASTM D6323-98 (2003) (for biomass)

		or equivalent.
	b. Composite fuel samples.	Procedure in §63.7521(d) or equivalent.
	c. Prepare composited fuel samples	SW-846-3050B (for solid samples) or SW-846-3020A (for liquid samples) or ASTM D2013-01 (for coal) or ASTM D5198-92 (2003) (for biomass) or equivalent.
	d. Determine heat content of the fuel type.	ASTM D5865-03a (for coal) or ASTME 711-87 (1996) (for biomass) or equivalent.
	e. Determine moisture content of the fuel type.	ASTM D3173-02 or ASTM E871-82 (1998) or equivalent.
	f. Measure chlorine concentration in fuel sample.	SW-846-9250 or ASTM E776-87 (1996) (for biomass) or equivalent.
	g. Convert concentrations into units of pounds of pollutant per MMBtu of heat content.	

Table 7 to Subpart DDDDD of Part 63 — Establishing Operating Limits

As stated in §63.7520, you must comply with the following requirements for establishing operating limits:

If you have an	And your operating	You must...	Using...	According to the following

applicable emission limit for...	limits are based on...			requirements
1. Particulate matter, mercury, or total selected metals.	a. Wet scrubber operating parameters	i. Establish a site-specific minimum pressure drop and minimum flow rate operating limit according to §63.7530(c)	(1) Data from the pressure drop and liquid flow rate monitors and the particulate matter, mercury, or total selected metals performance test.	(a) You must collect pressure drop and liquid flow-rate data every 15 minutes during the entire period of the performance tests; (b) Determine the average pressure drop and liquid flow-rate for each individual test run in the three-run performance test by computing the average of all the 15-minute readings taken during each test run.
	b. Electrostatic precipitator operating parameters (option only for units with additional wet scrubber	i. Establish a site-specific minimum voltage and secondary current	(1) Data from the pressure drop and liquid flow rate monitors and the particulate matter, mercury, or total selected metals performance test.	(a) You must collect voltage and secondary current or total power input data every 15 minutes during the entire period of the performance tests; (b) Determine the average voltage and secondary current or total power input for each individual test

	control)	or total power input according to §63.7530(c)		run in the three-run performance test by computing the average of all the 15-minute readings taken during each test run.
	c. A site-specific opacity limit (only for units that meet the criteria for having a site-specific opacity limit according to §63.7530(c)(6)(i)	i. Establish a site-specific maximum opacity operating limit according to §63.7530(c)	(1) Data from the continuous opacity monitoring system and the particulate matter, mercury, or total selected metals performance test.	(a) Collecting the opacity monitoring system data according to §63.7525(b) and §63.7535; and (b) Reducing the opacity monitoring data to 6-minute averages; and (c) Determine the average opacity for each individual test run in the three-run performance test by computing the average of all the 6-minute readings taken during each test run.

2. Hydrogen Chloride	a. Wet scrubber operating parameters	i. Establish a site-specific minimum pressure drop and minimum flow rate operating limit according to §63.7530(c)	(1) Data from the pH, pressure drop, and liquid flow rate monitors and the hydrogen chloride performance test.	(a) You must collect pH, pressure drop, and liquid flow-rate data every 15 minutes during the entire period of the performance tests; (b) Determine the average pH, pressure drop, and liquid flow-rate for each individual test run in the three-run performance test by computing the average of all the 15-minute readings taken during each test run.
	b. Dry scrubber operating parameters	i. Establish a site-specific minimum sorbent injection rate operating	(1) Data from the sorbent injection rate monitors and the hydrogen chloride performance test.	(a) You must collect sorbent injection rate data every 15 minutes during the entire period of the performance tests; (b) Determine the average sorbent injection rate for each individual test run in the three-run performance test by computing

		limit according to §63.7530(c)		the average of all the 15-minute readings taken during each test run.

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 affected sources 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(b) and 63.7535; and b. Reducing the opacity monitoring data to 6-minute averages; and c. Maintaining opacity to less than or equal to 20 percent (6-minute average) except for one 6-minute period per hour of not more than 27 percent for existing sources; OR maintaining opacity to less than or equal to 10 percent (1-hour block average) for new sources.
2. Fabric Filter Bag Leak Detection Operation.	Installing and operating a bag leak detection system according to §63.7525 and operating the fabric filter such that the requirements in §63.7540(a)(9) are met.

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3. 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 3-hour block averages; and c. Maintaining the 3-hour average pressure drop and liquid flow-rate at or above the operating limits established during the performance test according to §63.7530 (c).
4. Wet Scrubber pH.	a. Collecting the pH monitoring system data according to §§63.7525 and 63.7535; and b. Reducing the data to 3-hour block averages; and c. Maintaining the 3-hour average pH at or above the operating limit established during the performance test according to §63.7530(c).
5. 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 3-hour block averages; and c. Maintaining the 3-hour average sorbent or carbon injection rate at or above the operating limit established during the performance test according to §63.7530(c).

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6. Electrostatic Precipitator Secondary Current and Voltage or Total Power Input.	a. Collecting the secondary current and voltage or total power input monitoring system data for the electrostatic precipitator according to §§63.7525 and 63.7535; and b. educing the data to 3-hour block averages; and c. Maintaining the 3-hour average secondary current and voltage or total power input at or above the operating limits established during the performance test according to §63.7530(c).
7. Fuel Pollutant Content.	a. Only burning the fuel types and fuel mixtures used to demonstrate compliance with the applicable emission limit according to §63.7530(c) or (d) as applicable; and b. Keeping monthly records of fuel use according to §63.7540(a).

Table 9 to Subpart DDDDD of Part 63 — Reporting Requirements

As stated in §63.7550, you must comply with the following requirements for reports:

You must submit a(n)	**The report must contain...**	**You must submit the report...**
1. compliance report	a. information required in §63.7550(c)(1)through(11) AND b. if there are no deviations from any emission limitation (emission limit and	semiannually according to the requirements in §63.7550(b).

	operating limit) that applies to you and there are no deviations from the requirements for work practice standards in Table 8 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 the 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) or work practice standard during the reporting period, the report must contain the information in §63.7550(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), the report must contain the information in §63.7550(e) AND d. if you had a startup, shutdown, or malfunction during the reporting period and you took actions consistent with your startup, shutdown, and malfunction plan, the compliance report must include the information in §63.10(d)(5)(i)	

2. an immediate startup, shutdown, and malfunction report if you had a startup, shutdown, or malfunction during the reporting period that is not consistent with your startup, shutdown, and malfunction plan	a. actions taken for the event AND b. The information in §63.10(d)(5)(ii)	i. by fax or telephone within 2 working days after starting actions inconsistent with the plan; and ii. by letter within 7 working days after the end of the event unless you have made alternative arrangements with the permitting authority.

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	Brief Description	Applicalbe
§63.1	Applicability	Initial Applicability Determination; Applicability After Standard Established; Permit Requirements; Extensions, Notifications	Yes.

§63.2	Definitions	Definitions for part 63 standards	Yes.
§63.3	Units and Abbreviations	Units and abbreviations for part 63 standards	Yes.
§63.4	Prohibited Activities	Prohibited Activities; Compliance date; Circumvention, Severability	Yes.
§63.5	Construction /Reconstruction	Applicability; applications; approvals	Yes.
§63.6(a)	Applicability	GP apply unless compliance extension AND GP 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 112(f)	Yes.
§63.6(b)(5)	Notification	Must notify if commenced construction or reconstruction after proposal	Yes.
§63.6(b)(6)	[Reserved]		

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§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 immediately upon becoming major, regardless of whether required to comply when they were an area source	Yes.
§63.6(c)(1)-(2)	Compliance Dates for Existing Sources	Comply according to date in subpart, which must be no later than 3 years after effective date AND For 112(f) standards, comply within 90 days of effective date unless compliance extension	Yes.
§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 subpart or by equivalent time period (e.g.,example, 3 years)	Yes.
§63.6(d)	[Reserved]		
§63.6(e)(1)-(2)	Operation & Maintenance	Operate to minimize emissions at all times AND Correct malfunctions as soon as practicable	Yes.

		AND Operation and maintenance requirements independently enforceable information Administrator will use to determine if operation and maintenance requirements were met	
§63.6(e)(3)	Startup, Shutdown, and Malfunction Plan (SSMP)	Requirement for SSM and startup, shutdown, malfunction plan Content of SSMP	Yes.
§63.6(f)(1)	Compliance Except During SSM	Comply with emission standards at all times except during SSM	Yes.
§63.6(f)(2)-(3)	Methods for Determining Compliance	Compliance based on performance test, operation and maintenance plans, records, inspection	Yes.
§63.6(g)(1)-(3)	Alternative Standard	Procedures for getting an alternative standard	Yes.
§63.6(h)(1)	Compliance with Opacity/VE Standards	Comply with opacity/VE emission limitations at all times except during SSM	Yes.
§63.6(h)(2)(i)	Determining Compliance with Opacity/Visible Emission (VE) Standards	If standard does not state test method, use Method 9 for opacity and Method 22 for VE	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	Yes.
§63.6(h)(3)	[Reserved]		
§63.6(h)(4)	Notification of Opacity/VE Observation Date	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 thirty, 6-minute averages	No.
§63.6(h)(6)	Records of Conditions During Opacity/VE observations	Keep records available and allow Administrator to inspect	No.
§63.6(h)(7)(i)	Report continuous opacity monitoring system Monitoring Data from Performance Test	Submit continuous opacity monitoring system data with other performance test data	Yes.

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§63.6(h)(7)(ii)	Using continuous opacity monitoring system instead of Method 9	Can submit continuous opacity monitoring system data instead of Method 9 results even if subpart requires Method 9, but must notify Administrator before performance test	No.
§63.6(h)(7)(iii)	Averaging time for continuous opacity monitoring system during performance test	To determine compliance, must reduce continuous opacity monitoring system data to 6-minute averages	Yes.
§63.6(h)(7)(iv)	Continuous opacity monitoring system requirements	Demonstrate that continuous opacity monitoring system performance evaluations are conducted according to §§63.8(e), continuous opacity monitoring system are properly maintained and operated according to 63.8(c) and data quality as §63.8(d)	Yes.

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§63.6(h)(7)(v)	Determining Compliance with Opacity/VE Standards	Continuous opacity monitoring system is probative but not conclusive evidence of compliance with opacity standard, even if Method 9 observation shows otherwise. Requirements for continuous opacity monitoring system to be probative evidence–proper maintenance, meeting PS 1, and data have not been altered	Yes.
§63.6(h)(8)	Determining Compliance with Opacity/VE Standards	Administrator will use all continuous opacity monitoring system, Method 9, and Method 22 results, as well as information about operation and maintenance to determine compliance	Yes.
§63.6(h)(9)	Adjusted Opacity Standard	Procedures for Administrator to adjust an opacity standard	Yes.
§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 source category from requirement to comply with rule	Yes.
§63.7(a)(1)	Performance Test Dates	Dates for Conducting Initial Performance Testing and Other Compliance Demonstrations	Yes.

§63.7(a)(2)	Performance Test Dates	New source with initial startup date before effective date has 180 days after effective date to demonstrate compliance	Yes.
§63.7(a)(2)(ii-viii)	[Reserved]		
§63.7(a)(2)(ix)	Performance Test Dates	New source that commenced construction between proposal and promulgation dates, when promulgated standard is more stringent than proposed standard, has 180 days after effective date or 180 days after startup of source, whichever is later, to demonstrate compliance AND If source initially demonstrates compliance with less stringent proposed standard, it has 3 years and 180 days after the effective date of the standard or 180 days after startup of source, whichever is later, to demonstrate compliance with promulgated standard	Yes. No.

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§63.7(a)(3)	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 Rescheduling	If rescheduling a performance test is necessary, must notify Administrator 5 days before scheduled date of rescheduled date	Yes.
§63.7(c)	Quality Assurance/Test Plan	Requirement to submit site-specific test plan 60 days before the test or on date Administrator agrees with: Test plan approval procedures AND Performance audit requirements AND 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 tests must be conducted under representative conditions	No.
		AND	

		Cannot conduct performance tests during SSM.	Yes.
		AND	
		Not a deviation to exceed standard during SSM	Yes.
		AND	
		Upon request of Administrator, make available records necessary to determine conditions of performance tests	Yes.
§63.7(e)(2)	Conditions for Conducting Performance Tests	Must conduct according to rule and EPA test methods unless Administrator approves alternative	Yes.
§63.7(e)(3)	Test Run Duration	Must have three separate test runs AND Compliance is based on arithmetic mean of three runs AND Conditions when data from an additional test run can be used	Yes.
§63.7(e)(4)	Interaction with other sections of the Act.	Nothing in §63.7(e)(1) through (4) can abrogate the Administrator's authority to require testing under Section 114 of the Act.	Yes.

§63.7(f)	Alternative Test Method	Procedures by which Administrator can grant approval to use an alternative test method	Yes.
§63.7(g)	Performance Test Data Analysis	Must include raw data in performance test report AND Must submit performance test data 60 days after end of test with the Notification of Compliance Status AND 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 part 60 apply	Yes.
§63.8(a)(3)	[Reserved]		
§63.8(a)(4)	Monitoring with Flares	Unless your rule says otherwise, the requirements for flares in §63.11 apply	No.

§63.8(b)(1)(i)-(ii)	Monitoring	Must conduct monitoring according to standard unless Administrator approves alternative	Yes.
§63.8(b)(1)(iii)	Monitoring	Flares not subject to this section unless otherwise specified in relevant standard	No.
§63.8(b)(2)-(3)	Multiple Effluents and Multiple Monitoring Systems	Specific requirements for installing monitoring systems AND Must install on each effluent before it is combined and before it is released to the atmosphere unless Administrator approves otherwise AND If more than one monitoring system on an emission point, must report all monitoring system results, unless one monitoring system is a backup	Yes.
§63.8(c)(1)	Monitoring System Operation and Maintenance	Maintain monitoring system in a manner consistent with good air pollution control practices	Yes.
§63.8(c)(1)(i)	Routine and Predictable SSM	Maintain and operate CMS according to §63.6(e)(1)	Yes.

§63.8(c)(1)(ii)	SSM not in SSMP	Must keep necessary parts available for routine repairs of CMSs	Yes.
§63.8(c)(1)(iii)	Compliance with Operation and Maintenance Requirements	Must develop and implement an SSMP for CMSs	Yes.
§63.8(c)(2)-(3)	Monitoring System Installation	Must install to get representative emission and parameter measurements AND Must verify operational status before or at performance test	Yes.
§63.8(c)(4)	Continuous Monitoring System (CMS) Requirements	CMSs must be operating except during breakdown, out-of-control, repair, maintenance, and high-level calibration drifts	No.
§63.8(c)(4)(i)	Continuous Monitoring System (CMS) Requirements	Continuous opacity monitoring system must have a minimum of one cycle of sampling and analysis for each successive 10-second period and one cycle of data recording for each successive 6-minute period	Yes.

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§63.8(c)(4)(ii)	Continuous Monitoring System (CMS) Requirements	Continuous emissions monitoring system must have a minimum of one cycle of operation for each successive 15-minute period	No.
§63.8(c)(5)	Continuous Opacity Monitoring system (COMS) Requirements	Must do daily zero and high level calibrations	Yes.
§63.8(c)(6)	Continuous Monitoring System (CMS) Requirements	Must do daily zero and high level calibrations	No.
§63.8(c)(7)-(8)	Continuous monitoring systems Requirements	Out-of-control periods, including reporting	Yes.
§63.8(d)	Continuous monitoring systems Quality Control	Requirements for continuous monitoring systems quality control, including calibration, etc. AND Must keep quality control plan on record for the life of the affected source. Keep old versions for 5 years after revisions	Yes.
§63.8(e)	Continuous monitoring systems Performance Evaluation	Notification, performance evaluation test plan, reports	Yes.

§63.8(f)(1)-(5)	Alternative Monitoring Method	Procedures for Administrator to approve alternative monitoring	Yes.
§63.8(f)(6)	Alternative to Relative Accuracy Test	Procedures for Administrator to approve alternative relative accuracy tests for continuous emissions monitoring system	No.
§63.8(g)(1)-(4)	Data Reduction	Continuous opacity monitoring system 6-minute averages calculated over at least 36 evenly spaced data points AND Continuous emissions monitoring system 1-hour averages computed over at least 4 equally spaced data points	Yes.
§63.8(g)(5)	Data Reduction	Data that cannot be used in computing averages for continuous emissions monitoring system and continuous opacity monitoring system	No.
§63.9(a)	Notification Requirements	Applicability and State Delegation	Yes.

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§63.9(b)(1)-(5)	Initial Notifications	Submit notification 120 days after effective date AND Notification of intent to construct/ reconstruct AND Notification of commencement of construct/reconstruct ; Notification of startup AND Contents of each	Yes.
§63.9(c)	Request for Compliance Extension	Can request if cannot comply by date or if installed BACT/LAER	Yes.
§63.9(d)	Notification of Special Compliance Requirements for New Source	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 Continuous Monitoring Systems	Notification of performance evaluation AND Notification using continuous opacity monitoring system data AND Notification that exceeded criterion for relative accuracy	Yes.
§63.9(h)(1)-(6)	Notification of Compliance Status	Contents AND Due 60 days after end of performance test or other compliance demonstration, When to submit to Federal vs. State authority	Yes.
§63.9(i)	Adjustment of Submittal Deadlines	Procedures for Administrator to approve change in 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 AND When to submit to Federal vs. State authority AND Procedures for owners of more than 1 source	Yes.
§63.10(b)(1)	Recordkeeping/Reporting	General Requirements AND Keep all records readily available AND Keep for 5 years	Yes.
§63.10(b)(2)(i)-(v)	Records related to Startup, Shutdown, and Malfunction	Occurrence of each of operation (process equipment) AND Occurrence of each malfunction of air pollution equipment AND Maintenance on air pollution control equipment AND Actions during startup, shutdown, and malfunction	Yes.

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§63.10(b)(2)(vi) and (x-xi)	Continuous monitoring systems Records	Malfunctions, inoperative, out-of-control AND Calibration checks AND Adjustments, maintenance	Yes.
§63.10(b)(2)(vii)-(ix)	Records	Measurements to demonstrate compliance with emission limitations AND Performance test, performance evaluation, and visible emission observation results AND Measurements to determine conditions of performance tests and performance evaluations.	Yes.
§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	No.
§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)(1),(5)-(8),(10)-(15)	Records	Additional Records for continuous monitoring systems	Yes.
§63.10(c)(7)-(8)	Records	Records of excess emissions and parameter monitoring exceedances for continuous monitoring systems	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	Yes.
§63.10(d)(4)	Progress Reports	Must submit progress reports on schedule if under compliance extension	Yes.
§63.10(d)(5)	Startup, Shutdown, and Malfunction Reports	Contents and submission	Yes.

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§63.10(e)(1)-(2)	Additional continuous monitoring systems Reports	Must report results for each CEM on a unit AND Written copy of performance evaluation AND 3 copies of continuous opacity monitoring system performance evaluation	Yes.
§63.10(e)(3)	Reports	Excess Emission Reports	No.
§63.10(e)(3)(i-iii)	Reports	Schedule for reporting excess emissions and parameter monitor exceedance (now defined as deviations)	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 exceedance (now defined as deviations) AND Provision to request semiannual reporting after compliance for one year AND	No.

		Submit report by 30th day following end of quarter or calendar half AND If there has not been an exceedance or excess emission (now defined as deviations), report contents is a statement that there have been no deviations	
§63.10(e)(3)(iv-v)	Excess Emissions Reports	Must submit report containing all of the information in §63.10(c)(5-13), §63.8(c)(7-8)	No.
§63.10(e)(3)(vi-viii)	Excess Emissions Report and Summary Report	Requirements for reporting excess emissions for continuous monitoring systems (now called deviations) Requires all of the information in §63.10(c)(5-13), §63.8(c)(7-8)	No.
§63.10(e)(4)	Reporting continuous opacity monitoring system data	Must submit continuous opacity monitoring system data with performance test data	Yes.
§63.10(f)	Waiver for Recordkeeping/Reporting	Procedures for Administrator to waive	Yes.
§63.11	Flares	Requirements for flares	No.

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§63.12	Delegation	State authority to enforce standards	Yes.
§63.13	Addresses	Addresses where reports, notifications, and requests are sent	Yes.
§63.14	Incorporation by Reference	Test methods incorporated by reference	Yes.
§63.15	Availability of Information	Public and confidential information	Yes.

Appendix A to Subpart DDDDD – Methodology and Criteria for Demonstrating Eligibility for the Health-Based Compliance Alternatives Specified for the Large Solid Fuel Subcategory

1. Purpose/Introduction

This appendix provides the methodology and criteria for demonstrating that your affected source is eligible for the compliance alternative for the HCl emission limit and/or the total selected metals (TSM) emission limit. This appendix specifies emissions testing methods that you must use to determine HCl, chlorine, and manganese emissions from the affected units and what parts of the affected source facility must be included in the eligibility demonstration. You must demonstrate that your affected source is eligible for the health-based compliance alternatives using either a look-up table analysis (based on the look-up tables included in this appendix) or a site-specific compliance demonstration performed according to the criteria specified in this appendix. This appendix also specifies how and when you file any eligibility demonstrations for your affected source and how to show that your affected source remains eligible for the health-based compliance alternatives in the future.

2. Who is eligible to demonstrate that they qualify for the health-based compliance alternatives?

Each new, reconstructed, or existing affected source may demonstrate that they are eligible for the health-based

compliance alternatives. Section 63.7490 of subpart DDDDD defines the affected source and explains which affected sources are new, existing, or reconstructed.

3. What parts of my facility have to be included in the health-based eligibility demonstration?

If you are attempting to determine your eligibility for the compliance alternative for HCl, you must include every emission point subject to subpart DDDDD in the eligibility demonstration.

If you are attempting to determine your eligibility for the compliance alternative for TSM, you must include every emission point subject to subpart DDDDD in the eligibility demonstration.

4. How do I determine HAP emissions from my affected source?

(a) You must conduct HAP emissions tests for every emission point covered under subpart DDDDD within the affected source facility according to the requirements in paragraphs (b) through (f) of this section and the methods specified in Table 1 of this appendix.

If you are attempting to determine your eligibility for the compliance alternative for HCl, you must test the subpart DDDDD units at your facility for both HCl and Cl_2.

If you are attempting to determine your eligibility for the compliance alternative for TSM, you must test the subpart DDDDD units at your facility for manganese.

(b) Periods when emissions tests must be conducted.

(1) You must not conduct emissions tests during periods of startup, shutdown, or malfunction, as specified in §63.7(e)(1).

(2) You must test under worst-case operating conditions as defined in this appendix. You must describe your worst-case operating conditions in your performance test report for the process and control systems (if applicable) and explain why the conditions are worst-case.

(c) Number of test runs. You must conduct three separate test runs for each test required in this section, as specified in §63.7(e)(3). Each test run must last at least 1 hour.

(d) Sampling locations. Sampling sites must be located at the outlet of the control device and prior to any releases to the atmosphere.

(e) Collection of monitoring data for HAP control devices. During the emissions test, you must collect operating parameter monitoring system data at least every 15 minutes during the entire emissions test and establish the site-specific operating requirements in Tables 3 or 4, as appropriate, of subpart DDDDD using data from the monitoring system and the procedures specified in §63.7530 of subpart DDDDD.

(f) Nondetect data. You may treat emissions of an individual HAP as zero if all of the test runs result in a nondetect measurement and the condition in paragraph (1) is met for the manganese test method. Otherwise nondetect data for individual HAP must be treated as one-half of the method detection limit.

(1) For manganese measured using Method 29 in appendix A to 40 CFR part 60, you analyze samples using atomic absorption spectroscopy (AAS).

(g) You must determine the maximum hourly emission rate for each appropriate emission point according to equation 1.

$$AveWeightedEmissions = \sum_{i=1}^{n} (Er \times Hm) \div \sum_{i=1}^{n} Hm$$

(Eq. 1)

Where:

MaxHourly Emissions	=	Maximum hourly emissions for hydrogen chloride, chlorine, or manganese, in units of pounds per hour.
Er	=	Emission rate (the 3-run average as determined according to Table 1 of this appendix) for hydrogen chloride, chlorine, or manganese, in units of pounds per million Btu of heat input.
Hm	=	Maximum rated heat input capacity of appropriate emission point, in

units of million Btu per hour.

5. What are the criteria for determining if my facility is eligible for the health-based compliance alternatives?

(a) Determine the HAP emissions from each appropriate emission point within the affected source facility using the procedures specified in section 4 of this appendix.

(b) Demonstrate that your facility is eligible for either of the health-based compliance alternatives using either the methods described in section 6 of this appendix (look-up table analysis) or section 7 of this appendix (site-specific compliance demonstration).

(c) Your facility is eligible for the health-based compliance alternative for HCl if 1 of the following 2 statements is true:

(1) The calculated HCl-equivalent emission rate is below the appropriate value in the look-up table;

(2) Your site-specific compliance demonstration indicates that your maximum HI for HC1 and $C1_2$ at a location where people live is less than or equal to 1.0;

(d) Your facility is eligible for the health-based compliance alternative for TSM if 1 of the following 2 statements is true:

(1) The manganese emission rate for all your subpart DDDDD sources is below the appropriate value in the look-up table;

(2) Your site-specific compliance demonstration indicates that your maximum HQ for manganese at a location where people live is less than or equal to 1.0;

6. How do I conduct a look-up table analysis?

You may use look-up tables to demonstrate that your facility is eligible for either the compliance alternative for the HCl emission limit or the compliance alternative for TSM emission limit.

(a) <u>HCl health-based compliance alternative.</u> To calculate the total toxicity-weighted HCl-equivalent emission rate for your facility, first calculate the total

affected source emission rate of HCl by summing the maximum hourly HCl emission rates from all your subpart DDDDD sources. Then, similarly, calculate the total affected source emission rate for Cl_2. Finally, calculate the toxicity-weighted emission rate (expressed in HCl equivalents) according to equation 2 of this appendix.

$$ER_{tw} = 3(ER_i \times (RfC_{HCl}/RfC_i)) \qquad \text{Eq. 2}$$

where:

ER_{tw} is the HC1-equivalent emission rate, lb/hr
ER_i is the emission rate of HAP i in lbs/hr
RfC_i is the reference concentration of HAP i
RfC_{HCl} is the reference concentration of HCl (RfCs for HC1 and $C1_2$ can be found at http://www.epa.gov/ttn/atw/toxsource/summary.html)

The calculated HCl-equivalent emission rate will then be compared to the appropriate allowable emission rate in Table 2 of this appendix. To determine the correct value from the table, a subpart DDDDD average value should be used for stack height and the minimum distance between any subpart DDDDD stack at the facility and the property boundary should be used for property boundary distance. If one or both of these values do not match the exact values in the lookup tables then use the next lowest table value. (Note: If your average stack height is less than 5 meters, you must use the 5 meter row.) Your facility is eligible to comply with the health-based alternative HCl emission limit if your toxicity-weighted HCl equivalent emission rate, determined using the methods specified in this appendix, does not exceed the appropriate value in Table 2 of this appendix.

(b) TSM Compliance Alternative. To calculate the total manganese emission rate for your affected source, sum the maximum hourly manganese emission rates for all your subpart DDDDD sources. The calculated manganese emission rate will then be compared to the allowable emission rate in the Table 3 of this appendix. To determine the correct value from the table, a subpart DDDDD average value should be used for stack height and the minimum distance between any subpart DDDDD stack at the facility and the property boundary should be used for property boundary distance. If one or both of

these values do not match the exact values in the lookup tables then use the next lowest table value. (Note: If your average stack height is less than 5 meters, you must use the 5 meter row.) Your facility may exclude manganese when demonstrating compliance with the TSM emission limit if your manganese emission rate, determined using the methods specified in this appendix, does not exceed the appropriate value specified in Table 3 of this appendix.

7. How do I conduct a site-specific compliance demonstration?

If you fail to demonstrate that your facility is able to comply with one or both of the alternative health-based emission standards using the lookup table approach, you may choose to perform a site-specific compliance demonstration for your facility. You may use any scientifically-accepted peer-reviewed risk assessment methodology for your site-specific compliance demonstration. An example of one approach for performing a site-specific compliance demonstration for air toxics can be found in the EPA's "Air Toxics Risk Assessment Reference Library, Volume 2, Site-Specific Risk Assessment Technical Resource Document", which may be obtained through the EPA's Air Toxics Website at www.epa.gov/ttn/atw.

(a) Your facility is eligible for the HCl alternative compliance option if your site-specific compliance demonstration shows that the maximum HI for HC1 and Cl_2 from your subpart DDDDD sources is less than 1.0.

(b) Your facility is eligible for the TSM alternative compliance option if your site-specific compliance demonstration shows that the maximum HQ for manganese from your subpart DDDDD sources is less than 1.0.

(c) at a minimum, your site-specific compliance demonstration must:

(1) estimate long-term inhalation exposures through the estimation of annual or multi-year average ambient concentrations;

(2) estimate the inhalation exposure for the individual most exposed to the facility's emissions;

(3) use site-specific, quality-assured data wherever possible;

(4) use health-protective default assumptions wherever site-specific data are not available, and;

(5) contain adequate documentation of the data and methods used for the assessment so that it is transparent and can be reproduced by an experienced risk assessor and emissions measurement expert.

(d) Your site-specific compliance demonstration need not:

(1) assume any attenuation of exposure concentrations due to the penetration of outdoor pollutants into indoor exposure areas;

(2) assume any reaction or deposition of the emitted pollutants during transport from the emission point to the point of exposure;

8. What must my health-based eligibility demonstration contain?

(a) Your health-based eligibility demonstration must contain, at a minimum, the information specified in paragraphs (a)(1) through (6) of this section.

(1) Identification of each appropriate emission point at the affected source facility, including the maximum rated capacity of each appropriate emission point.

(2) Stack parameters for each appropriate emission point including, but not limited to, the parameters listed in (a)(2)(i) through (iv) below:

(i) Emission release type

(ii) Stack height, stack area, stack gas temperature, and stack gas exit velocity

(iii) Plot plan showing all emission points, nearby residences, and fenceline.

(iv) Identification of any control devices used to reduce emissions from each appropriate emission point.

(3) Emission test reports for each pollutant and appropriate emission point which has been tested using the test methods specified in Table 1 of this appendix, including a description of the process parameters identified

as being worst case. For those emissions which are not measured but are included in the assessment, the calculation method used, the inputs and outputs of any estimation developed, and any supporting references should be included in the documentation.

(4) Identification of the RfC values used in your look-up table analysis or site-specific compliance demonstration.

(5) Calculations used to determine the HCl-equivalent or manganese emission rates according to sections 6(a) or (b) of this appendix.

(6) Identification of the controlling process factors (including, but not limited to, fuel type, heat input rate, type of control devices, process parameters reflecting the emissions rates used for your eligibility demonstration) that will become Federally enforceable permit conditions used to show that your facility remains eligible for the health-based compliance alternatives.

(b) If you use the look-up table analysis in section 6 of this appendix to demonstrate that your facility is eligible for either health-based compliance alternative, your eligibility demonstration must contain, at a minimum, the information in paragraphs (a) and (b)(1) through (3) of this section.

(1) Calculations used to determine the average stack height of the subpart DDDDD emission points.

(2) Identification of the subpart DDDDD emission point with the minimum distance to the property boundary of the facility.

(3) Comparison of the values in the look-up tables (Tables 2 and 3 of this appendix) to your maximum HCl-equivalent or manganese emission rates.

(c) If you use a site-specific compliance demonstration as described in section 7 of this appendix to demonstrate that your facility is eligible, your eligibility demonstration must contain, at a minimum, the information in paragraphs (a) and (c)(1) through (7) of this section:

(1) Identification of the risk assessment methodology used.

(2) Documentation of the fate and transport model used.

(3) Documentation of the fate and transport model inputs, including the information described in paragraphs (a)(1) through (5) of this section converted to the dimensions required for the model and all of the following that apply: meteorological data; building, land use, and terrain data; receptor locations and population data; and other facility-specific parameters input into the model.

(4) Documentation of the fate and transport model outputs.

(5) Documentation of any exposure assessment and risk characterization calculations.

(6) Comparison of the HQ HI to the limit of 1.0.

9. When do I have to complete and submit my health-based eligibility demonstration?

(a) If you have an existing affected source, you must complete and submit your eligibility demonstration to your permitting authority, along with a signed certification that the demonstration is an accurate depiction of your facility, no later than the date one year prior to the compliance date of subpart DDDDD. A separate copy of the eligibility demonstration must be submitted to: U.S. EPA, Risk and Exposure Assessment Group, Emission Standards Division (C404-01), Attn: Group Leader, Research Triangle Park, North Carolina 27711.

(b) If you have a new or reconstructed affected source that starts up before the effective date of subpart DDDDD, or an affected source that is an area source that increases its emissions or its potential to emit such that it becomes a major source of HAP before the effective date of subpart DDDDD, then you must comply with the requirements of subpart DDDDD until your eligibility demonstration is completed and submitted to your permitting authority.

(c) If you have a new or reconstructed affected source that starts up after the effective date for subpart DDDDD, or an affected source that is an area source that increases its emissions or its potential to emit such that it becomes a major source of HAP after the effective date for subpart DDDDD, then you must follow the schedule in paragraphs (1) and (2) of this section.

(1) You must complete and submit a preliminary eligibility demonstration based on the information (e.g., equipment types, estimated emission rates, etc.) used to obtain your title V permit. You must base your preliminary eligibility demonstration on the maximum emissions allowed under your title V permit. If the preliminary eligibility demonstration indicates that your affected source facility is eligible for either compliance alternative, then you may start up your new affected source and your new affected source will be considered in compliance with the alternative HCl standard and subject to the compliance requirements in this appendix or, in the case of manganese, your compliance demonstration with the TSM emission limit is based on 7 metals (excluding manganese).

(2) You must conduct the emission tests specified in section 4 of this appendix upon initial startup and use the results of these emissions tests to complete and submit your eligibility demonstration within 180 days following your initial startup date. To be eligible, you must meet the criteria in section 11 of this appendix within 18 months following initial startup of your affected source.

10. When do I become eligible for the health-based compliance alternatives?

To be eligible for either health-based compliance alternative, the parameters that defined your affected source as eligible for the health-based compliance alternatives (including, but not limited to, fuel type, type of control devices, process parameters reflecting the emissions rates used for your eligibility demonstration) must be incorporated as Federally enforceable limits into your title V permit. If you do not meet these criteria, then your affected source is subject to the applicable emission limits, operating limits, and work practice standards in Subpart DDDDD.

11. How do I ensure that my facility remains eligible for the health-based compliance alternatives?

(a) You must update your eligibility demonstration and resubmit it each time you have a process change, such that any of the parameters that defined your affected source changes in a way that could result in increased HAP emissions (including, but not limited to, fuel type, change in type of control device, changes in process parameters documented as worst-case conditions during the emissions

testing used for your approved eligibility demonstration).

(b) If you are updating your eligibility demonstration to account for an action in paragraph (a) of this section, then you must perform emission testing according to section 4 of this appendix for the subpart DDDDD emission points that may have increased HAP emissions beyond the levels reflected in your previously approved eligibility demonstration due to the process change. You must submit your revised eligibility demonstration to the permitting authority prior to revising your permit to incorporate the process change. If your updated eligibility demonstration indicates that your affected source is no longer eligible for the health-based compliance alternatives, then you must comply with the applicable emission limits, operating limits, and compliance requirements in Subpart DDDDD prior to making the process change and revising your permit.

13. What records must I keep?

You must keep records of the information used in developing the eligibility demonstration for your affected source, including all of the information specified in section 8 of this appendix.

14. Definitions.

The definitions in §63.7575 of subpart DDDDD apply to this appendix. Additional definitions applicable for this appendix are as follows:

Hazard Index (HI) means the sum of more than one hazard quotient for multiple substances and/or multiple exposure pathways.

Hazard Quotient (HQ) means the ratio of the predicted media concentration of a pollutant to the media concentration at which no adverse effects are expected. For inhalation exposures, the HQ is calculated as the air concentration divided by the RfC.

Look-up table analysis means a risk screening analysis based on comparing the HAP or HAP-equivalent emission rate from the affected source to the appropriate maximum allowable HAP or HAP-equivalent emission rates specified in Tables 2 and 3 of this appendix.

Reference Concentration (RfC) means an estimate (with

uncertainty spanning perhaps an order of magnitude) of a continuous inhalation exposure to the human population (including sensitive subgroups) that is likely to be without an appreciable risk of deleterious effects during a lifetime. It can be derived from various types of human or animal data, with uncertainty factors generally applied to reflect limitations of the data used.

Worst-case operating conditions means operation of an affected unit during emissions testing under the conditions that result in the highest HAP emissions or that result in the emissions stream composition (including HAP and non-HAP) that is most challenging for the control device if a control device is used. For example, worst case conditions could include operation of an affected unit firing solid fuel likely to produce the most HAP.

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Table 1 to Appendix B of Subpart DDDDD. Emission Test Methods.

For...	You must...	Using...
(1) each subpart DDDDD emission point for which you choose to use a compliance alternative	select sampling ports' location and the number of traverse points	Method 1 of 40 CFR part 60, appendix A.
(2) each emission DDDDD emission point for which you choose to use a compliance alternative	determine velocity and volumetric flow rate;	Method 2, 2F, or 2G in appendix A to 40 CFR part 60.
(3) each emission DDDDD emission point for which you choose to use a compliance alternative	conduct gas molecular weight analysis	Method 3A or 3B in appendix A to 40 CFR part 60.
(4) each emission DDDDD emission point for which you choose to use a compliance alternative	measure moisture content of the stack gas	Method 4 in appendix A to 40 CFR part 60.
(5) each emission DDDDD emission point for which you choose to use the HCl compliance alternative	measure the hydrogen chloride and chlorine emission concentrations	Method 26 or 26A in appendix A to 40 CFR part 60.
(6) each emission DDDDD emission point for which you choose to use the TSM compliance alternative	measure the manganese emission concentration	Method 29 in appendix A to 40 CFR part 60.

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(7) each emission DDDDD emission point for which you choose to use a compliance alternative	convert emissions concentration to lb per MMBtu emission rates.	Method 19 F-factor methodology in appendix A to part 60 of this chapter.

Table 2 to Appendix A of Subpart DDDDD. Allowable toxicity-weighted emission rate expressed in HCl equivalents (lbs/hr)

Stack ht.(m)	distance to property boundary (m) 0	50	100	150	200	250	500	1000	1500	2000	3000	5000
5	114.9	114.9	114.9	114.9	114.9	114.9	144.3	287.3	373.0	373.0	373.0	373.0
10	188.5	188.5	188.5	188.5	188.5	188.5	195.3	328.0	453.5	434.4	434.4	434.4
20	386.1	386.1	386.1	386.1	386.1	386.1	386.1	425.4	580.0	602.7	602.7	602.7
30	396.1	396.1	396.1	396.1	396.1	396.1	396.1	436.3	596.2	690.6	807.8	816.5
40	408.1	408.1	408.1	408.1	408.1	408.1	408.1	448.2	613.3	715.5	832.2	966.0
50	421.4	421.4	421.4	421.4	421.4	421.4	421.4	460.6	631.0	746.3	858.2	1002.8
60	435.5	435.5	435.5	435.5	435.5	435.5	435.5	473.4	649.0	778.6	885.0	1043.4
70	450.2	450.2	450.2	450.2	450.2	450.2	450.2	486.6	667.4	813.8	912.4	1087.4
80	465.5	465.5	465.5	465.5	465.5	465.5	465.5	500.0	685.9	849.8	940.9	1134.8
100	497.5	497.5	497.5	497.5	497.5	497.5	497.5	527.4	723.6	917.1	1001.2	1241.3
200	677.3	677.3	677.3	677.3	677.3	677.3	677.3	682.3	919.8	1167.1	1390.4	1924.6

Table 3 to Appendix A of Subpart DDDDD. Allowable Manganese Emission Rate (lbs/hr)

Stack ht.(m)	distance to property boundary (m) 0	50	100	150	200	250	500	1000	1500	2000	3000	5000
5	0.29	0.29	0.29	0.29	0.29	0.29	0.36	0.72	0.93	0.93	0.93	0.93
10	0.47	0.47	0.47	0.47	0.47	0.47	0.49	0.82	1.13	1.09	1.09	1.09
20	0.97	0.97	0.97	0.97	0.97	0.97	0.97	1.06	1.45	1.51	1.51	1.51
30	0.99	0.99	0.99	0.99	0.99	0.99	0.99	1.09	1.49	1.73	2.02	2.04
40	1.02	1.02	1.02	1.02	1.02	1.02	1.02	1.12	1.53	1.79	2.08	2.42
50	1.05	1.05	1.05	1.05	1.05	1.05	1.05	1.15	1.58	1.87	2.15	2.51
60	1.09	1.09	1.09	1.09	1.09	1.09	1.09	1.18	1.62	1.95	2.21	2.61
70	1.13	1.13	1.13	1.13	1.13	1.13	1.13	1.22	1.67	2.03	2.28	2.72

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80	1.16	1.16	1.16	1.16	1.16	1.16	1.16	1.25	1.71	2.12	2.35	2.84
100	1.24	1.24	1.24	1.24	1.24	1.24	1.24	1.32	1.81	2.29	2.50	3.10
200	1.69	1.69	1.69	1.69	1.69	1.69	1.69	1.71	2.30	2.92	3.48	4.81

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Federal Register

Friday,
March 5, 2004

Part II

Environmental Protection Agency

40 CFR Part 63

National Emission Standards for Hazardous Air Pollutants for Stationary Combustion Turbines; Final Rule

ENVIRONMENTAL PROTECTION AGENCY

40 CFR Part 63

[OAR–2002–0060; FRL–7554–2]

RIN 2060–AG–67

National Emission Standards for Hazardous Air Pollutants for Stationary Combustion Turbines

AGENCY: Environmental Protection Agency (EPA).

ACTION: Final rule.

SUMMARY: This action promulgates national emission standards for hazardous air pollutants (NESHAP) for stationary combustion turbines. We have identified stationary combustion turbines as major sources of hazardous air pollutants (HAP) emissions such as formaldehyde, toluene, benzene, and acetaldehyde. The NESHAP will implement section 112(d) of the Clean Air Act (CAA) by requiring all major sources to meet HAP emission standards reflecting the application of the maximum achievable control technology (MACT) for combustion turbines. In the final NESHAP, we have divided the stationary combustion turbine category into eight subcategories, including lean premix gas-fired turbines, lean premix oil-fired turbines, diffusion flame gas-fired turbines, diffusion flame oil-fired turbines, emergency turbines, turbines with a rated peak power output of less than 1.0 megawatt (MW), turbines burning landfill or digester gas, and turbines located on the North Slope of Alaska. We have also adopted a final emission standard requiring control of formaldehyde emissions for all new or reconstructed stationary combustion turbines in the four lean premix and diffusion flame subcategories. We estimate that 20 percent of the stationary combustion turbines affected by the final rule will be located at major sources. As a result, the environmental, energy, and economic impacts presented in this preamble reflect these estimates. The final rule will protect public health by reducing exposure to air pollution, by reducing total national HAP emissions by an estimated 98 tons per year (tpy) in the 5th year after the rule is promulgated.

EFFECTIVE DATE: March 5, 2004.

ADDRESSES: *Docket.* Docket ID No. OAR–2002–0060 (paper docket No. A–95–51) contains supporting information used in developing the standards. The docket is located at the U.S. EPA, 1301 Constitution Avenue, NW., Washington, DC 20460 in room B102, and may be inspected from 8:30 a.m. to 4:30 p.m., Monday through Friday, excluding legal holidays.

FOR FURTHER INFORMATION CONTACT: For further information concerning applicability and rule determinations, contact the appropriate State or local agency representative. For information concerning the analyses performed in developing the NESHAP, contact Mr. Sims Roy, Combustion Group, Emission Standards Division (MD-C439–01), U.S. EPA, Research Triangle Park, North Carolina 27711; telephone number (919) 541–5263; facsimile number (919) 541–5450; electronic mail address ''*roy.sims@epa.gov*.''

SUPPLEMENTARY INFORMATION: *Regulated Entities.* Categories and entities potentially regulated by this action include:

Category	SIC	NAICS	Examples of regulated entities
Any industry using a stationary combustion turbine as defined in the regulation.	4911	2211	Electric power generation, transmission, or distribution
	4922	486210	Natural gas transmission
	1311	211111	Crude petroleum and natural gas production
	1321	211112	Natural gas liquids producers
	4931	221	Electric and other services combined

This table is not intended to be exhaustive, but rather provides a guide for readers regarding entities likely to be regulated by this action. To determine whether your facility is regulated by this action, you should examine the applicability criteria in § 63.6085 of the final rule. If you have any questions regarding the applicability of this action to a particular entity, consult the person listed in the preceding **FOR FURTHER INFORMATION CONTACT** section.

Docket. The EPA has established an official public docket for this action under Docket ID No. OAR–2002–0060 (A–95–51). The official public docket consists of the documents specifically referenced in this action, any public comments received, and other information related to this action. Although a part of the official docket, the public docket does not include Confidential Business Information (CBI) or other information whose disclosure is restricted by statute. The official public docket is the collection of materials that is available for public viewing at the Air and Radiation Docket in the EPA Docket Center, (EPA/DC) EPA West, Room B102, 1301 Constitution Ave., NW., Washington, DC 20460. The EPA Docket Center Public Reading Room is open from 8:30 a.m. to 4:30 p.m., Monday through Friday, excluding legal holidays. The telephone number for the Reading Room is (202) 566–1744, and the telephone number for the Air and Radiation Docket is (202) 566–1742. A reasonable fee may be charged for copying docket materials.

Electronic Access. You may access this **Federal Register** document electronically through the EPA Internet under the ''**Federal Register**'' listings at *http://www.epa.gov/fedrgstr/*.

An electronic version of the public docket is available through EPA's electronic public docket and comment system, EPA Dockets. You may use EPA Dockets at *http://www.epa.gov/edocket/* to view public comments, access the index listing of the contents of the official public docket, and to access those documents in the public docket that are available electronically. Although not all docket materials may be available electronically, you may still access any of the publicly available docket materials through the docket facility identified above. Once in the system, select ''search,'' then key in the appropriate docket identification number.

Judicial Review. Under section 307(b)(1) of the CAA, judicial review of the final NESHAP is available only by filing a petition for review in the U.S. Court of Appeals for the District of Columbia Circuit by May 4, 2004. Under section 307(d)(7)(B) of the CAA, only an objection to a rule or procedure raised with reasonable specificity during the period for public comment can be raised during judicial review. Moreover, under section 307(b)(2) of the CAA, the requirements established by the final rule may not be challenged separately in any civil or criminal proceeding brought to enforce these requirements.

Background Information Document. The EPA proposed the NESHAP for stationary combustion turbines on January 14, 2003 (68 FR 1888), and

received 75 comment letters on the proposal. A background information document (BID) (''National Emission Standards for Stationary Combustion Turbines, Summary of Public Comments and Responses,'') containing EPA's responses to each public comment is available in Docket ID No. OAR–2002–0060 (A–95–51).

Outline. The information presented in this preamble is organized as follows:

I. Background
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I. Background

A. What is the Source of Authority for Development of NESHAP?

Section 112 of the CAA requires us to list categories and subcategories of major sources and area sources of HAP and to establish NESHAP for the listed source categories and subcategories. The stationary turbine source category was listed on July 16, 1992 (57 FR 31576). Major sources of HAP are those that have the potential to emit greater than 10 tpy of any one HAP or 25 tpy of any combination of HAP.

B. What Criteria are Used in the Development of NESHAP?

Section 112 of the CAA requires that we establish NESHAP for the control of HAP from both new and existing major sources. The CAA requires the NESHAP to reflect the maximum degree of reduction in emissions of HAP that is achievable. This level of control is commonly referred to as the MACT.

The MACT floor is the minimum control level allowed for NESHAP and is defined under section 112(d)(3) of the CAA. In essence, the MACT floor ensures that the standard is set at a level that assures that all major sources achieve the level of control at least as stringent as that already achieved by the better controlled and lower emitting sources in each source category or subcategory. For new sources, the MACT standards cannot be less stringent than the emission control that is achieved in practice by the best controlled similar source. The MACT standards for existing sources can be less stringent than standards for new sources, but they cannot be less stringent than the average emission limitation achieved by the best performing 12 percent of existing sources in the category or subcategory (or the best performing five sources for categories or subcategories with fewer than 30 sources).

In developing MACT, we also consider control options that are more stringent than the floor. We may establish standards more stringent than the floor based on the consideration of cost of achieving the emissions reductions, any non-air quality health and environmental impacts, and energy requirements.

C. What are the Health Effects Associated with HAP from Stationary Combustion Turbines?

Emission data collected during development of the NESHAP show that several HAP are emitted from stationary combustion turbines. These HAP emissions are formed during combustion or result from HAP compounds contained in the fuel burned.

Among the HAP which have been measured in emission tests that were conducted at natural gas fired and distillate oil fired combustion turbines are: 1,3 butadiene, acetaldehyde, acrolein, benzene, ethylbenzene, formaldehyde, naphthalene, poly aromatic hydrocarbons (PAH) propylene oxide, toluene, and xylenes. Metallic HAP from distillate oil fired stationary combustion turbines that have been measured are: arsenic, beryllium, cadmium, chromium, lead, manganese, mercury, nickel, and selenium. Natural gas fired stationary combustion turbines do not emit metallic HAP.

Although numerous HAP may be emitted from combustion turbines, only a few account for essentially all the mass of HAP emissions from stationary combustion turbines. These HAP are: formaldehyde, toluene, benzene, and acetaldehyde.

The HAP emitted in the largest quantity is formaldehyde. Formaldehyde is a probable human carcinogen and can cause irritation of the eyes and respiratory tract, coughing, dry throat, tightening of the chest, headache, and heart palpitations. Acute inhalation has caused bronchitis, pulmonary edema, pneumonitis, pneumonia, and death due to respiratory failure. Long-term exposure can cause dermatitis and sensitization of the skin and respiratory tract.

Other HAP emitted in significant quantities from stationary combustion turbines include toluene, benzene, and acetaldehyde. The health effect of primary concern for toluene is dysfunction of the central nervous system (CNS). Toluene vapor also

causes narcosis. Controlled exposure of human subjects produced mild fatigue, weakness, confusion, lacrimation, and paresthesia; at higher exposure levels there were also euphoria, headache, dizziness, dilated pupils, and nausea. After-effects included nervousness, muscular fatigue, and insomnia persisting for several days. Acute exposure may cause irritation of the eyes, respiratory tract, and skin. It may also cause fatigue, weakness, confusion, headache, and drowsiness. Very high concentrations may cause unconsciousness and death.

Benzene is a known human carcinogen. The health effects of benzene include nerve inflammation, CNS depression, and cardiac sensitization. Chronic exposure to benzene can cause fatigue, nervousness, irritability, blurred vision, and labored breathing and has produced anorexia and irreversible injury to the blood-forming organs; effects include aplastic anemia and leukemia. Acute exposure can cause dizziness, euphoria, giddiness, headache, nausea, staggering gait, weakness, drowsiness, respiratory irritation, pulmonary edema, pneumonia, gastrointestinal irritation, convulsions, and paralysis. Benzene can also cause irritation to the skin, eyes, and mucous membranes.

Acetaldehyde is a probable human carcinogen. The health effects for acetaldehyde are irritation of the eyes, mucous membranes, skin, and upper respiratory tract, and it is a CNS depressant in humans. Chronic exposure can cause conjunctivitis, coughing, difficult breathing, and dermatitis. Chronic exposure may cause heart and kidney damage, embryotoxicity, and teratogenic effects.

We do not have the type of current detailed data on each of the facilities covered by the final rule and the people living around the facilities that would be necessary to conduct an analysis to determine the actual population exposures to the HAP emitted from these facilities and potential for resultant health effects. Therefore, we do not know the extent to which the adverse health effects described above occur in the populations surrounding these facilities. However, to the extent the adverse effects do occur, the final rule will reduce emissions and subsequent exposures.

D. What is the Regulatory Development Background of the Source Category?

In September 1996, we chartered the Industrial Combustion Coordinated Rulemaking (ICCR) advisory committee under the Federal Advisory Committee Act (FACA). The committee's objective was to develop recommendations for regulations for several combustion source categories under sections 112 and 129 of the CAA. The ICCR advisory committee, also known as the Coordinating Committee, formed Source Work Groups for the various combustor types covered under the ICCR. One work group, the Combustion Turbine Work Group, was formed to research issues related to stationary combustion turbines. The Combustion Turbine Work Group submitted recommendations, information, and data analyses to the Coordinating Committee, which in turn considered them and submitted recommendations and information to us. The Committee's 2-year charter expired in September 1998. We considered the Committee's recommendations in developing the final rule for stationary combustion turbines.

We have received a petition from the Gas Turbine Association (GTA) requesting that we delist certain subcategories of combustion turbines. We have been working with GTA to improve and supplement the data supporting this petition. Once a final determination has been made concerning the delisting petition, we will promptly make any conforming amendments to the Stationary Combustion Turbine NESHAP which are warranted.

II. Summary of the Final Rule

A. What Sources are Subject to the Final Rule?

The final rule applies to you if you own or operate a stationary combustion turbine which is located at a major source of HAP emissions. 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 tpy (9.07 megagrams per year (Mg/yr)) or more or any combination of HAP at a rate of 25 tpy (22.68 Mg/yr) or more.

Section 112(n)(4) of the CAA requires that the aggregation of HAP for purposes of determining whether an oil and gas production facility is major or nonmajor be done only with respect to particular sites within the source and not on a total aggregated site basis. We referenced the requirements of section 112(n)(4) of the CAA in our NESHAP for Oil and Natural Gas Production Facilities in subpart HH of 40 CFR part 63. As in subpart HH, we plan to aggregate HAP emissions for the purposes of determining a major HAP source for turbines only with respect to particular sites within an oil and gas production facility. The sites are called surface sites and may include a combination of any of the following equipment: glycol dehydrators, tanks which have potential for flash emissions, reciprocating internal combustion engines, and combustion turbines.

The EPA acknowledges that the definition of major source in the final rule may be different from those found in other rules, however, this does not alter the definition of major source in other rules and, therefore, does not affect the Oil and Natural Gas Production Facilities NESHAP (subpart HH of 40 CFR part 63) or any other rule applicability.

Eight subcategories have been defined within the stationary combustion turbine source category. While all stationary combustion turbines are subject to the final rule, each subcategory has distinct requirements. For example, existing combustion turbines and stationary combustion turbines with a rated peak power output of less than 1.0 MW (at International Organization for Standardization (ISO) standard day conditions) are not required to comply with emission limitations, recordkeeping or reporting requirements in the final rule. New or reconstructed combustion turbines must comply with emission limitations, recordkeeping and reporting requirements in the final rule. You must determine your source's subcategory to determine which requirements apply to your source.

The final rule does not apply to stationary combustion turbines located at an area source of HAP emissions. An area source of HAP emissions is a contiguous site under common control that is not a major source.

Stationary combustion turbines located at research or laboratory facilities are not subject to the final rule if research is conducted on the turbine itself and the turbine is not being used to power other applications at the research or laboratory facility.

The final rule does not cover duct burners. They are part of the waste heat recovery unit in a combined cycle system. Waste heat recovery units, whether part of a cogeneration system or a combined cycle system, are steam generating units and are not covered by the final rule.

Finally, the final rule does not apply to stationary combustion engine test cells/stands since these facilities are already covered by another NESHAP, 40 CFR part 63, subpart PPPPP.

B. What Source Categories and Subcategories are Affected by the Final Rule?

The final rule covers stationary combustion turbines. A stationary combustion turbine includes all equipment including, but not limited to, the turbine, the fuel, air, lubrication and exhaust gas systems, control systems (except emissions control equipment), and any ancillary components and sub-components comprising any simple cycle stationary combustion turbine, any regenerative/recuperative cycle stationary combustion turbine, or the combustion turbine portion of any stationary combined cycle steam/electric generating system. Stationary means that the combustion turbine is not self-propelled or intended to be propelled while performing its function. A stationary combustion turbine may, however, be mounted on a vehicle for portability or transportability.

Stationary combustion turbines have been divided into the following eight subcategories: (1) Emergency stationary combustion turbines, (2) stationary combustion turbines which burn landfill or digester gas equivalent to 10 percent or more of the gross heat input on an annual basis or where gasified MSW is used to generate 10 percent or more of the gross heat input to the stationary combustion turbine on an annual basis, (3) stationary combustion turbines of less than 1 MW rated peak power output, (4) stationary lean premix combustion turbines when firing gas and when firing oil at sites where all turbines fire oil no more than 1000 hours annually (also referred to herein as ''lean premix gas-fired turbines''), (5) stationary lean premix combustion turbines when firing oil at sites where all turbines fire oil more than 1000 hours annually (also referred to herein as ''lean premix oil-fired turbines''), (6) stationary diffusion flame combustion turbines when firing gas and when firing oil at sites where all turbines fire oil no more than 1000 hours annually (also referred to herein as ''diffusion flame gas-fired turbines''), (7) stationary diffusion flame combustion turbines when firing oil at sites where all turbines fire oil more than 1000 hours annually (also referred to herein as ''diffusion flame oil-fired turbines''), and (8) stationary combustion turbines operated on the North Slope of Alaska (defined as the area north of the Arctic Circle (latitude 66.5° North)).

Emergency stationary combustion turbine means any stationary combustion turbine that operates in an emergency situation. Examples include stationary combustion turbines used to produce power for critical networks or equipment (including power supplied to portions of a facility) when electric power from the local utility is interrupted, or stationary combustion turbines used to pump water in the case of fire or flood, etc. Emergency stationary combustion turbines do not include stationary combustion turbines used as peaking units at electric utilities or stationary combustion turbines at industrial facilities that typically operate at low capacity factors. Emergency stationary combustion turbines may be operated for the purpose of maintenance checks and readiness testing, provided that the tests are required by the manufacturer, the vendor, or the insurance company associated with the turbine. Required testing of such units should be minimized, but there is no time limit on the use of emergency stationary sources.

Stationary combustion turbines which burn landfill or digester gas equivalent to 10 percent or more of the gross heat input on an annual basis or stationary combustion turbines where gasified MSW is used to generate 10 percent or more of the gross heat input to the stationary combustion turbine on an annual basis qualify as a separate subcategory because the types of control available for these turbines are limited.

Stationary combustion turbines of less than 1 MW rated peak power output were also identified as a subcategory. These small stationary combustion turbines are few in number and, to our knowledge, none use emission control technology to reduce HAP. Therefore, it would be inappropriate to require HAP emission controls to be applied to them without further information on control technology performance.

Two subcategories of stationary lean premix combustion turbines were established: stationary lean premix combustion turbines when firing gas and when firing oil at sites where all turbines fire oil no more than 1000 hours annually (also referred to as ''lean premix gas-fired turbines''), and stationary lean premix combustion turbines when firing oil at sites where all turbines fire oil more than 1000 hours annually (also referred to as ''lean premix oil-fired turbines''). Lean premix technology, introduced in the 1990's, was developed to reduce nitrogen oxide (NO_X) emissions without the use of add-on controls. In a lean premix combustor, the air and fuel are thoroughly mixed to form a lean mixture for combustion. Mixing may occur before or in the combustion chamber. Lean premix combustors emit lower levels of NO_X, carbon monoxide (CO), formaldehyde and other HAP than diffusion flame combustion turbines.

Two subcategories of stationary diffusion flame combustion turbines were established: stationary diffusion flame combustion turbines when firing gas and when firing oil at sites where all turbines fire oil no more than 1000 hours annually (also referred to as ''diffusion flame gas-fired turbines''), and stationary diffusion flame combustion turbines when firing oil at sites where all turbines fire oil more than 1000 hours annually (also referred to as ''diffusion flame oil-fired turbines''). In a diffusion flame combustor, the fuel and air are injected at the combustor and are mixed only by diffusion prior to ignition. Hazardous air pollutant emissions from these turbines can be significantly decreased with the addition of air pollution control equipment.

Stationary combustion turbines located on the North Slope of Alaska have been identified as a subcategory due to operating limitations and uncertainties regarding the application of controls to these units. There are very few of these units, and none have installed emission controls for the reduction of HAP.

C. What are the Primary Sources of HAP Emissions and What are the Emissions?

Combustion turbines are acknowledged as the cleanest and most efficient method of producing electrical power. The sources of emissions are the exhaust gases from combustion of gaseous and liquid fuels in a stationary combustion turbine. Hazardous air pollutants that are present in the exhaust gases from stationary combustion turbines include formaldehyde, toluene, benzene, and acetaldehyde.

D. What are the Emission Limitations and Operating Limitations?

As the owner or operator of a new or reconstructed lean premix gas-fired turbine, a new or reconstructed lean premix oil-fired turbine, a new or reconstructed diffusion flame gas-fired turbine, or a new or reconstructed diffusion flame oil-fired turbine, you must comply with the emission limitation to reduce the concentration of formaldehyde in the exhaust from the new or reconstructed stationary combustion turbine to 91 parts per billion by volume (ppbv) or less, dry basis (ppbvd), at 15 percent oxygen by the effective date of the standards (or upon startup if you start up your stationary combustion turbine after the effective date of the standards).

Attachment 1
Attachment 1

If you comply with the emission limitation for formaldehyde emissions and you use an oxidation catalyst emission control device, you must continuously monitor the oxidation catalyst inlet temperature and maintain the inlet temperature to the oxidation catalyst within the range recommended by the catalyst manufacturer.

If you comply with the emission limitation for formaldehyde emissions and you do not use an oxidation catalyst emission control device, you must petition the Administrator for approval of operating limitations or approval of no operating limitations.

E. What are the Initial Compliance Requirements?

If you operate a new or reconstructed lean premix gas-fired turbine, a new or reconstructed lean premix oil-fired turbine, a new or reconstructed diffusion flame gas-fired turbine, or a new or reconstructed diffusion flame oil-fired turbine, you must conduct an initial performance test using Test Method 320 of 40 CFR part 63, appendix A, or ASTM D6348–03 to demonstrate that the outlet concentration of formaldehyde is 91 ppbvd or less (corrected to 15 percent oxygen). To correct to 15 percent oxygen, dry basis, you must measure oxygen using Method 3A or 3B of 40 CFR part 60, appendix A, and moisture using either Method 4 of 40 CFR part 60, appendix A, Test Method 320 of 40 CFR part 63, appendix A, or ASTM D6348–03. The initial performance test must be conducted at high load conditions, defined as 100 percent ±10 percent.

If you operate a new or reconstructed stationary combustion turbine in one of the subcategories required to comply with an emission limitation and use an oxidation catalyst emission control device, you must also install a continuous parameter monitoring system (CPMS) to continuously monitor the oxidation catalyst inlet temperature.

If you operate a new or reconstructed stationary combustion turbine in one of the subcategories required to comply with an emission limitation and you do not use an oxidation catalyst emission control device, you must petition the Administrator for approval of operating limitations or approval of no operating limitations.

If you petition the Administrator for approval of operating limitations, your petition must include the following: (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.

If you petition the Administrator for approval of no operating limitations, your petition must include the following: (1) Identification of the parameters associated with operation of the stationary combustion turbine 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 these parameters and changes in HAP emissions; (3) for those parameters with a relationship to HAP emissions, a discussion of whether establishing limitations on these parameters would serve to limit HAP emissions; (4) for those parameters with a relationship to HAP emissions, a discussion of how you could establish upper and/or lower values for these parameters which would establish limits on these parameters in operating limitations; (5) for those parameters with a relationship to HAP emissions, a discussion identifying the methods you could use to measure these parameters and the instruments you could use to monitor them, as well as the relative accuracy and precision of these methods and instruments; (6) for these 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, unreasonable, or unnecessary to adopt these parameters as operating limitations.

F. What are the Continuous Compliance Provisions?

Several general continuous compliance requirements apply to stationary combustion turbines required to comply with the emission limitations. You are required to comply with the emission limitations and the operating limitations (if applicable) at all times, except during startup, shutdown, and malfunction of your stationary combustion turbine. You must also operate and maintain your stationary combustion turbine, air pollution control equipment, and monitoring equipment according to good air pollution control practices at all times, including startup, shutdown, and malfunction. You must conduct monitoring at all times that the stationary combustion turbine is operating, except during periods of malfunction of the monitoring equipment or necessary repairs and quality assurance or control activities, such as calibration checks.

To demonstrate continuous compliance with the emission limitations, you must conduct annual performance tests for formaldehyde. You must conduct the annual performance tests using Test Method 320 of 40 CFR part 63, appendix A, or ASTM D6348–03 to demonstrate that the outlet concentration of formaldehyde is at or below 91 ppbvd of formaldehyde (correct to 15 percent oxygen). The annual performance test must be conducted at high load conditions, defined as 100 percent ±10 percent.

If you operate a new or reconstructed stationary combustion turbine in one of the subcategories required to comply with an emission limitation and you use an oxidation catalyst emission control device, you must demonstrate continuous compliance with the operating limitations by continuously monitoring the oxidation catalyst inlet temperature. The 4-hour rolling average of the valid data must be within the range recommended by the catalyst manufacturer.

If you operate a new or reconstructed stationary combustion turbine in one of the subcategories required to comply with an emission limitation and you do not use an oxidation catalyst emission control device, you must demonstrate continuous compliance with the operating limitations by continuously monitoring parameters which have been approved by the Administrator (if any).

G. What are the Notification, Recordkeeping and Reporting Requirements?

You must submit all of the applicable notifications as listed in the NESHAP General Provisions (40 CFR part 63, subpart A), including an initial notification, notification of performance test or evaluation, and a notification of compliance, for each stationary combustion turbine which must comply with the emission limitations. If your new or reconstructed stationary

combustion turbine is located at a major source, has greater than 1 MW rated peak power output, and is an emergency stationary combustion turbine, a combustion turbine which burns landfill or digester gas equivalent to 10 percent or more of the gross heat input on an annual basis or where gasified MSW is used to generate 10 percent or more of the gross heat input to the stationary combustion turbine on an annual basis, or a stationary combustion turbine located on the North Slope of Alaska, you must submit only an initial notification.

For each combustion turbine in one of the subcategories which is subject to an emission limitation, you must record all of the data necessary to determine if you are in compliance with the emission limitation. Your records must be in a form suitable and readily available for review. You must also keep each record for 5 years following the date of each occurrence, measurement, maintenance, report, or record. Records must remain on site for at least 2 years and then can be maintained off site for the remaining 3 years.

III. Summary of Responses to Major Comments

A more detailed summary of comments and our responses can be found in the Summary of Public Comments and Responses document, which is available from several sources (see Addresses section).

A. Applicability

Comment: Several commenters said that the definition of affected source should be modified to be consistent with the definition found in § 63.2 of the General Provisions.

Response: Although 40 CFR 63.2 of the General Provisions provides that we will generally adopt a broad definition of affected source, which includes all emission units within each subcategory which are located within the same contiguous area, this section also provides that we may adopt a narrower definition of affected source in instances where we determine that the broader definition would ''create significant administrative, practical, or implementation problems'' and ''the different definition would resolve those problems.'' This is such an instance. Because of the way that the subcategories of combustion turbines are defined, individual turbines can switch between subcategories based on the fuel they are burning. We have taken some steps in the definition of subcategories to limit the frequency of such switching between subcategories, because we believe it could create confusion and complicate compliance determinations. However, fuel specific subcategories are necessary to derive a MACT floor which appropriately considers the difference in the composition of the HAP emitted based on the fuel used. Thus, we cannot eliminate the possibility that individual turbines will switch subcategories. Use of the broader definition of affected source specified by the General Provisions would require very complex aggregate compliance determinations, because an individual turbine could be part of one affected source at one time and part of a different affected source at another time. This would require that the contribution of each turbine to total emissions for all emission units within each subcategory be adjusted to reflect the proportionate time the unit was operating within that subcategory. We believe such complicated compliance determinations to be impractical and, therefore, have decided to adopt a definition which establishes each individual combustion turbine as the affected source.

Comment: One commenter said that the final rule should be explicit as to whether the 1 MW capacity level for inclusion in the less than 1 MW rated peak power subcategory applies to an individual combustion turbine or applies to the aggregate capacity of a group of combustion turbines.

Response: We intended for the 1 MW capacity level to apply to an individual combustion turbine, not the aggregate capacity of a group of combustion turbines. This clarification has been made in the final rule.

Comment: Several commenters stated that EPA should increase the 1 MW capacity threshold. Comments received included suggestions to exclude from the rule turbines rated less than 10 MW and recommendations to create a subcategory for units with a capacity of 25 MW or less. Some commenters said that the size applicability criteria should be adjusted to be consistent with the MACT floor.

Response: Although 3 MW is the smallest size unit that is known to have add-on HAP control, we feel it is appropriate to set the cutoff for inclusion in the less than 1 MW rated peak power subcategory at 1 MW because the control technology used for 3 MW units can be transferred to units as small as 1 MW.

Comment: Many commenters recommended that EPA provide an emission threshold as an alternative applicability cutoff. Eight commenters recommended that the emission threshold should be set at less than 1 tpy of formaldehyde emissions. One commenter suggested that EPA should include a greater than 2 tpy formaldehyde applicability requirement.

Response: The basis for this comment is the Oil and Natural Gas Production and Natural Gas Transmission and Storage NESHAP (promulgated on June 17, 1999). In that rule, HAP emissions from process vents at glycol dehydration units that are located at major HAP sources and from process vents at certain area source glycol dehydration units are required to be controlled unless the actual flowrate of natural gas in the unit is less than 85,000 cubic meters per day (3.0 million standard cubic feet per day), on an annual average basis, or the benzene emissions from the unit are less than 0.9 Mg/yr (1 tpy). The 1 tpy emission threshold in the Oil and Natural Gas Production and Natural Gas Transmission and Storage MACT is equivalent to the smallest size glycol dehydration unit with control of HAP emissions and is, therefore, based on equivalence, not risk.

Comment: Multiple commenters expressed that the emission factors presented in Table 1 of the preamble should be removed, or wording should be added to acknowledge the use of factors from other sources. Three commenters said that EPA should not dictate emission factors for major source determination; owners and operators should be allowed to determine appropriate emission factors for their facility.

Response: We agree with the commenter and have not included Table 1 from the proposal preamble in the final rule. Table 1 was intended to simplify major source determination, *e.g.*, facilities would not have to develop their own emission factors. We agree that all turbines may not fit the emissions mold as projected in Table 1. The use of the emission factors in Table 1 was intended to be optional; we were not dictating the use of these emission factors.

The emission factors in Table 1 of the preamble to the proposed rule were based on emissions data from test reports that were reviewed and accepted by EPA according to a common set of acceptance criteria. However, we received several comments regarding the quality of the emissions data we used and as a result, performed an extensive review of tests used at proposal and new tests received during the comment period. As a result of that review, revised emission factors for stationary combustion turbines were calculated and are presented in a memorandum included in the rule docket (OAR–2002–0060, A–95–51). That memorandum has emission factors

for both high load and all load conditions. The emission standards in the final rule are based on data for high loads.

We believe that the emission factors presented in the memorandum provide the most accurate information on stationary combustion turbine emission factors. However, caution should be used when using data collected using California Air Resources Board (CARB) Method 430 or EPA Method 0011 in determining applicability. We have used CARB 430 and EPA Method 0011 in developing emission factors but applied a bias factor to the data to make the emissions data comparable with emissions data measured by Fourier Transform Infrared (FTIR).

Comment: Multiple commenters supported the creation of a subcategory for limited use combustion turbines with a capacity utilization of 10 percent or less. One commenter expressed the view that the limited use subcategory should apply to all limited use combustion turbines, not just electric power peak shaving units.

Three commenters supported the exemption for limited use units and EPA's finding that no emission reduction should be required for these units.

Several commenters requested that EPA increase the allowable operating time for limited use turbines. One commenter recommended that the 50-hour allowance for limited use be increased to 200 hours to allow for maintenance checks. Two commenters stated that a more appropriate cut-off is 500 hours per year, which one commenter said is consistent with EPA policy for designating emergency engines for title V permits and is also appropriate because year-to-year variability in the utilization does not result in routine changes in a unit's status. A commenter also suggested that EPA could develop a more refined approach; for example, the cutoff for turbines greater than 10 MW could be 200 hours per year.

One commenter said that if a 10 percent utilization is not implemented, the testing of combustion turbines to assure the unit will be operational when needed should be excluded from the operating limit, because these testing operations can range from weekly testing for more than 1 hour to several times each month.

Two commenters contended that the subcategorization of limited use combustion turbines without controls is not protective of public health, because these combustion turbines operate mostly in the summer months when the public is more likely to be exposed to the emissions.

Two commenters remarked that any subcategorization of limited use combustion turbines should include a permit requirement that these units operate less than 876 hours per year. To lower costs for these units, less onerous monitoring requirements such as periodic stack tests with a temperature sensor on the catalyst could be required.

One commenter expressed the view that existing limited use combustion turbines might be exempted from the MACT emission limits, but new limited use combustion turbines should not be exempted. The commenter observed that in New Jersey, limited use units generally operate for less than 250 hours per year.

Response: The preamble for the proposed rule included a subcategory for limited use stationary combustion turbines and defined them as operating 50 hours or less per calendar year. We solicited comments on creating a subcategory of limited use stationary combustion turbines with capacity utilization of 10 percent or less and used for electric power peak shaving. After considering all of the comments, we decided not to include a subcategory for limited use stationary combustion turbines in the final rule. A subcategory of limited use stationary combustion turbines with capacity utilization of 10 percent or less and used for electric power peak shaving was not created because these sources are similar sources to units equipped with add-on oxidation catalyst control, and their operation only during peak periods does not preclude them from being equipped with add-on oxidation catalyst control. In response to the comment regarding subcategorization of limited use combustion turbines not being protective of public health, our objective in subcategorizing is not to protect public health, but to establish groups of sources which share common characteristics that are related to the availability of potential emission control strategies. In any case, we have not adopted a limited use subcategory, because we determined that creation of such subcategory would not change the nature of the required controls.

Comment: Two commenters recommended that to be consistent with most other NESHAP, EPA should add an exemption for research and development to the final rule.

Response: We agree that stationary combustion turbines located at a research or laboratory facility should not be subject to the NESHAP if research is conducted on the turbine itself and the turbine is not being used to power other applications at the research or laboratory facility. A definition of research or laboratory facility is included in the final rule.

Comment: One commenter remarked that primary fuel is not defined in the rule. The commenter noted that applying the exemption only to turbines using landfill or digester gas as primary fuel is overly restrictive. The commenter suggested that the exemption should be for turbines with annual landfill and digester gas consumption of 10 percent or more of the total fuel consumption on an annual basis based on gross heat input. Other commenters requested that the exemption for firing landfill or digester gas be expanded to include combustion turbines used at gasification plants.

Response: We agree that it is appropriate to provide guidelines for the usage of landfill and digester gas. We have written the final rule to define turbines in the landfill and digester gas subcategory as those which burn landfill or digester gas equivalent to 10 percent or more of the gross heat input on an annual basis. In the final rule, the subcategory for combustion turbines firing landfill or digester gas has been expanded to include units where gasified MSW is used to generate 10 percent or more of the gross heat input to the turbine on an annual basis. We have specified in the final rule that new turbines in this subcategory must daily monitor their fuel usage with a separate fuel meter to measure the volume flow rate of each fuel. Finally, the final rule requires new combustion turbines in this subcategory to submit annual reports documenting the fuel flow rate of each fuel and the heating values used to calculate and demonstrate that the percentage of heat input provided by landfill, digester gas, or gasified MSW is equivalent to 10 percent or more of the total fuel consumption on an annual basis based on gross heat input.

Comment: Several commenters urged EPA to add a subcategory to cover turbines installed north of the Arctic Circle (North Slope) and to specify no additional control requirements for the subcategory. The commenters stated that technologies identified for controlling HAP emissions from stationary combustion turbines are unproven or have met with limited success in northern Alaska above the Arctic Circle. Lean premix combustion turbines have met with limited success on the Alaska's North Slope. The annual average temperature above the Arctic Circle is approximately 10°F, with winter temperatures that can drop below −50°F. Turbine manufacturers have been required to ''de-tune'' the

lean premix turbines to ensure the integrity of the equipment at these cold ambient temperatures.

One of the technical issues with lean premix operation at the North Slope is the very wide range of ambient temperatures over which the turbine must operate. A range of −50°F to 80°F (130°F range) is a very challenging requirement for turbine manufacturers. They have to employ various air bleed, inlet guide vane control, or fuel staging to allow them to operate at the cold extremes. Sites in Canada have reported having to tune their lean premix engines differently for the summer and winter months. Even when temperatures drop to extremely low levels in the lower 48 states, the duration of those low temperatures is normally measured in hours; on the North Slope it is not uncommon for equipment to have to endure months of severe cold. In addition to this large range, at the colder end of the range the airflow on some turbine models can be 40 percent higher than at the standard ISO design conditions of 60°F, creating an especially acute problem in lean premix units. Turbine manufacturers with experience in the Arctic do not guarantee NO_X and CO levels at cold ambient temperatures (below 0°F). Therefore, lean premix turbines that can achieve low NO_X emissions typical of the lower 48 states' applications have not been demonstrated to be achievable north of the Arctic Circle. On the North Slope, less than 0°F represents about one-half of the year.

According to the commenters, vendors of CO oxidation catalysts have indicated that their products will perform adequately on the North Slope, but the technology has never been tried. To date, no CO oxidation catalyst has ever been installed on a turbine on the North Slope. It is unknown what impacts the extreme thermal conditions of North Slope operation will have on CO oxidation catalysts.

Response: We agree with the commenters that a subcategory should be created for turbines installed north of the Arctic Circle to recognize their distinct differences. There is a substantial difference in temperature between the North Slope of Alaska and even the coldest areas in the lower 48 states. As noted by the commenters, turbine operators on the North Slope of Alaska have experienced problems with operation of the turbines in lean premix mode, and turbine manufacturers do not guarantee the performance of their turbines at the ambient temperatures typically found north of the Arctic Circle. In addition, no turbines on the North Slope of Alaska are equipped with oxidation catalyst control. Therefore, a subcategory for turbines north of the Arctic Circle has been established. The North Slope of Alaska is defined as above the Arctic Circle (latitude 66.5° North). Stationary combustion turbines operated on the North Slope of Alaska are not required to meet the emission limitations. However, new or reconstructed stationary combustion turbines operated on the North Slope of Alaska must submit an initial notification.

Comment: Two commenters expressed the view that the routine exchange of aeroderivative turbines for routine overhaul should not result in a facility becoming a new source. One commenter stated that EPA should provide an exemption for temporary replacement engines during routine rebuilds, and a mechanism to reduce the likelihood a source would suddenly trigger new source preconstruction review/approval and MACT requirements arising from an unexpected repair or replacement of a stationary combustion turbine.

Response: The definition of reconstructed turbine in the proposed rule is consistent with the General Provisions of 40 CFR part 63. If an existing combustion turbine is refurbished to the extent that it meets the definition of reconstruction, then it should be considered a reconstructed source. We are not aware of any routine refurbishment for which the fixed capital cost of the new components exceeds 50 percent of the fixed capital cost that would be required to construct a comparable new source.

B. Definitions

Comment: One commenter requested that the definition of lean premix stationary combustion turbine be modified to recognize that fuel and air mixing may be occurring in the combustor of some lean premix combustion turbines. The definition should be modified to include these types of stationary combustion turbines that burn a lean mixture and thoroughly mix their fuel prior to combustion in the combustor.

Response: We have written the definition of lean premix in the final rule to recognize that fuel and air mixing may be occurring in the combustor of some lean premix combustion turbines.

Comment: Several commenters said that the definition of emergency stationary combustion turbine should include operational allowances for the periodic operation/testing to verify operational readiness. One commenter requested that the definition be clarified, or extended to allow for operations in anticipation of an emergency situation. Four commenters asked for clarification as to whether loss of power that constitutes an emergency is limited to power supplied to the facility as a whole or includes power supplied to portions of a facility.

Response: We agree with the commenters who stated that readiness testing should be included in the definition of emergency operation. Accordingly, we have written the definition of emergency stationary combustion turbine to include allowances for readiness testing in the final rule. The routine testing and maintenance must be within limits recommended by the turbine manufacturer or other entity such as an insurance company. However, we disagree with the commenter who requested the definition to include operations in anticipation of an emergency situation. Exempt operations will be limited to emergency situations only. We agree that loss of power can include power supplied to portions of a facility, and we have, therefore, written the definition of stationary emergency combustion turbine in the final rule to make this clear.

Comment: Several commenters recommended that the definition of ''stationary combustion turbine'' include all appropriate associated equipment.

Response: We agree with the commenters' suggestions and have written the definition of stationary combustion turbines in the final rule to reflect appropriate comments. The definition of a stationary combustion turbine does not include emissions control equipment.

Comment: One commenter expressed support for the definition of major source except that the phrase ''except when they are on the same surface site'' should be removed from the combustion turbine major source definition. This phrase is not present in the 40 CFR part 63, subpart HH, major source definition that is the template for the combustion turbine MACT major source definition. Section 112(n)(4) of the CAA requires that wells and associated equipment not be aggregated even within the same surface site except as provided in the combustion turbine MACT major source definition. In the combustion turbine MACT major source definition, the phrase ''storage vessel with flash emissions potential'' should be changed to ''storage vessel with the potential for flash emissions'' to conform to the 40 CFR part 63, subpart HH, definition.

The commenter also stated that the General Provision major source

definition presented in the combustion turbine MACT is different from those found in the definition of major source in the NESHAP from Oil and Natural Gas Production Facilities (40 CFR 63.761). The significance of this difference is that sources that are area sources under subpart HH could possibly be rendered ''major sources'' under the combustion turbine MACT. The EPA should acknowledge this possibility in the preamble to the final rule and clearly state that this does not change the source's status under subpart HH or any other MACT. Another commenter recommended that the preamble clarify that the definition of major source in the combustion turbine MACT does not alter the definition of major source in subpart HH, and, therefore, does not affect subpart HH applicability.

Response: We agree with the commenters and have written the major source definition in the final rule to reflect appropriate comment. We have acknowledged in the preamble to the final rule that the definition of major source in the final rule may be different from those found in other rules. However, this does not alter the definition of major source in other rules, and, therefore, does not affect the Oil and Natural Gas Production Facilities NESHAP (subpart HH of 40 CFR part 63) or any other rule applicability.

Comment: One commenter observed that landfill and digester gas are defined in the proposed rule as being formed through anaerobic decomposition, which is usually but not always the case.

Response: We agree with the commenter that landfill and digester gas are not always formed only through anaerobic decomposition. As a result, we have written the definition of landfill and digester gas in the final rule acknowledging that these gases are usually formed through anaerobic decomposition, but not always by inserting the word ''typically'' in front of ''formed'' in both definitions.

C. Dates

Comment: Two commenters stated that immediate compliance is unrealistic for new and reconstructed turbines and recommended a 1-year compliance timeframe. Other commenters recommended that the final rule allow 1 year to conduct the initial performance test, rather than the 180 days provided by the 40 CFR part 63, General Provisions.

Response: Immediate compliance is appropriate for new or reconstructed turbines and is consistent with the General Provisions of 40 CFR part 63. Sources are required to install the proper equipment and meet the applicable emission limitations on startup. However, we allow sources 180 days to demonstrate compliance. We feel that 180 days is sufficient time to conduct the initial performance test, consistent with the General Provisions. Sources have the option to petition for additional time if necessary.

Comment: One commenter requested that EPA allow a facility with identical combustion turbines to conduct performance tests on only one of the units to demonstrate compliance with the emission limits for all of the identical units.

Response: We are not allowing facilities with identical combustion turbines to conduct performance tests on only one of the units to demonstrate compliance with the emission limits for all of the identical units because not all apparently identical facilities produce the same emissions. We have turned down many similar requests and have asked owners and operators to run stack tests on all individual units.

Comment: Two commenters requested that the rule provide 1 year for initial notification of MACT applicability, as in the Oil and Natural Gas Production and the Natural Gas Transmission and Storage MACT, instead of 120 days.

Response: We do not agree that 1 year is necessary for initial notification of MACT applicability. An initial notification is not a time consuming activity.

D. MACT

Comment: Three commenters took issue with the MACT floor for new diffusion flame stationary combustion turbines. The commenters stated that no formaldehyde emissions data or oxidation catalyst control efficiency data were available to EPA to support setting the MACT floor for new diffusion flame stationary combustion turbines; newer models of turbines in the diffusion flame category should be evaluated to identify the best-performing unit.

Response: At proposal, we had limited emissions data for stationary combustion turbines, including one test for a diffusion flame turbine with add-on HAP emission control, and we requested HAP emissions test data from stationary combustion turbines. We received new emissions data for diffusion flame turbines during the comment period, including an additional formaldehyde test on a diffusion flame unit equipped with add-on HAP emissions control. The new data also include several tests conducted using FTIR, which is regarded as the most accurate measurement method for formaldehyde for stationary combustion turbines. Thus, the data set has been significantly improved, both quantitatively and qualitatively, and we feel that the data set is sufficient to identify the best-performing unit.

Based on comments and information received during the public comment period, the diffusion flame subcategory was divided further into subcategories for diffusion flame combustion turbines when firing gas and when firing oil at sites where all turbines fire oil for no more than 1000 hours annually (''diffusion flame gas-fired turbines'') and for diffusion flame combustion turbines when firing oil at sites where all turbines fire oil more than 1000 hours annually (''diffusion flame oil-fired turbines'').

In addition, based on information received during the public comment period indicating that oxidation catalysts are in use on some existing diffusion flame combustion turbines, we reevaluated the MACT floor for new turbines in each of the diffusion flame subcategories.

Comment: One commenter contended that the MACT floor for existing diffusion flame is unlawful because EPA did not identify the best performing sources or determine the emission levels they are achieving; EPA merely considered whether or not they are equipped with a catalyst. The commenter stated that whether or not the relevant best sources are equipped with control equipment, they are achieving some emission level, and EPA must determine the average emission level they are achieving and set floors at that level.

Response: We agree with the commenter that all factors which might control HAP emissions must be considered in making a floor determination for each subcategory, and that this analysis cannot be properly limited to add-on controls. However, we disagree that it must express the floor as a quantitative emission level in those instances where the source on which the floor determination is based has not adopted or implemented any measure that would reduce emissions. In this instance, we decided to subcategorize within diffusion flame combustion turbines based on the fuel which is used, because the composition of HAP emissions differs materially based on whether gas or oil is used. We then determined for each subcategory of diffusion flame combustion turbines that emissions of each HAP are relatively homogenous across that subcategory, and that there are not any

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adjustments of the turbines or other operational modifications except for the use of add-on controls which would be effective in reducing HAP emissions. Since the source on which the floor for existing sources in each subcategory of diffusion flame turbines is based has not installed such add-on controls, we determined that the MACT floor for each such subcategory requires no emission reductions. We have also established fuel-based subcategories within lean premix combustion turbines, and have made a comparable determination that the MACT floor for existing sources within each of these subcategories requires no emission reductions.

Comment: One commenter said that the MACT floor for new diffusion flame units is unlawful because EPA did not identify the best-performing diffusion flame combustion turbine and the floor does not reflect what that source achieved in practice. According to the commenter, EPA ignored other factors that affect a source's performance (fuel, design, age, maintenance, operator training, skill and care, differences in effectiveness of catalysts). The performance of all sources using an oxidation catalyst is not the same and cannot possibly reflect the performance of the single best source.

Response: We agree with the commenter that the standard for new sources within each subcategory must be based on the emission levels achieved in practice by the best controlled similar source. However, we think that the performance in reducing emissions by the best controlled source will not be uniform, and that it would be inappropriate to establish a standard which could not be consistently met even by the source upon which the standard is based. We, therefore, believe that there must be some allowance made for the intrinsic variability in the effectiveness of controls in the standard we establish. We do not think that the performance of oxidation catalysts differs as much from one turbine to the next as suggested by the commenter, and we believe that the emission control levels achieved in practice by catalysts on differing turbines is one factor we may appropriately consider in evaluating the variability in emission control levels which is intrinsic to catalyst operation.

Comment: One commenter observed that EPA stated that it considered fuel switching but could not find a less HAP emitting fuel. The EPA's own data show that combustion turbines burning fuel oil have higher benzene and xylene emissions than combustion turbines firing natural gas or landfill gas. Had EPA tested other HAP, it would likely have found that fuel oil produces higher levels of those HAP as well. The EPA has already found the entire diesel exhaust stream to be hazardous.

Response: We agree with the commenter that the composition of HAP emissions are different for combustion turbines firing natural gas and combustion turbines firing oil. We have evaluated both the data we had prior to proposal and the data received since proposal; the test data support the conclusion that HAP emissions are different for different fuels for stationary diffusion flame units. Uncontrolled formaldehyde emissions are in general lower as a result of the combustion of distillate oil than for natural gas. Other differences in emissions between natural gas and distillate oil include higher levels of pollutants such as PAH and metals for stationary combustion turbines burning distillate oil.

We proposed one subcategory for combustion turbines using lean premix technology and another subcategory for combustion turbines using diffusion flame technology. However, in recognition of the clear differences we found in the composition of HAP emissions depending on the fuel that is used, we have determined that it is appropriate to subcategorize further based on fuel use. In devising appropriate subcategories based on fuel use, we need to consider that many combustion turbines are configured both to use natural gas and distillate oil. These dual fuel units typically burn natural gas as their primary fuel, and only utilize distillate oil as a backup. To limit the frequency of switching between subcategories caused by limited usage of a backup fuel, we have defined the gas subcategories in a manner which permits combustion turbines that fire gas to remain in the gas subcategory if all turbines at the site in question fire oil no more than a total of 1000 hours during the calendar year.

Comment: Several commenters took issue with the methodology and data used to set the MACT floors for lean premix units. Two commenters contended that EPA's determination of the floor for existing lean premix turbines is fundamentally flawed, and that reliance on a single data point and the assumptions made to compensate for the inherent error and variability is not appropriate. It was suggested that EPA must obtain additional information before it can set a floor.

Two commenters stated that data from all five combustion turbines should be used to set the MACT floor for existing lean premix turbines. One commenter determined that the formaldehyde limit should be 219 ppb if EPA declines to set the floor as no emission reduction.

Several commenters remarked than the MACT floor for new and existing lean premix turbines does not reflect a reasonable estimate of formaldehyde emissions achieved in practice by the best-performing source; EPA should adjust the MACT floor to reflect formaldehyde emissions reasonably expected over the operating range of the best-performing lean premix turbine. One commenter observed that EPA's use of the performance test of one ''best'' lean premix unit is not statistically viable and does not meet the statutory requirement for setting the MACT floor.

Two commenters said that EPA's emission standard for lean premix combustion turbines is unlawful and EPA should establish a ''no control'' emission limitation. It was also stated that EPA did not determine that the best performers in the subcategory were ''controlling'' their emissions in a duplicable manner. They stated that EPA improperly set the floor for the existing lean premix subcategory; EPA based the floor on the performance of the best source for which it had data, instead of basing it on the average emission limitation of the five sources for which it had data. They also stated that all of the variability that either the best performers will experience or that will affect the attainability of emissions had not been considered and suggested that EPA consider the normal turbine variations based on time, fuel, location, weather, and the repeatability of testing and monitoring methods.

Response: As previously discussed, we had limited emissions data at proposal for stationary combustion turbines. We had five tests for formaldehyde emissions for lean premix combustion turbines, none of which were on lean premix units with add-on HAP emission control. We received new emissions data for lean premix turbines, including two formaldehyde tests on a lean premix unit equipped with add-on HAP emissions control. The new data also include several tests conducted using FTIR, which is regarded as the most accurate measurement method for formaldehyde for stationary combustion turbines. Thus, the data set has been significantly improved, both quantitatively and qualitatively, and EPA believes that the data set is sufficient to identify the best-performing unit.

Also, as discussed previously, we decided that it is appropriate to subcategorize based on fuel within the subcategories for diffusion flame and lean premix combustion turbines. We have established subcategories for lean

premix combustion turbines when firing gas and when firing oil at sites where all turbines fire oil for no more than 1000 hours annually (''lean premix gas-fired turbines''), and for lean premix combustion turbines when firing oil at sites where all turbines fire oil more than 1000 hours annually (''lean premix oil-fired turbines'').

As a result of comments and the new data submitted post-proposal, we also have reevaluated the MACT floor for both existing and new turbines in each of the lean premix subcategories.

Comment: One commenter said that the MACT floor for existing lean premix combustion turbines is unlawful. The floor (formaldehyde) is at a level far worse than the emission levels achieved by the best source. The 95 percent reduction standard is unlawful because it does not even purport to reflect the actual emission levels achieved by the relevant best sources. The commenter also stated that CO is not a valid surrogate.

Response: We reevaluated the MACT floor for existing gas-fired and oil-fired LPC units as a result of comments and the new data submitted post-proposal. We do not agree that CO reduction is not a valid surrogate for HAP reduction, however, the alternative CO emission limitation has been removed from the final rule due to CO measurement difficulties. Thus, the commenter's concerns are moot. We have determined that formaldehyde is an appropriate and valid surrogate for each of the organic HAP that can be controlled by a catalyst, and that the standard for such organic HAP can be reasonably expressed in terms of formaldehyde emissions measured after exiting any control device.

Comment: One commenter stated that the MACT floor for new lean premix units does not reflect the actual performance of the single best source.

Response: As explained above, we believe that we must accommodate intrinsic variability in performance when setting a standard which is based on the performance of the best controlled similar source. It would make no sense to adopt a standard based on the best controlled source which could not be consistently met even by that source.

Comment: One commenter remarked that for MACT, EPA's rejection of potential control technologies that might be applied, including wet scrubbers, dry scrubbers, and activated carbon, without even considering them is unlawful, and that EPA's argument that a greater degree of reduction could not be achieved through the use of clean fuels is unlawful.

Response: We agree with the commenter that the effect of the choice of natural gas or fuel oil on the composition of HAP emissions is significant, and we have, therefore, subcategorized further within both lean premix and diffusion flame turbines based on which of these fuels is used. We are not aware of any data indicating that HAP emissions could be consistently reduced by selection of particular clean fuels within these general fuel groups. As for the other novel emission control technologies to which the commenter refers, we do not believe that these technologies are in use on any combustion turbine and we do not consider any sources utilizing such controls to be similar sources. Moreover, we are unable based on available information to determine that these technologies would be both efficacious and cost effective in reducing HAP emissions from combustion turbines.

Comment: One commenter remarked that for existing emergency, limited use, landfill or digester gas fired, and less than 1 MW units, EPA did not set a floor that reflects the emission levels that the best performing sources actually achieved. The EPA has not identified the relevant best performing sources and has not determined the average emission limitation achieved by such sources, therefore, EPA's floors for these sources are unlawful.

Response: We have not decided to establish a limited use subcategory. For the emergency, landfill or digester gas fired, and less than 1 MW subcategories, we have not identified any adjustments or other operational modifications that would materially reduce emissions by these units and we have determined that no add-on controls are presently in use. In these circumstances, we believe that we have appropriately established the floors for these sources as no emission reduction.

Comment: One commenter said that for new emergency, limited use, landfill or digester gas fired, and less than 1 MW units, the floor is unlawful because EPA did not identify the single best controlled source in any of these subcategories and did not set floors reflecting such source's actual performance.

Response: As noted above, we have not decided to establish a limited use subcategory. For the emergency, landfill or digester gas fired, and less than 1 MW subcategories, we have not identified any adjustments or operational modifications that would materially reduce emissions by these units and we have determined that no add-on controls are presently in use. We also have determined because of the specific characteristics of turbines in these subcategories that the turbines in other subcategories that utilize add-on controls are not similar sources. In these circumstances, we believe that we have appropriately determined that the new source MACT floor for these subcategories should also be no emission reduction.

Comment: One commenter contended that EPA's rejection of beyond the floor standards for new emergency, limited use, landfill or digester gas fired, and less than 1 MW units is arbitrary and capricious. The EPA does not state the cost of applying any control technology or indicate the quantity of the HAP that would be reduced.

Response: We believe that the record includes analysis demonstrating that it is not cost effective to require HAP controls for turbines in instances where no similar source has installed such controls.

Comment: One commenter said that EPA's proposal is unlawful because EPA must set standards for each listed HAP. Oxidation catalyst control devices do not control many of the HAP that combustion turbines emit, for example metals.

Response: We do not agree that it is required to establish a discrete standard for each listed HAP. However, we do agree that each listed HAP must be separately considered by EPA, both in determining the MACT floors and in establishing the emission standards for each subcategory. If emissions of a particular HAP are relatively homogenous for a particular subcategory, and there are no adjustments or operational modifications except for add-on controls which would reduce emissions of that HAP, the MACT floor and the emission standard for that HAP may be expressed as a level of emission reduction corresponding to the efficacy of add-on controls. Moreover, if the data demonstrate that control of emissions of a particular HAP is a suitable surrogate for control of emissions of a group of listed HAP, we may appropriately set the standard in terms of a level of emission reduction or an emission level for that particular HAP.

In establishing new source standards for certain subcategories, we determined that formaldehyde is an appropriate surrogate for the other organic HAP which are also controlled by an oxidation catalyst. While use of an oxidation catalyst does not control the metallic HAP which are emitted by turbines burning distillate oil, there are no combustion turbines or similar sources utilizing other technologies to

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control metallic HAP. Moreover, we do not believe it would be practical or cost effective to require control of these metallic HAP and, therefore, the floor and the standard for each metallic HAP was appropriately set at no emission reduction.

Comment: One commenter noted that EPA's floors must reflect the average emission levels achieved by the relevant best sources. Thus, even if some of the relevant best sources are not using any control device, the agency must average their performance with that of the relevant best sources that are using a control device. That some of the relevant best performers are not using an end-of-stack control technology does not allow EPA to discount the performance of other best performers that are using such technology.

Response: We do not agree with the premise of this commenter that the existing source MACT floor (the average emission limitation achieved by the best performing 12 percent of existing sources or the best performing five existing sources in subcategories with fewer than 30 sources) must be calculated by determining the arithmetic average of the emission limitations achieved individually by each of these sources. We have consistently construed the statute to permit us to determine the average emission limitation by selecting the median facility among the best performing 12 percent or five existing sources. We think this well-established construction of the statute is reasonable, because an arithmetic average will quite often not coincide with the level of emission reduction that has been achieved in practice by any real facility. We do not think it is appropriate to establish an existing source MACT floor which may not be achievable by most of the sources from which it was derived. Nor do we think it is required to set a standard which is less stringent than most of the sources from which it is derived are achieving. Use of the emission limitation achieved by the median facility avoids these problems.

E. Emission Limitations

Comment: Many commenters stated that the final rule should only apply emission standards to the load range represented by the emissions data used to determine emission limitations.

Response: The emission standards are based on data from testing at high loads (90 percent and greater). To address the concerns expressed by the commenters about the emission standards being applicable at full load only, the final rule specifies that the performance test must be conducted at high load conditions, defined as 100 percent ±10 percent.

Comment: Many commenters took issue with the data used to set the formaldehyde emission limitation. The commenters noted that the test reports used to set the limit used two different test methods and that the limit was based on only five data points and, therefore, does not reflect a level of performance that is achievable for all sources. One commenter said that EPA has not provided enough data to know definitively what the standard should be. Another commenter stated that EPA must obtain additional information before it can set a floor.

The commenters also had concerns about possible errors in the test reports that are the source of the emissions data used to set the formaldehyde emission limitation. One commenter said that close examination of the five reports uncovers questions regarding the actual test procedures, comparability, data reduction and data reporting that should be revisited before finalizing the formaldehyde concentration limit. They stated that all five reports appear to have calculation errors and/or other data quality issues that significantly affect the reported formaldehyde concentration, the comparability of the results because different test methods were used, and/or uncertainty associated with the average result. One commenter also reviewed the five tests used to set the standard and found that all of the five tests used do not present valid quantitative results; and that data from these tests may not be used to establish a quantitative emission standard for formaldehyde emissions from lean premix combustion turbines.

One commenter said that CARB 430 may report anomalously low formaldehyde emissions; therefore, the standard may be too stringent and unachievable in practice. Two commenters questioned whether the CARB 430 data used to develop the standard followed CARB method requirements. One commenter believed that the results from all tests used to determine the MACT floor should be recalculated using CARB 430 procedures so the data can be justifiably compared and that results should also be recalculated using the American Society of Mechanical Engineers measurement uncertainty analysis procedure. The EPA should then use these results for establishing the formaldehyde concentration limit. The commenter estimated that an enforceable formaldehyde concentration limit should be in the range of approximately 100 to 500 ppb.

One commenter said that a single emission test does not fully reflect the variability that will be seen by the best performing source employing any technology. The EPA should properly assess variability that may be experienced by the best performing sources under the worst foreseeable conditions that are expected to recur. Emission testing conducted by the commenter in conjunction with the Gas Turbine Institute indicates that 43 ppb is not achievable for small industrial and aeroderivative turbines.

Several commenters suggested a revised level for the emission limitation. One commenter said that EPA must revise the limit upward to at least 63 ppb. Two commenters stated that additional formaldehyde data suggests that EPA should consider setting the emission standard to 90 ppbvd given the tremendous variability in the few measurements that are available. One commenter submitted a summary table of data for nine tests conducted on lean premix combustion turbines. The test results show a variability between high and low loads of 34 percent; also, six out of nine tests were above 43 ppb.

Response: As a result of comments received during the comment period, we performed an extensive review of tests used at proposal and new tests received during the comment period. A screening analysis of the formaldehyde test data for diffusion flame combustor turbines was conducted. Tests conducted using CARB 430 were evaluated due to the CARB advisory issued April 28, 2000, which stated that formaldehyde data measured by CARB 430 where the NO_X emissions were greater than 50 ppm should be flagged as non-quantitative. Tests where the NO_X emissions were greater than 50 ppm, or tests where the NO_X levels were unknown, were excluded from our analysis. Most of the diffusion flame tests in the EPA's combustion turbine emissions database were unable to pass the screening. The tests unable to pass the screening were not equipped with add-on control for the reduction of HAP.

The remaining test reports were further analyzed and reviewed to ensure the methods were used correctly in calculating and reporting formaldehyde concentrations and to check that proper quality assurance (QA)/quality control (QC) procedures were followed. A number of errors were found in the test reports where CARB 430 was used to quantify formaldehyde concentrations. In several instances, the CARB 430 reporting protocol was not followed. If the analytical concentration is less than five times the average field blank, then CARB 430 uses five times the field

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blank as the reported result to correct for interferences or contaminants that can react with the formaldehyde or dinitrophenylhydrazine to yield negative bias. However, many test reports did not report formaldehyde concentrations in this fashion. The formaldehyde concentrations were, therefore, recalculated where the CARB 430 reporting protocol was not followed correctly.

No errors were found in test reports which used FTIR to measure formaldehyde concentrations in the stationary combustion turbine exhaust. The reported formaldehyde concentrations were representative of stationary combustion turbines and the measured QA/QC parameters were within acceptable limits as set in the method.

We agree that CARB 430 generally understates the formaldehyde concentration in the exhaust gas from stationary combustion turbines. Since EPA Method 0011 is a similar method to CARB 430, it is believed that Method 0011 also understates the emissions of formaldehyde. We feel that FTIR is a more accurate and reliable method than CARB 430. Several test reports were received during the comment period on recent testing on small lean premix combustion turbines which used both CARB 430 and FTIR to measure formaldehyde emissions. An analysis was conducted to correlate formaldehyde concentrations measured by CARB 430 and formaldehyde concentrations measured by FTIR. A linear regression was performed on the CARB 430 and FTIR formaldehyde data from these tests which gave a slope of 1.667 with a correlation coefficient of 0.561. Therefore, we concluded that CARB 430 formaldehyde results are on average 1.7 times lower than FTIR formaldehyde results. To account for the differences in the methods, a bias factor of 1.7 was applied to the CARB 430 and Method 0011 formaldehyde emissions data to make these data comparable to FTIR.

As a result of a complete data review, including emissions data we had at proposal and new emissions data we received during the comment period, we currently have a very different data set as compared to what we had at proposal. For example, the amount of data for lean premix units increased, while the amount of data for diffusion flame units decreased. As discussed previously, the new data set was used to determine the MACT floors. For new lean premix gas-fired turbines and new lean premix oil-fired turbines, a formaldehyde emission limitation of 91 ppb was established for the MACT floor. It is felt that this emission limitation will be achievable for both small and large size combustion turbines. We considered establishing separate subcategories by size but found that there was little difference in emissions among the best performing small and large units. The best performing large lean premix unit was controlled by an oxidation catalyst, and EPA had data from two separate tests of this turbine. Formaldehyde emissions were measured at 19 and 91 ppb. The best performing small lean premix unit (less than 25 MW) had uncontrolled formaldehyde emissions of 68 ppb, which is within the range of emissions for the large lean premix unit.

We have adequately considered the variability in emissions by the best performing source. We have emissions data for two tests for the best performing turbine in the lean premix gas-fired turbine subcategory; the formaldehyde emissions varied by a factor of five between the two tests. Since both tests were performed under similar conditions but at different times, they represent the variability of the best performing unit. The MACT floor for this subcategory was set based on the higher formaldehyde measurement, thus the variability of the best performing unit has been accounted for. Similar variability factors were applied for the other subcategories. This is explained further in section III.E.

F. Monitoring, Recordkeeping, and Reporting

Comment: Multiple commenters requested that the CO continuous emission monitoring system (CEMS) requirement be removed and periodic testing/parametric monitoring be adopted. Some commenters cited the cost burden of a CEMS, and others noted that a requirement for CO CEMS imposes an excessive cost burden for smaller turbines. One commenter also noted that CEMS have typically not been required on small turbines and personnel would not be familiar with CEMS operation and maintenance, resulting in increased capital and operating costs. Furthermore, one commenter felt that there would not be significant emissions reduction for the use of CEMS compared to the use of inlet temperature monitoring and periodic emission testing, the requirement is inconsistent with previous EPA decisions on monitoring, and there are deficiencies in the test methods and performance protocols. One commenter questioned whether the low measurements can be made accurately and reliably on a continuous basis without jeopardizing the flexibility of facility operations.

Many commenters recommended alternatives to the CO CEMS requirement. One commenter suggested the option of monitoring compliance with a one-time performance test for CO. One commenter said that an option could be reliance on a Federal CO permit limit combined with periodic CO stack testing. If the permitted CO limit is relatively high, compliance with the formaldehyde limit at that level could first be determined using an initial formaldehyde test. If the CO limits/concentration are low, initial formaldehyde testing should not be necessary. The commenter recommended that EPA establish a default minimum compliance demonstration at 5 parts per million (ppm). One commenter recommended that EPA evaluate periodic stack tests, conducted on the same schedule as relative accuracy test audit (RATA) testing as an alternative to CEMS. At a minimum, this approach should be pursued for units with oxidation catalyst systems that would qualify as peaking units under the Acid Rain Program and are not otherwise required to conduct emissions monitoring for CO or other pollutants.

One commenter said that a more workable solution would be to measure downstream CO, but only if a CEMS is already required for NO_X. A catalyst efficiency test could be performed periodically to confirm continued reduction efficiency (an option to perform this check with portable analyzer should be included). One commenter said that if EPA includes an option to monitor CO emissions using CPMS rather than CO CEMS, a requirement to replace a catalyst bed when the pressure drop increases by more than 2 inches of water from the drop measured during the initial performance test may not be appropriate. Particular vendors are better able to specify the conditions under which catalyst replacement is warranted.

Response: In the preamble for the proposed rule, we solicited comments on the performance capabilities of a state-of-the-art CO CEMS and its ability to measure the low concentrations of CO in the exhaust of a stationary combustion turbine following an oxidation catalyst control device. In general, commenters did not support CO CEMS, stating that existing CO CEMS technology and EPA performance criteria are not adequate to reliably and accurately measure trace levels of CO. Due to the CO measurement difficulties, EPA has decided not to include the CO

emission reduction limitation in the final rule.

Comment: One commenter remarked that subsequent performance testing (suggest no more frequent than annually) is needed for units meeting the formaldehyde limit, and that there should also be some methodology for the demonstration of continuous compliance.

Response: We agree with the commenter that subsequent performance testing is needed for units meeting the formaldehyde limit. The final rule includes a requirement for annual performance testing for units meeting the formaldehyde limit and designated requirements for continuous compliance. For sources equipped with oxidation catalyst control, continuous compliance will be demonstrated by continuously monitoring the inlet temperature to the catalyst and maintaining the inlet temperature within the range suggested by the catalyst manufacturer. Sources that are not equipped with oxidation catalyst control must petition the Administrator for approval of operating limitations or approval of no operating limitations.

Comment: One commenter said that EPA should allow facilities to use existing test data to demonstrate compliance with the emission limitation if the test was conducted using the same methods specified in the rule and no process changes have been made since the test, or it can be demonstrated that the results of the performance test reliably demonstrate compliance despite process changes.

Response: Since there are no emission limitation requirements for existing sources in the final rule, we expect that few facilities will have existing test data to demonstrate compliance. Facilities that came online after the proposal would be the only sources that may have conducted emissions testing prior to the stack testing requirements of the final rule, and we will allow facilities to use existing test data to demonstrate initial compliance with the emission limitation if the data is of good quality and is no older than 2 years. (After the initial compliance demonstration, facilities must then begin to follow the annual compliance test schedule.) The facility must petition the Administrator for approval and demonstrate that the tests were conducted using the same test methods specified in the subpart, the test method procedures were correctly followed, no process or equipment changes have been made since the test, and the data are of good quality and less than 2 years old. This has been specified in the final rule.

G. Test Methods

Comment: Several commenters expressed concern regarding the accuracy and precision of CARB Method 430 at levels commensurate with the proposed standard. Two commenters noted that CARB Method 430 is susceptible to interferences. One commenter said that sample loss and measurement uncertainties can contribute to large measurement variability. Another commenter contended that CARB Method 430 is an indirect measurement method and is inferior to Method 320. This commenter also said that CARB Method 430 cannot give realistic results.

Response: New information provided during the public comment period where CARB 430 and FTIR were concurrently tested showed that CARB 430 using the CARB reporting protocol is biased low by a factor of 1.7 compared to FTIR. Therefore, we agree with the commenters' concerns regarding the accuracy of CARB Method 430 and that it is an indirect measurement method, however, EPA disagrees that CARB Method 430 cannot give realistic results. In some cases, we believe that CARB Method 430 can provide realistic results. However, we also agree that FTIR would be the better compliance method. Therefore, we have specified Method 320 and ASTM D6348–03 as the compliance procedures in the final rule.

Comment: Several issues were raised in the comments received regarding EPA Method 0011. One commenter did not support the use of EPA Method 0011 for combustion turbines because there is no need for isokinetic sampling in combustion turbine stacks, compared to CARB Method 430 the field procedure is more complex, the potential for chronic field contamination is much greater, the QA/QC procedures are vastly inferior, the data reporting procedures especially with respect to blanks are more vague, and the method does not have sufficient sensitivity for demonstrating compliance with the proposed formaldehyde limit.

Response: We agree with the commenters that the method has many shortcomings and limited application opportunities for use in measuring formaldehyde emissions from stationary combustion turbines. Accordingly, we are not including EPA Method 0011 in the final rule. Both EPA Method 0011 and CARB Method 430 can be requested on a case-by-case basis as part of EPA's alternative method review process.

Comment: Several commenters did not support Method 323. The commenters said that the method should not be used for measuring very low concentrations of formaldehyde. The minimum detection levels of the method are not suitable for the emission standards. Two commenters also noted that the method has not been validated or demonstrated for use on combustion turbines with low ppb range formaldehyde emissions.

Response: We agree with commenters that Method 323 should not be used for measuring low concentrations of formaldehyde from combustion turbines. Therefore, we are not including Method 323 in the final rule.

Comment: Numerous commenters said that CO CEMS cannot reliably measure trace level CO concentrations and 95 percent CO reduction. One commenter remarked that EPA provides no information to show that CEMS are available to accurately measure low CO concentrations, and the use of CO CEMS for low levels is well beyond the scope of current 40 CFR part 60 CEMS performance standards. Also, vendor claims for CO CEMS and CO instrumental analyzers, unless accompanied by emissions test data obtained under known and controlled conditions applicable to the subject source type, should not be considered adequate proof of availability and performance.

Response: We agree that existing CO CEMS technology and EPA performance criteria are not adequate to reliably and accurately measure trace levels of CO. The American Society for Testing and Materials (ASTM) is currently trying to address this issue, with participation by EPA. The requirement for CO CEMS has not been included in the final rule.

Comment: Three commenters sought an allowance for site specific emission limits where duct burners are utilized and the formaldehyde limit applies. Three commenters recommended that facilities should be allowed to either accept the formaldehyde limit at the stack with the duct burner in operation, or be allowed to petition the EPA for an alternate (higher) formaldehyde limit for the combined turbine/duct burner co-firing.

Response: We have included the commenters' suggestions that facilities be allowed to accept the formaldehyde limit at the stack with the duct burner in operation in the final rule; however, it is not necessary to specify in the final rule that affected sources are allowed to petition EPA for an alternate formaldehyde limit.

H. Risk-Based Approaches

The preamble to the proposed rule requested comment on whether there might be further ways to structure the

final rule to focus on the facilities which pose significant risks and avoid the imposition of high costs on facilities that pose little risk to public health and the environment. Specifically, we requested comment on the technical and legal viability of three risk-based approaches: an applicability cutoff for threshold pollutants under the authority of CAA section 112(d)(4), subcategorization and delisting under the authority of CAA section 112(c)(1) and (9), and, a concentration-based applicability threshold.[1]

We indicated that we would evaluate all comments before determining whether either approach would be included in the final rule. Numerous commenters submitted detailed comments on these risk-based approaches. These comments are summarized in the Response-to-Comments document (*see* **SUPPLEMENTARY INFORMATION** section).

Based on our consideration of the comments received and other factors, we have decided not to include the risk-based approaches in today's final rule. The risk-based approaches described in the proposed rule and addressed in the comments we received raise a number of complex issues. In addition, we must issue the final rule expeditiously because the statutory deadline for promulgation has passed, and we have agreed to a binding schedule in a consent decree entered in *Sierra Club* v. *Whitman*, Civil Action No. 1:01CV01537 (D.D.C.). Given the range of issues raised by the risk-based approaches and the need to promulgate a final rule expeditiously, we believe that it is appropriate not to include any risk-based approaches in today's final rule.

I. Other

Comment: Two commenters remarked that EPA's declaration that diesel fired turbines cannot be operated in the lean premix mode is a misstatement. While some manufacturers, on some models, only offer liquid fuel capability in diffusion flame mode, other manufacturers have offered the dual fuel option on lean premix turbines since the mid-1990's. One commenter stated that the standard should be modified because of the dual fuel capability of combustion turbines. The commenter noted that EPA has no data to represent lean premix liquid fuel operation and, therefore, cannot determine an appropriate standard.

Response: At the time the NESHAP were proposed, we were not aware of the availability of diesel fired turbines that operated in the lean premix mode. We have since contacted several turbine manufacturers in an attempt to obtain more information about these units, and two manufacturers confirmed that they do offer diesel firing while operating in lean premix mode. The commenter is correct that we have no emissions test data for lean premix units firing liquid fuel, however, information provided by the manufacturers indicated that their emission guarantees for CO and hydrocarbons were similar for both natural gas and diesel. Also, testing on dual fuel diffusion flame units shows that formaldehyde emissions are actually lower for distillate oil firing. Therefore, we have established an emission standard for lean premix oil-fired units in the final rule.

Comment: One commenter observed that HAP emissions from sources burning natural gas are enormously different from sources burning other fuels such as diesel. The commenter questioned EPA's argument that the summation of emission factors for various HAP for different fuels is comparable. The commenter also said that EPA does not explain what the summation of emission factors means or how it might be relevant to EPA's floors for any HAP.

Response: We agree with the commenter that the composition of HAP emissions from sources burning natural gas is different than from sources burning diesel fuel. Uncontrolled formaldehyde emissions are in general lower as a result of the combustion of distillate oil than for natural gas. Other differences in emissions between natural gas and distillate oil include higher levels of pollutants such as PAH and metals for stationary combustion turbines burning distillate oil. We agree that the summation of emission factors for various HAP for different fuels may be different. As discussed in the response to previous comments, due to the differences in HAP emissions, subcategories based on fuel were established for both diffusion flame and lean premix turbines.

IV. Rationale for Selecting the Final Standards

A. How Did We Select the Source Category and Any Subcategories?

Stationary combustion turbines can be major sources of HAP emissions and, as a result, we listed them as a major source category for regulatory development under section 112 of the CAA, which allows us to establish subcategories within a source category for the purpose of regulation. Consequently, we evaluated several criteria associated with stationary combustion turbines which might serve as potential subcategories.

We identified emergency stationary combustion turbines as a subcategory. Emergency stationary combustion turbines operate only in emergencies, such as a loss of power provided by another source. These types of stationary combustion turbines operate infrequently and, when called upon to operate, must respond without failure and without lengthy periods of startup. These conditions limit the applicability of HAP emission control technology to emergency stationary combustion turbines.

Similarly, stationary combustion turbines which burn landfill or digester gas equivalent to 10 percent or more of the gross heat input on an annual basis or where gasified MSW is used to generate 10 percent or more of the gross heat input to the stationary combustion turbine on an annual basis were identified as a subcategory. Landfill gas, digester gas, and gasified MSW contain a family of chemicals referred to as siloxanes, which limit the application of HAP emission control technology.

Stationary combustion turbines of less than 1 MW rated peak power output were also identified as a subcategory. We believe these small stationary combustion turbines are few in number. These small stationary combustion turbines are sufficiently dissimilar from larger combustion turbines that we cannot evaluate the feasibility of emission control technology based on information concerning the larger turbines. To our knowledge, none of the smaller turbines use emission control technology to reduce HAP. Therefore, we believe it would be inappropriate to require HAP emission controls to be applied to them without further information on control technology performance.

Stationary combustion turbines can be classified as either diffusion flame or lean premix. We examined formaldehyde test data for both diffusion flame and lean premix stationary combustion turbines and observed that uncontrolled formaldehyde emissions for stationary lean premix combustion turbines are significantly lower than those of stationary diffusion flame combustion turbines. Due to the difference in the two technologies, we decided to establish subcategories for diffusion flame and lean premix stationary combustion turbines.

[1] See 68 FR 1276 (January 9, 2003) (Plywood and Composite Wood Products Proposed NESHAP) and docket number A–98–44 (White Papers submitted to EPA outlining the risk-based approaches).

Attachment 1
Attachment 1

We further investigated subcategorizing lean premix turbines based on fuel. At the time of proposal, EPA was not aware of the availability of distillate oil fired stationary combustion turbines that operated in the lean premix mode. We received comments indicating otherwise during the public comment period from combustion turbine manufacturers. We believe there is a difference in uncontrolled HAP emissions between natural gas and distillate oil for stationary lean premix combustion turbines. This is based on test data for stationary diffusion flame combustion turbines which clearly show there is a difference in the composition of uncontrolled HAP emissions between natural gas and distillate oil. We believe this also would apply to stationary lean premix combustion turbines. For stationary lean premix combustion turbines, NO_X emissions also vary depending on which fuel is burned in the combustion process. Information from combustion turbine vendors indicate that NO_X emission guarantees for distillate oil can be up to five times higher than the NO_X emission guarantees for natural gas for stationary lean premix combustion turbines. Finally, the mass of total emissions may be similar for natural gas and distillate oil, but some pollutants such as formaldehyde are lower for distillate oil and other pollutants such as PAH and metals are higher for oil. For all practical purposes, uncontrolled natural gas metal emissions are nonexistent, while they are emitted in small quantities when burning distillate oil.

We expect that the majority of distillate oil burned in stationary combustion turbines will be fuel oil number 2. We recognize that stationary combustion turbine owners and operators may burn different varieties of distillate oil, however we believe that any other distillate oil combusted will be of similar quality and composition to fuel oil number 2. We do not anticipate that owners and operators will burn any other liquid based fuel that is more contaminated with metals than fuel oil number 2 and expect that most available liquid fuels that may be used in stationary combustion turbines will be similar and fairly consistent.

In recognition of the clear differences we found in the composition of HAP emissions depending on the fuel that is used, we have determined that it is appropriate to subcategorize further within stationary lean premix combustion turbines based on fuel use. In devising appropriate subcategories based on fuel use, we needed to consider that many combustion turbines are configured both to use natural gas and distillate oil. These dual fuel units typically burn natural gas as their primary fuel, and only utilize distillate oil as a backup. Without some allowance for this limited backup use of distillate oil, these turbines might switch subcategories frequently, causing confusion for sources and complicating compliance demonstrations. To limit the frequency of switching between subcategories which would result from limited usage of distillate oil as a backup fuel, we have defined the lean premix gas-fired subcategory in a manner which permits turbines that fire gas using lean premix technology to remain in the subcategory if all turbines at the site in question fire oil no more than a total of 1000 hours during the calendar year. We believe this 1000 hour allowance will be sufficient to accommodate those situations where distillate oil is used only as a backup. The lean premix gas-fired turbines subcategory will be defined to include: (a) Each stationary combustion turbine which is equipped only to fire gas using lean premix technology, (b) each stationary combustion turbine which is equipped both to fire gas using lean premix technology and to fire oil, during any period when it is firing gas, and (c) each stationary combustion turbine which is equipped both to fire gas using lean premix technology and to fire oil, and is located at a major source where all stationary combustion turbines fire oil no more than an aggregate total of 1000 hours during the calendar year.

The lean premix oil-fired turbines subcategory will be defined to include: (a) each stationary combustion turbine which is equipped only to fire oil using lean premix technology, and (b) each stationary combustion turbine which is equipped both to fire oil using lean premix technology and to fire gas, and is located at a major source where all stationary combustion turbines fire oil more than an aggregate total of 1000 hours during the calendar year, during any period when it is firing oil. We do not know of any actual combustion turbines which would be in this subcategory, but this is possible because we have been advised that combustion turbines can be configured to burn oil using lean premix technology.

We further investigated subcategorizing diffusion flame turbines based on fuel. For diffusion flame turbines, test data show that HAP emissions vary depending on which fuel is burned. Formaldehyde emissions are in general lower for diffusion flame units firing distillate oil versus diffusion flame units firing natural gas. Emissions data also show that NO_X levels are higher for diffusion flame units firing distillate oil than diffusion flame units firing natural gas. Finally, other fuel differences between natural gas and distillate oil include higher levels of pollutants such as PAH and metals in the emissions of stationary diffusion flame combustion turbines burning distillate oil. Quantities of these pollutants are small for distillate oil; metal emissions from natural gas are at non-detectable levels. As previously indicated, we expect that most owners and operators of stationary combustion turbines will burn distillate oil of the form fuel oil number 2. However, we recognize that other liquid based fuels may be also be fired, but these fuels will be similar to fuel oil number 2, and do not expect owners and operators to burn any other fuel that is more contaminated with metals.

As in the case of the lean premix turbines, we concluded based on the clear differences in the composition of HAP emissions depending on the fuel that is used that it is appropriate to subcategorize further within stationary diffusion flame combustion turbines based on fuel use. As in the case of the lean premix turbines, we have included a 1000 hour per site allowance for limited backup use of distillate oil in order to limit the frequency that dual fuel turbines will switch subcategories. We believe this 1000 hour allowance will be sufficient to accommodate those situations where distillate oil is used only as a backup.

The diffusion flame gas-fired turbines subcategory will be defined to include: (a) Each stationary combustion turbine which is equipped only to fire gas using diffusion flame technology, (b) each stationary combustion turbine which is equipped both to fire gas using diffusion flame technology and to fire oil, during any period when it is firing gas, and (c) each stationary combustion turbine which is equipped both to fire gas using diffusion flame technology and to fire oil, and is located at a major source where all stationary combustion turbines fire oil no more than an aggregate total of 1000 hours during the calendar year.

The diffusion flame oil-fired turbines subcategory will be defined to include: (a) each stationary combustion turbine which is equipped only to fire oil using diffusion flame technology, and (b) each stationary combustion turbine which is equipped both to fire oil using diffusion flame technology and to fire gas, and is located at a major source where all stationary combustion turbines fire oil more than an aggregate total of 1000 hours during the calendar year, during

any period when it is firing oil. We expect that the vast majority of all stationary combustion turbines which are primarily oil-fired will be included in this subcategory.

Stationary combustion turbines located on the North Slope of Alaska have been identified as a subcategory due to operation limitations and uncertainties regarding the application of controls to these units. There are very few of these units, and none have installed emission controls for the reduction of HAP.

B. What Are the Requirements for Stationary Combustion Turbines Located at Area Sources?

The final rule does not apply to stationary combustion turbines located at an area source of HAP emissions. An area source is any source that is not a major source of HAP emissions. In developing our Urban Air Toxics Strategy, we identified area sources we believe warrant regulation to protect the environment and the public health and satisfy the statutory requirements in section 112 of the CAA pertaining to area sources. Stationary combustion turbines located at area sources were not included on that list. As a result, the final rule does not apply to these stationary combustion turbines.

C. What Is the Affected Source?

The final rule applies to any stationary combustion turbine located at a major source. Consequently, a stationary combustion turbine located at major sources of HAP emissions is the affected source under the final rule.

The General Provisions at 40 CFR 63.2 require us to generally adopt a broad definition of affected source, which includes all emission units within each subcategory that are located within the same contiguous area. However, § 63.2 also provides that we may adopt a narrower definition of affected source in instances where we determine that the broader definition would ''create significant administrative, practical, or implementation problems'' and ''the different definition would resolve those problems.'' This is such an instance.

Although we have taken some steps in the definition of subcategories to limit the frequency of switching between subcategories, we cannot eliminate the possibility that some individual turbines will be switched from one subcategory to another. Use of the broader definition of affected source specified by the General Provisions would require very complex aggregate compliance determinations because an individual turbine could be part of one affected source at one time and part of a different affected source at another time. This would require that the contribution of each turbine to total emissions for all emission units within each subcategory be adjusted to reflect the proportionate time the unit was operating within that subcategory. Such complicated compliance determinations are impractical and, therefore, we have decided to adopt a definition which establishes each individual combustion turbine as the affected source.

D. How Did We Determine the Basis and Level of the Emission Limitations for Existing Sources?

As established in section 112 of the CAA, the MACT standards must be no less stringent than the MACT floor. The MACT floor for existing sources is the average emission limitation achieved by the best performing 12 percent of existing sources in the subcategory (or the best performing five existing sources in subcategories with fewer than 30 sources).

From the applicable judicial precedent, we can derive certain basic principles which we must follow in deriving the MACT floor. All HAP emitted by sources in the category or subcategory in question must be considered in determining the MACT floor. If a particular HAP is an appropriate surrogate for evaluating emission reductions which have been achieved for a group of HAP, the MACT floor may be expressed in terms of that HAP. However, we must explain our basis for concluding there is a relationship between control of emissions of the HAP we utilize to characterize the MACT floor and control of other HAP. If we determine that the MACT floor requires differing controls affecting more than one group of HAP, multiple measures of the MACT floor may be necessary.

In addition, when deriving the MACT floor for a particular category or subcategory, we must consider all measures which could result in reduction of HAP emissions. These measures will include potential installation of add-on control technology, but other operational modifications such as adjustment of equipment, revision of work practices, and material substitution should also be considered. Where emissions are relatively homogeneous across the sources in a category or subcategory, and any variation in HAP emissions which does occur cannot be readily attributed to differences in any factor which is susceptible to control by the owner or operator, the MACT floor for a particular HAP or group of HAP may be expressed in terms of reductions achieved by use of potential add-on controls.

Existing Lean Premix Combustion Turbines

As explained above, we have established two subcategories of stationary lean premix combustion turbines, lean premix gas-fired turbines and lean premix oil-fired turbines. Emissions of each HAP are relatively homogeneous within each of these two subcategories, and any variation in HAP emissions cannot be readily controlled except by add-on control. To determine the MACT floor for both subcategories of existing stationary lean premix combustion turbines, the EPA's combustion turbine inventory database was consulted.

The inventory database provides population information on stationary combustion turbines in the United States (U.S.) and was constructed in order to support the development of the rule. Data in the inventory database are based on information from available databases, such as the Aerometric Information Retrieval System (AIRS), the Ozone Transport and Assessment Group (OTAG), and State and local agencies' databases. The first version of the database was released in 1997. Subsequent versions have been released reflecting additional or updated data. The most recent release of the database is version 4, released in November 1998.

The inventory database contains information on approximately 4,800 stationary combustion turbines. The current stationary combustion turbine population is estimated to be about 8,000 turbines. Therefore, the inventory database represents about 60 percent of the stationary combustion turbines in the U.S. At least 20 percent of those turbines are estimated to be lean premix combustion turbines, based on conversations with turbine manufacturers.

The information contained in the inventory database is believed to be representative of stationary combustion turbines primarily because of its comprehensiveness. The database includes both small and large stationary combustion turbines in different user segments. Forty-eight percent are ''industrial,'' 39 percent are ''utility,'' and 13 percent are ''pipeline.'' Note that independent power producers (IPP) are included in the utility and industrial segments.

We examined all of the information available to us including the inventory database to identify any operational modifications such as equipment adjustments or work practice revisions which might be associated with lower

HAP emissions. We were unsuccessful in identifying any such operational modifications. Therefore, we were unable to utilize any factors other than add-on controls in deriving the MACT floor.

Another approach we investigated to identify a MACT floor was to review the requirements in existing State regulations and permits. No State regulations exist for HAP emission limits for stationary combustion turbines. Only one State permit limitation for a single HAP (benzene) was identified. Therefore, we were unable to use State regulations or permits in deriving a MACT floor.

The only add-on control technology currently proven to reduce HAP emissions from stationary lean premix combustion turbines is an oxidation catalyst emission control device. At proposal, the inventory database indicated that no existing stationary lean premix combustion turbines were controlled with oxidation catalyst systems. During the public comment period, we received a test report where a lean premix combustion turbine burning natural gas was tested twice about 2 years apart with an oxidation catalyst in operation.

We estimate that about 1 percent of existing lean premix gas-fired turbines may have oxidation catalyst systems installed. Accordingly, the average of the best performing 12 percent is no emission reduction. Therefore, the MACT floor for existing lean premix gas-fired turbines for each individual HAP is no emission reduction.

For lean premix oil-fired turbines, we do not have any data indicating that turbines in this subcategory are in actual use, nor do we have data indicating that oxidation catalysts have been installed. Accordingly, the average emission limitation achieved by the best performing existing units in this subcategory for each individual HAP would also be no emission reduction.

To determine MACT for both subcategories of existing stationary lean premix combustion turbines, we evaluated regulatory alternatives more stringent than the MACT floor. We considered requiring the use of an oxidation catalyst emission control device. According to catalyst vendors, oxidation catalysts are currently being used on some existing lean premix stationary combustion turbines. In addition, we recently received a test report where testing was conducted on a lean premix unit with an oxidation catalyst. However, an analysis of the application of oxidation catalyst control to existing lean premix stationary combustion turbines showed that the incremental cost per ton of HAP removed was excessive. We have not identified any operational modifications which are not currently in use for these turbines but might result in HAP reductions. Nor have we identified any technologies to control those metallic HAP which may be emitted during burning of distillate oil which are technologically feasible and cost-effective. For these reasons, we concluded that MACT for each individual HAP for existing sources in both subcategories of existing stationary lean premix combustion turbines is the same as the MACT floor, *i.e.,* no emission reduction.

Existing Diffusion Flame Combustion Turbines

As explained above, we have established two subcategories of stationary diffusion flame combustion turbines, diffusion flame gas-fired turbines and diffusion flame oil-fired turbines. We believe emissions of each HAP are relatively homogeneous within each of these two subcategories and any variation in HAP emissions cannot be readily controlled except by add-on control. To determine the MACT floor for both subcategories of existing stationary diffusion flame combustion turbines, we consulted the inventory database previously discussed in this preamble. At least 80 percent of those turbines are assumed to be diffusion flame combustion turbines, based on conversations with turbine manufacturers.

We investigated the use of operational modifications such as equipment adjustments and work practice revisions for stationary diffusion flame combustion turbines to determine if HAP reductions associated with such operational modifications might be relevant in deriving the MACT floor. We found no relevant references in the inventory database.

Most stationary diffusion flame combustion turbines will not operate unless preset conditions established by the manufacturer are met. Stationary diffusion flame combustion turbines, by manufacturer design, permit little operator involvement and there are no operating parameters, such as air/fuel ratio, for the operator to adjust. We concluded, therefore, that there are no specific operational modifications which could reduce HAP emissions or which could serve to identify a MACT floor.

Another approach we investigated to identify a MACT floor was to review the requirements in existing State regulations and permits. No State regulations exist for HAP emission limits for stationary combustion turbines. Only one State permit limitation for a single HAP (benzene) was identified. Therefore, we were unable to use State regulations or permits in deriving a MACT floor.

We examined the inventory database for information on HAP emission control technology. There were no turbines controlled with oxidation catalyst systems in the inventory database so we used information supplied by catalyst vendors. There are about 200 oxidation catalyst systems installed in the U.S. The only control technology currently proven to reduce HAP emissions from stationary diffusion flame combustion turbines is an oxidation catalyst emission control device, such as a CO oxidation catalyst. These control devices are used to reduce CO emissions and are currently installed on several stationary combustion turbines.

Less than 3 percent of existing stationary diffusion flame gas-fired turbines in the U.S., based on information in our inventory database and information from catalyst vendors, are equipped with oxidation catalyst emission control devices. Therefore, the average emission limitation for the best performing 12 percent of existing diffusion flame gas-fired turbines is no emission reduction and the MACT floor for each individual HAP for existing turbines in this subcategory is also no emission reduction.

We estimate that less than 1 percent of existing stationary diffusion flame oil-fired turbines have oxidation catalyst systems installed. Thus, the average of the best performing 12 percent of existing diffusion flame oil-fired turbines is no emission reduction for organic HAP. No technologies to control metallic HAP have been installed on the existing turbines in this subcategory. Therefore, the MACT floor for each individual HAP for existing turbines in the diffusion flame oil-fired subcategory is no emission reduction.

To determine MACT for both subcategories of existing diffusion flame combustion turbines, regulatory alternatives more stringent than the MACT floor were evaluated. One beyond-the-floor regulatory option is requiring an oxidation catalyst. However, cost per ton estimates of oxidation catalyst emission control devices for control of total HAP from stationary diffusion flame combustion turbines were deemed excessive. In addition, we did not identify any operational modifications which are not currently in use for these turbines but might result in HAP reductions. Moreover, we did not identify any

technologies to control those metallic HAP which may be emitted during burning of distillate oil which are technologically feasible and cost-effective. For these reasons, MACT for each individual HAP for turbines in both subcategories of existing stationary diffusion flame combustion turbines is the same as the MACT floor, *i.e.*, no emission reduction.

E. How Did We Determine the Basis and Level of the Emission Limitations and Operating Limitations for New Sources?

For new sources, the MACT floor is defined as the emission control that is achieved in practice by the best controlled similar source. To be a similar source, a source should not have any characteristics that differ sufficiently to have a material effect on the feasibility of emission controls, but the source need not be in the same source category or subcategory.

We considered using a surrogate in order to reduce the costs associated with monitoring while at the same time being relatively sure that the pollutants the surrogate is supposed to represent are also controlled. We investigated the use of formaldehyde concentration as a surrogate for all organic HAP emissions. Formaldehyde is the HAP emitted in the highest concentrations from stationary combustion turbines. Formaldehyde, toluene, benzene, and acetaldehyde account for essentially all the mass of HAP emissions from the stationary combustion turbine exhaust, and emissions data show that these pollutants are equally controlled by an oxidation catalyst.

Information from testing conducted on a diffusion flame combustion turbine equipped with an oxidation catalyst control system indicated that the formaldehyde and acetaldehyde emission reduction efficiency achieved was 97 and 94 percent, respectively. Later, after review of an expert task group, the conclusion reached was that both formaldehyde and acetaldehyde were controlled at least 90 percent. In addition, emissions tests conducted on reciprocating internal combustion engines (RICE) at Colorado State University (CSU) in 1998 showed that the benzene emission reduction efficiency across an oxidation catalyst averaged 73 percent, and the toluene emission reduction averaged 77 percent for 16 runs at various engine conditions on a two-stroke lean burn engine. The toluene emission reduction efficiency across the oxidation catalyst averaged 85 percent for ten runs at various engine conditions on a compression ignition RICE. We would expect the emissions reductions efficiencies for benzene and toluene from combustion turbines to be as high or higher than those reported for the CSU RICE tests since combustion turbines catalyst temperatures are generally higher. Finally, catalyst performance information obtained from a catalyst vendor indicated that the percent conversion for an oxidation catalyst system installed on combustion turbines did not vary significantly between formaldehyde, benzene, and toluene. The percent conversion was measured at 77, 72, and 71 for formaldehyde, benzene, and toluene, respectively. Although emissions reductions for large molecules may in theory be less than for formaldehyde, the above information shows that formaldehyde is a good surrogate for the most significant HAP pollutants emitted from combustion turbines as demonstrated by evaluating the reduction efficiency of larger, heavier molecules, hence taking differences in molecular density into account. In addition, emission data show that HAP emission levels and formaldehyde emission levels are related, in the sense that when emissions of one are low, emissions of the other are low and vice versa. This leads us to conclude that emission control technologies which lead to reductions in formaldehyde emissions will lead to reductions in organic HAP emissions. For the reasons provided above, it is appropriate to use formaldehyde as a surrogate for all organic HAP emissions.

New Lean Premix Gas-Fired Turbines

To determine the MACT floor for new stationary lean premix gas-fired turbines, we reviewed the emissions data we had available at proposal and additional test reports received during the comment period. In order to set the MACT floor for new sources in this subcategory, we chose the best performing turbine. Emissions of each HAP are relatively homogeneous within the subcategory of stationary lean premix gas-fired turbines and any variation in HAP emissions cannot be readily controlled except by add-on control. The best performing turbine is equipped with an oxidation catalyst.

The formaldehyde concentration from the best performing turbine was measured at the outlet of the control device using CARB 430. Concerns were raised during the public comment period that CARB 430 formaldehyde results can be biased low as compared to formaldehyde results obtained by FTIR. For a comprehensive discussion of test methods and the development of the correlation between CARB 430 and FTIR formaldehyde levels, please refer to the memorandum entitled ''Review of Test Methods and Data used to Quantify Formaldehyde Concentrations from Combustion Turbines'' in the docket. A bias factor of 1.7 was, therefore, applied to the formaldehyde concentration of the best performing turbine. The best performing turbine was tested twice under the same conditions about 2 years apart where one test measured 19 ppbvd and the other test measured 91 ppbvd formaldehyde (numbers have been bias corrected). We determined that since both of these tests were performed under similar conditions but at different times, this represented the variability of the best performing unit and used the higher value as the MACT floor. The MACT floor for organic HAP for new stationary lean premix gas-fired turbines is, therefore, an emission limit of 91 ppbvd formaldehyde at 15 percent oxygen.

We recognize that our selection of an emission limit of 91 ppbvd formaldehyde is based on quite limited data. We think that each new combustion turbine in this subcategory should be able to achieve compliance with this limit if an oxidation catalyst is properly installed and operated. If actual emission data demonstrate that we are incorrect, and that sources which properly install and operate an oxidation catalyst cannot consistently achieve compliance, we will revise the standard accordingly.

No beyond-the-floor regulatory alternatives were identified for new lean premix gas-fired turbines. We are not aware of any add-on control devices which can reduce organic HAP emissions to levels lower than those resulting from the application of oxidation catalyst systems. We, therefore, determined that MACT for organic HAP emissions from new stationary lean premix gas-fired turbines is the same as the MACT floor, *i.e.*, an emission limit of 91 ppbvd formaldehyde at 15 percent oxygen.

New Lean Premix Oil-Fired Turbines

We do not have any tests for lean premix combustion turbines firing any other fuels besides natural gas. However, we expect that emissions of organic HAP will be controlled by installation of an oxidation catalyst on any units in this subcategory to a degree similar to lean premix gas-fired turbines and diffusion flame oil-fired turbines. We also expect that organic HAP emissions from lean premix oil-fired turbines would be equal to or less than organic HAP emissions from lean premix gas-fired turbines. We have these expectations based on the fact that dual-fuel units using oxidation catalyst systems operate on distillate oil and the

fact that catalyst vendors indicate that oxidation catalyst systems operate equally well on either fuel. Therefore, we used the best performing turbine from the lean premix gas-fired turbine subcategory to set the MACT floor for lean premix oil-fired turbines. As a result, the MACT floor for organic HAP for new stationary lean premix oil-fired turbines is an emission limit of 91 ppbvd formaldehyde at 15 percent oxygen.

We are not aware of any similar sources which are equipped with emission control devices that could also reduce emissions of metallic HAP. We also examined the inventory database in an attempt to identify any operating modifications which might reduce metal emissions, but could not identify any such practices. We also referred to the inventory database to determine if any similar sources are equipped with emission controls for the reduction of particulate matter (PM) which would also reduce metal emissions. No such units were found in the inventory database and none were identified by commenters during the public comment period. For this reason, the MACT floor for new stationary lean premix oil-fired turbines is no emission control for metallic HAP emissions.

We were unable to identify any beyond-the-floor regulatory alternatives for new stationary lean premix oil-fired turbines. We know of no emission control technology currently available which can reduce HAP emissions to levels lower than those achieved through use of an oxidation catalyst. We also have not identified any add-on controls for metallic HAP. We conclude, therefore, that MACT for new lean premix oil-fired turbines would be equivalent to the MACT floor, *i.e.*, an emission limit of 91 ppbvd formaldehyde at 15 percent oxygen organic HAP, and no emission reduction for metallic HAP.

New Diffusion Flame Gas-Fired Turbines

In the proposed rule, we requested sources to submit any HAP emissions test data available from stationary combustion turbines. After the proposal, we also contacted several State agencies to request emissions test data from diffusion flame combustion turbines. Due to the CARB advisory issued on April 28, 2000, which stated that formaldehyde emissions data where the NO_X levels were greater than 50 ppmvd were suspect and should be flagged as non-quantitative, we conducted an analysis of existing diffusion flame emissions test data. Tests where the NO_X emissions were greater than 50 ppm or tests where the NO_X levels were unknown were excluded from our analysis. Most of the diffusion flame tests in the emissions database were unable to pass the screening. Therefore, we specifically requested States to provide test reports for diffusion flame combustion turbines where Method 320 was used, or CARB 430 was used and the NO_X emissions were below 50 ppmvd. During the comment period we received three additional test reports for testing conducted on a total of five stationary diffusion flame combustion turbines.

To identify the MACT floor for new stationary diffusion flame gas-fired turbines, we based our analysis on the performance of the best turbine. Individual HAP emissions are relatively homogeneous within the subcategory of stationary diffusion flame gas-fired turbines and any variation in HAP emissions cannot be readily controlled except by add-on control. The best performing turbine in this subcategory is equipped with an oxidation catalyst.

As previously indicated, formaldehyde is the HAP emitted in the highest concentrations from stationary combustion turbines and data show control of organic HAP emissions and formaldehyde emissions are related. We have, therefore, concluded that formaldehyde is an appropriate surrogate for all organic HAP emissions.

Formaldehyde was measured by CARB 430 at the outlet of the oxidation catalyst. We applied a bias factor of 1.7 to the formaldehyde concentration obtained by CARB 430 for the best performing turbine. The corrected outlet concentration of formaldehyde from the best performing turbine was 15 ppbvd. We only have one controlled test for this turbine, but we expect that similar variability would be associated with this turbine as was associated with the best performing lean premix turbine. Therefore, applying a factor of 5 to the formaldehyde concentration measured at the outlet of the best performing diffusion flame turbine is appropriate to account for variability. Therefore, we would establish a formaldehyde emission limitation of 75 ppbvd based on the outlet of the control device. However, with a similar control system, we would expect that the emission limit should be no lower than the emission limit for lean premix turbines since diffusion flame turbines on average emit more HAP. The MACT floor for new stationary diffusion flame combustion gas-fired turbines is, therefore, an emission limit of 91 ppbvd formaldehyde at 15 percent oxygen.

We were unable to identify any beyond-the-floor regulatory alternatives for new stationary diffusion flame gas-fired turbines. We know of no emission control technology currently available which can reduce organic HAP emissions to levels lower than that achieved through the use of an oxidation catalyst. We concluded, therefore, that MACT for organic HAP emissions from new diffusion flame stationary gas-fired turbines is equivalent to the MACT floor, *i.e.*, an emission limit of 91 ppbvd formaldehyde at 15 percent oxygen.

New Diffusion Flame Oil-Fired Turbines

To determine the MACT floor for new diffusion flame oil-fired turbines, we again based our analysis on the best performing turbine. Emissions of each individual HAP are relatively homogeneous within stationary diffusion flame oil-fired turbines and any variation in HAP emissions cannot be readily controlled except by add-on control. The best performing turbine in this subcategory is equipped with an oxidation catalyst.

As previously described in more detail, we are using formaldehyde as a surrogate for all organic HAP emissions. The formaldehyde was measured with EPA Method 0011 at the outlet of the control device. The EPA Method 0011 is similar to CARB 430 and the problems associated with CARB 430 are expected to be associated with EPA Method 0011. So again we applied a bias factor of 1.7 to the formaldehyde outlet concentration of the best performing diffusion flame oil-fired turbine. The corrected formaldehyde concentration from this turbine is 44 ppbvd. We only had one controlled test for this turbine, but would expect some variability as has been shown with other turbines. However, since formaldehyde emissions from distillate oil fired turbines are lower on average by a factor of 1.4, we do not believe that the MACT emission limit should be set higher than the emission limit for new stationary diffusion flame gas-fired turbines. Therefore, the MACT floor for organic HAP for new stationary diffusion flame oil-fired turbines is an emission limit of 91 ppbvd formaldehyde at 15 percent oxygen.

We examined the inventory database to identify any operating practices which could affect metal emissions. We were unable to identify any such practices. We also determined that no similar sources are equipped with emission control devices for the reduction of PM which could also reduce metal emissions. Therefore, the MACT floor for metallic HAP for new diffusion flame oil-fired turbines is no emission reduction.

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To determine MACT for new stationary diffusion oil-fired turbines, we tried to identify beyond-the-floor options. There are currently no beyond-the-floor regulatory alternatives for this subcategory as we know of no emission control technology current available that can reduce organic HAP emissions to levels lower than that obtained with the use of an oxidation catalyst. We also have not identified any add-on controls for metallic HAP. We conclude, therefore, that MACT for new diffusion flame oil-fired turbines would be equivalent to the MACT floor, *i.e.*, an emission limit of 91 ppbvd formaldehyde at 15 percent oxygen organic HAP, and no emission reduction for metallic HAP.

Other Subcategories

Although the final rule will apply to all stationary combustion turbines located at major sources of HAP emissions, emergency stationary combustion turbines, stationary combustion turbines which burn landfill or digester gas equivalent to 10 percent or more of the gross heat input on an annual basis or where gasified MSW is used to generate 10 percent or more of the gross heat input to the stationary combustion turbine on an annual basis, stationary combustion turbines of less than 1 MW rated peak power output, and stationary combustion turbines located on the North Slope of Alaska are not required to meet the emission limitations or operating limitations.

For each of the other subcategories of stationary combustion turbines, we have concerns about the applicability of emission control technology. For example, emergency stationary combustion turbines operate infrequently. In addition, when called upon to operate they must respond immediately without failure and without lengthy startup periods. This infrequent operation limits the applicability of HAP emission control technology.

Landfill and digester gases contain a family of silicon based gases called siloxanes. Siloxanes are also a component of municipal waste. Combustion of siloxanes forms compounds that can foul post-combustion catalysts, rendering catalysts inoperable within a very short period of time. It is our judgment based on public comments that firing even 10 percent landfill or digester gas will cause fouling that will render the oxidation catalyst inoperable within a short period of time. Pretreatment of exhaust gases to remove siloxanes was investigated. However, no pretreatment systems are in use and their long term effectiveness is unknown. We also considered fuel switching for this subcategory of turbines. Switching to a different fuel such as natural gas or diesel would potentially allow the turbine to apply an oxidation catalyst emission control device. However, fuel switching would defeat the purpose of using this type of fuel which would then either be allowed to escape uncontrolled or would be burned in a flare with no energy recovery. We believe that switching landfill or digester gas or gasified MSW to another fuel is inappropriate and is an environmentally inferior option.

For stationary combustion turbines of less than 1 MW rated peak power output, we have concerns about the effectiveness of scaling down the oxidation catalyst emission control technology. Just as there are often unforeseen problems associated with scaling up a technology, there can be problems associated with scaling down a technology.

Stationary combustion turbines located on the North Slope of Alaska have been identified as a subcategory due to operation limitations and uncertainties regarding the application of controls to these units. There are very few of these units; in addition, none have installed emission controls for the reduction of HAP.

As a result, we identified subcategories for each of these types of stationary combustion turbines and investigated MACT floors and MACT for each subcategory. As expected, since we identified these types of stationary combustion turbines as separate subcategories based on concerns about the applicability of emission control technology, we found no stationary combustion turbines in these subcategories using any emission control technology to reduce HAP emissions. As discussed above, we are not aware of any work practices that might constitute a MACT floor, nor did we find that the use of a particular fuel results in HAP emission reductions. The MACT floor, therefore, for each of these subcategories is no emission reduction.

Despite our concerns with the applicability of emission control technology, we examined the cost per ton of HAP removed for these subcategories. This analysis can be found in the docket (Docket ID No. OAR–2002–0060 (A–95–51)) for the final rule. Whether our concerns are warranted or not, we consider the incremental cost per ton of HAP removed excessive—primarily because of the very small reduction in HAP emissions that would result.

We also considered the non-air health, environmental, and energy impacts of an oxidation catalyst system, as discussed previously in this preamble, and concluded that there would be only a small energy impact and no non-air health or environmental impacts. However, as stated above, we did not adopt this regulatory option due to cost considerations and concerns about the applicability of this technology to these subcategories. We were not able to identify any other means of achieving HAP emission reduction for these subcategories.

As a result, for all of these reasons, we conclude that MACT for these subcategories is the MACT floor (*i.e.*, no emission reduction).

F. How Did We Select the Initial Compliance Requirements?

New and reconstructed sources complying with the emission limitation for formaldehyde emissions are required to conduct an initial performance test. The purpose of the initial test is to demonstrate initial compliance with the formaldehyde emission limitation.

G. How Did We Select the Continuous Compliance Requirements?

If you must comply with the emission limitations, continuous compliance with these requirements is required at all times except during startup, shutdown, and malfunction of your stationary combustion turbine. You are required to develop a startup, shutdown, and malfunction plan.

We considered requiring FTIR CEMS; however, we concluded that the costs of FTIR CEMS were excessive and were not yet demonstrated at the low formaldehyde levels of the standards. We considered requiring those sources to continuously monitor operating load to demonstrate continuous compliance because the data establishing the formaldehyde outlet concentration level are based on tests that were done at high loads. However, we believe that the performance of a stationary combustion turbine at high load is also indicative of its operation at lower loads. In fact, the operator can make no parameter adjustments that would lead to lower emissions.

For these reasons, EPA determined that it would be appropriate to require sources that comply with the emission limitation for formaldehyde emissions and that use an oxidation catalyst emission control device to continuously monitor the oxidation catalyst inlet temperature. Continuously monitoring the oxidation catalyst inlet temperature and maintaining this temperature within the range recommended by the

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catalyst manufacturer will ensure proper operation of the oxidation catalyst emission control device and continuous compliance with the emission limitation for formaldehyde.

Sources that do not use an oxidation catalyst emission control device are required to petition the Administrator for approval of operating limitations or approval of no operating limitations.

H. How Did We Select the Testing Methods To Measure These Low Concentrations of Formaldehyde?

The final rule requires the use of Method 320 or ASTM D6348–03 to determine compliance with the emission limitation for formaldehyde. With regard to formaldehyde, we believe systems meeting the requirements of Method 320, a self-validating FTIR method, can be used to attain detection limits for formaldehyde concentrations well below the current emission limitations with a path length of 10 meters or less. Some of the older technology may require 100 or even 200 meter path lengths. We expect state-of-the-art digital signal processing (to reduce signal to noise ratio) would be needed. Method 320 also includes formaldehyde spike recovery criteria, which require spike recoveries of 70 to 130 percent.

While we believe FTIR systems can meet the requirements of Method 320 and measure formaldehyde concentrations at these low levels, we have limited experience with their use. As a result, we solicited comments on the ability and use of FTIR systems to meet the validation and quality assurance requirements of Method 320 for the purpose of determining compliance with the emission limitation for formaldehyde. Commenters were generally in agreement that Method 320 is the most accurate and reliable test method currently available to test for formaldehyde emissions from the stationary combustion turbine exhaust.

We are also allowing the use of ASTM D6348–03 in the final rule to determine compliance with the emission limitation for formaldehyde. As mentioned in the preamble to the proposed rule, the method was reviewed by the EPA as a potential alternative to Method 320. Suggested revisions to ASTM D6348–98 were sent to ASTM by the EPA that would allow the EPA to accept ASTM D6348–98 as an acceptable alternative. The ASTM has revised the method following EPA's suggested revisions. The EPA has determined that the revised method, ASTM D6348–03, ''Standard Test Method for Determination of Gaseous Compounds by Extractive Direct Interface Fourier Transform Infrared (FTIR) Spectroscopy,'' is an acceptable alternative to Method 320 for formaldehyde measurement.

As an alternative to Method 320, we proposed Method 323 for natural gas-fired sources. Method 323 uses the acetyl acetone colorimetric method to measure formaldehyde emissions in the exhaust of natural gas-fired, stationary combustion sources. Commenters did not support Method 323 and were concerned whether this method could provide reliable results. In addition, Method 323 has not been validated or demonstrated for use on stationary combustion turbines emitting low formaldehyde emissions. Therefore, Method 323 has not been included as a compliance method for formaldehyde in the final rule.

At proposal we believed CARB Method 430 and EPA SW–846 Method 0011 were capable of measuring formaldehyde concentrations at these low levels. Commenters were not supportive of these methods. In addition, CARB 430 is susceptible to interferences and sample loss contributes to large measurement variability. Method 0011 uses a similar analytical approach to CARB 430 and has many shortcomings and limited application opportunities. Accordingly, we are not including CARB 430 and Method 0011 in the final rule.

For these reasons, EPA has specified that Method 320 or ASTM D6348–03 should be used to determine compliance with the formaldehyde emission limitation in the final rule.

I. How Did We Select the Notification, Recordkeeping and Reporting Requirements?

The notification, recordkeeping, and reporting requirements are based on the NESHAP General Provisions of 40 CFR part 63.

V. Summary of Environmental, Energy and Economic Impacts

We estimate that 20 percent of the stationary combustion turbines affected by the final rule will be located at major sources. As a result, the environmental, energy, and economic impacts presented in this preamble reflect these estimates.

The outcome of the petition to delist certain subcategories which has been submitted to EPA could significantly affect the estimated impacts of the final rule. If approved, the delisting could significantly decrease the number of sources affected by the final rule and could affect the final emission estimates. Thus, the estimated impacts could change.

A. What Are the Air Quality Impacts?

The final rule will reduce total national HAP emissions by an estimated 98 tpy in the 5th year after the standards are promulgated. The emission reduction achieved by the final rule would be due to the sources that install an oxidation catalyst control system. We estimate that all new stationary combustion turbines will install oxidation catalyst control to comply with the standards.

To estimate air impacts, national HAP emissions in the absence of the final rule (*i.e.*, HAP emission baseline) were calculated. We then assumed a HAP reduction of 90 percent, achieved by using oxidation catalyst emission control devices to comply with the formaldehyde emission limitation, and applied this reduction to the baseline HAP emissions to estimate total national HAP emission reduction. The total national HAP emission reduction is the sum of formaldehyde, acetaldehyde, benzene, and toluene emissions reductions. In addition to HAP emission reduction, the final rule will reduce criteria air pollutant emissions, primarily CO emissions.

B. What Are the Cost Impacts?

The national total annualized cost of the final rule in the 5th year following promulgation is estimated to be about $43 million. Approximately $147,400 of that amount is the estimated annualized cost for monitoring, recordkeeping, and reporting. To calculate the annualized control costs, we obtained estimates of the capital costs of oxidation catalyst emission control devices from vendors. We then calculated the national total annualized costs of control for the new stationary combustion turbines installing oxidation catalyst emission control in the next 5 years. Our projection of new stationary combustion turbine capacity that will come online during the next 5 years is based on estimates from the Department of Energy indicating that 218 new stationary combustion turbines will begin operation between 2002 and 2007.

C. What Are the Economic Impacts?

The EPA prepared an economic impact analysis to evaluate the impacts the final rule would have on combustion turbines producers, consumers of goods and services produced by combustion turbines, and society. The analysis shows minimal changes in prices and output for products made by the 24 industries affected by the final rule. The price increase for affected output is less than 0.02 percent and the reduction in output

is less than 0.02 percent for each affected industry. Estimates of impacts on fuel markets show price increases of less than 0.06 percent for petroleum products and natural gas, and price increases of 0.53 and 0.72 percent for base-load and peak-load electricity, respectively. The price of coal is expected to decline by about 0.24 percent, and this is due to a small reduction in demand for this fuel type. Reductions in output are expected to be less than 0.67 percent for each energy type, including base-load and peak-load electricity. The social costs of the final rule are estimated at $7.8 million (1998 dollars). Social costs include the compliance costs, but also include those costs that reflect changes in the national economy due to changes in consumer and producer behavior in response to the compliance costs associated with a regulation. In this case, changes in energy use among both consumers and producers to reduce the impact of the regulatory requirements of the final rule lead to the estimated social costs being somewhat less than the total annualized compliance cost estimate of $43 million (1998$). The primary reason for the lower social cost estimate is the increase in electricity supply generated by existing unaffected sources, which mostly offsets the impact of increased electricity prices to consumers.

For more information on these impacts, please refer to the economic impact analysis in the public docket.

D. What Are the Non-Air Health, Environmental and Energy Impacts?

The only energy requirement is a small increase in fuel consumption resulting from back pressure caused by operating an oxidation catalyst emission control device. This energy impact is small in comparison to the costs of other impacts. There are no known non-air environmental or health impacts as a result of the implementation of the final rule.

VI. Statutory and Executive Order Reviews

A. Executive Order 12866: Regulatory Planning and Review

Under Executive Order 12866 (58 FR 51735, October 4, 1993), we must determine whether a regulatory action is ''significant'' and, therefore, subject to review by the Office of Management and Budget (OMB) and the requirements of the Executive Order. The Executive Order defines ''significant regulatory action'' as one that is likely to result in a rule that may:

(1) Have an annual effect on the economy of $100 million or more or adversely affect in a material way the economy, a sector of the economy, productivity, competition, jobs, the environment, public health or safety, or State, local, or tribal governments or communities;

(2) Create a serious inconsistency or otherwise interfere with an action taken or planned by another agency;

(3) Materially alter the budgetary impact of entitlements, grants, user fees, or loan programs, or the rights and obligation of recipients thereof; or

(4) Raise novel legal or policy issues arising out of legal mandates, the President's priorities, or the principles set forth in the Executive Order.

Pursuant to the terms of Executive Order 12866, we have determined that the final rule is a ''significant regulatory action'' within the meaning of the Executive Order. As such, this action was submitted to OMB for review. Changes made in response to OMB suggestions or recommendations are included in the docket.

B. Paperwork Reduction Act

The information collection requirements in the final rule have been submitted for approval to the Office of Management and Budget under the Paperwork Reduction Act, 44 U.S.C. 3501 *et seq.* The information requirements are not enforceable until OMB approves them.

The information requirements are based on notification, recordkeeping, and reporting requirements in the NESHAP General Provisions (40 CFR part 63, subpart A), which are mandatory for all operators subject to national emission standards. These recordkeeping and reporting requirements are specifically authorized by section 114 of the CAA (42 U.S.C. 7414). All information submitted to EPA pursuant to the recordkeeping and reporting requirements for which a claim of confidentiality is made is safeguarded according to Agency policies set forth in 40 CFR part 2, subpart B.

The final rule will require maintenance inspections of the control devices but will not require any notifications or reports beyond those required by the General Provisions. The recordkeeping requirements require only the specific information needed to determine compliance.

The annual monitoring, reporting, and recordkeeping burden for this collection (averaged over the first 3 years after the effective date of the final rule) is estimated to be 2,448 labor hours per year at a total annual cost of $333,450. This estimate includes a one-time performance test, semiannual excess emission reports, maintenance inspections, notifications, and recordkeeping. Total capital/startup costs associated with the monitoring requirements over the 3-year period of the ICR are estimated at $22,500, with no operation and maintenance costs.

Burden means the total time, effort, or financial resources expended by persons to generate, maintain, retain, or disclose or provide information to or for a Federal agency. This includes the time needed to review instructions; develop, acquire, install, and utilize technology and systems for the purposes of collecting, validating, and verifying information, processing and maintaining information, and disclosing and providing information; adjust the existing ways to comply with any previously applicable instructions and requirements; train personnel to be able to respond to a collection of information; search data sources; complete and review the collection of information; and transmit or otherwise disclose the information.

An Agency may not conduct or sponsor, and a person is not required to respond to, a collection of information unless it displays a currently valid OMB control number. The OMB control numbers for EPA's regulations in 40 CFR are listed in 40 CFR part 9. When this ICR is approved by OMB, the Agency will publish a technical amendment to 40 CFR part 9 in the **Federal Register** to display the OMB control number for the approved information collection requirements contained in this final rule.

C. Regulatory Flexibility Act

The EPA has determined that it is not necessary to prepare a regulatory flexibility analysis in connection with the final rule. The EPA has also determined that the final rule will not have a significant economic impact on a substantial number of small entities.

For purposes of assessing the impacts of today's rule on small entities, small entity is defined as: (1) A small business whose parent company has fewer than 100 or 1,000 employees, or fewer than 4 billion kW-hr per year of electricity usage, depending on size definition for the affected North American Industry Classification System (NAICS) code; (2) a small governmental jurisdiction that is a government of a city, county, town, school district or special district with a population of less than 50,000; and (3) a small organization that is any not-for-profit enterprise which is independently owned and operated and is not dominant in its field. It should be noted that small entities in 6 NAICS codes are affected by the final rule, and the small

business definition applied to each industry by NAICS code is that listed in the Small Business Administration (SBA) size standards (13 CFR 121).

After considering the economic impacts of today's final rule on small entities, EPA has concluded that this action will not have a significant economic impact on a substantial number of small entities. We have determined, based on the existing combustion turbines inventory, that 29 small entities out of 300 in the industries impacted by the final rule may be affected. None of these small entities will incur control costs associated with the final rule, but will incur monitoring, recordkeeping, and reporting costs and the costs of performance testing. These 29 small entities own 51 affected turbines in the existing combustion turbines inventory, which represents 2.5 percent of the existing turbines overall. Of these entities, 22 of these entities are small communities and 7 are affected small firms. None of the 29 affected small entities are estimated to have compliance costs that exceed one-half of 1 percent of their revenues. The median compliance costs to affected small entities is 0.07 percent of sales. In addition, the final rule is likely to also increase profits at the many small firms and increase revenues for the many small communities using combustion turbines that are not affected by the final rule as a result of the very slight increase in market prices.

It should be noted that it is likely that the ongoing deregulation of the electric power industry across the nation should minimize the rule's impacts on small entities. Increased competition in the electric power industry is forecasted to decrease the market price for wholesale electric power. It is likely that open access to the grid and lower market prices for electricity will make it less attractive for local communities to purchase and operate new combustion turbines. For more information on the results of the analysis of small entity impacts, please refer to the economic impact analysis in the docket.

Although the final rule will not have a significant economic impact on a substantial number of small entities, EPA nonetheless has tried to reduce the impact of the final rule on small entities. In the final rule, the Agency is applying the minimum level of control and the minimum level of monitoring, recordkeeping, and reporting to affected sources allowed by the Clean Air Act. Existing stationary combustion turbines have no emission requirements. In addition, as mentioned earlier in the preamble, new turbines with capacities under 1.0 MW are not subject to the final rule. This provision should reduce the level of small entity impacts.

D. Unfunded Mandates Reform Act of 1995

Title II of the Unfunded Mandates Reform Act of 1995 (UMRA), Public Law 104–4, establishes requirements for Federal agencies to assess the effects of their regulatory actions on State, local, and tribal governments and the private sector. Under section 202 of the UMRA, we generally must prepare a written statement, including a cost-benefit analysis, for proposed and final rules with ''Federal mandates'' that may result in expenditures to State, local, and tribal governments, in the aggregate, or to the private sector, of $100 million or more in any 1 year. Before promulgating a rule for which a written statement is needed, section 205 of the UMRA generally requires us to identify and consider a reasonable number of regulatory alternatives and adopt the least costly, most cost-effective or least burdensome alternative that achieves the objectives of the rule. The provisions of section 205 do not apply when they are inconsistent with applicable law. Moreover, section 205 allows us to adopt an alternative other than the least costly, most cost-effective or least burdensome alternative if the Administrator publishes with the final rule an explanation why that alternative was not adopted. Before we establish any regulatory requirements that may significantly or uniquely affect small governments, including tribal governments, we must develop a small government agency plan under section 203 of the UMRA. The plan must provide for notifying potentially affected small governments, enabling officials of affected small governments to have meaningful and timely input in the development of regulatory proposals with significant Federal intergovernmental mandates, and informing, educating, and advising small governments on compliance with the regulatory requirements.

The EPA has determined that the final rule contains a Federal mandate that will not result in expenditures of $100 million or more for State, local, and tribal governments, in the aggregate, or the private sector in any 1 year. The highest cost in any 1 year is less than $43 million. Thus, today's rule is not subject to the requirements of sections 202 and 205 of the UMRA.

Although not required by the UMRA, we have consulted with State and local air pollution control officials. We also have held meetings on the rule with many of the stakeholders from numerous individual companies, environmental groups, consultants and vendors, labor unions, and other interested parties. We have added materials to the Air docket to document those meetings.

In addition, we have determined that the final rule contains no regulatory requirements that might significantly or uniquely affect small governments. Therefore, today's rule is not subject to the requirements of section 203 of the UMRA.

E. Executive Order 13132: Federalism

Executive Order 13132 (64 FR 43255, August 10, 1999) requires us to develop an accountable process to ensure ''meaningful and timely input by State and local officials in the development of regulatory policies that have federalism implications.'' ''Policies that have federalism implications'' are defined in the Executive Order to include regulations that have ''substantial direct effects on the States, on the relationship between the national government and the States, or on the distribution of power and responsibilities among the various levels of government.''

The final rule does not have federalism implications. It will not have substantial direct effects on the States, on the relationship between the national government and the States, or on the distribution of power and responsibilities among the various levels of government, as specified in Executive Order 13132. The final rule primarily affects private industry, and does not impose significant economic costs on State or local governments. Thus, Executive Order 13132 does not apply to the final rule.

Although not required by Executive Order 13132, we consulted with representatives of State and local governments to enable them to provide meaningful and timely input into the development of the final rule. This consultation took place during the ICCR committee meetings where members representing State and local governments participated in developing recommendations for EPA's combustion-related rules, including the final rule. The concerns raised by representatives of State and local governments were considered during the development of the final rule.

F. Executive Order 13175: Consultation and Coordination With Indian Tribal Governments

Executive Order 13175 (65 FR 67249, November 6, 2000) requires EPA to develop an accountable process to ensure ''meaningful and timely input by tribal officials in the development of

regulatory policies that have tribal implications.'' ''Policies that have tribal implications'' is defined in the Executive Order to include regulations that have ''substantial direct effects on one or more Indian tribes, on the relationship between the Federal government and the Indian tribes, or on the distribution of power and responsibilities between the Federal government and Indian tribes.''

The final rule does not have tribal implications. It will not have substantial direct effects on tribal governments, on the relationship between the Federal government and Indian tribes, or on the distribution of power and responsibilities between the Federal government and Indian tribes, as specified in Executive Order 13175. Thus, Executive Order 13175 does not apply to the final rule.

G. Executive Order 13045: Protection of Children From Environmental Health Risks and Safety Risks

Executive Order 13045 (62 FR 19885, April 23, 1997) applies to any rule that: (1) Is determined to be ''economically significant'' as defined under Executive Order 12866, and (2) concerns an environmental health or safety risk that we have reason to believe may have a disproportionate effect on children. If the regulatory action meets both criteria, we must evaluate the environmental health or safety effects of the planned rule on children, and explain why the planned regulation is preferable to other potentially effective and reasonably feasible alternatives.

We interpret Executive Order 13045 as applying only to those regulatory actions that are based on health or safety risks, such that the analysis required under section 5–501 of the Executive Order has the potential to influence the regulation. The final rule is not subject to Executive Order 13045 because it is based on technology performance and not on health or safety risks.

H. Executive Order 13211: Actions Concerning Regulations That Significantly Affect Energy Supply, Distribution, or Use

This rule is not a ''significant energy action'' as defined in Executive Order 13211, ''Actions Concerning Regulations That Significantly Affect Energy Supply, Distribution, or Use'' (66 Fed. Reg. 28355 (May 22, 2001)) because it is not likely to have a significant adverse effect on the supply, distribution, or use of energy. The basis for this determination is provided below.

The increase in petroleum product output, which includes increases in fuel production, is estimated at 0.013 percent, or about 2,003 barrels per day based on 2000 U.S. fuel production nationwide. The reduction in coal production is estimated at 0.00007 percent, or about 7,936 short tons per year based on 2000 U.S. coal production nationwide. The reduction in electricity output is estimated at 0.083 percent, or about 20.4 billion kilowatt-hours per year based on 2000 U.S. electricity production nationwide. Production of natural gas is expected to increase by 11.7 million cubic feet (ft^3) per day. The maximum of all energy price increases, which include increases in natural gas prices as well as those for petroleum products, coal, and electricity, is estimated to be the 0.71 percent increase in peak-load electricity rates nationwide. Energy distribution costs may increase by roughly no more than the same amount as electricity rates. We expect that there will be no discernable impact on the import of foreign energy supplies, and no other adverse outcomes are expected to occur with regards to energy supplies. Also, the increase in cost of energy production should be minimal given the very small increase in fuel consumption resulting from back pressure related to operation of oxidation catalyst emission control devices. All of the estimates presented above account for some passthrough of costs to consumers as well as the direct cost impact to producers. For more information on these estimated energy effects, please refer to the economic impact analysis for the final rule. This analysis is available in the public docket.

No new combustion turbines with a capacity of less than 1.0 MW will be affected. Also, the control level applied to affected new combustion turbines is the minimum that can be applied consistent with the provisions of the Clean Air Act.

Therefore, we conclude that the final rule when implemented will not have a significant adverse effect on the supply, distribution, or use of energy.

I. National Technology Transfer and Advancement Act

As noted in the proposed rule, section 12(d) of the National Technology Transfer and Advancement Act (NTTAA) of 1995 (Public Law No. 104–113; 15 U.S.C. 272 note) directs the EPA to use voluntary consensus standards in their regulatory and procurement activities unless to do so would be inconsistent with applicable law or otherwise impractical. Voluntary consensus standards are technical standards (*e.g.*, materials specifications, test methods, sampling procedures, business practices) developed or adopted by one or more voluntary consensus bodies. The NTTAA directs EPA to provide Congress, through annual reports to the Office of Management and Budget (OMB), with explanations when an agency does not use available and applicable voluntary consensus standards.

The final rule involves technical standards. The EPA cites the following standards in the final rule: EPA Methods 1, 1A, 3A, 3B, 4, and 320. Consistent with the NTTAA, EPA conducted searches to identify voluntary consensus standards in addition to these EPA methods. No applicable voluntary consensus standards were identified for EPA Method 1A. The search and review results have been documented and are placed in the docket (Docket ID No. OAR–2002–0060 (A–95–51)) for the final rule.

The search for emissions measurement procedures identified six voluntary consensus standards. The EPA determined that five of these six standards identified for measuring emissions of the HAP or surrogates subject to emission standards in the final rule were impractical alternatives to EPA test methods for the purposes of the rule. Therefore, EPA does not intend to adopt these standards for this purpose. (See Docket ID No. OAR–2002–0060 (A–95–51) for further information on the methods.)

The voluntary consensus standard ASTM D6348–03, ''Standard Test Method for Determination of Gaseous Compounds by Extractive Direct Interface Fourier Transform Infrared (FTIR) Spectroscopy,'' is an acceptable alternative to EPA Method 320 for formaldehyde measurement provided that, 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.

Section 63.6120 and Table 3 to subpart YYYY of the final rule list the EPA testing methods included in the regulation. Under §§ 63.7(f) and 63.8(f) of subpart A of the General Provisions, a source may apply to EPA for permission to use alternative test methods or alternative monitoring requirements in place of any of the EPA testing methods, performance specifications, or procedures.

J. Congressional Review Act

The Congressional Review Act, 5 U.S.C. section 801 *et seq.*, as added by the Small Business Regulatory Enforcement Fairness Act of 1996, generally provides that before a rule may take effect, the agency promulgating the rule must submit a

rule report, which includes a copy of the rule, to each House of the Congress and to the Comptroller General of the United States. The EPA will submit a report containing today's final rule and other required information to the U.S. Senate, the U.S. House of Representatives, and the comptroller General of the United States prior to publication of the rule in the **Federal Register**. This action is not a ''major rule'' as defined by 5 U.S.C. 804(2). The final rule will be effective on March 5, 2004.

List of Subjects in 40 CFR Part 63

Environmental protection, Administrative practice and procedure, Air pollution control, Hazardous substances, Intergovernmental relations, Reporting and recordkeeping requirements.

Dated: August 29, 2003.

Marianne Lamont Horinko,

Acting Administrator.

■ For the reasons set out in the preamble, title 40, chapter I, part 63 of the Code of the Federal Regulations is amended as follows:

PART 63—[AMENDED]

■ 1. The authority citation for part 63 continues to read as follows:

Authority: 42 U.S.C. 7401, *et seq.*

■ 2. Part 63 is amended by adding subpart YYYY to read as follows:

Subpart YYYY—National Emission Standards for Hazardous Air Pollutants for Stationary Combustion Turbines

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What This Subpart Covers

§ 63.6080 What is the purpose of subpart YYYY?

Subpart YYYY establishes national emission limitations and operating limitations for hazardous air pollutants (HAP) emissions from stationary combustion turbines located at major sources of HAP emissions, and requirements to demonstrate initial and continuous compliance with the emission and operating limitations.

§ 63.6085 Am I subject to this subpart?

You are subject to this subpart if you own or operate a stationary combustion turbine located at a major source of HAP emissions.

(a) Stationary combustion turbine means all equipment, including but not limited to the turbine, the fuel, air, lubrication and exhaust gas systems, control systems (except emissions control equipment), and any ancillary components and sub-components comprising any simple cycle stationary combustion turbine, any regenerative/recuperative cycle stationary combustion turbine, the combustion turbine portion of any stationary cogeneration cycle combustion system, or the combustion turbine portion of any stationary combined cycle steam/electric generating system. Stationary means that the combustion turbine is not self propelled or intended to be propelled while performing its function, although it may be mounted on a vehicle for portability or transportability. Stationary combustion turbines covered by this subpart include simple cycle stationary combustion turbines, regenerative/recuperative cycle stationary combustion turbines, cogeneration cycle stationary combustion turbines, and combined cycle stationary combustion turbines. Stationary combustion turbines subject to this subpart do not include turbines located at a research or laboratory facility, if research is conducted on the turbine itself and the turbine is not being used to power other applications at the research or laboratory facility.

(b) A major source of HAP emissions is a contiguous site under common control 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.

§ 63.6090 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 combustion turbine located at a major source of HAP emissions.

(1) *Existing stationary combustion turbine.* A stationary combustion turbine is existing if you commenced construction or reconstruction of the stationary combustion turbine on or before January 14, 2003. A change in ownership of an existing stationary combustion turbine does not make that stationary combustion turbine a new or reconstructed stationary combustion turbine.

(2) *New stationary combustion turbine.* A stationary combustion turbine is new if you commenced construction of the stationary

combustion turbine after January 14, 2003.

(3) *Reconstructed stationary combustion turbine.* A stationary combustion turbine is reconstructed if you meet the definition of reconstruction in § 63.2 of subpart A of this part and reconstruction is commenced after January 14, 2003.

(b) *Subcategories with limited requirements.*

(1) A new or reconstructed stationary combustion turbine located at a major source which meets either of the following criteria does not have to meet the requirements of this subpart and of subpart A of this part except for the initial notification requirements of § 63.6145(d):

(i) The stationary combustion turbine is an emergency stationary combustion turbine; or

(ii) The stationary combustion turbine is located on the North Slope of Alaska.

(2) A stationary combustion turbine which burns landfill gas or digester gas equivalent to 10 percent or more of the gross heat input on an annual basis, or a stationary combustion turbine where gasified municipal solid waste (MSW) is used to generate 10 percent or more of the gross heat input on an annual basis does not have to meet the requirements of this subpart except for:

(i) The initial notification requirements of § 63.6145(d); and

(ii) Additional monitoring and reporting requirements as provided in § 63.6125(c) and § 63.6150.

(3) An existing, new, or reconstructed stationary combustion turbine with a rated peak power output of less than 1.0 megawatt (MW) at International Organization for Standardization (ISO) standard day conditions, which is located at a major source, does not have to meet the requirements of this subpart and of subpart A of this part. This determination applies to the capacities of individual combustion turbines, whether or not an aggregated group of combustion turbines has a common add-on air pollution control device. No initial notification is necessary, even if the unit appears to be subject to other requirements for initial notification. For example, a 0.75 MW emergency turbine would not have to submit an initial notification.

(4) Existing stationary combustion turbines in all subcategories do not have to meet the requirements of this subpart and of subpart A of this part. No initial notification is necessary for any existing stationary combustion turbine, even if a new or reconstructed turbine in the same category would require an initial notification.

(5) Combustion turbine engine test cells/stands do not have to meet the requirements of this subpart but may have to meet the requirements of subpart A of this part if subject to another subpart. No initial notification is necessary, even if the unit appears to be subject to other requirements for initial notification.

§ 63.6092 Are duct burners and waste heat recovery units covered by subpart YYYY?

No, duct burners and waste heat recovery units are considered steam generating units and are not covered under this subpart. In some cases, it may be difficult to separately monitor emissions from the turbine and duct burner, so sources are allowed to meet the required emission limitations with their duct burners in operation.

§ 63.6095 When do I have to comply with this subpart?

(a) *Affected sources.* (1) If you start up a new or reconstructed stationary combustion turbine which is a lean premix gas-fired stationary combustion turbine, a lean premix oil-fired stationary combustion turbine, a diffusion flame gas-fired stationary combustion turbine, or a diffusion flame oil-fired stationary combustion turbine as defined by this subpart on or before March 5, 2004, you must comply with the emission limitations and operating limitations in this subpart no later than March 5, 2004.

(2) If you start up a new or reconstructed stationary combustion turbine which is a lean premix gas-fired stationary combustion turbine, a lean premix oil-fired stationary combustion turbine, a diffusion flame gas-fired stationary combustion turbine, or a diffusion flame oil-fired stationary combustion turbine as defined by this subpart after March 5, 2004, you must comply with the emission limitations and operating limitations in this subpart upon startup of your affected source.

(b) *Area sources that become major sources.* If your new or reconstructed stationary combustion turbine is an area source that increases its emissions or its potential to emit such that it becomes a major source of HAP, it must be in compliance with any applicable requirements of this subpart when it becomes a major source.

(c) You must meet the notification requirements in § 63.6145 according to the schedule in § 63.6145 and in 40 CFR part 63, subpart A.

Emission and Operating Limitations

§ 63.6100 What emission and operating limitations must I meet?

For each new or reconstructed stationary combustion turbine which is a lean premix gas-fired stationary combustion turbine, a lean premix oil-fired stationary combustion turbine, a diffusion flame gas-fired stationary combustion turbine, or a diffusion flame oil-fired stationary combustion turbine as defined by this subpart, you must comply with the emission limitations and operating limitations in Table 1 and Table 2 of this subpart.

General Compliance Requirements

§ 63.6105 What are my general requirements for complying with this subpart?

(a) You must be in compliance with the emission limitations and operating limitations which apply to you at all times except during startup, shutdown, and malfunctions.

(b) If you must comply with emission and operating limitations, you must operate and maintain your stationary combustion turbine, oxidation catalyst emission control device or other air pollution control equipment, and monitoring equipment in a manner consistent with good air pollution control practices for minimizing emissions at all times including during startup, shutdown, and malfunction.

Testing and Initial Compliance Requirements

§ 63.6110 By what date must I conduct the initial performance tests or other initial compliance demonstrations?

(a) You must conduct the initial performance tests or other initial compliance demonstrations in Table 4 of this subpart that apply to you within 180 calendar days after the compliance date that is specified for your stationary combustion turbine in § 63.6095 and according to the provisions in § 63.7(a)(2).

(b) An owner or operator is not required to conduct an initial performance test to determine outlet formaldehyde concentration on units for which a performance test has been previously conducted, but the test must meet all of the conditions described in paragraphs (b)(1) through (b)(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.

§ 63.6115 When must I conduct subsequent performance tests?

Subsequent performance tests must be performed on an annual basis as specified in Table 3 of this subpart.

§ 63.6120 What performance tests and other procedures must I use?

(a) You must conduct each performance test in Table 3 of this subpart that applies to you.

(b) Each performance test must be conducted according to the requirements of the General Provisions at § 63.7(e)(1) and under the specific conditions in Table 2 of this subpart.

(c) Do not conduct performance tests or compliance evaluations during periods of startup, shutdown, or malfunction. Performance tests must be conducted at high load, defined as 100 percent plus or minus 10 percent.

(d) You must conduct three separate test runs for each performance test, and each test run must last at least 1 hour.

(e) If your stationary combustion turbine is not equipped with an oxidation catalyst, you must petition the Administrator for operating limitations that you will monitor to demonstrate compliance with the formaldehyde emission limitation in Table 1. You must measure these operating parameters during the initial performance test and continuously monitor thereafter. Alternatively, you may petition the Administrator for approval of no additional operating limitations. If you submit a petition under this section, you must not conduct the initial performance test until after the petition has been approved or disapproved by the Administrator.

(f) If your stationary combustion turbine is not equipped with an oxidation catalyst and you petition the Administrator for approval of additional operating limitations to demonstrate compliance with the formaldehyde emission limitation in Table 1, your petition must include the following information described in paragraphs (f)(1) through (5) of this section.

(1) Identification of the specific parameters you propose to use as additional 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.

(g) If you petition the Administrator for approval of no additional operating limitations, your petition must include the information described in paragraphs (g)(1) through (7) of this section.

(1) Identification of the parameters associated with operation of the stationary combustion turbine 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 why establishing limitations on the parameters is not possible;

(4) For the parameters which could change in such a way as to increase HAP emissions, a discussion of why you could not establish upper and/or lower values for the parameters which would establish limits on the parameters as operating limitations;

(5) For the parameters which could change in such a way as to increase HAP emissions, 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, unreasonable or unnecessary to adopt the parameters as operating limitations.

§ 63.6125 What are my monitor installation, operation, and maintenance requirements?

(a) If you are operating a stationary combustion turbine that is required to comply with the formaldehyde emission limitation and you use an oxidation catalyst emission control device, you must monitor on a continuous basis your catalyst inlet temperature in order to comply with the operating limitations in Table 2 and as specified in Table 5 of this subpart.

(b) If you are operating a stationary combustion turbine that is required to comply with the formaldehyde emission limitation and you are not using an oxidation catalyst, you must continuously monitor any parameters specified in your approved petition to the Administrator, in order to comply with the operating limitations in Table 2 and as specified in Table 5 of this subpart.

(c) If you are operating a stationary combustion turbine which fires landfill gas or digester gas equivalent to 10 percent or more of the gross heat input on an annual basis, or a stationary combustion turbine where gasified MSW is used to generate 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 turbine in a manner which minimizes HAP emissions.

(d) If you are operating a lean premix gas-fired stationary combustion turbine or a diffusion flame gas-fired stationary combustion turbine as defined by this subpart, and you use any quantity of distillate oil to fire any new or existing stationary combustion turbine which is located at the same major source, you must monitor and record your distillate oil usage daily for all new and existing stationary combustion turbines located at the major source with a non-resettable hour meter to measure the number of hours that distillate oil is fired.

§ 63.6130 How do I demonstrate initial compliance with the emission and operating limitations?

(a) You must demonstrate initial compliance with each emission and operating limitation that applies to you according to Table 4 of this subpart.

(b) You must submit the Notification of Compliance Status containing results of the initial compliance demonstration according to the requirements in § 63.6145(f).

Continuous Compliance Requirements

§ 63.6135 How do I monitor and collect data to demonstrate continuous compliance?

(a) Except for monitor malfunctions, associated repairs, and required quality assurance or quality control activities (including, as applicable, calibration checks and required zero and span adjustments of the monitoring system), you must conduct all parametric monitoring at all times the stationary combustion turbine is operating.

(b) Do not use data recorded during monitor malfunctions, associated repairs, and required quality assurance or quality control activities for meeting the requirements of this subpart, including data averages and calculations. You must use all the data collected during all other periods in assessing the performance of the control device or in assessing emissions from the new or reconstructed stationary combustion turbine.

§ 63.6140 How do I demonstrate continuous compliance with the emission and operating limitations?

(a) You must demonstrate continuous compliance with each emission limitation and operating limitation in Table 1 and Table 2 of this subpart according to methods specified in Table 5 of this subpart.

(b) You must report each instance in which you did not meet each emission imitation or operating limitation. You must also report each instance in which you did not meet the requirements in Table 7 of 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 § 63.6150.

(c) Consistent with §§ 63.6(e) and 63.7(e)(1), deviations that occur during a period of startup, shutdown, and malfunction are not violations if you have operated your stationary combustion turbine in full conformity with all provisions of your startup, shutdown, and malfunction plan, and you have otherwise satisfied the general duty to minimize emissions established by § 63.6(e)(1)(i).

Notifications, Reports, and Records

§ 63.6145 What notifications must I submit and when?

(a) You must submit all of the notifications in §§ 63.7(b) and (c), 63.8(e), 63.8(f)(4), and 63.9(b) and (h) that apply to you by the dates specified.

(b) As specified in § 63.9(b)(2), if you start up your new or reconstructed stationary combustion turbine before March 5, 2004, you must submit an Initial Notification not later than 120 calendar days after March 5, 2004.

(c) As specified in § 63.9(b), if you start up your new or reconstructed stationary combustion turbine on or after March 5, 2004, you must submit an Initial Notification not later than 120 calendar days after you become subject to this subpart.

(d) If you are required to submit an Initial Notification but are otherwise not affected by the emission limitation requirements of this subpart, in accordance with § 63.6090(b), your notification must include the information in § 63.9(b)(2)(i) through (v) and a statement that your new or reconstructed stationary combustion turbine has no additional emission limitation requirements and must explain the basis of the exclusion (for example, that it operates exclusively as an emergency stationary combustion turbine).

(e) If you are required to conduct an initial performance test, you must submit a notification of intent to conduct an initial performance test at least 60 calendar days before the initial performance test is scheduled to begin as required in § 63.7(b)(1).

(f) If you are required to comply with the emission limitation for formaldehyde, you must submit a Notification of Compliance Status according to § 63.9(h)(2)(ii). For each performance test required to demonstrate compliance with the emission limitation for formaldehyde, you must submit the Notification of Compliance Status, including the performance test results, before the close of business on the 60th calendar day following the completion of the performance test.

§ 63.6150 What reports must I submit and when?

(a) Anyone who owns or operates a stationary combustion turbine which must meet the emission limitation for formaldehyde must submit a semiannual compliance report according to Table 6 of this subpart. The semiannual compliance report must contain the information described in paragraphs (a)(1) through (a)(4) of this section. The semiannual compliance report must be submitted by the dates specified in paragraphs (b)(1) through (b)(5) of this section, unless the Administrator has approved a different schedule.

(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) For each deviation from an emission limitation, the compliance report must contain the information in paragraphs (a)(4)(i) through (a)(4)(iii) of this section.

(i) The total operating time of each stationary combustion turbine during the reporting period.

(ii) Information on the number, duration, and cause of deviations (including unknown cause, if applicable), as applicable, and the corrective action taken.

(iii) Information on the number, duration, and cause for monitor downtime incidents (including unknown cause, if applicable, other than downtime associated with zero and span and other daily calibration checks).

(b) Dates of submittal for the semiannual compliance report are provided in (b)(1) through (b)(5) of this section.

(1) The first semiannual compliance report must cover the period beginning on the compliance date specified in § 63.6095 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 specified in § 63.6095.

(2) The first semiannual 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 in § 63.6095.

(3) Each subsequent semiannual compliance report must cover the semiannual reporting period from January 1 through June 30 or the semiannual reporting period from July 1 through December 31.

(4) Each subsequent semiannual 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 combustion turbine that is subject to permitting regulations pursuant to 40 CFR part 70 or 71, and if the permitting authority has established the date for submitting annual reports pursuant to 40 CFR 70.6(a)(3)(iii)(A) or 40 CFR 71.6(a)(3)(iii)(A), you may submit the first and subsequent compliance reports according to the dates the permitting authority has established instead of according to the dates in paragraphs (b)(1) through (4) of this section.

(c) If you are operating as a stationary combustion turbine which fires landfill gas or digester gas equivalent to 10 percent or more of the gross heat input on an annual basis, or a stationary

combustion turbine where gasified MSW is used to generate 10 percent or more of the gross heat input on an annual basis, you must submit an annual report according to Table 6 of this subpart by the date specified unless the Administrator has approved a different schedule, according to the information described in paragraphs (d)(1) through (5) of this section. You must report the data specified in (c)(1) through (c)(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, digester gas, or gasified MSW 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.

(d) Dates of submittal for the annual report are provided in (d)(1) through (d)(5) of this section.

(1) The first annual report must cover the period beginning on the compliance date specified in § 63.6095 and ending on December 31.

(2) The first annual report must be postmarked or delivered no later than January 31.

(3) Each subsequent annual report must cover the annual reporting period from January 1 through December 31.

(4) Each subsequent annual report must be postmarked or delivered no later than January 31.

(5) For each stationary combustion turbine that is subject to permitting regulations pursuant to 40 CFR part 70 or 71, and if the permitting authority has established the date for submitting annual 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 (d)(1) through (4) of this section.

(e) If you are operating a lean premix gas-fired stationary combustion turbine or a diffusion flame gas-fired stationary combustion turbine as defined by this subpart, and you use any quantity of distillate oil to fire any new or existing stationary combustion turbine which is located at the same major source, you must submit an annual report according to Table 6 of this subpart by the date specified unless the Administrator has approved a different schedule, according to the information described in paragraphs (d)(1) through (5) of this section. You must report the data specified in (e)(1) through (e)(3) of this section.

(1) The number of hours distillate oil was fired by each new or existing stationary combustion turbine during the reporting period.

(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.

§ 63.6155 What records must I keep?

(a) You must keep the records as described in paragraphs (a)(1) through (5).

(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 requirements in § 63.10(b)(2)(xiv).

(2) Records of performance tests and performance evaluations as required in § 63.10(b)(2)(viii).

(3) Records of the occurrence and duration of each startup, shutdown, or malfunction as required in § 63.10(b)(2)(i).

(4) Records of the occurrence and duration of each malfunction of the air pollution control equipment, if applicable, as required in § 63.10(b)(2)(ii).

(5) Records of all maintenance on the air pollution control equipment as required in § 63.10(b)(iii).

(b) If you are operating a stationary combustion turbine which fires landfill gas, digester gas or gasified MSW equivalent to 10 percent or more of the gross heat input on an annual basis, or if you are operating a lean premix gas-fired stationary combustion turbine or a diffusion flame gas-fired stationary combustion turbine as defined by this subpart, and you use any quantity of distillate oil to fire any new or existing stationary combustion turbine which is located at the same major source, you must keep the records of your daily fuel usage monitors.

(c) You must keep the records required in Table 5 of this subpart to show continuous compliance with each operating limitation that applies to you.

§ 63.6160 In what form and how long must I keep my records?

(a) You must maintain all applicable records in such a manner that they can be readily accessed and are suitable for inspection 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 retain your records of the most recent 2 years on site or your records must be accessible on site. Your records of the remaining 3 years may be retained off site.

Other Requirements and Information

§ 63.6165 What parts of the General Provisions apply to me?

Table 7 of this subpart shows which parts of the General Provisions in § 63.1 through 15 apply to you.

§ 63.6170 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 EPA Administrator has delegated authority to your State, local, or tribal agency, then that agency (as well as the U.S. EPA) has the authority to implement and enforce this subpart. You should contact your EPA Regional Office to find out 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 section 40 CFR part 63, subpart E, the authorities contained in paragraph (c) of this section are retained by the EPA 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:

(1) Approval of alternatives to the emission limitations or operating limitations in § 63.6100 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 to determine outlet formaldehyde concentration, as specified in § 63.6110(b).

§ 63.6175 What definitions apply to this subpart?

Terms used in this subpart are defined in the CAA; in 40 CFR 63.2, the General Provisions of this part; and in this section:

Area source means any stationary source of HAP that is not a major source as defined in this part.

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 reciprocating internal combustion engines.

CAA means the Clean Air Act (42 U.S.C. 7401 *et seq.*, as amended by Public Law 101–549, 104 Stat. 2399).

Cogeneration cycle stationary combustion turbine means any stationary combustion turbine that recovers heat from the stationary combustion turbine exhaust gases using an exhaust heat exchanger, such as a heat recovery steam generator.

Combined cycle stationary combustion turbine means any stationary combustion turbine that recovers heat from the stationary combustion turbine exhaust gases using an exhaust heat exchanger to generate steam for use in a steam turbine.

Combustion turbine engine test cells/stands means engine test cells/stands, as defined in subpart PPPPP of this part, that test stationary combustion turbines.

Compressor station means any permanent combination of compressors that move natural gas at increased pressure from fields, in transmission pipelines, or into storage.

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;

(3) Fails to meet any emission limitation or operating limitation in this subpart during malfunction, regardless of whether or not such failure is permitted by this subpart; or

(4) Fails to conform to any provision of the applicable startup, shutdown, or malfunction plan, or to satisfy the general duty to minimize emissions established by § 63.6(e)(1)(i).

Diffusion flame gas-fired stationary combustion turbine means:

(1)(i) Each stationary combustion turbine which is equipped only to fire gas using diffusion flame technology,

(ii) Each stationary combustion turbine which is equipped both to fire gas using diffusion flame technology and to fire oil, during any period when it is firing gas, and

(iii) Each stationary combustion turbine which is equipped both to fire gas using diffusion flame technology and to fire oil, and is located at a major source where all new, reconstructed, and existing stationary combustion turbines fire oil no more than an aggregate total of 1000 hours during the calendar year.

(2) Diffusion flame gas-fired stationary combustion turbines do not include:

(i) Any emergency stationary combustion turbine,

(ii) Any stationary combustion turbine located on the North Slope of Alaska, or

(iii) Any stationary combustion turbine burning landfill gas or digester gas equivalent to 10 percent or more of the gross heat input on an annual basis, or any stationary combustion turbine where gasified MSW is used to generate 10 percent or more of the gross heat input on an annual basis.

Diffusion flame oil-fired stationary combustion turbine means:

(1)(i) Each stationary combustion turbine which is equipped only to fire oil using diffusion flame technology, and

(ii) Each stationary combustion turbine which is equipped both to fire oil using diffusion flame technology and to fire gas, and is located at a major source where all new, reconstructed, and existing stationary combustion turbines fire oil more than an aggregate total of 1000 hours during the calendar year, during any period when it is firing oil.

(2) Diffusion flame oil-fired stationary combustion turbines do not include:

(i) Any emergency stationary combustion turbine, or

(ii) Any stationary combustion turbine located on the North Slope of Alaska.

Diffusion flame technology means a configuration of a stationary combustion turbine where fuel and air are injected at the combustor and are mixed only by diffusion prior to ignition.

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.

Distillate oil 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.

Emergency stationary combustion turbine means any stationary combustion turbine that operates in an emergency situation. Examples include stationary combustion turbines used to produce power for critical networks or equipment (including power supplied to portions of a facility) when electric power from the local utility is interrupted, or stationary combustion turbines used to pump water in the case of fire or flood, etc. Emergency stationary combustion turbines do not include stationary combustion turbines used as peaking units at electric utilities or stationary combustion turbines at industrial facilities that typically operate at low capacity factors. Emergency stationary combustion turbines may be operated for the purpose of maintenance checks and readiness testing, provided that the tests are required by the manufacturer, the vendor, or the insurance company associated with the turbine. Required testing of such units should be minimized, but there is no time limit on the use of emergency stationary combustion turbines.

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 pollutant (HAP) means any air pollutant listed in or pursuant to section 112(b) of the CAA.

ISO standard day conditions means 288 degrees Kelvin (15°C), 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 premix gas-fired stationary combustion turbine means:

(1)(i) Each stationary combustion turbine which is equipped only to fire gas using lean premix technology,

(ii) Each stationary combustion turbine which is equipped both to fire gas using lean premix technology and to

fire oil, during any period when it is firing gas, and

(iii) Each stationary combustion turbine which is equipped both to fire gas using lean premix technology and to fire oil, and is located at a major source where all new, reconstructed, and existing stationary combustion turbines fire oil no more than an aggregate total of 1000 hours during the calendar year.

(2) Lean premix gas-fired stationary combustion turbines do not include:

(i) Any emergency stationary combustion turbine,

(ii) Any stationary combustion turbine located on the North Slope of Alaska, or

(iii) Any stationary combustion turbine burning landfill gas or digester gas equivalent to 10 percent or more of the gross heat input on an annual basis, or any stationary combustion turbine where gasified MSW is used to generate 10 percent or more of the gross heat input on an annual basis.

Lean premix oil-fired stationary combustion turbine means:

(1)(i) Each stationary combustion turbine which is equipped only to fire oil using lean premix technology, and

(ii) Each stationary combustion turbine which is equipped both to fire oil using lean premix technology and to fire gas, and is located at a major source where all new, reconstructed, and existing stationary combustion turbines fire oil more than an aggregate total of 1000 hours during the calendar year, during any period when it is firing oil.

(2) Lean premix oil-fired stationary combustion turbines do not include:

(i) Any emergency stationary combustion turbine, or

(ii) Any stationary combustion turbine located on the North Slope of Alaska.

Lean premix technology means a configuration of a stationary combustion turbine where the air and fuel are thoroughly mixed to form a lean mixture for combustion in the combustor. Mixing may occur before or in the combustion chamber.

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 this section, 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 this section, 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 this standard to be exceeded. Failures that are caused in part by poor maintenance or careless operation are not malfunctions.

Municipal solid waste as used in this subpart is as defined in § 60.1465 of Subpart AAAA of 40 CFR Part 60, New Source Performance Standards for Small Municipal Waste Combustion Units.

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. May be field or pipeline quality. For the purposes of this subpart, the definition of natural gas includes similarly constituted fuels such as field gas, refinery gas, and syngas.

Natural gas transmission means the pipelines used for the long distance transport of natural gas (excluding processing). Specific equipment used in natural gas transmission includes the land, mains, valves, meters, boosters, regulators, storage vessels, dehydrators, compressors, and their driving units and appurtenances, and equipment used transporting gas from a production plant, delivery point of purchased gas, gathering system, storage area, or other wholesale source of gas to one or more distribution area(s).

Natural gas transmission and storage facility means any grouping of equipment where natural gas is processed, compressed, or stored prior to entering a pipeline to a local distribution company or (if there is no local distribution company) to a final end user. Examples of a facility for this source category are: an underground natural gas storage operation; or a natural gas compressor station that receives natural gas via pipeline, from an underground natural gas storage operation, or from a natural gas processing plant. The emission points associated with these phases include, but are not limited to, process vents. Processes that may have vents include, but are not limited to, dehydration and compressor station engines. Facility, for the purpose of a major source determination, means natural gas transmission and storage equipment that is located inside the boundaries of an individual surface site (as defined in this section) and is connected by ancillary equipment, such as gas flow lines or power lines. Equipment that is part of a facility will typically be located within close proximity to other equipment located at the same facility. Natural gas transmission and storage equipment or groupings of equipment located on different gas leases, mineral fee tracts, lease tracts, subsurface unit areas, surface fee tracts, or surface lease tracts shall not be considered part of the same facility.

North Slope of Alaska means the area north of the Arctic Circle (latitude 66.5 degrees North).

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 emission control device means an emission control

device that incorporates catalytic oxidation to reduce CO emissions.

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.

Regenerative/recuperative cycle stationary combustion turbine means any stationary combustion turbine that recovers heat from the stationary combustion turbine exhaust gases using an exhaust heat exchanger to preheat the combustion air entering the combustion chamber of the stationary combustion turbine.

Research or laboratory facility means any stationary source whose primary purpose is to conduct research and development into new processes and products, where such source 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* matter.

Simple cycle stationary combustion turbine means any stationary combustion turbine that does not recover heat from the stationary combustion turbine exhaust gases.

Stationary combustion turbine means all equipment, including but not limited to the turbine, the fuel, air, lubrication and exhaust gas systems, control systems (except emissions control equipment), and any ancillary components and sub-components comprising any simple cycle stationary combustion turbine, any regenerative/recuperative cycle stationary combustion turbine, the combustion turbine portion of any stationary cogeneration cycle combustion system, or the combustion turbine portion of any stationary combined cycle steam/electric generating system. Stationary means that the combustion turbine is not self propelled or intended to be propelled while performing its function. Stationary combustion turbines do not include turbines located at a research or laboratory facility, if research is conducted on the turbine itself and the turbine is not being used to power other applications at the research or laboratory facility.

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.

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.

Tables to Subpart YYYY of Part 63.

As stated in § 63.6100, you must comply with the following emission limitations:

TABLE 1 TO SUBPART YYYY OF PART 63.—EMISSION LIMITATIONS

For each new or reconstructed stationary combustion turbine described in § 63.6100 which is . . .	You must meet the following emission limitations . . .
1. a lean premix gas-fired stationary combustion turbine as defined in this subpart, 2. a lean premix oil-fired stationary combustion turbine as defined in this subpart, 3. a diffusion flame gas-fired stationary combustion turbine as defined in this subpart, or 4. a diffusion flame oil-fired stationary combustion turbine as defined in this subpart.	limit the concentration of formaldehyde to 91 ppbvd or less at 15 percent O_2.

As stated in §§ 63.6100 and 63.6140, you must comply with the following operating limitations:

TABLE 2 TO SUBPART YYYY OF PART 63.—OPERATING LIMITATIONS

For . . .	You must . . .
1. each stationary combustion turbine that is required to comply with the emission limitation for formaldehyde and is using an oxidation catalyst.	maintain the 4-hour rolling average of the catalyst inlet temperature within the range suggested by the catalyst manufacturer.
2. each stationary combustion turbine that is required to comply with the emission limitation for formaldehyde and is not using an oxidation catalyst.	maintain any operating limitations approved by the Administrator.

As stated in § 63.6120, you must comply with the following requirements for performance tests and initial compliance demonstrations:

TABLE 3 TO SUBPART YYYY OF PART 63.—REQUIREMENTS FOR PERFORMANCE TESTS AND INITIAL COMPLIANCE DEMONSTRATIONS

You must . . .	Using . . .	According to the following requirements . . .
a. demonstrate formaldehyde emissions meet the emission limitations specified in Table 1 by a performance test initially and on an annual basis AND.	Test Method 320 of 40 CFR part 63, appendix A; ASTM D6348–03 provided that %R as determined in Annex A5 of ASTM D6348–03 is equal or greater than 70% and less than or equal to 130%; or other methods approved by the Administrator.	formaldehyde concentration must be corrected to 15 percent O_2, dry basis. Results of this test consist of the average of the three 1 hour runs. Test must be conducted within 10 percent of 100 percent load.
b. select the sampling port location and the number of traverse points AND.	Method 1 or 1A of 40 CFR part 60, appendix A § 63.7(d)(1)(i).	if using an air pollution control device, the sampling site must be located at the outlet of the air pollution control device.
c. determine the O_2 concentration at the sampling port location AND.	Method 3A or 3B of 40 CFR part 60, appendix A.	measurements to determine O_2 concentration must be made at the same time as the performance test.
d. determine the moisture content at the sampling port location for the purposes of correcting the formaldehyde concentration to a dry basis.	Method 4 of 40 CFR part 60, appendix A or Test Method 320 of 40 CFR part 63, appendix A, or ASTM D6348–03.	measurements to determine moisture content must be made at the same time as the performance test.

As stated in §§ 63.6110 and 63.6130, you must comply with the following requirements to demonstrate initial compliance with emission limitations:

TABLE 4 TO SUBPART YYYY OF PART 63.—INITIAL COMPLIANCE WITH EMISSION LIMITATIONS

For the . . .	You have demonstrated initial compliance if . . .
emission limitation for formaldehyde..	the average formaldehyde concentration meets the emission limitations specified in Table 1.

As stated in §§ 63.6135 and 63.6140, you must comply with the following requirements to demonstrate continuing compliance with operating limitations:

TABLE 5 OF SUBPART YYYY OF PART 63.—CONTINUOUS COMPLIANCE WITH OPERATING LIMITATIONS

For each stationary combustion turbine complying with the emission limitation for formaldehyde . . .	You must demonstrate continuous compliance by . . .
1. with an oxidation catalyst	continuously monitoring the inlet temperature to the catalyst and maintaining the 4-hour rolling average of the inlet temperature within the range suggested by the catalyst manufacturer.
2. without the use of an oxidation catalyst	continuously monitoring the operating limitations that have been approved in your petition to the Administrator.

As stated in § 63.6150, you must comply with the following requirements for reports:

TABLE 6 OF SUBPART YYYY OF PART 63.—REQUIREMENTS FOR REPORTS

If you own or operate a . . .	you must . . .	According to the following requirements . . .
1. stationary combustion turbine which must comply with the formaldehyde emission limitation.	report your compliance status	semiannually, according to the requirements of § 63.6150.
2. stationary combustion turbine which fires landfill gas, digester gas or gasified MSW equivalent to 10 percent or more of the gross heat input on an annual basis.	report (1) 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, digester gas, or gasified MSW is equivalent to 10 percent or more of the gross heat input on an annual basis, (2) the operating limits provided in your federally enforceable permit, and any deviations from these limits, and (3) any problems or errors suspected with the meters.	annually, according to the requirements in § 63.6150.

TABLE 6 OF SUBPART YYYY OF PART 63.—REQUIREMENTS FOR REPORTS—Continued

If you own or operate a . . .	you must . . .	According to the following requirements . . .
3. a lean premix gas-fired stationary combustion turbine or a diffusion flame gas-fired stationary combustion turbine as defined by this subpart, and you use any quantity of distillate oil to fire any new or existing stationary combustion turbine which is located at the same major source.	report (1) the number of hours distillate oil was fired by each new or existing stationary combustion turbine during the reporting period, (2) the operating limits provided in your federally enforceable permit, and any deviations from these limits, and (3) any problems or errors suspected with the meters.	annually, according to the requirements in § 63.6150.

You must comply with the applicable General Provisions requirements:

TABLE 7 OF SUBPART YYYY OF PART 63.—APPLICABILITY OF GENERAL PROVISIONS TO SUBPART YYYY

Citation	Subject	Applies to Subpart YYYY	Explanation
§ 63.1	General applicability of the General Provisions.	Yes	Additional terms defined in § 63.6175.
§ 63.2	Definitions	Yes	Additional terms defined in § 63.6175.
§ 63.3	Units and abbreviations	Yes.	
§ 63.4	Prohibited activities	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.	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.	Yes.	
§ 63.6(d)	[Reserved].		
§ 63.6(e)(1)	Operation and maintenance	Yes.	
§ 63.6(e)(2)	[Reserved].		
§ 63.6(e)(3)	SSMP	Yes.	
§ 63.6(f)(1)	Applicability of standards except during startup, shutdown, or malfunction (SSM).	Yes.	
§ 63.6(f)(2)	Methods for determining compliance	Yes.	
§ 63.6(f)(3)	Finding of compliance	Yes.	
§ 63.6(g)(1)–(3)	Use of alternative standard	Yes.	
§ 63.6(h)	Opacity and visible emission standards	No	Subpart YYYY 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 YYYY contains performance test dates at § 63.6110.
§ 63.7(a)(3)	Section 114 authority	Yes.	
§ 63.7(b)(1)	Notification of performance test	Yes.	
§ 63.7(b)(2)	Notification of rescheduling	Yes.	
§ 63.7(c)	Quality assurance/test plan	Yes.	
§ 63.7(d)	Testing facilities	Yes.	
§ 63.7(e)(1)	Conditions for conducting performance tests.	Yes.	
§ 63.7(e)(2)	Conduct of performance tests and reduction of data.	Yes	Subpart YYYY specifies test methods at § 63.6120.
§ 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 YYYY contains specific requirements for monitoring at § 63.6125.
§ 63.8(a)(2)	Performance specifications	Yes.	
§ 63.8(a)(3)	[Reserved].		
§ 63.8(a)(4)	Monitoring for control devices	No.	

TABLE 7 OF SUBPART YYYY OF PART 63.—APPLICABILITY OF GENERAL PROVISIONS TO SUBPART YYYY—Continued

Citation	Subject	Applies to Subpart YYYY	Explanation
§ 63.8(b)(1)	Monitoring	Yes.	
§ 63.8(b)(2)–(3)	Multiple effluents and multiple monitoring systems.	Yes.	
§ 63.8(c)(1)	Monitoring system operation and maintenance.	Yes.	
§ 63.8(c)(1)(i)	Routine and predictable SSM	Yes.	
§ 63.8(c)(1)(ii)	Parts for repair of CMS readily available	Yes.	
§ 63.8(c)(1)(iii)	SSMP for CMS required	Yes.	
§ 63.8(c)(2)–(3)	Monitoring system installation	Yes.	
§ 63.8(c)(4)	Continuous monitoring system (CMS) requirements.	Yes	Except that subpart YYYY does not require continuous opacity monitoring systems (COMS).
§ 63.8(c)(5)	COMS minimum procedures	No.	
§ 63.8(c)(6)–(8)	CMS requirements	Yes	Except that subpart YYYY 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.
§ 63.8(f)(1)–(5)	Alternative monitoring method	Yes.	
§ 63.8(f)(6)	Alternative to relative accuracy test	Yes.	
§ 63.8(g)	Data reduction	Yes	Except that provisions for COMS are not applicable. Averaging periods for demonstrating compliance are specified at §§ 63.6135 and 63.6140.
§ 63.9(a)	Applicability and State delegation of notification requirements.	Yes.	
§ 63.9(b)(1)–(5)	Initial notifications	Yes	Except that § 63.9(b)(3) is reserved.
§ 63.9(c)	Request for compliance extension	Yes.	
§ 63.9(d)	Notification of special compliance requirements for new sources.	Yes.	
§ 63.9(e)	Notification of performance test	Yes.	
§ 63.9(f)	Notification of visible emissions/opacity test.	No	Subpart YYYY does not contain opacity or VE standards.
§ 63.9(g)(1)	Notification of performance evaluation	Yes.	
§ 63.9(g)(2)	Notification of use of COMS data	No	Subpart YYYY does not contain opacity or VE standards.
§ 63.9(g)(3)	Notification that criterion for alternative to relative accuracy test audit (RATA) is exceeded.	Yes	If alternative is in use.
§ 63.9(h)	Notification of compliance status	Yes	Except that notifications for sources not conducting performance tests are due 30 days after completion of performance evaluations. § 63.9(h)(4) is reserved.
§ 63.9(i)	Adjustment of submittal deadlines	Yes.	
§ 63.9(j)	Change in previous information	Yes.	
§ 63.10(a)	Administrative provisions for recordkeeping and reporting.	Yes.	
§ 63.10(b)(1)	Record retention	Yes.	
§ 63.10(b)(2)(i)–(iii)	Records related to SSM	Yes.	
§ 63.10(b)(2)(iv)–(v)	Records related to actions during SSM	Yes.	
§ 63.10(b)(2)(vi)–(xi)	CMS 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 CMS.	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 YYYY does not contain opacity or VE standards.
§ 63.10(d)(4)	Progress reports	Yes.	
§ 63.10(d)(5)	Startup, shutdown, and malfunction reports.	No	Subpart YYYY does not require reporting of startup, shutdowns, or malfunctions.
§ 63.10(e)(1) and (2)(i)	Additional CMS reports	Yes.	
§ 63.10(e)(2)(ii)	COMS-related report	No	Subpart YYYY does not require COMS.
§ 63.10(e)(3)	Excess emissions and parameter exceedances reports.	Yes.	

TABLE 7 OF SUBPART YYYY OF PART 63.—APPLICABILITY OF GENERAL PROVISIONS TO SUBPART YYYY—Continued

Citation	Subject	Applies to Subpart YYYY	Explanation
§ 63.10(e)(4)	Reporting COMS data	No	Subpart YYYY does not require COMS.
§ 63.10(f)	Waiver for recordkeeping and 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.	

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