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

**CERTIFIED MAIL**

**RE: Final Title V Chapter 3745-77 permit**

14-09-00-0896
PSI Energy, Madison Generating Station
John F. Funke
Cinergy Corp
P.O. Box 960, Room 552 Annex
Cincinnati, OH 45201

Dear John F. Funke:

Enclosed is the Title V permit that allows you to operate the facility in the manner indicated in the permit. Because this permit may contain several conditions and restrictions, we urge you to read it carefully.

The Ohio EPA is encouraging companies to investigate pollution prevention and energy conservation. Not only will this reduce pollution and energy consumption, but it can also save you money. If you would like to learn ways you can save money while protecting the environment, please contact our Office of Pollution Prevention at (614) 644-3469.

You are hereby notified that this action of the Director is final and may be appealed to the Environmental Review Appeals Commission pursuant to Section 3745.04 of the Ohio Revised Code. The appeal must be in writing and set forth the action complained of and the grounds upon which the appeal is based. It must be filed with the Environmental Review Appeals Commission within thirty (30) days after notice of the Director's action. A copy of the appeal must be served on the Director of the Ohio Environmental Protection Agency within three (3) days of filing with the Commission. It is also requested by the Director that a copy of the appeal be served upon the Environmental Enforcement Section of the Office of the Attorney General. An appeal may be filed with the Environmental Review Appeals Commission at the following address:

Environmental Review Appeals Commission
309 South Fourth Street, Room 222
Columbus, Ohio 43215

If you have any questions, please contact Hamilton County Dept. of Environmental Services.

Sincerely,

Michael W. Ahern

Michael W. Ahern
Permit Issuance and Data Management Section
Division of Air Pollution Control

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

State of Ohio Environmental Protection Agency

# FINAL TITLE V PERMIT

| Issue Date: **08/24/04** | Effective Date: **09/14/04** | Expiration Date: **09/14/09** |
|---|---|---|

This document constitutes issuance of a Title V permit for Facility ID: 14-09-00-0896 to:
PSI Energy, Madison Generating Station
250 William Howard Taft Rd
Cincinnati, OH 45219-2660

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

P001 (#1 Turbine)
84.65 Megawatt (Nominal) Simple-Cycle
Combustion Turbine #1

P002 (#2 Turbine)
84.65 Megawatt (Nominal) Simple-Cycle
Combustion Turbine #2

P003 (#3 Turbine)
84.65 Megawatt (Nominal) Simple-Cycle
Combustion Turbine #3

P004 (#4 Turbine)
84.65 Megawatt (Nominal) Simple-Cycle
Combustion Turbine #4

P005 (#5 Turbine)
84.65 Megawatt (Nominal) Simple-Cycle
Combustion Turbine #5

P006 (#6 Turbine)
84.65 Megawatt (Nominal) Simple-Cycle
Combustion Turbine #6

P007 (#7 Turbine)
84.65 Megawatt (Nominal) Simple-Cycle
Combustion Turbine #7

P008 (#8 Turbine)
84.65 Megawatt (Nominal) Simple-Cycle
Combustion Turbine #8

P009 (#1 EDG)
1.5 Megawatt Emergency Diesel Generator #1

P010 (#2 EDG)
1.5 Megawatt Emergency Diesel Generator #2

P011 (Fire Pump)
140 Kilowatt Emergency Diesel Fire Pump

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
(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.** The following insignificant emissions unit is located at this facility:

F001: roadways and parking areas.

Each insignificant emissions unit at this facility must comply with all applicable State and federal regulations, and 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 of the applicable requirements contained in the federally-approved versions of OAC Chapters 3745-17, 3745-18, and/or 3745-21.

**2.** 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.

**3.** 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, Subpart M.

**4.** 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 P001 through P008.

**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 ZZZZ (NESHAP for Reciprocating Internal Combustion Engines), in accordance with 40 CFR Parts 63.6580 through 63.6675 (including the Table(s) and Appendix(ices) referenced in Subpart ZZZZ), 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 ZZZZ 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 P009 and P010.

## B. State Only Enforceable Section

**1.** The following insignificant emissions unit located at this facility is exempt from permit requirements because it is not subject to any applicable requirements (as defined in OAC rule 3745-77-01(H)) or because it meets the "de minimus" criteria established in OAC rule 3745-15-05:

L001: non-halogenated solvent parts washer.

# Part III - Terms and Conditions for Emissions Units

**Emissions Unit ID:** #1 Turbine (P001)

**Activity Description:** 84.65 Megawatt (Nominal) Simple-Cycle Combustion Turbine #1

## 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 |
|---|---|---|
| 84.65 megawatt (nominal) natural gas/diesel fuel-fired simple cycle combustion turbine using dry low NOx combustors (natural gas firing) or water injection (diesel fuel firing) to control NOx emissions. | OAC rules 3745-31-11 through 3745-31-20<br>(PTI 14-04682) | This emissions unit shall not exceed the following emission limitations:<br><br>58.0 lbs of sulfur dioxide (SO2) emissions/hour*<br><br>6.0 lbs of sulfuric acid (H2SO4) mist emissions/hour*<br><br>0.008 lb of particulate emissions (PE)/particulate matter with a diameter of 10 microns or less (PM10** emissions)/mmBtu*<br><br>* The hourly emission limitations and the lb of PE/PM10 emissions/mmBtu emission limitation specified above represent this emissions unit's potentials to emit for all operating conditions, including startup and shutdown. Therefore, no additional monitoring, record keeping or reporting requirements are required to demonstrate compliance with these emission limitations.<br><br>**The total PM10 emissions were evaluated and did not trigger any additional federal requirements, therefore, the emissions are being regulated as particulate emissions (PE). |

| Operations, Property, and/or Equipment | Applicable Rules/ Requirements | Applicable Emissions Limitations/Control Measures |
|---|---|---|
| | | 196.0 lbs of NOx emissions/hour, excluding startup and shutdown periods<br><br>54.0 lbs of CO emissions/hour, excluding startup and shutdown periods<br><br>when burning natural gas, 15 ppm of NOx, by volume, at 15% oxygen, on a dry basis, (as a 1-hour average, at full load)<br><br>when burning diesel fuel, 42 ppm of NOx, by volume, at 15% oxygen, on a dry basis (as a 1-hour average, at full load)<br><br>when burning natural gas at full load, 12 ppm of NOx, by volume, at 15% oxygen, on a dry basis (based on a rolling, 12-month average summation of the monthly NOx emissions, in ppm)<br><br>when burning diesel fuel, 0.0456 lb of SO2 emissions/mmBtu of actual heat input<br><br>The sulfur content of the natural gas and diesel fuel burned in this emissions unit shall not exceed 0.05% sulfur, by weight.<br><br>Emissions from startup and shutdown operations shall not exceed the following emission limitations:<br><br>when burning natural gas<br><br>83 lbs of NOx/startup and shutdown cycle<br>308 lbs of CO/startup and shutdown cycle<br><br>when burning diesel fuel<br><br>130 lbs of NOx/startup and shutdown cycle<br>354 lbs of CO/startup and shutdown cycle<br><br>See Section A.I.2.c below. |

| Operations, Property, and/or Equipment | Applicable Rules/ Requirements | Applicable Emissions Limitations/Control Measures |
|---|---|---|
| | | Emissions units P001 through P008, combined, shall not exceed the following emission limitations:<br><br>60.5 tons of PE/PM10 emissions per rolling, 12-month period<br><br>120.8 tons of SO2 emissions per rolling, 12-month period<br><br>733.3 tons of nitrogen oxides (NOx) emissions per rolling, 12-month period<br><br>541.0 tons of carbon monoxide (CO) emissions per rolling, 12-month period<br><br>12.2 tons of H2SO4 mist emissions per rolling, 12-month period<br><br>7.7 tons of benzene emissions per rolling, 12-month period<br><br>0.00084 ton of beryllium emissions per rolling, 12-month period<br><br>0.012 ton of arsenic emissions per rolling, 12-month period<br><br>The rolling, 12-month emission limitations are based upon a summation of the pollutant-specific emissions generated under all operating conditions, including startup and shutdown periods, for both natural gas and diesel fuel. |

| Operations, Property, and/or Equipment | Applicable Rules/ Requirements | Applicable Emissions Limitations/Control Measures |
|---|---|---|
| | OAC rule 3745-31-05(A)(3) (PTI 14-04682) | This emissions unit shall not exceed the following emission limitations:<br><br>10.0 lbs of volatile organic compound (VOC) emissions/hour*<br>0.15 ton per year of lead emissions<br>0.0023 ton per year of mercury emissions<br><br>See Section A.I.2.b below.<br><br>Compliance with this rule also includes compliance with the requirements of OAC rule 3745-31-05(C) and OAC rule 3745-17-07(A) when burning diesel fuel.<br><br>* The hourly VOC emission limitation specified above represent this emissions unit's potential to emit for all operating conditions, including startup and shutdown. Therefore, no additional monitoring, record keeping or reporting requirements are required to demonstrate compliance with this emission limitation. |
| | OAC rule 3745-31-05(C) | 36.4 tons of VOC emissions per rolling, 12-month period from emissions units P001 through P008, combined. |
| | OAC rule 3745-17-07(A) | See Section A.I.2.a below. |
| | 40 CFR Part 60, Subpart GG | The emission limitations established in 40 CFR Part 60, Subpart GG for SO2 and NOx are less stringent than those established pursuant to OAC rule 3745-31-05(C). |
| | OAC rule 3745-17-11(B)(4) | The PE limitation specified by this rule is less stringent the PE limitation established pursuant to OAC rule 3745-31-05(C). |
| | OAC rule 3745-18-06(F) | The SO2 emission limitation specified by this rule (0.5 lb of SO2 emissions/mmBtu) is less stringent than the SO2 emission limitation established pursuant to OAC rule 3745-31-05(C). |
| | OAC rules 3745-21-08(B) and 3745-23-06(B) | See Section A.I.2.j below. |

## 2. Additional Terms and Conditions

**2.a** Visible PE from any stack shall not exceed 20% opacity, as a 6-minute average, except as specified by rule when burning diesel fuel.

**2.b** Visible PE from any stack shall not exceed 10% opacity, as a 6-minute average when burning natural gas.

**2.c** The permittee shall operate and maintain dry low NOx burners when burning natural gas and operate and maintain a water injection system when burning diesel fuel.

**2.d** "Full load" shall be defined as the nameplate electrical output of 84.65 megawatts. Any load that is greater than or equal to 90% of the nameplate electrical output shall be considered full load.

**2.e** "Normal operation" shall be defined as the period when the combustion turbine achieves dry low NOx mode (GE Mode 6). GE Mode 6 is defined by the manufacturer as the low emissions mode during which all burner nozzles are in use, burning a lean pre-mixed gas for steady-state operation. The continuous emissions monitoring system will indicate and record the GE Mode 6 status of the combustion turbine, including when the emissions unit is shutdown and when operating in startup and shutdown modes.

**2.f** "Startup" shall be defined as the period between when the combustion turbine is initially started (initial fuel light-off) until the combustion turbine completes transition to GE Mode 6. "Shutdown" shall be defined as the period beginning when the combustion turbine leaves the GE Mode 6 and ending when combustion has ceased.

**2.g** "Startup and shutdown cycle" shall be defined as a startup period followed by a consecutive shutdown period.

**2.h** For the purpose of this permit, the term "diesel fuel" shall be considered to be any low sulfur fuel oil that is burned in this emissions unit, as defined in 40 CFR Part 72.2.

**2.i** Compliance with the startup and shutdown NOx and CO lbs/cycle emission limitations, the NOx and CO emission limitations during steady-state operations, and the NOx ppm emission limitations during full load operations shall be demonstrated by the use of dual range NOx and CO continuous emission monitoring systems (CEMs). For CEM systems with dual ranges, certification testing shall be performed on the range normally used for measuring emissions.

**2.j** 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 technology requirements established pursuant to OAC rule 3745-31-05(A)(3) in Permit to Install 14-4682.

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 technology requirements established pursuant to OAC rule 3745-31-05(A)(3) in Permit to Install 14-4682.

**2.k** For the purposes of this permit and for the hazardous air pollutants (HAPs) emitted from this emissions unit, the best available control technology determination to satisfy the requirements of 40 CFR Part 52.21 is equivalent to the maximum achievable control technology determination used to satisfy the requirements of 40 CFR Parts 63.41 through 63.44.

**2. Additional Terms and Conditions (continued)**

**2.l** In lieu of the requirements of 40 CFR Part 60.334(a) to install and operate a continuous monitoring system to monitor and record the fuel consumption and the ratio of water to fuel being fired in this emissions unit, the permittee shall operate and maintain systems to continuously monitor and record emissions of NOx for this emissions unit in accordance with this permit.

In lieu of the excess emissions reports required under 40 CFR Part 60.334, the permittee shall submit excess emissions reports for this emissions unit in accordance with this permit.

In lieu of the test methods and procedures required under 40 CFR Part 60.335, the permittee shall follow the monitoring and testing requirements for this emissions unit in accordance with this permit.

## II. Operational Restrictions

**1.** The maximum annual natural gas usage rate for emissions units P001 through P008, combined, shall not exceed 20,300,000,000 cubic feet per rolling, 12-month period.

**2.** The maximum annual diesel fuel usage rate for emissions units P001 through P008, combined, shall not exceed 34,000,000 gallons per rolling, 12-month period.

**3.** The permittee shall burn only pipeline quality natural gas or diesel fuel in this emissions unit.

**4.** The quality of diesel fuel burned in this emissions unit shall have a combination of heat and sulfur content which is sufficient to comply with the allowable SO2 emission limitation of 0.0456 lb of SO2/mmBtu of actual heat input. The diesel fuel shall have a sulfur content of 0.05%, by weight, or less.

**5.** When the emissions unit is operating in startup and shutdown conditions, as defined in Section A.I.2.f above, each startup and shutdown cycle shall not exceed 1.0 hour in duration.

**6.** With the exception of startup and shutdown, this emissions unit shall be operated in GE Mode 6, defined as normal or full load operation (see Sections A.I.2.d and A.I.2.e above).

## III. Monitoring and/or Record Keeping Requirements

**1.** The permittee shall maintain daily records of the following information:

a. the emissions unit's actual electrical output for each operating hour; and

b. for each day during which the permittee burns a fuel other than pipeline quality natural gas and/or diesel fuel, the permittee shall maintain a record of the type and quantity of fuel burned in this emissions unit.

**2.** The permittee shall maintain monthly records of the following information:

a. the total amount of natural gas burned, in cubic feet, for emissions units P001 through P008, combined;

b. the total amount of diesel fuel burned, in gallons, for emissions units P001 through P008, combined;

c. the rolling, 12-month summation of the total amount of natural gas burned, in cubic feet, for emissions units P001 through P008, combined (the amount of natural gas burned for the current month plus the total amount of natural gas burned for the previous 11 calendar months);

d. the rolling, 12-month summation of the total amount of diesel fuel burned, in gallons, for emissions units P001 through P008, combined (the amount of diesel fuel burned for the current month plus the total amount of diesel fuel burned for the previous 11 calendar months);

e. the date and duration, in minutes, of each startup and shutdown cycle;

f. the emissions, in pounds, for NOx* and CO* when burning natural gas for each startup and shutdown cycle;

g. the emissions, in pounds, for NOx* and CO* when burning diesel fuel for each startup and shutdown cycle;

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

h. the total emissions, in tons, for NOx*, CO*, PE/PM10, SO2 , VOC, H2SO4, and benzene when burning natural gas for all operating conditions;

i. the total emissions, in tons, for NOx*, CO*, PE/PM10, SO2, VOC, H2SO4, benzene, beryllium and arsenic when burning diesel fuel for all operating conditions;

j. the rolling, 12-month emissions, in tons, for NOx*, CO*, PE/PM10, SO2, VOC, H2SO4, benzene, beryllium and arsenic for emissions units P001 through P008, combined, when burning natural gas and diesel fuel (the total emissions calculated in (h) + (i)) for the current month plus the total emissions for the previous 11 calendar months); and

k. the rolling, 12-month average of NOx* emissions, in ppm, when burning natural gas at full load for this emissions unit (the NOx ppm average for the current month (from the CEMs data) plus the total NOx ppm average for the previous 11 calendar months).

* The permittee shall use the continuous NOx and CO emissions monitoring data to determine the NOx and CO emissions for these emissions units. During any period when the NOx and/or the CO emissions monitoring systems are not operational, the permittee shall use the appropriate missing data procedures specified in 40 CFR Part 75 to determine NOx and CO emissions or an approved data substitution protocol for the purpose of calculating the rolling, 12-month emission rates. The data substitution values shall not be used to demonstrate compliance with the hourly NOx and CO emission limitations applicable during normal operation of this emissions unit.

**3.** The permittee shall monitor and record the sulfur content of the natural gas being burned in this emissions unit or make the demonstration that the sulfur content of the natural gas does not need to be monitored and recorded in accordance with the provisions specified in 40 CFR Part 60.334(b). Owners, operators or fuel vendors may develop custom fuel schedules for the determination of the sulfur content based on the design and operation of the affected facility and the characteristics of the fuel supply. Except as provided in 40 CFR Parts 60.334(i)(3)(i) and 60.334(i)(3)(ii), these custom schedules shall be substantiated with data and must be approved by the Ohio EPA, Central Office before they can be used.

Analyses for the purpose of determining the sulfur content of the natural gas may be performed by the permittee, the fuel vendor, or any other qualified agency in accordance with the analytical methods specified in 40 CFR Part 60, Subpart GG, Section 60.335(d) or equivalent methods as approved by the Administrator.

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

**4.** The permittee shall maintain records of the diesel fuel burned in this emissions unit in accordance with either Alternative 1 or Alternative 2 described below:

a. Alternative 1:

For each shipment of oil received for burning in this emissions unit, the permittee shall collect or require the oil supplier to collect a representative grab sample of oil and maintain records of the total quantity of oil received, the permittee's or oil supplier's analyses for sulfur content and heat content, and the calculated sulfur dioxide emission rate (in lbs/mmBtu). (The sulfur dioxide emission rate shall be calculated in accordance with the formula specified in OAC rule 3745-18-04(F).) 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 may be represented by a single batch analysis from the supplier.

b. Alternative 2:

The permittee shall collect a representative grab sample of oil that is burned in this emissions unit for each day when the emission unit is in operation. If additional fuel oil is added to the tank serving this emissions unit on a day when the emissions unit is in operation, the permittee shall collect a sufficient number of grab samples to develop a composite sample representative of the fuel oil burned in this emissions unit. A representative grab sample of oil does not need to be collected on days when this emissions unit is only operated for the purpose of "test-firing". The permittee shall maintain records of the total quantity of oil burned each day (except for the purpose of test-firing), the permittee's analyses for sulfur content and heat content, and the calculated sulfur dioxide emission rate (in lbs/mmBtu). [The sulfur dioxide emission rate shall be calculated in accordance with the formula specified in OAC rule 3745-18-04(F).]

The permittee shall perform or require the supplier to perform the analyses for sulfur content and heat content in accordance with the following ASTM methods: ASTM method D4294 for sulfur content and ASTM method D240 for heat content. The newest or most recent revisions to the applicable test method shall be used for analyses. Alternative, equivalent methods may be used upon written approval by the Hamilton County Department of Environmental Services - Air Quality Control Division.

**5.** The permittee shall operate and maintain equipment to continuously monitor and record the actual fuel flow to this emissions unit when it is in operation. Such continuous monitoring and recording equipment shall comply with the requirements specified in 40 CFR Part 75. If the fuel flow monitoring and/or recording equipment is (are) not in service when the emissions unit is in operation, the permittee shall comply with the appropriate missing data procedures specified in 40 CFR Part 75.

**6.** The permittee shall operate and maintain equipment to continuously monitor and record the percent oxygen (as a 1-hr average) in the stack serving this emissions unit when the emissions unit is in operation. Such continuous monitoring and recording equipment shall comply with the requirements specified in 40 CFR Part 75. The monitoring and recording equipment shall be installed, calibrated, operated and maintained in accordance with the manufacturer's recommendations, with any modifications deemed necessary by the permittee.

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

**7.** The permittee shall operate and maintain equipment to continuously monitor and record NOx emissions from this emissions unit in units of the applicable standard(s). Such continuous monitoring and recording equipment shall comply with the applicable requirements specified in 40 CFR Part 60 and Part 75.

Each continuous monitoring system consists of all the equipment used to acquire and record data and includes the sample extraction and transport hardware, sample conditioning hardware, analyzers, and data processing hardware and software.

The permittee shall maintain on-site documentation from the USEPA or the Ohio EPA that the continuous NOx monitoring system has been certified in accordance with the applicable requirements specified in 40 CFR Part 60 and Part 75. The letter of certification shall be made available to the Director upon request.

The permittee shall maintain records of the following data obtained by the continuous NOx monitoring system: emissions of NOx in ppmvd at 15% oxygen on an hourly average basis, emissions of NOx in lbs/hr, results of daily zero/span calibration checks, results of quarterly cylinder gas audits, linearity checks, or relative accuracy test audits, and magnitude of manual calibration adjustments.

The permittee shall develop a written quality assurance/quality control plan for the continuous NOx monitoring system designed to ensure continuous valid and representative readings of NOx emissions in units of the applicable standard(s). The plan shall follow the applicable requirements of 40 CFR Part 60, Appendix F and 40 CFR Part 75, Appendix B. The quality assurance/quality control plan and a logbook documenting the activities related to the continuous NOx monitoring system must be kept on site and available for inspection during regular office hours.

The permittee may conduct the relative accuracy test audits for the continuous nitrogen oxides monitoring system in accordance with the frequencies required for monitoring systems subject to 40 CFR Part 75, Appendix B; however, the permittee is still required to provide the audit results in units of the applicable standard(s), in accordance with 40 CFR Part 60. In addition, linearity checks conducted pursuant to 40 CFR Part 75, Appendix B, may be used in place of quarterly cylinder gas audits, as required in 40 CFR Part 60.

**8.** The permittee shall operate and maintain equipment to continuously monitor and record CO emissions from this emissions unit in units of the applicable standard(s). Such continuous monitoring and recording equipment shall comply with the requirements specified in 40 CFR Part 60.

Each continuous monitoring system consists of all the equipment used to acquire and record data and includes the sample extraction and transport hardware, sample conditioning hardware, analyzers, and data processing hardware and software.

The permittee shall maintain on-site documentation from the USEPA or the Ohio EPA that the continuous CO monitoring system has been certified in accordance with 40 CFR Part 60. The letter of certification shall be made available to the Director upon request.

The permittee shall maintain records of the following data obtained by the continuous CO monitoring system: emissions of CO in lbs/hr, results of daily zero/span calibration checks, results of quarterly cylinder gas audits or relative accuracy test audits, and magnitude of manual calibration adjustments.

The permittee shall develop a written quality assurance/quality control plan for the continuous CO monitoring system designed to ensure continuous valid and representative readings of CO emissions in units of the applicable standard(s). The plan shall follow the requirements of 40 CFR Part 60, Appendix F. The quality assurance/quality control plan and a logbook documenting the activities related to the continuous CO monitoring system must be kept on site and available for inspection during regular office hours.

The permittee may conduct the relative accuracy test audits for the continuous carbon monoxide monitoring system in accordance with the frequencies required for monitoring systems subject to 40 CFR Part 75, Appendix B; however, the permittee is still required to provide the audit results in units of the applicable standard(s), in accordance with 40 CFR Part 60. Cylinder gas audits may be conducted in accordance with the frequencies specified in 40 CFR Part 75, Appendix B for linearity checks.

## IV. Reporting Requirements

**1.** 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.

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

a. all exceedances of the rolling, 12-month natural gas usage limitation for emissions units P001 through P008, combined;

b. all exceedances of the rolling, 12-month emission limitations for PE/PM10, SO2, NOx, CO, H2SO4 mist, VOC, benzene, beryllium and arsenic for emissions units P001 through P008, combined;

c. all exceedances of the sulfur content restriction (i.e., 0.05%, by weight) for the fuels (natural gas and diesel fuel) received for burning in this emissions unit;

d. all exceedances of the SO2 lbs/mmBtu emission limitation when burning diesel fuel in this emissions unit;

e. all exceedances of the 1.0 hour startup and shutdown cycle operational restriction;

f. all exceedances of the rolling, 12-month diesel fuel usage limitation for emissions units P001 through P008, combined;

g. all exceedances of the startup and shutdown emission limitations specified in Section A.I.1 when burning natural gas;

h. all exceedances of the startup and shutdown emission limitations specified in Section A.I.1 when burning diesel fuel; and

i. each day when a fuel other than natural gas or diesel fuel was burned in this emissions unit.

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

**4.** 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 Control Division documenting the date, commencement and completion times, duration, magnitude, reason (if known), and corrective actions taken (if any), of all instances of NOx values in excess of the applicable emission limitations (emissions of NOx in ppmvd at 15% oxygen on an hourly average basis and emissions of NOx in lbs/hr) specified in the terms and conditions of this permit.

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 Control Division documenting any continuous NOx 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 analyzer 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 analyzer 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 31, April 30, July 31, and October 31 of each year and shall address the data obtained during the previous calendar quarter.

The permittee shall submit a summary of the excess emission report. The summary shall be submitted to the Hamilton County Department of Environmental Services - Air Quality Control Division within 30 days following the end of each calendar quarter in a manner prescribed by the Director.

## IV. Reporting Requirements (continued)

**5.** 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 Control Division documenting the date, commencement and completion times, duration, magnitude, reason (if known), and corrective actions taken (if any) of all instances of CO values in excess of any applicable emission limitations (emissions of CO in lbs/hr) specified in the terms and conditions of this permit.

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 Control Division documenting any continuous CO 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 analyzer 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 analyzer while the emissions unit was on line shall also be included in the quarterly report. These quarterly excess emission reports shall be submitted by January 31, April 30, July 31, and October 31 of each year and shall address the data obtained during the previous calendar quarter.

The permittee shall submit a summary of the excess emission report. The summary shall be submitted to the Hamilton County Department of Environmental Services - Air Quality Control Division within 30 days following the end of the calendar quarter.

**6.** The permittee shall submit annual reports that specify the total mercury and lead emissions from this emissions unit for the previous calendar year. The reports shall be submitted by April 15 of each year. This reporting requirement may be satisfied by including and identifying the specific emission data for this emissions unit in the annual Fee Emission Report.

## V. Testing Requirements

**1.** Compliance with the emission limitations, fuel usage restrictions, and fuel sulfur content restriction specified in Sections A.I and A.II shall be determined by the following methods:

**1.a** Emission Limitations:
Emissions from startup and shutdown operations shall not exceed the following emission limitations:

when burning natural gas

83 lbs of NOx/startup and shutdown cycle
308 lbs of CO/startup and shutdown cycle

when burning diesel fuel

130 lbs of NOx/startup and shutdown cycle
354 lbs of CO/startup and shutdown cycle

Applicable Compliance Method:
The lbs/cycle emission limitations were established based on emission data contained in the PTI modification application (PTI 14-04682) submitted March, 2001 and the emission factors from the background document, Reference 16, for Stationary Gas Turbines in AP-42, Fifth Edition, Section 3.1, dated April 2000.

Compliance with the NOx and CO emission limitations shall be determined by the continuous emission monitoring data collected pursuant to the record keeping requirements specified in Sections A.III.2, A.III.7, and A.III.8.

## V. Testing Requirements (continued)

**1.b** Emission Limitations:
The hourly emissions from this emissions unit shall not exceed the following limitations:

i. 58.0 lbs of SO2 emissions/hour;
ii. 54.0 lbs of CO emissions/hour;
iii. 196.0 lbs of NOx emissions/hour;
iv. 6.0 lbs of H2SO4 mist emissions/hour; and
v. 10.0 lbs of VOC emissions/hour.

Applicable Compliance Method:
The hourly emission limitations are based upon the emissions unit's potentials to emit and the manufacturer's guaranteed emission data found in PTI 14-4682 submitted April 26, 1999.

Compliance with the NOx emission limitation shall be determined by the continuous emission monitoring data collected pursuant to the record keeping requirements specified in Section A.III.8.

Compliance with the CO emission limitation shall be determined by the continuous emission monitoring data collected pursuant to the record keeping requirements specified in Section A.III.9.

If required, the permittee shall demonstrate compliance with the hourly NOx emission limitation through emission tests performed in accordance with Methods 1 through 4 and 7 of 40 CFR Part 60, Appendix A.

If required, the permittee shall demonstrate compliance with the hourly SO2 emission limitation through emission tests performed in accordance with Methods 1 through 4 and 6 of 40 CFR Part 60, Appendix A.

If required, the permittee shall demonstrate compliance with the hourly CO emission limitation through emission tests performed in accordance with Methods 1 through 4 and 10 of 40 CFR Part 60, Appendix A.

If required, the permittee shall demonstrate compliance with the hourly H2SO4 mist emission limitation through emission tests performed in accordance with Methods 1 through 4 and 8 of 40 CFR Part 60, Appendix A.

If required, the permittee shall demonstrate compliance with the hourly VOC emission limitation through emission tests performed in accordance with Methods 1 through 4 and 25 of 40 CFR Part 60, Appendix A.

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

## V. Testing Requirements (continued)

**1.c** Emission Limitations:
The total emissions from emissions units P001 through P008, combined, shall not exceed the following emission limitations:

i. 60.5 tons of PE/PM10 emissions per rolling, 12-month period;
ii. 120.8 tons of SO2 emissions per rolling, 12-month period;
iii. 733.3 tons of NOx emissions per rolling, 12-month period;
iv. 541.0 tons of CO emissions per rolling, 12-month period;
v. 36.4 tons of VOC emissions per rolling, 12-month period;
vi. 12.2 tons of H2SO4 mist emissions per rolling, 12-month period;
vii. 7.7 tons of benzene* emissions per rolling, 12-month period;
viii. 0.00084 ton of beryllium* emissions per rolling, 12-month period; and
ix. 0.012 ton of arsenic* emissions per rolling, 12-month period.

Applicable Compliance Method:
Compliance with the rolling, 12-month PE/PM10, SO2, NOx, CO and VOC, H2SO4, benzene, beryllium and arsenic emission limitations specified above shall be determined by the record keeping requirements specified in Section A.III.2.j.

Emission factors for PE/PM10, VOC, SO2, and H2SO4 are specified in the manufacturers guaranteed performance data contained in the application for PTI 14-4682 submitted to the Hamilton County Department of Environmental Services on April 26, 1999.

* The emission factors as specified in AP-42, Fifth Edition, Section 3.1 "Stationary Gas Turbines", updated 4/00 are 0.000011 lb.mmBtu for arsenic, 0.000055 lb/mmBtu for benzene, and 0.00000031 lb/mmBtu for beryllium, from diesel fuel-fired turbines.

The emission factor as specified in AP-42 Fifth Edition, Section 3.1 "Stationary Gas Turbines", updated 4/00 is 0.000012 lb/mmBtu for benzene, from natural gas-fired turbines.

The emission factor for beryllium and arsenic when natural gas is burned is insignificant based upon the manufacturer's guaranteed emission data contained in the application for PTI 14-4682 submitted to the Hamilton County Department of Environmental Services on April 26, 1999.

**1.d** Emission Limitations:
0.15 ton per year of lead emissions and 0.0023 ton per year of mercury emissions.

Applicable Compliance Method:
The lead and mercury emission limitations specified above were determined by multiplying the maximum fuel usage capacity of the equipment, as provided by the manufacturer in PTI 14-4682 submitted April 26, 1999, by the pollutant specific emission factor found in AP-42, Fifth Edition, Section 3.1 "Stationary Gas Turbines," updated 4/00, by the maximum heat content of the fuel, and dividing by 2,000 lbs/ton. The emission factor as specified in the above referenced AP-42 is 0.000014 lbs/mmBtu for lead and 0.0000012 lbs/mmBtu for mercury, from diesel fuel-fired turbines.

The emission factor for mercury and lead when natural gas is burned is insignificant based upon the manufacturer's guaranteed emission data contained in the application for PTI 14-4682 submitted to the Hamilton County Department of Environmental Services on April 26, 1999.

## V. Testing Requirements (continued)

**1.e** Emission Limitations:
when burning natural gas, 15 ppm of NOx, by volume, at 15% oxygen, on a dry basis, (as a 1-hour average, at full load)

when burning diesel fuel, 42 ppm of NOx, by volume, at 15% oxygen, on a dry basis (as a 1-hour average, at full load)

when burning natural gas at full load, 12 ppm of NOx, by volume, at 15% oxygen, on a dry basis (based on a rolling, 12-month summation of the average monthly NOx emissions, in ppm)

Applicable Compliance Method:
Compliance with the NOx emission limitations shall be determined by the continuous emission monitoring data collected pursuant to the record keeping requirements specified in Sections A.III.6 and A.III.7 and the record keeping requirements specified in Section A.III.2.

If required, the permittee shall demonstrate compliance with the non-rolling ppm NOx emission limitations through emission tests performed in accordance with Methods 1 through 4 and 7 of 40 CFR Part 60, Appendix A.

**1.f** Emission Limitation:
0.008 lb of PE/PM10 emissions/mmBtu

Applicable Compliance Method:
The lb/mmBtu emission limitation represents the emissions unit's potential to emit and is based upon the manufacturer's guaranteed emission data contained in the application for PTI 14-4682 submitted to the Hamilton County Department of Environmental Services on April 26, 1999. The total PM10 emissions were evaluated and did not trigger any additional federal requirements, therefore, the emissions are being regulated as particulate emissions (PE) and are subject to the PE compliance demonstration as noted below.

If required, the permittee shall demonstrate compliance with the PE/PM10 emission limitation through emission tests performed in accordance with Methods 1 through 5 of 40 CFR Part 60, Appendix A.

**1.g** Emission Limitation:
Visible particulate emissions from any stack shall not exceed 20% opacity, as a 6-minute average, except as specified by rule, when burning diesel fuel.

Applicable Compliance Method:
If required, compliance with the visible particulate emission limitation shall be determined 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).

**1.h** Emission Limitation:
Visible particulate emissions from any stack shall not exceed 10% opacity, as a 6-minute average, when burning natural gas.

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

## V. Testing Requirements (continued)

**1.i** Emission Limitation:
0.0456 lb of SO2 emissions/mmBtu when burning diesel fuel;

Applicable Compliance Method:
Compliance with the SO2 emission limitation shall be determined by the sulfur analysis of the fuels burned pursuant to the requirements specified in Section A.lll.4 and by documenting that the sulfur content of each shipment of oil received during a calendar month or each daily sample meets the 0.05%, by weight, sulfur content restriction.

If required, the permittee shall demonstrate compliance with the SO2 emission limitation through emission tests performed in accordance with Methods 1 through 4 and 6 of 40 CFR Part 60, Appendix A.

**1.j** Sulfur Content Restriction:
The sulfur content of the natural gas and diesel fuel burned in this emissions unit shall not exceed 0.05% sulfur, by weight.

Applicable Compliance Method:
Compliance with the sulfur content restriction shall be determined by the record keeping requirements specified in Sections A.III.3 and A.III.4.

**1.k** Natural Gas and Diesel Fuel Usage Restrictions:
The maximum annual natural gas usage rate for emissions units P001 through P008, combined, shall not exceed 20,300,000,000 cubic feet per rolling, 12-month period.

The maximum annual diesel fuel usage rate for emissions units P001 through P008, combined, shall not exceed 34,000,000 gallons per rolling, 12-month period.

Applicable Compliance Method:
Compliance with the natural gas and diesel fuel usage restrictions shall be determined by the record keeping requirements specified in Section A.III.2.

## 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 |
|---|---|---|
| 84.65 megawatt (nominal) natural gas/diesel fuel-fired simple cycle combustion turbine using dry low NOx combustors (natural gas firing) or water injection (diesel fuel firing) to control NOx emissions. | OAC rule 3745-31-28 | The requirements established pursuant to this rule are equivalent to the requirements established pursuant to 40 CFR Parts 63.41 through 63.44. This regulation has been promulgated in the Ohio Administrative Code; however, it has not yet been approved as part of the Ohio State Implementation Plan. |

**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:** #2 Turbine (P002)

**Activity Description:** 84.65 Megawatt (Nominal) Simple-Cycle Combustion Turbine #2

## 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 |
|---|---|---|
| 84.65 megawatt (nominal) natural gas/diesel fuel-fired simple cycle combustion turbine using dry low NOx combustors (natural gas firing) or water injection (diesel fuel firing) to control NOx emissions. | OAC rules 3745-31-11 through 3745-31-20<br>(PTI 14-04682) | This emissions unit shall not exceed the following emission limitations:<br><br>58.0 lbs of sulfur dioxide (SO2) emissions/hour*<br><br>6.0 lbs of sulfuric acid (H2SO4) mist emissions/hour*<br><br>0.008 lb of particulate emissions (PE)/particulate matter with a diameter of 10 microns or less (PM10** emissions)/mmBtu*<br><br>* The hourly emission limitations and the lb of PE/PM10 emissions/mmBtu emission limitation specified above represent this emissions unit's potentials to emit for all operating conditions, including startup and shutdown. Therefore, no additional monitoring, record keeping or reporting requirements are required to demonstrate compliance with these emission limitations.<br><br>**The total PM10 emissions were evaluated and did not trigger any additional federal requirements, therefore, the emissions are being regulated as particulate emissions (PE). |

| Operations, Property, and/or Equipment | Applicable Rules/ Requirements | Applicable Emissions Limitations/Control Measures |
|---|---|---|
| | | 196.0 lbs of NOx emissions/hour, excluding startup and shutdown periods<br><br>54.0 lbs of CO emissions/hour, excluding startup and shutdown periods<br><br>when burning natural gas, 15 ppm of NOx, by volume, at 15% oxygen, on a dry basis, (as a 1-hour average, at full load)<br><br>when burning diesel fuel, 42 ppm of NOx, by volume, at 15% oxygen, on a dry basis (as a 1-hour average, at full load)<br><br>when burning natural gas at full load, 12 ppm of NOx, by volume, at 15% oxygen, on a dry basis (based on a rolling, 12-month average summation of the monthly NOx emissions, in ppm)<br><br>when burning diesel fuel, 0.0456 lb of SO2 emissions/mmBtu of actual heat input<br><br>The sulfur content of the natural gas and diesel fuel burned in this emissions unit shall not exceed 0.05% sulfur, by weight.<br><br>Emissions from startup and shutdown operations shall not exceed the following emission limitations:<br><br>when burning natural gas<br><br>83 lbs of NOx/startup and shutdown cycle<br>308 lbs of CO/startup and shutdown cycle<br><br>when burning diesel fuel<br><br>130 lbs of NOx/startup and shutdown cycle<br>354 lbs of CO/startup and shutdown cycle<br><br>See Section A.I.2.c below. |

| Operations, Property, and/or Equipment | Applicable Rules/ Requirements | Applicable Emissions Limitations/Control Measures |
|---|---|---|
| | | Emissions units P001 through P008, combined, shall not exceed the following emission limitations:<br><br>60.5 tons of PE/PM10 emissions per rolling, 12-month period<br><br>120.8 tons of SO2 emissions per rolling, 12-month period<br><br>733.3 tons of nitrogen oxides (NOx) emissions per rolling, 12-month period<br><br>541.0 tons of carbon monoxide (CO) emissions per rolling, 12-month period<br><br>12.2 tons of H2SO4 mist emissions per rolling, 12-month period<br><br>7.7 tons of benzene emissions per rolling, 12-month period<br><br>0.00084 ton of beryllium emissions per rolling, 12-month period<br><br>0.012 ton of arsenic emissions per rolling, 12-month period<br><br>The rolling, 12-month emission limitations are based upon a summation of the pollutant-specific emissions generated under all operating conditions, including startup and shutdown periods, for both natural gas and diesel fuel. |

| Operations, Property, and/or Equipment | Applicable Rules/ Requirements | Applicable Emissions Limitations/Control Measures |
|---|---|---|
| | OAC rule 3745-31-05(A)(3) (PTI 14-04682) | This emissions unit shall not exceed the following emission limitations:<br><br>10.0 lbs of volatile organic compound (VOC) emissions/hour*<br>0.15 ton per year of lead emissions<br>0.0023 ton per year of mercury emissions<br><br>See Section A.I.2.b below.<br><br>Compliance with this rule also includes compliance with the requirements of OAC rule 3745-31-05(C) and OAC rule 3745-17-07(A) when burning diesel fuel.<br><br>* The hourly VOC emission limitation specified above represent this emissions unit's potential to emit for all operating conditions, including startup and shutdown. Therefore, no additional monitoring, record keeping or reporting requirements are required to demonstrate compliance with this emission limitation. |
| | OAC rule 3745-31-05(C) | 36.4 tons of VOC emissions per rolling, 12-month period from emissions units P001 through P008, combined. |
| | OAC rule 3745-17-07(A) | See Section A.I.2.a below. |
| | 40 CFR Part 60, Subpart GG | The emission limitations established in 40 CFR Part 60, Subpart GG for SO2 and NOx are less stringent than those established pursuant to OAC rule 3745-31-05(C). |
| | OAC rule 3745-17-11(B)(4) | The PE limitation specified by this rule is less stringent the PE limitation established pursuant to OAC rule 3745-31-05(C). |
| | OAC rule 3745-18-06(F) | The SO2 emission limitation specified by this rule (0.5 lb of SO2 emissions/mmBtu) is less stringent than the SO2 emission limitation established pursuant to OAC rule 3745-31-05(C). |
| | OAC rules 3745-21-08(B) and 3745-23-06(B) | See Section A.I.2.j below. |

## 2. Additional Terms and Conditions

**2.a** Visible PE from any stack shall not exceed 20% opacity, as a 6-minute average, except as specified by rule when burning diesel fuel.

**2.b** Visible PE from any stack shall not exceed 10% opacity, as a 6-minute average when burning natural gas.

**2.c** The permittee shall operate and maintain dry low NOx burners when burning natural gas and operate and maintain a water injection system when burning diesel fuel.

**2.d** "Full load" shall be defined as the nameplate electrical output of 84.65 megawatts. Any load that is greater than or equal to 90% of the nameplate electrical output shall be considered full load.

**2.e** "Normal operation" shall be defined as the period when the combustion turbine achieves dry low NOx mode (GE Mode 6). GE Mode 6 is defined by the manufacturer as the low emissions mode during which all burner nozzles are in use, burning a lean pre-mixed gas for steady-state operation. The continuous emissions monitoring system will indicate and record the GE Mode 6 status of the combustion turbine, including when the emissions unit is shutdown and when operating in startup and shutdown modes.

**2.f** "Startup" shall be defined as the period between when the combustion turbine is initially started (initial fuel light-off) until the combustion turbine completes transition to GE Mode 6. "Shutdown" shall be defined as the period beginning when the combustion turbine leaves the GE Mode 6 and ending when combustion has ceased.

**2.g** "Startup and shutdown cycle" shall be defined as a startup period followed by a consecutive shutdown period.

**2.h** For the purpose of this permit, the term "diesel fuel" shall be considered to be any low sulfur fuel oil that is burned in this emissions unit, as defined in 40 CFR Part 72.2.

**2.i** Compliance with the startup and shutdown NOx and CO lbs/cycle emission limitations, the NOx and CO emission limitations during steady-state operations, and the NOx ppm emission limitations during full load operations shall be demonstrated by the use of dual range NOx and CO continuous emission monitoring systems (CEMs). For CEM systems with dual ranges, certification testing shall be performed on the range normally used for measuring emissions.

**2.j** 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 technology requirements established pursuant to OAC rule 3745-31-05(A)(3) in Permit to Install 14-4682.

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 technology requirements established pursuant to OAC rule 3745-31-05(A)(3) in Permit to Install 14-4682.

**2.k** For the purposes of this permit and for the hazardous air pollutants (HAPs) emitted from this emissions unit, the best available control technology determination to satisfy the requirements of 40 CFR Part 52.21 is equivalent to the maximum achievable control technology determination used to satisfy the requirements of 40 CFR Parts 63.41 through 63.44.

**2. Additional Terms and Conditions (continued)**

**2.l** In lieu of the requirements of 40 CFR Part 60.334(a) to install and operate a continuous monitoring system to monitor and record the fuel consumption and the ratio of water to fuel being fired in this emissions unit, the permittee shall operate and maintain systems to continuously monitor and record emissions of NOx for this emissions unit in accordance with this permit.

In lieu of the excess emissions reports required under 40 CFR Part 60.334, the permittee shall submit excess emissions reports for this emissions unit in accordance with this permit.

In lieu of the test methods and procedures required under 40 CFR Part 60.335, the permittee shall follow the monitoring and testing requirements for this emissions unit in accordance with this permit.

## II. Operational Restrictions

**1.** The maximum annual natural gas usage rate for emissions units P001 through P008, combined, shall not exceed 20,300,000,000 cubic feet per rolling, 12-month period.

**2.** The maximum annual diesel fuel usage rate for emissions units P001 through P008, combined, shall not exceed 34,000,000 gallons per rolling, 12-month period.

**3.** The permittee shall burn only pipeline quality natural gas or diesel fuel in this emissions unit.

**4.** The quality of diesel fuel burned in this emissions unit shall have a combination of heat and sulfur content which is sufficient to comply with the allowable SO2 emission limitation of 0.0456 lb of SO2/mmBtu of actual heat input. The diesel fuel shall have a sulfur content of 0.05%, by weight, or less.

**5.** When the emissions unit is operating in startup and shutdown conditions, as defined in Section A.I.2.f above, each startup and shutdown cycle shall not exceed 1.0 hour in duration.

**6.** With the exception of startup and shutdown, this emissions unit shall be operated in GE Mode 6, defined as normal or full load operation (see Sections A.I.2.d and A.I.2.e above).

## III. Monitoring and/or Record Keeping Requirements

**1.** The permittee shall maintain daily records of the following information:

a. the emissions unit's actual electrical output for each operating hour; and

b. for each day during which the permittee burns a fuel other than pipeline quality natural gas and/or diesel fuel, the permittee shall maintain a record of the type and quantity of fuel burned in this emissions unit.

**2.** The permittee shall maintain monthly records of the following information:

a. the total amount of natural gas burned, in cubic feet, for emissions units P001 through P008, combined;

b. the total amount of diesel fuel burned, in gallons, for emissions units P001 through P008, combined;

c. the rolling, 12-month summation of the total amount of natural gas burned, in cubic feet, for emissions units P001 through P008, combined (the amount of natural gas burned for the current month plus the total amount of natural gas burned for the previous 11 calendar months);

d. the rolling, 12-month summation of the total amount of diesel fuel burned, in gallons, for emissions units P001 through P008, combined (the amount of diesel fuel burned for the current month plus the total amount of diesel fuel burned for the previous 11 calendar months);

e. the date and duration, in minutes, of each startup and shutdown cycle;

f. the emissions, in pounds, for NOx* and CO* when burning natural gas for each startup and shutdown cycle;

g. the emissions, in pounds, for NOx* and CO* when burning diesel fuel for each startup and shutdown cycle;

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

h. the total emissions, in tons, for NOx*, CO*, PE/PM10, SO2 , VOC, H2SO4, and benzene when burning natural gas for all operating conditions;

i. the total emissions, in tons, for NOx*, CO*, PE/PM10, SO2, VOC, H2SO4, benzene, beryllium and arsenic when burning diesel fuel for all operating conditions;

j. the rolling, 12-month emissions, in tons, for NOx*, CO*, PE/PM10, SO2, VOC, H2SO4, benzene, beryllium and arsenic for emissions units P001 through P008, combined, when burning natural gas and diesel fuel (the total emissions calculated in (h) + (i)) for the current month plus the total emissions for the previous 11 calendar months); and

k. the rolling, 12-month average of NOx* emissions, in ppm, when burning natural gas at full load for this emissions unit (the NOx ppm average for the current month (from the CEMs data) plus the total NOx ppm average for the previous 11 calendar months).

* The permittee shall use the continuous NOx and CO emissions monitoring data to determine the NOx and CO emissions for these emissions units. During any period when the NOx and/or the CO emissions monitoring systems are not operational, the permittee shall use the appropriate missing data procedures specified in 40 CFR Part 75 to determine NOx and CO emissions or an approved data substitution protocol for the purpose of calculating the rolling, 12-month emission rates. The data substitution values shall not be used to demonstrate compliance with the hourly NOx and CO emission limitations applicable during normal operation of this emissions unit.

**3.** The permittee shall monitor and record the sulfur content of the natural gas being burned in this emissions unit or make the demonstration that the sulfur content of the natural gas does not need to be monitored and recorded in accordance with the provisions specified in 40 CFR Part 60.334(b). Owners, operators or fuel vendors may develop custom fuel schedules for the determination of the sulfur content based on the design and operation of the affected facility and the characteristics of the fuel supply. Except as provided in 40 CFR Parts 60.334(i)(3)(i) and 60.334(i)(3)(ii), these custom schedules shall be substantiated with data and must be approved by the Ohio EPA, Central Office before they can be used.

Analyses for the purpose of determining the sulfur content of the natural gas may be performed by the permittee, the fuel vendor, or any other qualified agency in accordance with the analytical methods specified in 40 CFR Part 60, Subpart GG, Section 60.335(d) or equivalent methods as approved by the Administrator.

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

**4.** The permittee shall maintain records of the diesel fuel burned in this emissions unit in accordance with either Alternative 1 or Alternative 2 described below:

a. Alternative 1:

For each shipment of oil received for burning in this emissions unit, the permittee shall collect or require the oil supplier to collect a representative grab sample of oil and maintain records of the total quantity of oil received, the permittee's or oil supplier's analyses for sulfur content and heat content, and the calculated sulfur dioxide emission rate (in lbs/mmBtu). (The sulfur dioxide emission rate shall be calculated in accordance with the formula specified in OAC rule 3745-18-04(F).) 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 may be represented by a single batch analysis from the supplier.

b. Alternative 2:

The permittee shall collect a representative grab sample of oil that is burned in this emissions unit for each day when the emission unit is in operation. If additional fuel oil is added to the tank serving this emissions unit on a day when the emissions unit is in operation, the permittee shall collect a sufficient number of grab samples to develop a composite sample representative of the fuel oil burned in this emissions unit. A representative grab sample of oil does not need to be collected on days when this emissions unit is only operated for the purpose of "test-firing". The permittee shall maintain records of the total quantity of oil burned each day (except for the purpose of test-firing), the permittee's analyses for sulfur content and heat content, and the calculated sulfur dioxide emission rate (in lbs/mmBtu). [The sulfur dioxide emission rate shall be calculated in accordance with the formula specified in OAC rule 3745-18-04(F).]

The permittee shall perform or require the supplier to perform the analyses for sulfur content and heat content in accordance with the following ASTM methods: ASTM method D4294 for sulfur content and ASTM method D240 for heat content. The newest or most recent revisions to the applicable test method shall be used for analyses. Alternative, equivalent methods may be used upon written approval by the Hamilton County Department of Environmental Services - Air Quality Control Division.

**5.** The permittee shall operate and maintain equipment to continuously monitor and record the actual fuel flow to this emissions unit when it is in operation. Such continuous monitoring and recording equipment shall comply with the requirements specified in 40 CFR Part 75. If the fuel flow monitoring and/or recording equipment is (are) not in service when the emissions unit is in operation, the permittee shall comply with the appropriate missing data procedures specified in 40 CFR Part 75.

**6.** The permittee shall operate and maintain equipment to continuously monitor and record the percent oxygen (as a 1-hr average) in the stack serving this emissions unit when the emissions unit is in operation. Such continuous monitoring and recording equipment shall comply with the requirements specified in 40 CFR Part 75. The monitoring and recording equipment shall be installed, calibrated, operated and maintained in accordance with the manufacturer's recommendations, with any modifications deemed necessary by the permittee.

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

**7.** The permittee shall operate and maintain equipment to continuously monitor and record NOx emissions from this emissions unit in units of the applicable standard(s). Such continuous monitoring and recording equipment shall comply with the applicable requirements specified in 40 CFR Part 60 and Part 75.

Each continuous monitoring system consists of all the equipment used to acquire and record data and includes the sample extraction and transport hardware, sample conditioning hardware, analyzers, and data processing hardware and software.

The permittee shall maintain on-site documentation from the USEPA or the Ohio EPA that the continuous NOx monitoring system has been certified in accordance with the applicable requirements specified in 40 CFR Part 60 and Part 75. The letter of certification shall be made available to the Director upon request.

The permittee shall maintain records of the following data obtained by the continuous NOx monitoring system: emissions of NOx in ppmvd at 15% oxygen on an hourly average basis, emissions of NOx in lbs/hr, results of daily zero/span calibration checks, results of quarterly cylinder gas audits, linearity checks, or relative accuracy test audits, and magnitude of manual calibration adjustments.

The permittee shall develop a written quality assurance/quality control plan for the continuous NOx monitoring system designed to ensure continuous valid and representative readings of NOx emissions in units of the applicable standard(s). The plan shall follow the applicable requirements of 40 CFR Part 60, Appendix F and 40 CFR Part 75, Appendix B. The quality assurance/quality control plan and a logbook documenting the activities related to the continuous NOx monitoring system must be kept on site and available for inspection during regular office hours.

The permittee may conduct the relative accuracy test audits for the continuous nitrogen oxides monitoring system in accordance with the frequencies required for monitoring systems subject to 40 CFR Part 75, Appendix B; however, the permittee is still required to provide the audit results in units of the applicable standard(s), in accordance with 40 CFR Part 60. In addition, linearity checks conducted pursuant to 40 CFR Part 75, Appendix B, may be used in place of quarterly cylinder gas audits, as required in 40 CFR Part 60.

**8.** The permittee shall operate and maintain equipment to continuously monitor and record CO emissions from this emissions unit in units of the applicable standard(s). Such continuous monitoring and recording equipment shall comply with the requirements specified in 40 CFR Part 60.

Each continuous monitoring system consists of all the equipment used to acquire and record data and includes the sample extraction and transport hardware, sample conditioning hardware, analyzers, and data processing hardware and software.

The permittee shall maintain on-site documentation from the USEPA or the Ohio EPA that the continuous CO monitoring system has been certified in accordance with 40 CFR Part 60. The letter of certification shall be made available to the Director upon request.

The permittee shall maintain records of the following data obtained by the continuous CO monitoring system: emissions of CO in lbs/hr, results of daily zero/span calibration checks, results of quarterly cylinder gas audits or relative accuracy test audits, and magnitude of manual calibration adjustments.

The permittee shall develop a written quality assurance/quality control plan for the continuous CO monitoring system designed to ensure continuous valid and representative readings of CO emissions in units of the applicable standard(s). The plan shall follow the requirements of 40 CFR Part 60, Appendix F. The quality assurance/quality control plan and a logbook documenting the activities related to the continuous CO monitoring system must be kept on site and available for inspection during regular office hours.

The permittee may conduct the relative accuracy test audits for the continuous carbon monoxide monitoring system in accordance with the frequencies required for monitoring systems subject to 40 CFR Part 75, Appendix B; however, the permittee is still required to provide the audit results in units of the applicable standard(s), in accordance with 40 CFR Part 60. Cylinder gas audits may be conducted in accordance with the frequencies specified in 40 CFR Part 75, Appendix B for linearity checks.

## IV. Reporting Requirements

**1.** 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.

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

a. all exceedances of the rolling, 12-month natural gas usage limitation for emissions units P001 through P008, combined;

b. all exceedances of the rolling, 12-month emission limitations for PE/PM10, SO2, NOx, CO, H2SO4 mist, VOC, benzene, beryllium and arsenic for emissions units P001 through P008, combined;

c. all exceedances of the sulfur content restriction (i.e., 0.05%, by weight) for the fuels (natural gas and diesel fuel) received for burning in this emissions unit;

d. all exceedances of the SO2 lbs/mmBtu emission limitation when burning diesel fuel in this emissions unit;

e. all exceedances of the 1.0 hour startup and shutdown cycle operational restriction;

f. all exceedances of the rolling, 12-month diesel fuel usage limitation for emissions units P001 through P008, combined;

g. all exceedances of the startup and shutdown emission limitations specified in Section A.I.1 when burning natural gas;

h. all exceedances of the startup and shutdown emission limitations specified in Section A.I.1 when burning diesel fuel; and

i. each day when a fuel other than natural gas or diesel fuel was burned in this emissions unit.

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

**4.** 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 Control Division documenting the date, commencement and completion times, duration, magnitude, reason (if known), and corrective actions taken (if any), of all instances of NOx values in excess of the applicable emission limitations (emissions of NOx in ppmvd at 15% oxygen on an hourly average basis and emissions of NOx in lbs/hr) specified in the terms and conditions of this permit.

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 Control Division documenting any continuous NOx 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 analyzer 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 analyzer 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 31, April 30, July 31, and October 31 of each year and shall address the data obtained during the previous calendar quarter.

The permittee shall submit a summary of the excess emission report. The summary shall be submitted to the Hamilton County Department of Environmental Services - Air Quality Control Division within 30 days following the end of each calendar quarter in a manner prescribed by the Director.

## IV. Reporting Requirements (continued)

**5.** 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 Control Division documenting the date, commencement and completion times, duration, magnitude, reason (if known), and corrective actions taken (if any) of all instances of CO values in excess of any applicable emission limitations (emissions of CO in lbs/hr) specified in the terms and conditions of this permit.

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 Control Division documenting any continuous CO 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 analyzer 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 analyzer while the emissions unit was on line shall also be included in the quarterly report. These quarterly excess emission reports shall be submitted by January 31, April 30, July 31, and October 31 of each year and shall address the data obtained during the previous calendar quarter.

The permittee shall submit a summary of the excess emission report. The summary shall be submitted to the Hamilton County Department of Environmental Services - Air Quality Control Division within 30 days following the end of the calendar quarter.

**6.** The permittee shall submit annual reports that specify the total mercury and lead emissions from this emissions unit for the previous calendar year. The reports shall be submitted by April 15 of each year. This reporting requirement may be satisfied by including and identifying the specific emission data for this emissions unit in the annual Fee Emission Report.

## V. Testing Requirements

**1.** Compliance with the emission limitations, fuel usage restrictions, and fuel sulfur content restriction specified in Sections A.I and A.II shall be determined by the following methods:

**1.a** Emission Limitations:
Emissions from startup and shutdown operations shall not exceed the following emission limitations:

when burning natural gas

83 lbs of NOx/startup and shutdown cycle
308 lbs of CO/startup and shutdown cycle

when burning diesel fuel

130 lbs of NOx/startup and shutdown cycle
354 lbs of CO/startup and shutdown cycle

Applicable Compliance Method:
The lbs/cycle emission limitations were established based on emission data contained in the PTI modification application (PTI 14-04682) submitted March, 2001 and the emission factors from the background document, Reference 16, for Stationary Gas Turbines in AP-42, Fifth Edition, Section 3.1, dated April 2000.

Compliance with the NOx and CO emission limitations shall be determined by the continuous emission monitoring data collected pursuant to the record keeping requirements specified in Sections A.III.2, A.III.7, and A.III.8.

## V. Testing Requirements (continued)

**1.b** Emission Limitations:
The hourly emissions from this emissions unit shall not exceed the following limitations:

i. 58.0 lbs of SO2 emissions/hour;
ii. 54.0 lbs of CO emissions/hour;
iii. 196.0 lbs of NOx emissions/hour;
iv. 6.0 lbs of H2SO4 mist emissions/hour; and
v. 10.0 lbs of VOC emissions/hour.

Applicable Compliance Method:
The hourly emission limitations are based upon the emissions unit's potentials to emit and the manufacturer's guaranteed emission data found in PTI 14-4682 submitted April 26, 1999.

Compliance with the NOx emission limitation shall be determined by the continuous emission monitoring data collected pursuant to the record keeping requirements specified in Section A.III.8.

Compliance with the CO emission limitation shall be determined by the continuous emission monitoring data collected pursuant to the record keeping requirements specified in Section A.III.9.

If required, the permittee shall demonstrate compliance with the hourly NOx emission limitation through emission tests performed in accordance with Methods 1 through 4 and 7 of 40 CFR Part 60, Appendix A.

If required, the permittee shall demonstrate compliance with the hourly SO2 emission limitation through emission tests performed in accordance with Methods 1 through 4 and 6 of 40 CFR Part 60, Appendix A.

If required, the permittee shall demonstrate compliance with the hourly CO emission limitation through emission tests performed in accordance with Methods 1 through 4 and 10 of 40 CFR Part 60, Appendix A.

If required, the permittee shall demonstrate compliance with the hourly H2SO4 mist emission limitation through emission tests performed in accordance with Methods 1 through 4 and 8 of 40 CFR Part 60, Appendix A.

If required, the permittee shall demonstrate compliance with the hourly VOC emission limitation through emission tests performed in accordance with Methods 1 through 4 and 25 of 40 CFR Part 60, Appendix A.

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

## V. Testing Requirements (continued)

**1.c** Emission Limitations:
The total emissions from emissions units P001 through P008, combined, shall not exceed the following emission limitations:

i. 60.5 tons of PE/PM10 emissions per rolling, 12-month period;
ii. 120.8 tons of SO2 emissions per rolling, 12-month period;
iii. 733.3 tons of NOx emissions per rolling, 12-month period;
iv. 541.0 tons of CO emissions per rolling, 12-month period;
v. 36.4 tons of VOC emissions per rolling, 12-month period;
vi. 12.2 tons of H2SO4 mist emissions per rolling, 12-month period;
vii. 7.7 tons of benzene* emissions per rolling, 12-month period;
viii. 0.00084 ton of beryllium* emissions per rolling, 12-month period; and
ix. 0.012 ton of arsenic* emissions per rolling, 12-month period.

Applicable Compliance Method:
Compliance with the rolling, 12-month PE/PM10, SO2, NOx, CO and VOC, H2SO4, benzene, beryllium and arsenic emission limitations specified above shall be determined by the record keeping requirements specified in Section A.III.2.j.

Emission factors for PE/PM10, VOC, SO2, and H2SO4 are specified in the manufacturers guaranteed performance data contained in the application for PTI 14-4682 submitted to the Hamilton County Department of Environmental Services on April 26, 1999.

* The emission factors as specified in AP-42, Fifth Edition, Section 3.1 "Stationary Gas Turbines", updated 4/00 are 0.000011 lb.mmBtu for arsenic, 0.000055 lb/mmBtu for benzene, and 0.00000031 lb/mmBtu for beryllium, from diesel fuel-fired turbines.

The emission factor as specified in AP-42 Fifth Edition, Section 3.1 "Stationary Gas Turbines", updated 4/00 is 0.000012 lb/mmBtu for benzene, from natural gas-fired turbines.

The emission factor for beryllium and arsenic when natural gas is burned is insignificant based upon the manufacturer's guaranteed emission data contained in the application for PTI 14-4682 submitted to the Hamilton County Department of Environmental Services on April 26, 1999.

**1.d** Emission Limitations:
0.15 ton per year of lead emissions and 0.0023 ton per year of mercury emissions.

Applicable Compliance Method:
The lead and mercury emission limitations specified above were determined by multiplying the maximum fuel usage capacity of the equipment, as provided by the manufacturer in PTI 14-4682 submitted April 26, 1999, by the pollutant specific emission factor found in AP-42, Fifth Edition, Section 3.1 "Stationary Gas Turbines," updated 4/00, by the maximum heat content of the fuel, and dividing by 2,000 lbs/ton. The emission factor as specified in the above referenced AP-42 is 0.000014 lbs/mmBtu for lead and 0.0000012 lbs/mmBtu for mercury, from diesel fuel-fired turbines.

The emission factor for mercury and lead when natural gas is burned is insignificant based upon the manufacturer's guaranteed emission data contained in the application for PTI 14-4682 submitted to the Hamilton County Department of Environmental Services on April 26, 1999.

## V. Testing Requirements (continued)

**1.e** Emission Limitations:
when burning natural gas, 15 ppm of NOx, by volume, at 15% oxygen, on a dry basis, (as a 1-hour average, at full load)

when burning diesel fuel, 42 ppm of NOx, by volume, at 15% oxygen, on a dry basis (as a 1-hour average, at full load)

when burning natural gas at full load, 12 ppm of NOx, by volume, at 15% oxygen, on a dry basis (based on a rolling, 12-month summation of the average monthly NOx emissions, in ppm)

Applicable Compliance Method:
Compliance with the NOx emission limitations shall be determined by the continuous emission monitoring data collected pursuant to the record keeping requirements specified in Sections A.III.6 and A.III.7 and the record keeping requirements specified in Section A.III.2.

If required, the permittee shall demonstrate compliance with the non-rolling ppm NOx emission limitations through emission tests performed in accordance with Methods 1 through 4 and 7 of 40 CFR Part 60, Appendix A.

**1.f** Emission Limitation:
0.008 lb of PE/PM10 emissions/mmBtu

Applicable Compliance Method:
The lb/mmBtu emission limitation represents the emissions unit's potential to emit and is based upon the manufacturer's guaranteed emission data contained in the application for PTI 14-4682 submitted to the Hamilton County Department of Environmental Services on April 26, 1999. The total PM10 emissions were evaluated and did not trigger any additional federal requirements, therefore, the emissions are being regulated as particulate emissions (PE) and are subject to the PE compliance demonstration as noted below.

If required, the permittee shall demonstrate compliance with the PE/PM10 emission limitation through emission tests performed in accordance with Methods 1 through 5 of 40 CFR Part 60, Appendix A.

**1.g** Emission Limitation:
Visible particulate emissions from any stack shall not exceed 20% opacity, as a 6-minute average, except as specified by rule, when burning diesel fuel.

Applicable Compliance Method:
If required, compliance with the visible particulate emission limitation shall be determined 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).

**1.h** Emission Limitation:
Visible particulate emissions from any stack shall not exceed 10% opacity, as a 6-minute average, when burning natural gas.

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

## V. Testing Requirements (continued)

**1.i** Emission Limitation:
0.0456 lb of SO2 emissions/mmBtu when burning diesel fuel;

Applicable Compliance Method:
Compliance with the SO2 emission limitation shall be determined by the sulfur analysis of the fuels burned pursuant to the requirements specified in Section A.lll.4 and by documenting that the sulfur content of each shipment of oil received during a calendar month or each daily sample meets the 0.05%, by weight, sulfur content restriction.

If required, the permittee shall demonstrate compliance with the SO2 emission limitation through emission tests performed in accordance with Methods 1 through 4 and 6 of 40 CFR Part 60, Appendix A.

**1.j** Sulfur Content Restriction:
The sulfur content of the natural gas and diesel fuel burned in this emissions unit shall not exceed 0.05% sulfur, by weight.

Applicable Compliance Method:
Compliance with the sulfur content restriction shall be determined by the record keeping requirements specified in Sections A.III.3 and A.III.4.

**1.k** Natural Gas and Diesel Fuel Usage Restrictions:
The maximum annual natural gas usage rate for emissions units P001 through P008, combined, shall not exceed 20,300,000,000 cubic feet per rolling, 12-month period.

The maximum annual diesel fuel usage rate for emissions units P001 through P008, combined, shall not exceed 34,000,000 gallons per rolling, 12-month period.

Applicable Compliance Method:
Compliance with the natural gas and diesel fuel usage restrictions shall be determined by the record keeping requirements specified in Section A.III.2.

## 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 |
|---|---|---|
| 84.65 megawatt (nominal) natural gas/diesel fuel-fired simple cycle combustion turbine using dry low NOx combustors (natural gas firing) or water injection (diesel fuel firing) to control NOx emissions. | OAC rule 3745-31-28 | The requirements established pursuant to this rule are equivalent to the requirements established pursuant to 40 CFR Parts 63.41 through 63.44. This regulation has been promulgated in the Ohio Administrative Code; however, it has not yet been approved as part of the Ohio State Implementation Plan. |

**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:** #3 Turbine (P003)

**Activity Description:** 84.65 Megawatt (Nominal) Simple-Cycle Combustion Turbine #3

## 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 |
|---|---|---|
| 84.65 megawatt (nominal) natural gas/diesel fuel-fired simple cycle combustion turbine using dry low NOx combustors (natural gas firing) or water injection (diesel fuel firing) to control NOx emissions. | OAC rules 3745-31-11 through 3745-31-20<br>(PTI 14-04682) | This emissions unit shall not exceed the following emission limitations:<br><br>58.0 lbs of sulfur dioxide (SO2) emissions/hour*<br><br>6.0 lbs of sulfuric acid (H2SO4) mist emissions/hour*<br><br>0.008 lb of particulate emissions (PE)/particulate matter with a diameter of 10 microns or less (PM10** emissions)/mmBtu*<br><br>* The hourly emission limitations and the lb of PE/PM10 emissions/mmBtu emission limitation specified above represent this emissions unit's potentials to emit for all operating conditions, including startup and shutdown. Therefore, no additional monitoring, record keeping or reporting requirements are required to demonstrate compliance with these emission limitations.<br><br>**The total PM10 emissions were evaluated and did not trigger any additional federal requirements, therefore, the emissions are being regulated as particulate emissions (PE). |

| Operations, Property, and/or Equipment | Applicable Rules/ Requirements | Applicable Emissions Limitations/Control Measures |
|---|---|---|
| | | 196.0 lbs of NOx emissions/hour, excluding startup and shutdown periods<br><br>54.0 lbs of CO emissions/hour, excluding startup and shutdown periods<br><br>when burning natural gas, 15 ppm of NOx, by volume, at 15% oxygen, on a dry basis, (as a 1-hour average, at full load)<br><br>when burning diesel fuel, 42 ppm of NOx, by volume, at 15% oxygen, on a dry basis (as a 1-hour average, at full load)<br><br>when burning natural gas at full load, 12 ppm of NOx, by volume, at 15% oxygen, on a dry basis (based on a rolling, 12-month average summation of the monthly NOx emissions, in ppm)<br><br>when burning diesel fuel, 0.0456 lb of SO2 emissions/mmBtu of actual heat input<br><br>The sulfur content of the natural gas and diesel fuel burned in this emissions unit shall not exceed 0.05% sulfur, by weight.<br><br>Emissions from startup and shutdown operations shall not exceed the following emission limitations:<br><br>when burning natural gas<br><br>83 lbs of NOx/startup and shutdown cycle<br>308 lbs of CO/startup and shutdown cycle<br><br>when burning diesel fuel<br><br>130 lbs of NOx/startup and shutdown cycle<br>354 lbs of CO/startup and shutdown cycle<br><br>See Section A.I.2.c below. |

| Operations, Property, and/or Equipment | Applicable Rules/ Requirements | Applicable Emissions Limitations/Control Measures |
|---|---|---|
| | | Emissions units P001 through P008, combined, shall not exceed the following emission limitations:<br><br>60.5 tons of PE/PM10 emissions per rolling, 12-month period<br><br>120.8 tons of SO2 emissions per rolling, 12-month period<br><br>733.3 tons of nitrogen oxides (NOx) emissions per rolling, 12-month period<br><br>541.0 tons of carbon monoxide (CO) emissions per rolling, 12-month period<br><br>12.2 tons of H2SO4 mist emissions per rolling, 12-month period<br><br>7.7 tons of benzene emissions per rolling, 12-month period<br><br>0.00084 ton of beryllium emissions per rolling, 12-month period<br><br>0.012 ton of arsenic emissions per rolling, 12-month period<br><br>The rolling, 12-month emission limitations are based upon a summation of the pollutant-specific emissions generated under all operating conditions, including startup and shutdown periods, for both natural gas and diesel fuel. |

| Operations, Property, and/or Equipment | Applicable Rules/ Requirements | Applicable Emissions Limitations/Control Measures |
|---|---|---|
| | OAC rule 3745-31-05(A)(3) (PTI 14-04682) | This emissions unit shall not exceed the following emission limitations:<br><br>10.0 lbs of volatile organic compound (VOC) emissions/hour*<br>0.15 ton per year of lead emissions<br>0.0023 ton per year of mercury emissions<br><br>See Section A.I.2.b below.<br><br>Compliance with this rule also includes compliance with the requirements of OAC rule 3745-31-05(C) and OAC rule 3745-17-07(A) when burning diesel fuel.<br><br>* The hourly VOC emission limitation specified above represent this emissions unit's potential to emit for all operating conditions, including startup and shutdown. Therefore, no additional monitoring, record keeping or reporting requirements are required to demonstrate compliance with this emission limitation. |
| | OAC rule 3745-31-05(C) | 36.4 tons of VOC emissions per rolling, 12-month period from emissions units P001 through P008, combined. |
| | OAC rule 3745-17-07(A) | See Section A.I.2.a below. |
| | 40 CFR Part 60, Subpart GG | The emission limitations established in 40 CFR Part 60, Subpart GG for SO2 and NOx are less stringent than those established pursuant to OAC rule 3745-31-05(C). |
| | OAC rule 3745-17-11(B)(4) | The PE limitation specified by this rule is less stringent the PE limitation established pursuant to OAC rule 3745-31-05(C). |
| | OAC rule 3745-18-06(F) | The SO2 emission limitation specified by this rule (0.5 lb of SO2 emissions/mmBtu) is less stringent than the SO2 emission limitation established pursuant to OAC rule 3745-31-05(C). |
| | OAC rules 3745-21-08(B) and 3745-23-06(B) | See Section A.I.2.j below. |

## 2. Additional Terms and Conditions

**2.a** Visible PE from any stack shall not exceed 20% opacity, as a 6-minute average, except as specified by rule when burning diesel fuel.

**2.b** Visible PE from any stack shall not exceed 10% opacity, as a 6-minute average when burning natural gas.

**2.c** The permittee shall operate and maintain dry low NOx burners when burning natural gas and operate and maintain a water injection system when burning diesel fuel.

**2.d** "Full load" shall be defined as the nameplate electrical output of 84.65 megawatts. Any load that is greater than or equal to 90% of the nameplate electrical output shall be considered full load.

**2.e** "Normal operation" shall be defined as the period when the combustion turbine achieves dry low NOx mode (GE Mode 6). GE Mode 6 is defined by the manufacturer as the low emissions mode during which all burner nozzles are in use, burning a lean pre-mixed gas for steady-state operation. The continuous emissions monitoring system will indicate and record the GE Mode 6 status of the combustion turbine, including when the emissions unit is shutdown and when operating in startup and shutdown modes.

**2.f** "Startup" shall be defined as the period between when the combustion turbine is initially started (initial fuel light-off) until the combustion turbine completes transition to GE Mode 6. "Shutdown" shall be defined as the period beginning when the combustion turbine leaves the GE Mode 6 and ending when combustion has ceased.

**2.g** "Startup and shutdown cycle" shall be defined as a startup period followed by a consecutive shutdown period.

**2.h** For the purpose of this permit, the term "diesel fuel" shall be considered to be any low sulfur fuel oil that is burned in this emissions unit, as defined in 40 CFR Part 72.2.

**2.i** Compliance with the startup and shutdown NOx and CO lbs/cycle emission limitations, the NOx and CO emission limitations during steady-state operations, and the NOx ppm emission limitations during full load operations shall be demonstrated by the use of dual range NOx and CO continuous emission monitoring systems (CEMs). For CEM systems with dual ranges, certification testing shall be performed on the range normally used for measuring emissions.

**2.j** 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 technology requirements established pursuant to OAC rule 3745-31-05(A)(3) in Permit to Install 14-4682.

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 technology requirements established pursuant to OAC rule 3745-31-05(A)(3) in Permit to Install 14-4682.

**2.k** For the purposes of this permit and for the hazardous air pollutants (HAPs) emitted from this emissions unit, the best available control technology determination to satisfy the requirements of 40 CFR Part 52.21 is equivalent to the maximum achievable control technology determination used to satisfy the requirements of 40 CFR Parts 63.41 through 63.44.

**2. Additional Terms and Conditions (continued)**

**2.l** In lieu of the requirements of 40 CFR Part 60.334(a) to install and operate a continuous monitoring system to monitor and record the fuel consumption and the ratio of water to fuel being fired in this emissions unit, the permittee shall operate and maintain systems to continuously monitor and record emissions of NOx for this emissions unit in accordance with this permit.

In lieu of the excess emissions reports required under 40 CFR Part 60.334, the permittee shall submit excess emissions reports for this emissions unit in accordance with this permit.

In lieu of the test methods and procedures required under 40 CFR Part 60.335, the permittee shall follow the monitoring and testing requirements for this emissions unit in accordance with this permit.

## II. Operational Restrictions

**1.** The maximum annual natural gas usage rate for emissions units P001 through P008, combined, shall not exceed 20,300,000,000 cubic feet per rolling, 12-month period.

**2.** The maximum annual diesel fuel usage rate for emissions units P001 through P008, combined, shall not exceed 34,000,000 gallons per rolling, 12-month period.

**3.** The permittee shall burn only pipeline quality natural gas or diesel fuel in this emissions unit.

**4.** The quality of diesel fuel burned in this emissions unit shall have a combination of heat and sulfur content which is sufficient to comply with the allowable SO2 emission limitation of 0.0456 lb of SO2/mmBtu of actual heat input. The diesel fuel shall have a sulfur content of 0.05%, by weight, or less.

**5.** When the emissions unit is operating in startup and shutdown conditions, as defined in Section A.I.2.f above, each startup and shutdown cycle shall not exceed 1.0 hour in duration.

**6.** With the exception of startup and shutdown, this emissions unit shall be operated in GE Mode 6, defined as normal or full load operation (see Sections A.I.2.d and A.I.2.e above).

## III. Monitoring and/or Record Keeping Requirements

**1.** The permittee shall maintain daily records of the following information:

a. the emissions unit's actual electrical output for each operating hour; and

b. for each day during which the permittee burns a fuel other than pipeline quality natural gas and/or diesel fuel, the permittee shall maintain a record of the type and quantity of fuel burned in this emissions unit.

**2.** The permittee shall maintain monthly records of the following information:

a. the total amount of natural gas burned, in cubic feet, for emissions units P001 through P008, combined;

b. the total amount of diesel fuel burned, in gallons, for emissions units P001 through P008, combined;

c. the rolling, 12-month summation of the total amount of natural gas burned, in cubic feet, for emissions units P001 through P008, combined (the amount of natural gas burned for the current month plus the total amount of natural gas burned for the previous 11 calendar months);

d. the rolling, 12-month summation of the total amount of diesel fuel burned, in gallons, for emissions units P001 through P008, combined (the amount of diesel fuel burned for the current month plus the total amount of diesel fuel burned for the previous 11 calendar months);

e. the date and duration, in minutes, of each startup and shutdown cycle;

f. the emissions, in pounds, for NOx* and CO* when burning natural gas for each startup and shutdown cycle;

g. the emissions, in pounds, for NOx* and CO* when burning diesel fuel for each startup and shutdown cycle;

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

h. the total emissions, in tons, for NOx*, CO*, PE/PM10, SO2 , VOC, H2SO4, and benzene when burning natural gas for all operating conditions;

i. the total emissions, in tons, for NOx*, CO*, PE/PM10, SO2, VOC, H2SO4, benzene, beryllium and arsenic when burning diesel fuel for all operating conditions;

j. the rolling, 12-month emissions, in tons, for NOx*, CO*, PE/PM10, SO2, VOC, H2SO4, benzene, beryllium and arsenic for emissions units P001 through P008, combined, when burning natural gas and diesel fuel (the total emissions calculated in (h) + (i)) for the current month plus the total emissions for the previous 11 calendar months); and

k. the rolling, 12-month average of NOx* emissions, in ppm, when burning natural gas at full load for this emissions unit (the NOx ppm average for the current month (from the CEMs data) plus the total NOx ppm average for the previous 11 calendar months).

* The permittee shall use the continuous NOx and CO emissions monitoring data to determine the NOx and CO emissions for these emissions units. During any period when the NOx and/or the CO emissions monitoring systems are not operational, the permittee shall use the appropriate missing data procedures specified in 40 CFR Part 75 to determine NOx and CO emissions or an approved data substitution protocol for the purpose of calculating the rolling, 12-month emission rates. The data substitution values shall not be used to demonstrate compliance with the hourly NOx and CO emission limitations applicable during normal operation of this emissions unit.

**3.** The permittee shall monitor and record the sulfur content of the natural gas being burned in this emissions unit or make the demonstration that the sulfur content of the natural gas does not need to be monitored and recorded in accordance with the provisions specified in 40 CFR Part 60.334(b). Owners, operators or fuel vendors may develop custom fuel schedules for the determination of the sulfur content based on the design and operation of the affected facility and the characteristics of the fuel supply. Except as provided in 40 CFR Parts 60.334(i)(3)(i) and 60.334(i)(3)(ii), these custom schedules shall be substantiated with data and must be approved by the Ohio EPA, Central Office before they can be used.

Analyses for the purpose of determining the sulfur content of the natural gas may be performed by the permittee, the fuel vendor, or any other qualified agency in accordance with the analytical methods specified in 40 CFR Part 60, Subpart GG, Section 60.335(d) or equivalent methods as approved by the Administrator.

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

**4.** The permittee shall maintain records of the diesel fuel burned in this emissions unit in accordance with either Alternative 1 or Alternative 2 described below:

a. Alternative 1:

For each shipment of oil received for burning in this emissions unit, the permittee shall collect or require the oil supplier to collect a representative grab sample of oil and maintain records of the total quantity of oil received, the permittee's or oil supplier's analyses for sulfur content and heat content, and the calculated sulfur dioxide emission rate (in lbs/mmBtu). (The sulfur dioxide emission rate shall be calculated in accordance with the formula specified in OAC rule 3745-18-04(F).) 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 may be represented by a single batch analysis from the supplier.

b. Alternative 2:

The permittee shall collect a representative grab sample of oil that is burned in this emissions unit for each day when the emission unit is in operation. If additional fuel oil is added to the tank serving this emissions unit on a day when the emissions unit is in operation, the permittee shall collect a sufficient number of grab samples to develop a composite sample representative of the fuel oil burned in this emissions unit. A representative grab sample of oil does not need to be collected on days when this emissions unit is only operated for the purpose of "test-firing". The permittee shall maintain records of the total quantity of oil burned each day (except for the purpose of test-firing), the permittee's analyses for sulfur content and heat content, and the calculated sulfur dioxide emission rate (in lbs/mmBtu). [The sulfur dioxide emission rate shall be calculated in accordance with the formula specified in OAC rule 3745-18-04(F).]

The permittee shall perform or require the supplier to perform the analyses for sulfur content and heat content in accordance with the following ASTM methods: ASTM method D4294 for sulfur content and ASTM method D240 for heat content. The newest or most recent revisions to the applicable test method shall be used for analyses. Alternative, equivalent methods may be used upon written approval by the Hamilton County Department of Environmental Services - Air Quality Control Division.

**5.** The permittee shall operate and maintain equipment to continuously monitor and record the actual fuel flow to this emissions unit when it is in operation. Such continuous monitoring and recording equipment shall comply with the requirements specified in 40 CFR Part 75. If the fuel flow monitoring and/or recording equipment is (are) not in service when the emissions unit is in operation, the permittee shall comply with the appropriate missing data procedures specified in 40 CFR Part 75.

**6.** The permittee shall operate and maintain equipment to continuously monitor and record the percent oxygen (as a 1-hr average) in the stack serving this emissions unit when the emissions unit is in operation. Such continuous monitoring and recording equipment shall comply with the requirements specified in 40 CFR Part 75. The monitoring and recording equipment shall be installed, calibrated, operated and maintained in accordance with the manufacturer's recommendations, with any modifications deemed necessary by the permittee.

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

**7.** The permittee shall operate and maintain equipment to continuously monitor and record NOx emissions from this emissions unit in units of the applicable standard(s). Such continuous monitoring and recording equipment shall comply with the applicable requirements specified in 40 CFR Part 60 and Part 75.

Each continuous monitoring system consists of all the equipment used to acquire and record data and includes the sample extraction and transport hardware, sample conditioning hardware, analyzers, and data processing hardware and software.

The permittee shall maintain on-site documentation from the USEPA or the Ohio EPA that the continuous NOx monitoring system has been certified in accordance with the applicable requirements specified in 40 CFR Part 60 and Part 75. The letter of certification shall be made available to the Director upon request.

The permittee shall maintain records of the following data obtained by the continuous NOx monitoring system: emissions of NOx in ppmvd at 15% oxygen on an hourly average basis, emissions of NOx in lbs/hr, results of daily zero/span calibration checks, results of quarterly cylinder gas audits, linearity checks, or relative accuracy test audits, and magnitude of manual calibration adjustments.

The permittee shall develop a written quality assurance/quality control plan for the continuous NOx monitoring system designed to ensure continuous valid and representative readings of NOx emissions in units of the applicable standard(s). The plan shall follow the applicable requirements of 40 CFR Part 60, Appendix F and 40 CFR Part 75, Appendix B. The quality assurance/quality control plan and a logbook documenting the activities related to the continuous NOx monitoring system must be kept on site and available for inspection during regular office hours.

The permittee may conduct the relative accuracy test audits for the continuous nitrogen oxides monitoring system in accordance with the frequencies required for monitoring systems subject to 40 CFR Part 75, Appendix B; however, the permittee is still required to provide the audit results in units of the applicable standard(s), in accordance with 40 CFR Part 60. In addition, linearity checks conducted pursuant to 40 CFR Part 75, Appendix B, may be used in place of quarterly cylinder gas audits, as required in 40 CFR Part 60.

**8.** The permittee shall operate and maintain equipment to continuously monitor and record CO emissions from this emissions unit in units of the applicable standard(s). Such continuous monitoring and recording equipment shall comply with the requirements specified in 40 CFR Part 60.

Each continuous monitoring system consists of all the equipment used to acquire and record data and includes the sample extraction and transport hardware, sample conditioning hardware, analyzers, and data processing hardware and software.

The permittee shall maintain on-site documentation from the USEPA or the Ohio EPA that the continuous CO monitoring system has been certified in accordance with 40 CFR Part 60. The letter of certification shall be made available to the Director upon request.

The permittee shall maintain records of the following data obtained by the continuous CO monitoring system: emissions of CO in lbs/hr, results of daily zero/span calibration checks, results of quarterly cylinder gas audits or relative accuracy test audits, and magnitude of manual calibration adjustments.

The permittee shall develop a written quality assurance/quality control plan for the continuous CO monitoring system designed to ensure continuous valid and representative readings of CO emissions in units of the applicable standard(s). The plan shall follow the requirements of 40 CFR Part 60, Appendix F. The quality assurance/quality control plan and a logbook documenting the activities related to the continuous CO monitoring system must be kept on site and available for inspection during regular office hours.

The permittee may conduct the relative accuracy test audits for the continuous carbon monoxide monitoring system in accordance with the frequencies required for monitoring systems subject to 40 CFR Part 75, Appendix B; however, the permittee is still required to provide the audit results in units of the applicable standard(s), in accordance with 40 CFR Part 60. Cylinder gas audits may be conducted in accordance with the frequencies specified in 40 CFR Part 75, Appendix B for linearity checks.

## IV. Reporting Requirements

**1.** 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.

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

a. all exceedances of the rolling, 12-month natural gas usage limitation for emissions units P001 through P008, combined;

b. all exceedances of the rolling, 12-month emission limitations for PE/PM10, SO2, NOx, CO, H2SO4 mist, VOC, benzene, beryllium and arsenic for emissions units P001 through P008, combined;

c. all exceedances of the sulfur content restriction (i.e., 0.05%, by weight) for the fuels (natural gas and diesel fuel) received for burning in this emissions unit;

d. all exceedances of the SO2 lbs/mmBtu emission limitation when burning diesel fuel in this emissions unit;

e. all exceedances of the 1.0 hour startup and shutdown cycle operational restriction;

f. all exceedances of the rolling, 12-month diesel fuel usage limitation for emissions units P001 through P008, combined;

g. all exceedances of the startup and shutdown emission limitations specified in Section A.I.1 when burning natural gas;

h. all exceedances of the startup and shutdown emission limitations specified in Section A.I.1 when burning diesel fuel; and

i. each day when a fuel other than natural gas or diesel fuel was burned in this emissions unit.

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

**4.** 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 Control Division documenting the date, commencement and completion times, duration, magnitude, reason (if known), and corrective actions taken (if any), of all instances of NOx values in excess of the applicable emission limitations (emissions of NOx in ppmvd at 15% oxygen on an hourly average basis and emissions of NOx in lbs/hr) specified in the terms and conditions of this permit.

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 Control Division documenting any continuous NOx 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 analyzer 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 analyzer 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 31, April 30, July 31, and October 31 of each year and shall address the data obtained during the previous calendar quarter.

The permittee shall submit a summary of the excess emission report. The summary shall be submitted to the Hamilton County Department of Environmental Services - Air Quality Control Division within 30 days following the end of each calendar quarter in a manner prescribed by the Director.

## IV. Reporting Requirements (continued)

**5.** 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 Control Division documenting the date, commencement and completion times, duration, magnitude, reason (if known), and corrective actions taken (if any) of all instances of CO values in excess of any applicable emission limitations (emissions of CO in lbs/hr) specified in the terms and conditions of this permit.

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 Control Division documenting any continuous CO 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 analyzer 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 analyzer while the emissions unit was on line shall also be included in the quarterly report. These quarterly excess emission reports shall be submitted by January 31, April 30, July 31, and October 31 of each year and shall address the data obtained during the previous calendar quarter.

The permittee shall submit a summary of the excess emission report. The summary shall be submitted to the Hamilton County Department of Environmental Services - Air Quality Control Division within 30 days following the end of the calendar quarter.

**6.** The permittee shall submit annual reports that specify the total mercury and lead emissions from this emissions unit for the previous calendar year. The reports shall be submitted by April 15 of each year. This reporting requirement may be satisfied by including and identifying the specific emission data for this emissions unit in the annual Fee Emission Report.

## V. Testing Requirements

**1.** Compliance with the emission limitations, fuel usage restrictions, and fuel sulfur content restriction specified in Sections A.I and A.II shall be determined by the following methods:

**1.a** Emission Limitations:
Emissions from startup and shutdown operations shall not exceed the following emission limitations:

when burning natural gas

83 lbs of NOx/startup and shutdown cycle
308 lbs of CO/startup and shutdown cycle

when burning diesel fuel

130 lbs of NOx/startup and shutdown cycle
354 lbs of CO/startup and shutdown cycle

Applicable Compliance Method:
The lbs/cycle emission limitations were established based on emission data contained in the PTI modification application (PTI 14-04682) submitted March, 2001 and the emission factors from the background document, Reference 16, for Stationary Gas Turbines in AP-42, Fifth Edition, Section 3.1, dated April 2000.

Compliance with the NOx and CO emission limitations shall be determined by the continuous emission monitoring data collected pursuant to the record keeping requirements specified in Sections A.III.2, A.III.7, and A.III.8.

## V. Testing Requirements (continued)

**1.b** Emission Limitations:
The hourly emissions from this emissions unit shall not exceed the following limitations:

i. 58.0 lbs of SO2 emissions/hour;
ii. 54.0 lbs of CO emissions/hour;
iii. 196.0 lbs of NOx emissions/hour;
iv. 6.0 lbs of H2SO4 mist emissions/hour; and
v. 10.0 lbs of VOC emissions/hour.

Applicable Compliance Method:
The hourly emission limitations are based upon the emissions unit's potentials to emit and the manufacturer's guaranteed emission data found in PTI 14-4682 submitted April 26, 1999.

Compliance with the NOx emission limitation shall be determined by the continuous emission monitoring data collected pursuant to the record keeping requirements specified in Section A.III.8.

Compliance with the CO emission limitation shall be determined by the continuous emission monitoring data collected pursuant to the record keeping requirements specified in Section A.III.9.

If required, the permittee shall demonstrate compliance with the hourly NOx emission limitation through emission tests performed in accordance with Methods 1 through 4 and 7 of 40 CFR Part 60, Appendix A.

If required, the permittee shall demonstrate compliance with the hourly SO2 emission limitation through emission tests performed in accordance with Methods 1 through 4 and 6 of 40 CFR Part 60, Appendix A.

If required, the permittee shall demonstrate compliance with the hourly CO emission limitation through emission tests performed in accordance with Methods 1 through 4 and 10 of 40 CFR Part 60, Appendix A.

If required, the permittee shall demonstrate compliance with the hourly H2SO4 mist emission limitation through emission tests performed in accordance with Methods 1 through 4 and 8 of 40 CFR Part 60, Appendix A.

If required, the permittee shall demonstrate compliance with the hourly VOC emission limitation through emission tests performed in accordance with Methods 1 through 4 and 25 of 40 CFR Part 60, Appendix A.

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

## V. Testing Requirements (continued)

**1.c** Emission Limitations:
The total emissions from emissions units P001 through P008, combined, shall not exceed the following emission limitations:

i. 60.5 tons of PE/PM10 emissions per rolling, 12-month period;
ii. 120.8 tons of SO2 emissions per rolling, 12-month period;
iii. 733.3 tons of NOx emissions per rolling, 12-month period;
iv. 541.0 tons of CO emissions per rolling, 12-month period;
v. 36.4 tons of VOC emissions per rolling, 12-month period;
vi. 12.2 tons of H2SO4 mist emissions per rolling, 12-month period;
vii. 7.7 tons of benzene* emissions per rolling, 12-month period;
viii. 0.00084 ton of beryllium* emissions per rolling, 12-month period; and
ix. 0.012 ton of arsenic* emissions per rolling, 12-month period.

Applicable Compliance Method:
Compliance with the rolling, 12-month PE/PM10, SO2, NOx, CO and VOC, H2SO4, benzene, beryllium and arsenic emission limitations specified above shall be determined by the record keeping requirements specified in Section A.III.2.j.

Emission factors for PE/PM10, VOC, SO2, and H2SO4 are specified in the manufacturers guaranteed performance data contained in the application for PTI 14-4682 submitted to the Hamilton County Department of Environmental Services on April 26, 1999.

* The emission factors as specified in AP-42, Fifth Edition, Section 3.1 "Stationary Gas Turbines", updated 4/00 are 0.000011 lb.mmBtu for arsenic, 0.000055 lb/mmBtu for benzene, and 0.00000031 lb/mmBtu for beryllium, from diesel fuel-fired turbines.

The emission factor as specified in AP-42 Fifth Edition, Section 3.1 "Stationary Gas Turbines", updated 4/00 is 0.000012 lb/mmBtu for benzene, from natural gas-fired turbines.

The emission factor for beryllium and arsenic when natural gas is burned is insignificant based upon the manufacturer's guaranteed emission data contained in the application for PTI 14-4682 submitted to the Hamilton County Department of Environmental Services on April 26, 1999.

**1.d** Emission Limitations:
0.15 ton per year of lead emissions and 0.0023 ton per year of mercury emissions.

Applicable Compliance Method:
The lead and mercury emission limitations specified above were determined by multiplying the maximum fuel usage capacity of the equipment, as provided by the manufacturer in PTI 14-4682 submitted April 26, 1999, by the pollutant specific emission factor found in AP-42, Fifth Edition, Section 3.1 "Stationary Gas Turbines," updated 4/00, by the maximum heat content of the fuel, and dividing by 2,000 lbs/ton. The emission factor as specified in the above referenced AP-42 is 0.000014 lbs/mmBtu for lead and 0.0000012 lbs/mmBtu for mercury, from diesel fuel-fired turbines.

The emission factor for mercury and lead when natural gas is burned is insignificant based upon the manufacturer's guaranteed emission data contained in the application for PTI 14-4682 submitted to the Hamilton County Department of Environmental Services on April 26, 1999.

## V. Testing Requirements (continued)

**1.e** Emission Limitations:
when burning natural gas, 15 ppm of NOx, by volume, at 15% oxygen, on a dry basis, (as a 1-hour average, at full load)

when burning diesel fuel, 42 ppm of NOx, by volume, at 15% oxygen, on a dry basis (as a 1-hour average, at full load)

when burning natural gas at full load, 12 ppm of NOx, by volume, at 15% oxygen, on a dry basis (based on a rolling, 12-month summation of the average monthly NOx emissions, in ppm)

Applicable Compliance Method:
Compliance with the NOx emission limitations shall be determined by the continuous emission monitoring data collected pursuant to the record keeping requirements specified in Sections A.III.6 and A.III.7 and the record keeping requirements specified in Section A.III.2.

If required, the permittee shall demonstrate compliance with the non-rolling ppm NOx emission limitations through emission tests performed in accordance with Methods 1 through 4 and 7 of 40 CFR Part 60, Appendix A.

**1.f** Emission Limitation:
0.008 lb of PE/PM10 emissions/mmBtu

Applicable Compliance Method:
The lb/mmBtu emission limitation represents the emissions unit's potential to emit and is based upon the manufacturer's guaranteed emission data contained in the application for PTI 14-4682 submitted to the Hamilton County Department of Environmental Services on April 26, 1999. The total PM10 emissions were evaluated and did not trigger any additional federal requirements, therefore, the emissions are being regulated as particulate emissions (PE) and are subject to the PE compliance demonstration as noted below.

If required, the permittee shall demonstrate compliance with the PE/PM10 emission limitation through emission tests performed in accordance with Methods 1 through 5 of 40 CFR Part 60, Appendix A.

**1.g** Emission Limitation:
Visible particulate emissions from any stack shall not exceed 20% opacity, as a 6-minute average, except as specified by rule, when burning diesel fuel.

Applicable Compliance Method:
If required, compliance with the visible particulate emission limitation shall be determined 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).

**1.h** Emission Limitation:
Visible particulate emissions from any stack shall not exceed 10% opacity, as a 6-minute average, when burning natural gas.

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

## V. Testing Requirements (continued)

**1.i** Emission Limitation:
0.0456 lb of SO2 emissions/mmBtu when burning diesel fuel;

Applicable Compliance Method:
Compliance with the SO2 emission limitation shall be determined by the sulfur analysis of the fuels burned pursuant to the requirements specified in Section A.lll.4 and by documenting that the sulfur content of each shipment of oil received during a calendar month or each daily sample meets the 0.05%, by weight, sulfur content restriction.

If required, the permittee shall demonstrate compliance with the SO2 emission limitation through emission tests performed in accordance with Methods 1 through 4 and 6 of 40 CFR Part 60, Appendix A.

**1.j** Sulfur Content Restriction:
The sulfur content of the natural gas and diesel fuel burned in this emissions unit shall not exceed 0.05% sulfur, by weight.

Applicable Compliance Method:
Compliance with the sulfur content restriction shall be determined by the record keeping requirements specified in Sections A.III.3 and A.III.4.

**1.k** Natural Gas and Diesel Fuel Usage Restrictions:
The maximum annual natural gas usage rate for emissions units P001 through P008, combined, shall not exceed 20,300,000,000 cubic feet per rolling, 12-month period.

The maximum annual diesel fuel usage rate for emissions units P001 through P008, combined, shall not exceed 34,000,000 gallons per rolling, 12-month period.

Applicable Compliance Method:
Compliance with the natural gas and diesel fuel usage restrictions shall be determined by the record keeping requirements specified in Section A.III.2.

## 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 |
|---|---|---|
| 84.65 megawatt (nominal) natural gas/diesel fuel-fired simple cycle combustion turbine using dry low NOx combustors (natural gas firing) or water injection (diesel fuel firing) to control NOx emissions. | OAC rule 3745-31-28 | The requirements established pursuant to this rule are equivalent to the requirements established pursuant to 40 CFR Parts 63.41 through 63.44. This regulation has been promulgated in the Ohio Administrative Code; however, it has not yet been approved as part of the Ohio State Implementation Plan. |

**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:** #4 Turbine (P004)

**Activity Description:** 84.65 Megawatt (Nominal) Simple-Cycle Combustion Turbine #4

## 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 |
|---|---|---|
| 84.65 megawatt (nominal) natural gas/diesel fuel-fired simple cycle combustion turbine using dry low NOx combustors (natural gas firing) or water injection (diesel fuel firing) to control NOx emissions. | OAC rules 3745-31-11 through 3745-31-20<br>(PTI 14-04682) | This emissions unit shall not exceed the following emission limitations:<br><br>58.0 lbs of sulfur dioxide (SO2) emissions/hour*<br><br>6.0 lbs of sulfuric acid (H2SO4) mist emissions/hour*<br><br>0.008 lb of particulate emissions (PE)/particulate matter with a diameter of 10 microns or less (PM10** emissions)/mmBtu*<br><br>* The hourly emission limitations and the lb of PE/PM10 emissions/mmBtu emission limitation specified above represent this emissions unit's potentials to emit for all operating conditions, including startup and shutdown. Therefore, no additional monitoring, record keeping or reporting requirements are required to demonstrate compliance with these emission limitations.<br><br>**The total PM10 emissions were evaluated and did not trigger any additional federal requirements, therefore, the emissions are being regulated as particulate emissions (PE). |

| Operations, Property, and/or Equipment | Applicable Rules/ Requirements | Applicable Emissions Limitations/Control Measures |
|---|---|---|
| | | 196.0 lbs of NOx emissions/hour, excluding startup and shutdown periods<br><br>54.0 lbs of CO emissions/hour, excluding startup and shutdown periods<br><br>when burning natural gas, 15 ppm of NOx, by volume, at 15% oxygen, on a dry basis, (as a 1-hour average, at full load)<br><br>when burning diesel fuel, 42 ppm of NOx, by volume, at 15% oxygen, on a dry basis (as a 1-hour average, at full load)<br><br>when burning natural gas at full load, 12 ppm of NOx, by volume, at 15% oxygen, on a dry basis (based on a rolling, 12-month average summation of the monthly NOx emissions, in ppm)<br><br>when burning diesel fuel, 0.0456 lb of SO2 emissions/mmBtu of actual heat input<br><br>The sulfur content of the natural gas and diesel fuel burned in this emissions unit shall not exceed 0.05% sulfur, by weight.<br><br>Emissions from startup and shutdown operations shall not exceed the following emission limitations:<br><br>when burning natural gas<br><br>83 lbs of NOx/startup and shutdown cycle<br>308 lbs of CO/startup and shutdown cycle<br><br>when burning diesel fuel<br><br>130 lbs of NOx/startup and shutdown cycle<br>354 lbs of CO/startup and shutdown cycle<br><br>See Section A.I.2.c below. |

| Operations, Property, and/or Equipment | Applicable Rules/ Requirements | Applicable Emissions Limitations/Control Measures |
|---|---|---|
| | | Emissions units P001 through P008, combined, shall not exceed the following emission limitations:<br><br>60.5 tons of PE/PM10 emissions per rolling, 12-month period<br><br>120.8 tons of SO2 emissions per rolling, 12-month period<br><br>733.3 tons of nitrogen oxides (NOx) emissions per rolling, 12-month period<br><br>541.0 tons of carbon monoxide (CO) emissions per rolling, 12-month period<br><br>12.2 tons of H2SO4 mist emissions per rolling, 12-month period<br><br>7.7 tons of benzene emissions per rolling, 12-month period<br><br>0.00084 ton of beryllium emissions per rolling, 12-month period<br><br>0.012 ton of arsenic emissions per rolling, 12-month period<br><br>The rolling, 12-month emission limitations are based upon a summation of the pollutant-specific emissions generated under all operating conditions, including startup and shutdown periods, for both natural gas and diesel fuel. |

| Operations, Property, and/or Equipment | Applicable Rules/ Requirements | Applicable Emissions Limitations/Control Measures |
|---|---|---|
| | OAC rule 3745-31-05(A)(3) (PTI 14-04682) | This emissions unit shall not exceed the following emission limitations:<br><br>10.0 lbs of volatile organic compound (VOC) emissions/hour*<br>0.15 ton per year of lead emissions<br>0.0023 ton per year of mercury emissions<br><br>See Section A.I.2.b below.<br><br>Compliance with this rule also includes compliance with the requirements of OAC rule 3745-31-05(C) and OAC rule 3745-17-07(A) when burning diesel fuel.<br><br>* The hourly VOC emission limitation specified above represent this emissions unit's potential to emit for all operating conditions, including startup and shutdown. Therefore, no additional monitoring, record keeping or reporting requirements are required to demonstrate compliance with this emission limitation. |
| | OAC rule 3745-31-05(C) | 36.4 tons of VOC emissions per rolling, 12-month period from emissions units P001 through P008, combined. |
| | OAC rule 3745-17-07(A) | See Section A.I.2.a below. |
| | 40 CFR Part 60, Subpart GG | The emission limitations established in 40 CFR Part 60, Subpart GG for SO2 and NOx are less stringent than those established pursuant to OAC rule 3745-31-05(C). |
| | OAC rule 3745-17-11(B)(4) | The PE limitation specified by this rule is less stringent the PE limitation established pursuant to OAC rule 3745-31-05(C). |
| | OAC rule 3745-18-06(F) | The SO2 emission limitation specified by this rule (0.5 lb of SO2 emissions/mmBtu) is less stringent than the SO2 emission limitation established pursuant to OAC rule 3745-31-05(C). |
| | OAC rules 3745-21-08(B) and 3745-23-06(B) | See Section A.I.2.j below. |

## 2. Additional Terms and Conditions

**2.a** Visible PE from any stack shall not exceed 20% opacity, as a 6-minute average, except as specified by rule when burning diesel fuel.

**2.b** Visible PE from any stack shall not exceed 10% opacity, as a 6-minute average when burning natural gas.

**2.c** The permittee shall operate and maintain dry low NOx burners when burning natural gas and operate and maintain a water injection system when burning diesel fuel.

**2.d** "Full load" shall be defined as the nameplate electrical output of 84.65 megawatts. Any load that is greater than or equal to 90% of the nameplate electrical output shall be considered full load.

**2.e** "Normal operation" shall be defined as the period when the combustion turbine achieves dry low NOx mode (GE Mode 6). GE Mode 6 is defined by the manufacturer as the low emissions mode during which all burner nozzles are in use, burning a lean pre-mixed gas for steady-state operation. The continuous emissions monitoring system will indicate and record the GE Mode 6 status of the combustion turbine, including when the emissions unit is shutdown and when operating in startup and shutdown modes.

**2.f** "Startup" shall be defined as the period between when the combustion turbine is initially started (initial fuel light-off) until the combustion turbine completes transition to GE Mode 6. "Shutdown" shall be defined as the period beginning when the combustion turbine leaves the GE Mode 6 and ending when combustion has ceased.

**2.g** "Startup and shutdown cycle" shall be defined as a startup period followed by a consecutive shutdown period.

**2.h** For the purpose of this permit, the term "diesel fuel" shall be considered to be any low sulfur fuel oil that is burned in this emissions unit, as defined in 40 CFR Part 72.2.

**2.i** Compliance with the startup and shutdown NOx and CO lbs/cycle emission limitations, the NOx and CO emission limitations during steady-state operations, and the NOx ppm emission limitations during full load operations shall be demonstrated by the use of dual range NOx and CO continuous emission monitoring systems (CEMs). For CEM systems with dual ranges, certification testing shall be performed on the range normally used for measuring emissions.

**2.j** 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 technology requirements established pursuant to OAC rule 3745-31-05(A)(3) in Permit to Install 14-4682.

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 technology requirements established pursuant to OAC rule 3745-31-05(A)(3) in Permit to Install 14-4682.

**2.k** For the purposes of this permit and for the hazardous air pollutants (HAPs) emitted from this emissions unit, the best available control technology determination to satisfy the requirements of 40 CFR Part 52.21 is equivalent to the maximum achievable control technology determination used to satisfy the requirements of 40 CFR Parts 63.41 through 63.44.

**2. Additional Terms and Conditions (continued)**

**2.l** In lieu of the requirements of 40 CFR Part 60.334(a) to install and operate a continuous monitoring system to monitor and record the fuel consumption and the ratio of water to fuel being fired in this emissions unit, the permittee shall operate and maintain systems to continuously monitor and record emissions of NOx for this emissions unit in accordance with this permit.

In lieu of the excess emissions reports required under 40 CFR Part 60.334, the permittee shall submit excess emissions reports for this emissions unit in accordance with this permit.

In lieu of the test methods and procedures required under 40 CFR Part 60.335, the permittee shall follow the monitoring and testing requirements for this emissions unit in accordance with this permit.

## II. Operational Restrictions

**1.** The maximum annual natural gas usage rate for emissions units P001 through P008, combined, shall not exceed 20,300,000,000 cubic feet per rolling, 12-month period.

**2.** The maximum annual diesel fuel usage rate for emissions units P001 through P008, combined, shall not exceed 34,000,000 gallons per rolling, 12-month period.

**3.** The permittee shall burn only pipeline quality natural gas or diesel fuel in this emissions unit.

**4.** The quality of diesel fuel burned in this emissions unit shall have a combination of heat and sulfur content which is sufficient to comply with the allowable SO2 emission limitation of 0.0456 lb of SO2/mmBtu of actual heat input. The diesel fuel shall have a sulfur content of 0.05%, by weight, or less.

**5.** When the emissions unit is operating in startup and shutdown conditions, as defined in Section A.I.2.f above, each startup and shutdown cycle shall not exceed 1.0 hour in duration.

**6.** With the exception of startup and shutdown, this emissions unit shall be operated in GE Mode 6, defined as normal or full load operation (see Sections A.I.2.d and A.I.2.e above).

## III. Monitoring and/or Record Keeping Requirements

**1.** The permittee shall maintain daily records of the following information:

a. the emissions unit's actual electrical output for each operating hour; and

b. for each day during which the permittee burns a fuel other than pipeline quality natural gas and/or diesel fuel, the permittee shall maintain a record of the type and quantity of fuel burned in this emissions unit.

**2.** The permittee shall maintain monthly records of the following information:

a. the total amount of natural gas burned, in cubic feet, for emissions units P001 through P008, combined;

b. the total amount of diesel fuel burned, in gallons, for emissions units P001 through P008, combined;

c. the rolling, 12-month summation of the total amount of natural gas burned, in cubic feet, for emissions units P001 through P008, combined (the amount of natural gas burned for the current month plus the total amount of natural gas burned for the previous 11 calendar months);

d. the rolling, 12-month summation of the total amount of diesel fuel burned, in gallons, for emissions units P001 through P008, combined (the amount of diesel fuel burned for the current month plus the total amount of diesel fuel burned for the previous 11 calendar months);

e. the date and duration, in minutes, of each startup and shutdown cycle;

f. the emissions, in pounds, for NOx* and CO* when burning natural gas for each startup and shutdown cycle;

g. the emissions, in pounds, for NOx* and CO* when burning diesel fuel for each startup and shutdown cycle;

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

h. the total emissions, in tons, for NOx*, CO*, PE/PM10, SO2 , VOC, H2SO4, and benzene when burning natural gas for all operating conditions;

i. the total emissions, in tons, for NOx*, CO*, PE/PM10, SO2, VOC, H2SO4, benzene, beryllium and arsenic when burning diesel fuel for all operating conditions;

j. the rolling, 12-month emissions, in tons, for NOx*, CO*, PE/PM10, SO2, VOC, H2SO4, benzene, beryllium and arsenic for emissions units P001 through P008, combined, when burning natural gas and diesel fuel (the total emissions calculated in (h) + (i)) for the current month plus the total emissions for the previous 11 calendar months); and

k. the rolling, 12-month average of NOx* emissions, in ppm, when burning natural gas at full load for this emissions unit (the NOx ppm average for the current month (from the CEMs data) plus the total NOx ppm average for the previous 11 calendar months).

* The permittee shall use the continuous NOx and CO emissions monitoring data to determine the NOx and CO emissions for these emissions units. During any period when the NOx and/or the CO emissions monitoring systems are not operational, the permittee shall use the appropriate missing data procedures specified in 40 CFR Part 75 to determine NOx and CO emissions or an approved data substitution protocol for the purpose of calculating the rolling, 12-month emission rates. The data substitution values shall not be used to demonstrate compliance with the hourly NOx and CO emission limitations applicable during normal operation of this emissions unit.

**3.** The permittee shall monitor and record the sulfur content of the natural gas being burned in this emissions unit or make the demonstration that the sulfur content of the natural gas does not need to be monitored and recorded in accordance with the provisions specified in 40 CFR Part 60.334(b). Owners, operators or fuel vendors may develop custom fuel schedules for the determination of the sulfur content based on the design and operation of the affected facility and the characteristics of the fuel supply. Except as provided in 40 CFR Parts 60.334(i)(3)(i) and 60.334(i)(3)(ii), these custom schedules shall be substantiated with data and must be approved by the Ohio EPA, Central Office before they can be used.

Analyses for the purpose of determining the sulfur content of the natural gas may be performed by the permittee, the fuel vendor, or any other qualified agency in accordance with the analytical methods specified in 40 CFR Part 60, Subpart GG, Section 60.335(d) or equivalent methods as approved by the Administrator.

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

**4.** The permittee shall maintain records of the diesel fuel burned in this emissions unit in accordance with either Alternative 1 or Alternative 2 described below:

a. Alternative 1:

For each shipment of oil received for burning in this emissions unit, the permittee shall collect or require the oil supplier to collect a representative grab sample of oil and maintain records of the total quantity of oil received, the permittee's or oil supplier's analyses for sulfur content and heat content, and the calculated sulfur dioxide emission rate (in lbs/mmBtu). (The sulfur dioxide emission rate shall be calculated in accordance with the formula specified in OAC rule 3745-18-04(F).) 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 may be represented by a single batch analysis from the supplier.

b. Alternative 2:

The permittee shall collect a representative grab sample of oil that is burned in this emissions unit for each day when the emission unit is in operation. If additional fuel oil is added to the tank serving this emissions unit on a day when the emissions unit is in operation, the permittee shall collect a sufficient number of grab samples to develop a composite sample representative of the fuel oil burned in this emissions unit. A representative grab sample of oil does not need to be collected on days when this emissions unit is only operated for the purpose of "test-firing". The permittee shall maintain records of the total quantity of oil burned each day (except for the purpose of test-firing), the permittee's analyses for sulfur content and heat content, and the calculated sulfur dioxide emission rate (in lbs/mmBtu). [The sulfur dioxide emission rate shall be calculated in accordance with the formula specified in OAC rule 3745-18-04(F).]

The permittee shall perform or require the supplier to perform the analyses for sulfur content and heat content in accordance with the following ASTM methods: ASTM method D4294 for sulfur content and ASTM method D240 for heat content. The newest or most recent revisions to the applicable test method shall be used for analyses. Alternative, equivalent methods may be used upon written approval by the Hamilton County Department of Environmental Services - Air Quality Control Division.

**5.** The permittee shall operate and maintain equipment to continuously monitor and record the actual fuel flow to this emissions unit when it is in operation. Such continuous monitoring and recording equipment shall comply with the requirements specified in 40 CFR Part 75. If the fuel flow monitoring and/or recording equipment is (are) not in service when the emissions unit is in operation, the permittee shall comply with the appropriate missing data procedures specified in 40 CFR Part 75.

**6.** The permittee shall operate and maintain equipment to continuously monitor and record the percent oxygen (as a 1-hr average) in the stack serving this emissions unit when the emissions unit is in operation. Such continuous monitoring and recording equipment shall comply with the requirements specified in 40 CFR Part 75. The monitoring and recording equipment shall be installed, calibrated, operated and maintained in accordance with the manufacturer's recommendations, with any modifications deemed necessary by the permittee.

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

**7.** The permittee shall operate and maintain equipment to continuously monitor and record NOx emissions from this emissions unit in units of the applicable standard(s). Such continuous monitoring and recording equipment shall comply with the applicable requirements specified in 40 CFR Part 60 and Part 75.

Each continuous monitoring system consists of all the equipment used to acquire and record data and includes the sample extraction and transport hardware, sample conditioning hardware, analyzers, and data processing hardware and software.

The permittee shall maintain on-site documentation from the USEPA or the Ohio EPA that the continuous NOx monitoring system has been certified in accordance with the applicable requirements specified in 40 CFR Part 60 and Part 75. The letter of certification shall be made available to the Director upon request.

The permittee shall maintain records of the following data obtained by the continuous NOx monitoring system: emissions of NOx in ppmvd at 15% oxygen on an hourly average basis, emissions of NOx in lbs/hr, results of daily zero/span calibration checks, results of quarterly cylinder gas audits, linearity checks, or relative accuracy test audits, and magnitude of manual calibration adjustments.

The permittee shall develop a written quality assurance/quality control plan for the continuous NOx monitoring system designed to ensure continuous valid and representative readings of NOx emissions in units of the applicable standard(s). The plan shall follow the applicable requirements of 40 CFR Part 60, Appendix F and 40 CFR Part 75, Appendix B. The quality assurance/quality control plan and a logbook documenting the activities related to the continuous NOx monitoring system must be kept on site and available for inspection during regular office hours.

The permittee may conduct the relative accuracy test audits for the continuous nitrogen oxides monitoring system in accordance with the frequencies required for monitoring systems subject to 40 CFR Part 75, Appendix B; however, the permittee is still required to provide the audit results in units of the applicable standard(s), in accordance with 40 CFR Part 60. In addition, linearity checks conducted pursuant to 40 CFR Part 75, Appendix B, may be used in place of quarterly cylinder gas audits, as required in 40 CFR Part 60.

**8.** The permittee shall operate and maintain equipment to continuously monitor and record CO emissions from this emissions unit in units of the applicable standard(s). Such continuous monitoring and recording equipment shall comply with the requirements specified in 40 CFR Part 60.

Each continuous monitoring system consists of all the equipment used to acquire and record data and includes the sample extraction and transport hardware, sample conditioning hardware, analyzers, and data processing hardware and software.

The permittee shall maintain on-site documentation from the USEPA or the Ohio EPA that the continuous CO monitoring system has been certified in accordance with 40 CFR Part 60. The letter of certification shall be made available to the Director upon request.

The permittee shall maintain records of the following data obtained by the continuous CO monitoring system: emissions of CO in lbs/hr, results of daily zero/span calibration checks, results of quarterly cylinder gas audits or relative accuracy test audits, and magnitude of manual calibration adjustments.

The permittee shall develop a written quality assurance/quality control plan for the continuous CO monitoring system designed to ensure continuous valid and representative readings of CO emissions in units of the applicable standard(s). The plan shall follow the requirements of 40 CFR Part 60, Appendix F. The quality assurance/quality control plan and a logbook documenting the activities related to the continuous CO monitoring system must be kept on site and available for inspection during regular office hours.

The permittee may conduct the relative accuracy test audits for the continuous carbon monoxide monitoring system in accordance with the frequencies required for monitoring systems subject to 40 CFR Part 75, Appendix B; however, the permittee is still required to provide the audit results in units of the applicable standard(s), in accordance with 40 CFR Part 60. Cylinder gas audits may be conducted in accordance with the frequencies specified in 40 CFR Part 75, Appendix B for linearity checks.

## IV. Reporting Requirements

**1.** 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.

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

a. all exceedances of the rolling, 12-month natural gas usage limitation for emissions units P001 through P008, combined;

b. all exceedances of the rolling, 12-month emission limitations for PE/PM10, SO2, NOx, CO, H2SO4 mist, VOC, benzene, beryllium and arsenic for emissions units P001 through P008, combined;

c. all exceedances of the sulfur content restriction (i.e., 0.05%, by weight) for the fuels (natural gas and diesel fuel) received for burning in this emissions unit;

d. all exceedances of the SO2 lbs/mmBtu emission limitation when burning diesel fuel in this emissions unit;

e. all exceedances of the 1.0 hour startup and shutdown cycle operational restriction;

f. all exceedances of the rolling, 12-month diesel fuel usage limitation for emissions units P001 through P008, combined;

g. all exceedances of the startup and shutdown emission limitations specified in Section A.I.1 when burning natural gas;

h. all exceedances of the startup and shutdown emission limitations specified in Section A.I.1 when burning diesel fuel; and

i. each day when a fuel other than natural gas or diesel fuel was burned in this emissions unit.

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

**4.** 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 Control Division documenting the date, commencement and completion times, duration, magnitude, reason (if known), and corrective actions taken (if any), of all instances of NOx values in excess of the applicable emission limitations (emissions of NOx in ppmvd at 15% oxygen on an hourly average basis and emissions of NOx in lbs/hr) specified in the terms and conditions of this permit.

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 Control Division documenting any continuous NOx 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 analyzer 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 analyzer 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 31, April 30, July 31, and October 31 of each year and shall address the data obtained during the previous calendar quarter.

The permittee shall submit a summary of the excess emission report. The summary shall be submitted to the Hamilton County Department of Environmental Services - Air Quality Control Division within 30 days following the end of each calendar quarter in a manner prescribed by the Director.

## IV. Reporting Requirements (continued)

**5.** 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 Control Division documenting the date, commencement and completion times, duration, magnitude, reason (if known), and corrective actions taken (if any) of all instances of CO values in excess of any applicable emission limitations (emissions of CO in lbs/hr) specified in the terms and conditions of this permit.

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 Control Division documenting any continuous CO 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 analyzer 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 analyzer while the emissions unit was on line shall also be included in the quarterly report. These quarterly excess emission reports shall be submitted by January 31, April 30, July 31, and October 31 of each year and shall address the data obtained during the previous calendar quarter.

The permittee shall submit a summary of the excess emission report. The summary shall be submitted to the Hamilton County Department of Environmental Services - Air Quality Control Division within 30 days following the end of the calendar quarter.

**6.** The permittee shall submit annual reports that specify the total mercury and lead emissions from this emissions unit for the previous calendar year. The reports shall be submitted by April 15 of each year. This reporting requirement may be satisfied by including and identifying the specific emission data for this emissions unit in the annual Fee Emission Report.

## V. Testing Requirements

**1.** Compliance with the emission limitations, fuel usage restrictions, and fuel sulfur content restriction specified in Sections A.I and A.II shall be determined by the following methods:

**1.a** Emission Limitations:
Emissions from startup and shutdown operations shall not exceed the following emission limitations:

when burning natural gas

83 lbs of NOx/startup and shutdown cycle
308 lbs of CO/startup and shutdown cycle

when burning diesel fuel

130 lbs of NOx/startup and shutdown cycle
354 lbs of CO/startup and shutdown cycle

Applicable Compliance Method:
The lbs/cycle emission limitations were established based on emission data contained in the PTI modification application (PTI 14-04682) submitted March, 2001 and the emission factors from the background document, Reference 16, for Stationary Gas Turbines in AP-42, Fifth Edition, Section 3.1, dated April 2000.

Compliance with the NOx and CO emission limitations shall be determined by the continuous emission monitoring data collected pursuant to the record keeping requirements specified in Sections A.III.2, A.III.7, and A.III.8.

## V. Testing Requirements (continued)

**1.b** Emission Limitations:
The hourly emissions from this emissions unit shall not exceed the following limitations:

i. 58.0 lbs of SO2 emissions/hour;
ii. 54.0 lbs of CO emissions/hour;
iii. 196.0 lbs of NOx emissions/hour;
iv. 6.0 lbs of H2SO4 mist emissions/hour; and
v. 10.0 lbs of VOC emissions/hour.

Applicable Compliance Method:
The hourly emission limitations are based upon the emissions unit's potentials to emit and the manufacturer's guaranteed emission data found in PTI 14-4682 submitted April 26, 1999.

Compliance with the NOx emission limitation shall be determined by the continuous emission monitoring data collected pursuant to the record keeping requirements specified in Section A.III.8.

Compliance with the CO emission limitation shall be determined by the continuous emission monitoring data collected pursuant to the record keeping requirements specified in Section A.III.9.

If required, the permittee shall demonstrate compliance with the hourly NOx emission limitation through emission tests performed in accordance with Methods 1 through 4 and 7 of 40 CFR Part 60, Appendix A.

If required, the permittee shall demonstrate compliance with the hourly SO2 emission limitation through emission tests performed in accordance with Methods 1 through 4 and 6 of 40 CFR Part 60, Appendix A.

If required, the permittee shall demonstrate compliance with the hourly CO emission limitation through emission tests performed in accordance with Methods 1 through 4 and 10 of 40 CFR Part 60, Appendix A.

If required, the permittee shall demonstrate compliance with the hourly H2SO4 mist emission limitation through emission tests performed in accordance with Methods 1 through 4 and 8 of 40 CFR Part 60, Appendix A.

If required, the permittee shall demonstrate compliance with the hourly VOC emission limitation through emission tests performed in accordance with Methods 1 through 4 and 25 of 40 CFR Part 60, Appendix A.

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

## V. Testing Requirements (continued)

**1.c** Emission Limitations:
The total emissions from emissions units P001 through P008, combined, shall not exceed the following emission limitations:

i. 60.5 tons of PE/PM10 emissions per rolling, 12-month period;
ii. 120.8 tons of SO2 emissions per rolling, 12-month period;
iii. 733.3 tons of NOx emissions per rolling, 12-month period;
iv. 541.0 tons of CO emissions per rolling, 12-month period;
v. 36.4 tons of VOC emissions per rolling, 12-month period;
vi. 12.2 tons of H2SO4 mist emissions per rolling, 12-month period;
vii. 7.7 tons of benzene* emissions per rolling, 12-month period;
viii. 0.00084 ton of beryllium* emissions per rolling, 12-month period; and
ix. 0.012 ton of arsenic* emissions per rolling, 12-month period.

Applicable Compliance Method:
Compliance with the rolling, 12-month PE/PM10, SO2, NOx, CO and VOC, H2SO4, benzene, beryllium and arsenic emission limitations specified above shall be determined by the record keeping requirements specified in Section A.III.2.j.

Emission factors for PE/PM10, VOC, SO2, and H2SO4 are specified in the manufacturers guaranteed performance data contained in the application for PTI 14-4682 submitted to the Hamilton County Department of Environmental Services on April 26, 1999.

* The emission factors as specified in AP-42, Fifth Edition, Section 3.1 "Stationary Gas Turbines", updated 4/00 are 0.000011 lb.mmBtu for arsenic, 0.000055 lb/mmBtu for benzene, and 0.00000031 lb/mmBtu for beryllium, from diesel fuel-fired turbines.

The emission factor as specified in AP-42 Fifth Edition, Section 3.1 "Stationary Gas Turbines", updated 4/00 is 0.000012 lb/mmBtu for benzene, from natural gas-fired turbines.

The emission factor for beryllium and arsenic when natural gas is burned is insignificant based upon the manufacturer's guaranteed emission data contained in the application for PTI 14-4682 submitted to the Hamilton County Department of Environmental Services on April 26, 1999.

**1.d** Emission Limitations:
0.15 ton per year of lead emissions and 0.0023 ton per year of mercury emissions.

Applicable Compliance Method:
The lead and mercury emission limitations specified above were determined by multiplying the maximum fuel usage capacity of the equipment, as provided by the manufacturer in PTI 14-4682 submitted April 26, 1999, by the pollutant specific emission factor found in AP-42, Fifth Edition, Section 3.1 "Stationary Gas Turbines," updated 4/00, by the maximum heat content of the fuel, and dividing by 2,000 lbs/ton. The emission factor as specified in the above referenced AP-42 is 0.000014 lbs/mmBtu for lead and 0.0000012 lbs/mmBtu for mercury, from diesel fuel-fired turbines.

The emission factor for mercury and lead when natural gas is burned is insignificant based upon the manufacturer's guaranteed emission data contained in the application for PTI 14-4682 submitted to the Hamilton County Department of Environmental Services on April 26, 1999.

## V. Testing Requirements (continued)

**1.e** Emission Limitations:
when burning natural gas, 15 ppm of NOx, by volume, at 15% oxygen, on a dry basis, (as a 1-hour average, at full load)

when burning diesel fuel, 42 ppm of NOx, by volume, at 15% oxygen, on a dry basis (as a 1-hour average, at full load)

when burning natural gas at full load, 12 ppm of NOx, by volume, at 15% oxygen, on a dry basis (based on a rolling, 12-month summation of the average monthly NOx emissions, in ppm)

Applicable Compliance Method:
Compliance with the NOx emission limitations shall be determined by the continuous emission monitoring data collected pursuant to the record keeping requirements specified in Sections A.III.6 and A.III.7 and the record keeping requirements specified in Section A.III.2.

If required, the permittee shall demonstrate compliance with the non-rolling ppm NOx emission limitations through emission tests performed in accordance with Methods 1 through 4 and 7 of 40 CFR Part 60, Appendix A.

**1.f** Emission Limitation:
0.008 lb of PE/PM10 emissions/mmBtu

Applicable Compliance Method:
The lb/mmBtu emission limitation represents the emissions unit's potential to emit and is based upon the manufacturer's guaranteed emission data contained in the application for PTI 14-4682 submitted to the Hamilton County Department of Environmental Services on April 26, 1999. The total PM10 emissions were evaluated and did not trigger any additional federal requirements, therefore, the emissions are being regulated as particulate emissions (PE) and are subject to the PE compliance demonstration as noted below.

If required, the permittee shall demonstrate compliance with the PE/PM10 emission limitation through emission tests performed in accordance with Methods 1 through 5 of 40 CFR Part 60, Appendix A.

**1.g** Emission Limitation:
Visible particulate emissions from any stack shall not exceed 20% opacity, as a 6-minute average, except as specified by rule, when burning diesel fuel.

Applicable Compliance Method:
If required, compliance with the visible particulate emission limitation shall be determined 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).

**1.h** Emission Limitation:
Visible particulate emissions from any stack shall not exceed 10% opacity, as a 6-minute average, when burning natural gas.

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

## V. Testing Requirements (continued)

**1.i** Emission Limitation:
0.0456 lb of SO2 emissions/mmBtu when burning diesel fuel;

Applicable Compliance Method:
Compliance with the SO2 emission limitation shall be determined by the sulfur analysis of the fuels burned pursuant to the requirements specified in Section A.lll.4 and by documenting that the sulfur content of each shipment of oil received during a calendar month or each daily sample meets the 0.05%, by weight, sulfur content restriction.

If required, the permittee shall demonstrate compliance with the SO2 emission limitation through emission tests performed in accordance with Methods 1 through 4 and 6 of 40 CFR Part 60, Appendix A.

**1.j** Sulfur Content Restriction:
The sulfur content of the natural gas and diesel fuel burned in this emissions unit shall not exceed 0.05% sulfur, by weight.

Applicable Compliance Method:
Compliance with the sulfur content restriction shall be determined by the record keeping requirements specified in Sections A.III.3 and A.III.4.

**1.k** Natural Gas and Diesel Fuel Usage Restrictions:
The maximum annual natural gas usage rate for emissions units P001 through P008, combined, shall not exceed 20,300,000,000 cubic feet per rolling, 12-month period.

The maximum annual diesel fuel usage rate for emissions units P001 through P008, combined, shall not exceed 34,000,000 gallons per rolling, 12-month period.

Applicable Compliance Method:
Compliance with the natural gas and diesel fuel usage restrictions shall be determined by the record keeping requirements specified in Section A.III.2.

## 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 |
|---|---|---|
| 84.65 megawatt (nominal) natural gas/diesel fuel-fired simple cycle combustion turbine using dry low NOx combustors (natural gas firing) or water injection (diesel fuel firing) to control NOx emissions. | OAC rule 3745-31-28 | The requirements established pursuant to this rule are equivalent to the requirements established pursuant to 40 CFR Parts 63.41 through 63.44. This regulation has been promulgated in the Ohio Administrative Code; however, it has not yet been approved as part of the Ohio State Implementation Plan. |

**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:** #5 Turbine (P005)

**Activity Description:** 84.65 Megawatt (Nominal) Simple-Cycle Combustion Turbine #5

## 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 |
|---|---|---|
| 84.65 megawatt (nominal) natural gas/diesel fuel-fired simple cycle combustion turbine using dry low NOx combustors (natural gas firing) or water injection (diesel fuel firing) to control NOx emissions. | OAC rules 3745-31-11 through 3745-31-20<br>(PTI 14-04682) | This emissions unit shall not exceed the following emission limitations:<br><br>58.0 lbs of sulfur dioxide (SO2) emissions/hour*<br><br>6.0 lbs of sulfuric acid (H2SO4) mist emissions/hour*<br><br>0.008 lb of particulate emissions (PE)/particulate matter with a diameter of 10 microns or less (PM10** emissions)/mmBtu*<br><br>* The hourly emission limitations and the lb of PE/PM10 emissions/mmBtu emission limitation specified above represent this emissions unit's potentials to emit for all operating conditions, including startup and shutdown. Therefore, no additional monitoring, record keeping or reporting requirements are required to demonstrate compliance with these emission limitations.<br><br>**The total PM10 emissions were evaluated and did not trigger any additional federal requirements, therefore, the emissions are being regulated as particulate emissions (PE). |

| Operations, Property, and/or Equipment | Applicable Rules/ Requirements | Applicable Emissions Limitations/Control Measures |
|---|---|---|
| | | 196.0 lbs of NOx emissions/hour, excluding startup and shutdown periods<br><br>54.0 lbs of CO emissions/hour, excluding startup and shutdown periods<br><br>when burning natural gas, 15 ppm of NOx, by volume, at 15% oxygen, on a dry basis, (as a 1-hour average, at full load)<br><br>when burning diesel fuel, 42 ppm of NOx, by volume, at 15% oxygen, on a dry basis (as a 1-hour average, at full load)<br><br>when burning natural gas at full load, 12 ppm of NOx, by volume, at 15% oxygen, on a dry basis (based on a rolling, 12-month average summation of the monthly NOx emissions, in ppm)<br><br>when burning diesel fuel, 0.0456 lb of SO2 emissions/mmBtu of actual heat input<br><br>The sulfur content of the natural gas and diesel fuel burned in this emissions unit shall not exceed 0.05% sulfur, by weight.<br><br>Emissions from startup and shutdown operations shall not exceed the following emission limitations:<br><br>when burning natural gas<br><br>83 lbs of NOx/startup and shutdown cycle<br>308 lbs of CO/startup and shutdown cycle<br><br>when burning diesel fuel<br><br>130 lbs of NOx/startup and shutdown cycle<br>354 lbs of CO/startup and shutdown cycle<br><br>See Section A.I.2.c below. |

| Operations, Property, and/or Equipment | Applicable Rules/ Requirements | Applicable Emissions Limitations/Control Measures |
|---|---|---|
| | | Emissions units P001 through P008, combined, shall not exceed the following emission limitations:<br><br>60.5 tons of PE/PM10 emissions per rolling, 12-month period<br><br>120.8 tons of SO2 emissions per rolling, 12-month period<br><br>733.3 tons of nitrogen oxides (NOx) emissions per rolling, 12-month period<br><br>541.0 tons of carbon monoxide (CO) emissions per rolling, 12-month period<br><br>12.2 tons of H2SO4 mist emissions per rolling, 12-month period<br><br>7.7 tons of benzene emissions per rolling, 12-month period<br><br>0.00084 ton of beryllium emissions per rolling, 12-month period<br><br>0.012 ton of arsenic emissions per rolling, 12-month period<br><br>The rolling, 12-month emission limitations are based upon a summation of the pollutant-specific emissions generated under all operating conditions, including startup and shutdown periods, for both natural gas and diesel fuel. |

| Operations, Property, and/or Equipment | Applicable Rules/ Requirements | Applicable Emissions Limitations/Control Measures |
|---|---|---|
| | OAC rule 3745-31-05(A)(3) (PTI 14-04682) | This emissions unit shall not exceed the following emission limitations:<br><br>10.0 lbs of volatile organic compound (VOC) emissions/hour*<br>0.15 ton per year of lead emissions<br>0.0023 ton per year of mercury emissions<br><br>See Section A.I.2.b below.<br><br>Compliance with this rule also includes compliance with the requirements of OAC rule 3745-31-05(C) and OAC rule 3745-17-07(A) when burning diesel fuel.<br><br>* The hourly VOC emission limitation specified above represent this emissions unit's potential to emit for all operating conditions, including startup and shutdown. Therefore, no additional monitoring, record keeping or reporting requirements are required to demonstrate compliance with this emission limitation. |
| | OAC rule 3745-31-05(C) | 36.4 tons of VOC emissions per rolling, 12-month period from emissions units P001 through P008, combined. |
| | OAC rule 3745-17-07(A) | See Section A.I.2.a below. |
| | 40 CFR Part 60, Subpart GG | The emission limitations established in 40 CFR Part 60, Subpart GG for SO2 and NOx are less stringent than those established pursuant to OAC rule 3745-31-05(C). |
| | OAC rule 3745-17-11(B)(4) | The PE limitation specified by this rule is less stringent the PE limitation established pursuant to OAC rule 3745-31-05(C). |
| | OAC rule 3745-18-06(F) | The SO2 emission limitation specified by this rule (0.5 lb of SO2 emissions/mmBtu) is less stringent than the SO2 emission limitation established pursuant to OAC rule 3745-31-05(C). |
| | OAC rules 3745-21-08(B) and 3745-23-06(B) | See Section A.I.2.j below. |

## 2. Additional Terms and Conditions

**2.a** Visible PE from any stack shall not exceed 20% opacity, as a 6-minute average, except as specified by rule when burning diesel fuel.

**2.b** Visible PE from any stack shall not exceed 10% opacity, as a 6-minute average when burning natural gas.

**2.c** The permittee shall operate and maintain dry low NOx burners when burning natural gas and operate and maintain a water injection system when burning diesel fuel.

**2.d** "Full load" shall be defined as the nameplate electrical output of 84.65 megawatts. Any load that is greater than or equal to 90% of the nameplate electrical output shall be considered full load.

**2.e** "Normal operation" shall be defined as the period when the combustion turbine achieves dry low NOx mode (GE Mode 6). GE Mode 6 is defined by the manufacturer as the low emissions mode during which all burner nozzles are in use, burning a lean pre-mixed gas for steady-state operation. The continuous emissions monitoring system will indicate and record the GE Mode 6 status of the combustion turbine, including when the emissions unit is shutdown and when operating in startup and shutdown modes.

**2.f** "Startup" shall be defined as the period between when the combustion turbine is initially started (initial fuel light-off) until the combustion turbine completes transition to GE Mode 6. "Shutdown" shall be defined as the period beginning when the combustion turbine leaves the GE Mode 6 and ending when combustion has ceased.

**2.g** "Startup and shutdown cycle" shall be defined as a startup period followed by a consecutive shutdown period.

**2.h** For the purpose of this permit, the term "diesel fuel" shall be considered to be any low sulfur fuel oil that is burned in this emissions unit, as defined in 40 CFR Part 72.2.

**2.i** Compliance with the startup and shutdown NOx and CO lbs/cycle emission limitations, the NOx and CO emission limitations during steady-state operations, and the NOx ppm emission limitations during full load operations shall be demonstrated by the use of dual range NOx and CO continuous emission monitoring systems (CEMs). For CEM systems with dual ranges, certification testing shall be performed on the range normally used for measuring emissions.

**2.j** 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 technology requirements established pursuant to OAC rule 3745-31-05(A)(3) in Permit to Install 14-4682.

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 technology requirements established pursuant to OAC rule 3745-31-05(A)(3) in Permit to Install 14-4682.

**2.k** For the purposes of this permit and for the hazardous air pollutants (HAPs) emitted from this emissions unit, the best available control technology determination to satisfy the requirements of 40 CFR Part 52.21 is equivalent to the maximum achievable control technology determination used to satisfy the requirements of 40 CFR Parts 63.41 through 63.44.

**2. Additional Terms and Conditions (continued)**

**2.l** In lieu of the requirements of 40 CFR Part 60.334(a) to install and operate a continuous monitoring system to monitor and record the fuel consumption and the ratio of water to fuel being fired in this emissions unit, the permittee shall operate and maintain systems to continuously monitor and record emissions of NOx for this emissions unit in accordance with this permit.

In lieu of the excess emissions reports required under 40 CFR Part 60.334, the permittee shall submit excess emissions reports for this emissions unit in accordance with this permit.

In lieu of the test methods and procedures required under 40 CFR Part 60.335, the permittee shall follow the monitoring and testing requirements for this emissions unit in accordance with this permit.

## II. Operational Restrictions

**1.** The maximum annual natural gas usage rate for emissions units P001 through P008, combined, shall not exceed 20,300,000,000 cubic feet per rolling, 12-month period.

**2.** The maximum annual diesel fuel usage rate for emissions units P001 through P008, combined, shall not exceed 34,000,000 gallons per rolling, 12-month period.

**3.** The permittee shall burn only pipeline quality natural gas or diesel fuel in this emissions unit.

**4.** The quality of diesel fuel burned in this emissions unit shall have a combination of heat and sulfur content which is sufficient to comply with the allowable SO2 emission limitation of 0.0456 lb of SO2/mmBtu of actual heat input. The diesel fuel shall have a sulfur content of 0.05%, by weight, or less.

**5.** When the emissions unit is operating in startup and shutdown conditions, as defined in Section A.I.2.f above, each startup and shutdown cycle shall not exceed 1.0 hour in duration.

**6.** With the exception of startup and shutdown, this emissions unit shall be operated in GE Mode 6, defined as normal or full load operation (see Sections A.I.2.d and A.I.2.e above).

## III. Monitoring and/or Record Keeping Requirements

**1.** The permittee shall maintain daily records of the following information:

a. the emissions unit's actual electrical output for each operating hour; and

b. for each day during which the permittee burns a fuel other than pipeline quality natural gas and/or diesel fuel, the permittee shall maintain a record of the type and quantity of fuel burned in this emissions unit.

**2.** The permittee shall maintain monthly records of the following information:

a. the total amount of natural gas burned, in cubic feet, for emissions units P001 through P008, combined;

b. the total amount of diesel fuel burned, in gallons, for emissions units P001 through P008, combined;

c. the rolling, 12-month summation of the total amount of natural gas burned, in cubic feet, for emissions units P001 through P008, combined (the amount of natural gas burned for the current month plus the total amount of natural gas burned for the previous 11 calendar months);

d. the rolling, 12-month summation of the total amount of diesel fuel burned, in gallons, for emissions units P001 through P008, combined (the amount of diesel fuel burned for the current month plus the total amount of diesel fuel burned for the previous 11 calendar months);

e. the date and duration, in minutes, of each startup and shutdown cycle;

f. the emissions, in pounds, for NOx* and CO* when burning natural gas for each startup and shutdown cycle;

g. the emissions, in pounds, for NOx* and CO* when burning diesel fuel for each startup and shutdown cycle;

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

h. the total emissions, in tons, for NOx*, CO*, PE/PM10, SO2 , VOC, H2SO4, and benzene when burning natural gas for all operating conditions;

i. the total emissions, in tons, for NOx*, CO*, PE/PM10, SO2, VOC, H2SO4, benzene, beryllium and arsenic when burning diesel fuel for all operating conditions;

j. the rolling, 12-month emissions, in tons, for NOx*, CO*, PE/PM10, SO2, VOC, H2SO4, benzene, beryllium and arsenic for emissions units P001 through P008, combined, when burning natural gas and diesel fuel (the total emissions calculated in (h) + (i)) for the current month plus the total emissions for the previous 11 calendar months); and

k. the rolling, 12-month average of NOx* emissions, in ppm, when burning natural gas at full load for this emissions unit (the NOx ppm average for the current month (from the CEMs data) plus the total NOx ppm average for the previous 11 calendar months).

* The permittee shall use the continuous NOx and CO emissions monitoring data to determine the NOx and CO emissions for these emissions units. During any period when the NOx and/or the CO emissions monitoring systems are not operational, the permittee shall use the appropriate missing data procedures specified in 40 CFR Part 75 to determine NOx and CO emissions or an approved data substitution protocol for the purpose of calculating the rolling, 12-month emission rates. The data substitution values shall not be used to demonstrate compliance with the hourly NOx and CO emission limitations applicable during normal operation of this emissions unit.

**3.** The permittee shall monitor and record the sulfur content of the natural gas being burned in this emissions unit or make the demonstration that the sulfur content of the natural gas does not need to be monitored and recorded in accordance with the provisions specified in 40 CFR Part 60.334(b). Owners, operators or fuel vendors may develop custom fuel schedules for the determination of the sulfur content based on the design and operation of the affected facility and the characteristics of the fuel supply. Except as provided in 40 CFR Parts 60.334(i)(3)(i) and 60.334(i)(3)(ii), these custom schedules shall be substantiated with data and must be approved by the Ohio EPA, Central Office before they can be used.

Analyses for the purpose of determining the sulfur content of the natural gas may be performed by the permittee, the fuel vendor, or any other qualified agency in accordance with the analytical methods specified in 40 CFR Part 60, Subpart GG, Section 60.335(d) or equivalent methods as approved by the Administrator.

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

**4.** The permittee shall maintain records of the diesel fuel burned in this emissions unit in accordance with either Alternative 1 or Alternative 2 described below:

a. Alternative 1:

For each shipment of oil received for burning in this emissions unit, the permittee shall collect or require the oil supplier to collect a representative grab sample of oil and maintain records of the total quantity of oil received, the permittee's or oil supplier's analyses for sulfur content and heat content, and the calculated sulfur dioxide emission rate (in lbs/mmBtu). (The sulfur dioxide emission rate shall be calculated in accordance with the formula specified in OAC rule 3745-18-04(F).) 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 may be represented by a single batch analysis from the supplier.

b. Alternative 2:

The permittee shall collect a representative grab sample of oil that is burned in this emissions unit for each day when the emission unit is in operation. If additional fuel oil is added to the tank serving this emissions unit on a day when the emissions unit is in operation, the permittee shall collect a sufficient number of grab samples to develop a composite sample representative of the fuel oil burned in this emissions unit. A representative grab sample of oil does not need to be collected on days when this emissions unit is only operated for the purpose of "test-firing". The permittee shall maintain records of the total quantity of oil burned each day (except for the purpose of test-firing), the permittee's analyses for sulfur content and heat content, and the calculated sulfur dioxide emission rate (in lbs/mmBtu). [The sulfur dioxide emission rate shall be calculated in accordance with the formula specified in OAC rule 3745-18-04(F).]

The permittee shall perform or require the supplier to perform the analyses for sulfur content and heat content in accordance with the following ASTM methods: ASTM method D4294 for sulfur content and ASTM method D240 for heat content. The newest or most recent revisions to the applicable test method shall be used for analyses. Alternative, equivalent methods may be used upon written approval by the Hamilton County Department of Environmental Services - Air Quality Control Division.

**5.** The permittee shall operate and maintain equipment to continuously monitor and record the actual fuel flow to this emissions unit when it is in operation. Such continuous monitoring and recording equipment shall comply with the requirements specified in 40 CFR Part 75. If the fuel flow monitoring and/or recording equipment is (are) not in service when the emissions unit is in operation, the permittee shall comply with the appropriate missing data procedures specified in 40 CFR Part 75.

**6.** The permittee shall operate and maintain equipment to continuously monitor and record the percent oxygen (as a 1-hr average) in the stack serving this emissions unit when the emissions unit is in operation. Such continuous monitoring and recording equipment shall comply with the requirements specified in 40 CFR Part 75. The monitoring and recording equipment shall be installed, calibrated, operated and maintained in accordance with the manufacturer's recommendations, with any modifications deemed necessary by the permittee.

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

**7.** The permittee shall operate and maintain equipment to continuously monitor and record NOx emissions from this emissions unit in units of the applicable standard(s). Such continuous monitoring and recording equipment shall comply with the applicable requirements specified in 40 CFR Part 60 and Part 75.

Each continuous monitoring system consists of all the equipment used to acquire and record data and includes the sample extraction and transport hardware, sample conditioning hardware, analyzers, and data processing hardware and software.

The permittee shall maintain on-site documentation from the USEPA or the Ohio EPA that the continuous NOx monitoring system has been certified in accordance with the applicable requirements specified in 40 CFR Part 60 and Part 75. The letter of certification shall be made available to the Director upon request.

The permittee shall maintain records of the following data obtained by the continuous NOx monitoring system: emissions of NOx in ppmvd at 15% oxygen on an hourly average basis, emissions of NOx in lbs/hr, results of daily zero/span calibration checks, results of quarterly cylinder gas audits, linearity checks, or relative accuracy test audits, and magnitude of manual calibration adjustments.

The permittee shall develop a written quality assurance/quality control plan for the continuous NOx monitoring system designed to ensure continuous valid and representative readings of NOx emissions in units of the applicable standard(s). The plan shall follow the applicable requirements of 40 CFR Part 60, Appendix F and 40 CFR Part 75, Appendix B. The quality assurance/quality control plan and a logbook documenting the activities related to the continuous NOx monitoring system must be kept on site and available for inspection during regular office hours.

The permittee may conduct the relative accuracy test audits for the continuous nitrogen oxides monitoring system in accordance with the frequencies required for monitoring systems subject to 40 CFR Part 75, Appendix B; however, the permittee is still required to provide the audit results in units of the applicable standard(s), in accordance with 40 CFR Part 60. In addition, linearity checks conducted pursuant to 40 CFR Part 75, Appendix B, may be used in place of quarterly cylinder gas audits, as required in 40 CFR Part 60.

**8.** The permittee shall operate and maintain equipment to continuously monitor and record CO emissions from this emissions unit in units of the applicable standard(s). Such continuous monitoring and recording equipment shall comply with the requirements specified in 40 CFR Part 60.

Each continuous monitoring system consists of all the equipment used to acquire and record data and includes the sample extraction and transport hardware, sample conditioning hardware, analyzers, and data processing hardware and software.

The permittee shall maintain on-site documentation from the USEPA or the Ohio EPA that the continuous CO monitoring system has been certified in accordance with 40 CFR Part 60. The letter of certification shall be made available to the Director upon request.

The permittee shall maintain records of the following data obtained by the continuous CO monitoring system: emissions of CO in lbs/hr, results of daily zero/span calibration checks, results of quarterly cylinder gas audits or relative accuracy test audits, and magnitude of manual calibration adjustments.

The permittee shall develop a written quality assurance/quality control plan for the continuous CO monitoring system designed to ensure continuous valid and representative readings of CO emissions in units of the applicable standard(s). The plan shall follow the requirements of 40 CFR Part 60, Appendix F. The quality assurance/quality control plan and a logbook documenting the activities related to the continuous CO monitoring system must be kept on site and available for inspection during regular office hours.

The permittee may conduct the relative accuracy test audits for the continuous carbon monoxide monitoring system in accordance with the frequencies required for monitoring systems subject to 40 CFR Part 75, Appendix B; however, the permittee is still required to provide the audit results in units of the applicable standard(s), in accordance with 40 CFR Part 60. Cylinder gas audits may be conducted in accordance with the frequencies specified in 40 CFR Part 75, Appendix B for linearity checks.

## IV. Reporting Requirements

**1.** 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.

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

a. all exceedances of the rolling, 12-month natural gas usage limitation for emissions units P001 through P008, combined;

b. all exceedances of the rolling, 12-month emission limitations for PE/PM10, SO2, NOx, CO, H2SO4 mist, VOC, benzene, beryllium and arsenic for emissions units P001 through P008, combined;

c. all exceedances of the sulfur content restriction (i.e., 0.05%, by weight) for the fuels (natural gas and diesel fuel) received for burning in this emissions unit;

d. all exceedances of the SO2 lbs/mmBtu emission limitation when burning diesel fuel in this emissions unit;

e. all exceedances of the 1.0 hour startup and shutdown cycle operational restriction;

f. all exceedances of the rolling, 12-month diesel fuel usage limitation for emissions units P001 through P008, combined;

g. all exceedances of the startup and shutdown emission limitations specified in Section A.I.1 when burning natural gas;

h. all exceedances of the startup and shutdown emission limitations specified in Section A.I.1 when burning diesel fuel; and

i. each day when a fuel other than natural gas or diesel fuel was burned in this emissions unit.

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

**4.** 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 Control Division documenting the date, commencement and completion times, duration, magnitude, reason (if known), and corrective actions taken (if any), of all instances of NOx values in excess of the applicable emission limitations (emissions of NOx in ppmvd at 15% oxygen on an hourly average basis and emissions of NOx in lbs/hr) specified in the terms and conditions of this permit.

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 Control Division documenting any continuous NOx 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 analyzer 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 analyzer 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 31, April 30, July 31, and October 31 of each year and shall address the data obtained during the previous calendar quarter.

The permittee shall submit a summary of the excess emission report. The summary shall be submitted to the Hamilton County Department of Environmental Services - Air Quality Control Division within 30 days following the end of each calendar quarter in a manner prescribed by the Director.

## IV. Reporting Requirements (continued)

**5.** 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 Control Division documenting the date, commencement and completion times, duration, magnitude, reason (if known), and corrective actions taken (if any) of all instances of CO values in excess of any applicable emission limitations (emissions of CO in lbs/hr) specified in the terms and conditions of this permit.

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 Control Division documenting any continuous CO 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 analyzer 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 analyzer while the emissions unit was on line shall also be included in the quarterly report. These quarterly excess emission reports shall be submitted by January 31, April 30, July 31, and October 31 of each year and shall address the data obtained during the previous calendar quarter.

The permittee shall submit a summary of the excess emission report. The summary shall be submitted to the Hamilton County Department of Environmental Services - Air Quality Control Division within 30 days following the end of the calendar quarter.

**6.** The permittee shall submit annual reports that specify the total mercury and lead emissions from this emissions unit for the previous calendar year. The reports shall be submitted by April 15 of each year. This reporting requirement may be satisfied by including and identifying the specific emission data for this emissions unit in the annual Fee Emission Report.

## V. Testing Requirements

**1.** Compliance with the emission limitations, fuel usage restrictions, and fuel sulfur content restriction specified in Sections A.I and A.II shall be determined by the following methods:

**1.a** Emission Limitations:
Emissions from startup and shutdown operations shall not exceed the following emission limitations:

when burning natural gas

83 lbs of NOx/startup and shutdown cycle
308 lbs of CO/startup and shutdown cycle

when burning diesel fuel

130 lbs of NOx/startup and shutdown cycle
354 lbs of CO/startup and shutdown cycle

Applicable Compliance Method:
The lbs/cycle emission limitations were established based on emission data contained in the PTI modification application (PTI 14-04682) submitted March, 2001 and the emission factors from the background document, Reference 16, for Stationary Gas Turbines in AP-42, Fifth Edition, Section 3.1, dated April 2000.

Compliance with the NOx and CO emission limitations shall be determined by the continuous emission monitoring data collected pursuant to the record keeping requirements specified in Sections A.III.2, A.III.7, and A.III.8.

## V. Testing Requirements (continued)

**1.b** Emission Limitations:
The hourly emissions from this emissions unit shall not exceed the following limitations:

i. 58.0 lbs of SO2 emissions/hour;
ii. 54.0 lbs of CO emissions/hour;
iii. 196.0 lbs of NOx emissions/hour;
iv. 6.0 lbs of H2SO4 mist emissions/hour; and
v. 10.0 lbs of VOC emissions/hour.

Applicable Compliance Method:
The hourly emission limitations are based upon the emissions unit's potentials to emit and the manufacturer's guaranteed emission data found in PTI 14-4682 submitted April 26, 1999.

Compliance with the NOx emission limitation shall be determined by the continuous emission monitoring data collected pursuant to the record keeping requirements specified in Section A.III.8.

Compliance with the CO emission limitation shall be determined by the continuous emission monitoring data collected pursuant to the record keeping requirements specified in Section A.III.9.

If required, the permittee shall demonstrate compliance with the hourly NOx emission limitation through emission tests performed in accordance with Methods 1 through 4 and 7 of 40 CFR Part 60, Appendix A.

If required, the permittee shall demonstrate compliance with the hourly SO2 emission limitation through emission tests performed in accordance with Methods 1 through 4 and 6 of 40 CFR Part 60, Appendix A.

If required, the permittee shall demonstrate compliance with the hourly CO emission limitation through emission tests performed in accordance with Methods 1 through 4 and 10 of 40 CFR Part 60, Appendix A.

If required, the permittee shall demonstrate compliance with the hourly H2SO4 mist emission limitation through emission tests performed in accordance with Methods 1 through 4 and 8 of 40 CFR Part 60, Appendix A.

If required, the permittee shall demonstrate compliance with the hourly VOC emission limitation through emission tests performed in accordance with Methods 1 through 4 and 25 of 40 CFR Part 60, Appendix A.

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

## V. Testing Requirements (continued)

**1.c** Emission Limitations:
The total emissions from emissions units P001 through P008, combined, shall not exceed the following emission limitations:

i. 60.5 tons of PE/PM10 emissions per rolling, 12-month period;
ii. 120.8 tons of SO2 emissions per rolling, 12-month period;
iii. 733.3 tons of NOx emissions per rolling, 12-month period;
iv. 541.0 tons of CO emissions per rolling, 12-month period;
v. 36.4 tons of VOC emissions per rolling, 12-month period;
vi. 12.2 tons of H2SO4 mist emissions per rolling, 12-month period;
vii. 7.7 tons of benzene* emissions per rolling, 12-month period;
viii. 0.00084 ton of beryllium* emissions per rolling, 12-month period; and
ix. 0.012 ton of arsenic* emissions per rolling, 12-month period.

Applicable Compliance Method:
Compliance with the rolling, 12-month PE/PM10, SO2, NOx, CO and VOC, H2SO4, benzene, beryllium and arsenic emission limitations specified above shall be determined by the record keeping requirements specified in Section A.III.2.j.

Emission factors for PE/PM10, VOC, SO2, and H2SO4 are specified in the manufacturers guaranteed performance data contained in the application for PTI 14-4682 submitted to the Hamilton County Department of Environmental Services on April 26, 1999.

* The emission factors as specified in AP-42, Fifth Edition, Section 3.1 "Stationary Gas Turbines", updated 4/00 are 0.000011 lb.mmBtu for arsenic, 0.000055 lb/mmBtu for benzene, and 0.00000031 lb/mmBtu for beryllium, from diesel fuel-fired turbines.

The emission factor as specified in AP-42 Fifth Edition, Section 3.1 "Stationary Gas Turbines", updated 4/00 is 0.000012 lb/mmBtu for benzene, from natural gas-fired turbines.

The emission factor for beryllium and arsenic when natural gas is burned is insignificant based upon the manufacturer's guaranteed emission data contained in the application for PTI 14-4682 submitted to the Hamilton County Department of Environmental Services on April 26, 1999.

**1.d** Emission Limitations:
0.15 ton per year of lead emissions and 0.0023 ton per year of mercury emissions.

Applicable Compliance Method:
The lead and mercury emission limitations specified above were determined by multiplying the maximum fuel usage capacity of the equipment, as provided by the manufacturer in PTI 14-4682 submitted April 26, 1999, by the pollutant specific emission factor found in AP-42, Fifth Edition, Section 3.1 "Stationary Gas Turbines," updated 4/00, by the maximum heat content of the fuel, and dividing by 2,000 lbs/ton. The emission factor as specified in the above referenced AP-42 is 0.000014 lbs/mmBtu for lead and 0.0000012 lbs/mmBtu for mercury, from diesel fuel-fired turbines.

The emission factor for mercury and lead when natural gas is burned is insignificant based upon the manufacturer's guaranteed emission data contained in the application for PTI 14-4682 submitted to the Hamilton County Department of Environmental Services on April 26, 1999.

## V. Testing Requirements (continued)

**1.e** Emission Limitations:
when burning natural gas, 15 ppm of NOx, by volume, at 15% oxygen, on a dry basis, (as a 1-hour average, at full load)

when burning diesel fuel, 42 ppm of NOx, by volume, at 15% oxygen, on a dry basis (as a 1-hour average, at full load)

when burning natural gas at full load, 12 ppm of NOx, by volume, at 15% oxygen, on a dry basis (based on a rolling, 12-month summation of the average monthly NOx emissions, in ppm)

Applicable Compliance Method:
Compliance with the NOx emission limitations shall be determined by the continuous emission monitoring data collected pursuant to the record keeping requirements specified in Sections A.III.6 and A.III.7 and the record keeping requirements specified in Section A.III.2.

If required, the permittee shall demonstrate compliance with the non-rolling ppm NOx emission limitations through emission tests performed in accordance with Methods 1 through 4 and 7 of 40 CFR Part 60, Appendix A.

**1.f** Emission Limitation:
0.008 lb of PE/PM10 emissions/mmBtu

Applicable Compliance Method:
The lb/mmBtu emission limitation represents the emissions unit's potential to emit and is based upon the manufacturer's guaranteed emission data contained in the application for PTI 14-4682 submitted to the Hamilton County Department of Environmental Services on April 26, 1999. The total PM10 emissions were evaluated and did not trigger any additional federal requirements, therefore, the emissions are being regulated as particulate emissions (PE) and are subject to the PE compliance demonstration as noted below.

If required, the permittee shall demonstrate compliance with the PE/PM10 emission limitation through emission tests performed in accordance with Methods 1 through 5 of 40 CFR Part 60, Appendix A.

**1.g** Emission Limitation:
Visible particulate emissions from any stack shall not exceed 20% opacity, as a 6-minute average, except as specified by rule, when burning diesel fuel.

Applicable Compliance Method:
If required, compliance with the visible particulate emission limitation shall be determined 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).

**1.h** Emission Limitation:
Visible particulate emissions from any stack shall not exceed 10% opacity, as a 6-minute average, when burning natural gas.

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

## V. Testing Requirements (continued)

**1.i** Emission Limitation:
0.0456 lb of SO2 emissions/mmBtu when burning diesel fuel;

Applicable Compliance Method:
Compliance with the SO2 emission limitation shall be determined by the sulfur analysis of the fuels burned pursuant to the requirements specified in Section A.lll.4 and by documenting that the sulfur content of each shipment of oil received during a calendar month or each daily sample meets the 0.05%, by weight, sulfur content restriction.

If required, the permittee shall demonstrate compliance with the SO2 emission limitation through emission tests performed in accordance with Methods 1 through 4 and 6 of 40 CFR Part 60, Appendix A.

**1.j** Sulfur Content Restriction:
The sulfur content of the natural gas and diesel fuel burned in this emissions unit shall not exceed 0.05% sulfur, by weight.

Applicable Compliance Method:
Compliance with the sulfur content restriction shall be determined by the record keeping requirements specified in Sections A.III.3 and A.III.4.

**1.k** Natural Gas and Diesel Fuel Usage Restrictions:
The maximum annual natural gas usage rate for emissions units P001 through P008, combined, shall not exceed 20,300,000,000 cubic feet per rolling, 12-month period.

The maximum annual diesel fuel usage rate for emissions units P001 through P008, combined, shall not exceed 34,000,000 gallons per rolling, 12-month period.

Applicable Compliance Method:
Compliance with the natural gas and diesel fuel usage restrictions shall be determined by the record keeping requirements specified in Section A.III.2.

## 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 |
|---|---|---|
| 84.65 megawatt (nominal) natural gas/diesel fuel-fired simple cycle combustion turbine using dry low NOx combustors (natural gas firing) or water injection (diesel fuel firing) to control NOx emissions. | OAC rule 3745-31-28 | The requirements established pursuant to this rule are equivalent to the requirements established pursuant to 40 CFR Parts 63.41 through 63.44. This regulation has been promulgated in the Ohio Administrative Code; however, it has not yet been approved as part of the Ohio State Implementation Plan. |

**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:** #6 Turbine (P006)

**Activity Description:** 84.65 Megawatt (Nominal) Simple-Cycle Combustion Turbine #6

## 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 |
|---|---|---|
| 84.65 megawatt (nominal) natural gas/diesel fuel-fired simple cycle combustion turbine using dry low NOx combustors (natural gas firing) or water injection (diesel fuel firing) to control NOx emissions. | OAC rules 3745-31-11 through 3745-31-20<br>(PTI 14-04682) | This emissions unit shall not exceed the following emission limitations:<br><br>58.0 lbs of sulfur dioxide (SO2) emissions/hour*<br><br>6.0 lbs of sulfuric acid (H2SO4) mist emissions/hour*<br><br>0.008 lb of particulate emissions (PE)/particulate matter with a diameter of 10 microns or less (PM10** emissions)/mmBtu*<br><br>* The hourly emission limitations and the lb of PE/PM10 emissions/mmBtu emission limitation specified above represent this emissions unit's potentials to emit for all operating conditions, including startup and shutdown. Therefore, no additional monitoring, record keeping or reporting requirements are required to demonstrate compliance with these emission limitations.<br><br>**The total PM10 emissions were evaluated and did not trigger any additional federal requirements, therefore, the emissions are being regulated as particulate emissions (PE). |

| Operations, Property, and/or Equipment | Applicable Rules/ Requirements | Applicable Emissions Limitations/Control Measures |
|---|---|---|
| | | 196.0 lbs of NOx emissions/hour, excluding startup and shutdown periods<br><br>54.0 lbs of CO emissions/hour, excluding startup and shutdown periods<br><br>when burning natural gas, 15 ppm of NOx, by volume, at 15% oxygen, on a dry basis, (as a 1-hour average, at full load)<br><br>when burning diesel fuel, 42 ppm of NOx, by volume, at 15% oxygen, on a dry basis (as a 1-hour average, at full load)<br><br>when burning natural gas at full load, 12 ppm of NOx, by volume, at 15% oxygen, on a dry basis (based on a rolling, 12-month average summation of the monthly NOx emissions, in ppm)<br><br>when burning diesel fuel, 0.0456 lb of SO2 emissions/mmBtu of actual heat input<br><br>The sulfur content of the natural gas and diesel fuel burned in this emissions unit shall not exceed 0.05% sulfur, by weight.<br><br>Emissions from startup and shutdown operations shall not exceed the following emission limitations:<br><br>when burning natural gas<br><br>83 lbs of NOx/startup and shutdown cycle<br>308 lbs of CO/startup and shutdown cycle<br><br>when burning diesel fuel<br><br>130 lbs of NOx/startup and shutdown cycle<br>354 lbs of CO/startup and shutdown cycle<br><br>See Section A.I.2.c below. |

| Operations, Property, and/or Equipment | Applicable Rules/ Requirements | Applicable Emissions Limitations/Control Measures |
|---|---|---|
| | | Emissions units P001 through P008, combined, shall not exceed the following emission limitations:<br><br>60.5 tons of PE/PM10 emissions per rolling, 12-month period<br><br>120.8 tons of SO2 emissions per rolling, 12-month period<br><br>733.3 tons of nitrogen oxides (NOx) emissions per rolling, 12-month period<br><br>541.0 tons of carbon monoxide (CO) emissions per rolling, 12-month period<br><br>12.2 tons of H2SO4 mist emissions per rolling, 12-month period<br><br>7.7 tons of benzene emissions per rolling, 12-month period<br><br>0.00084 ton of beryllium emissions per rolling, 12-month period<br><br>0.012 ton of arsenic emissions per rolling, 12-month period<br><br>The rolling, 12-month emission limitations are based upon a summation of the pollutant-specific emissions generated under all operating conditions, including startup and shutdown periods, for both natural gas and diesel fuel. |

| Operations, Property, and/or Equipment | Applicable Rules/ Requirements | Applicable Emissions Limitations/Control Measures |
|---|---|---|
| | OAC rule 3745-31-05(A)(3) (PTI 14-04682) | This emissions unit shall not exceed the following emission limitations:<br><br>10.0 lbs of volatile organic compound (VOC) emissions/hour*<br>0.15 ton per year of lead emissions<br>0.0023 ton per year of mercury emissions<br><br>See Section A.I.2.b below.<br><br>Compliance with this rule also includes compliance with the requirements of OAC rule 3745-31-05(C) and OAC rule 3745-17-07(A) when burning diesel fuel.<br><br>* The hourly VOC emission limitation specified above represent this emissions unit's potential to emit for all operating conditions, including startup and shutdown. Therefore, no additional monitoring, record keeping or reporting requirements are required to demonstrate compliance with this emission limitation. |
| | OAC rule 3745-31-05(C) | 36.4 tons of VOC emissions per rolling, 12-month period from emissions units P001 through P008, combined. |
| | OAC rule 3745-17-07(A) | See Section A.I.2.a below. |
| | 40 CFR Part 60, Subpart GG | The emission limitations established in 40 CFR Part 60, Subpart GG for SO2 and NOx are less stringent than those established pursuant to OAC rule 3745-31-05(C). |
| | OAC rule 3745-17-11(B)(4) | The PE limitation specified by this rule is less stringent the PE limitation established pursuant to OAC rule 3745-31-05(C). |
| | OAC rule 3745-18-06(F) | The SO2 emission limitation specified by this rule (0.5 lb of SO2 emissions/mmBtu) is less stringent than the SO2 emission limitation established pursuant to OAC rule 3745-31-05(C). |
| | OAC rules 3745-21-08(B) and 3745-23-06(B) | See Section A.I.2.j below. |

## 2. Additional Terms and Conditions

**2.a** Visible PE from any stack shall not exceed 20% opacity, as a 6-minute average, except as specified by rule when burning diesel fuel.

**2.b** Visible PE from any stack shall not exceed 10% opacity, as a 6-minute average when burning natural gas.

**2.c** The permittee shall operate and maintain dry low NOx burners when burning natural gas and operate and maintain a water injection system when burning diesel fuel.

**2.d** "Full load" shall be defined as the nameplate electrical output of 84.65 megawatts. Any load that is greater than or equal to 90% of the nameplate electrical output shall be considered full load.

**2.e** "Normal operation" shall be defined as the period when the combustion turbine achieves dry low NOx mode (GE Mode 6). GE Mode 6 is defined by the manufacturer as the low emissions mode during which all burner nozzles are in use, burning a lean pre-mixed gas for steady-state operation. The continuous emissions monitoring system will indicate and record the GE Mode 6 status of the combustion turbine, including when the emissions unit is shutdown and when operating in startup and shutdown modes.

**2.f** "Startup" shall be defined as the period between when the combustion turbine is initially started (initial fuel light-off) until the combustion turbine completes transition to GE Mode 6. "Shutdown" shall be defined as the period beginning when the combustion turbine leaves the GE Mode 6 and ending when combustion has ceased.

**2.g** "Startup and shutdown cycle" shall be defined as a startup period followed by a consecutive shutdown period.

**2.h** For the purpose of this permit, the term "diesel fuel" shall be considered to be any low sulfur fuel oil that is burned in this emissions unit, as defined in 40 CFR Part 72.2.

**2.i** Compliance with the startup and shutdown NOx and CO lbs/cycle emission limitations, the NOx and CO emission limitations during steady-state operations, and the NOx ppm emission limitations during full load operations shall be demonstrated by the use of dual range NOx and CO continuous emission monitoring systems (CEMs). For CEM systems with dual ranges, certification testing shall be performed on the range normally used for measuring emissions.

**2.j** 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 technology requirements established pursuant to OAC rule 3745-31-05(A)(3) in Permit to Install 14-4682.

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 technology requirements established pursuant to OAC rule 3745-31-05(A)(3) in Permit to Install 14-4682.

**2.k** For the purposes of this permit and for the hazardous air pollutants (HAPs) emitted from this emissions unit, the best available control technology determination to satisfy the requirements of 40 CFR Part 52.21 is equivalent to the maximum achievable control technology determination used to satisfy the requirements of 40 CFR Parts 63.41 through 63.44.

**2. Additional Terms and Conditions (continued)**

**2.l** In lieu of the requirements of 40 CFR Part 60.334(a) to install and operate a continuous monitoring system to monitor and record the fuel consumption and the ratio of water to fuel being fired in this emissions unit, the permittee shall operate and maintain systems to continuously monitor and record emissions of NOx for this emissions unit in accordance with this permit.

In lieu of the excess emissions reports required under 40 CFR Part 60.334, the permittee shall submit excess emissions reports for this emissions unit in accordance with this permit.

In lieu of the test methods and procedures required under 40 CFR Part 60.335, the permittee shall follow the monitoring and testing requirements for this emissions unit in accordance with this permit.

## II. Operational Restrictions

**1.** The maximum annual natural gas usage rate for emissions units P001 through P008, combined, shall not exceed 20,300,000,000 cubic feet per rolling, 12-month period.

**2.** The maximum annual diesel fuel usage rate for emissions units P001 through P008, combined, shall not exceed 34,000,000 gallons per rolling, 12-month period.

**3.** The permittee shall burn only pipeline quality natural gas or diesel fuel in this emissions unit.

**4.** The quality of diesel fuel burned in this emissions unit shall have a combination of heat and sulfur content which is sufficient to comply with the allowable SO2 emission limitation of 0.0456 lb of SO2/mmBtu of actual heat input. The diesel fuel shall have a sulfur content of 0.05%, by weight, or less.

**5.** When the emissions unit is operating in startup and shutdown conditions, as defined in Section A.I.2.f above, each startup and shutdown cycle shall not exceed 1.0 hour in duration.

**6.** With the exception of startup and shutdown, this emissions unit shall be operated in GE Mode 6, defined as normal or full load operation (see Sections A.I.2.d and A.I.2.e above).

## III. Monitoring and/or Record Keeping Requirements

**1.** The permittee shall maintain daily records of the following information:

a. the emissions unit's actual electrical output for each operating hour; and

b. for each day during which the permittee burns a fuel other than pipeline quality natural gas and/or diesel fuel, the permittee shall maintain a record of the type and quantity of fuel burned in this emissions unit.

**2.** The permittee shall maintain monthly records of the following information:

a. the total amount of natural gas burned, in cubic feet, for emissions units P001 through P008, combined;

b. the total amount of diesel fuel burned, in gallons, for emissions units P001 through P008, combined;

c. the rolling, 12-month summation of the total amount of natural gas burned, in cubic feet, for emissions units P001 through P008, combined (the amount of natural gas burned for the current month plus the total amount of natural gas burned for the previous 11 calendar months);

d. the rolling, 12-month summation of the total amount of diesel fuel burned, in gallons, for emissions units P001 through P008, combined (the amount of diesel fuel burned for the current month plus the total amount of diesel fuel burned for the previous 11 calendar months);

e. the date and duration, in minutes, of each startup and shutdown cycle;

f. the emissions, in pounds, for NOx* and CO* when burning natural gas for each startup and shutdown cycle;

g. the emissions, in pounds, for NOx* and CO* when burning diesel fuel for each startup and shutdown cycle;

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

h. the total emissions, in tons, for NOx*, CO*, PE/PM10, SO2 , VOC, H2SO4, and benzene when burning natural gas for all operating conditions;

i. the total emissions, in tons, for NOx*, CO*, PE/PM10, SO2, VOC, H2SO4, benzene, beryllium and arsenic when burning diesel fuel for all operating conditions;

j. the rolling, 12-month emissions, in tons, for NOx*, CO*, PE/PM10, SO2, VOC, H2SO4, benzene, beryllium and arsenic for emissions units P001 through P008, combined, when burning natural gas and diesel fuel (the total emissions calculated in (h) + (i)) for the current month plus the total emissions for the previous 11 calendar months); and

k. the rolling, 12-month average of NOx* emissions, in ppm, when burning natural gas at full load for this emissions unit (the NOx ppm average for the current month (from the CEMs data) plus the total NOx ppm average for the previous 11 calendar months).

* The permittee shall use the continuous NOx and CO emissions monitoring data to determine the NOx and CO emissions for these emissions units. During any period when the NOx and/or the CO emissions monitoring systems are not operational, the permittee shall use the appropriate missing data procedures specified in 40 CFR Part 75 to determine NOx and CO emissions or an approved data substitution protocol for the purpose of calculating the rolling, 12-month emission rates. The data substitution values shall not be used to demonstrate compliance with the hourly NOx and CO emission limitations applicable during normal operation of this emissions unit.

**3.** The permittee shall monitor and record the sulfur content of the natural gas being burned in this emissions unit or make the demonstration that the sulfur content of the natural gas does not need to be monitored and recorded in accordance with the provisions specified in 40 CFR Part 60.334(b). Owners, operators or fuel vendors may develop custom fuel schedules for the determination of the sulfur content based on the design and operation of the affected facility and the characteristics of the fuel supply. Except as provided in 40 CFR Parts 60.334(i)(3)(i) and 60.334(i)(3)(ii), these custom schedules shall be substantiated with data and must be approved by the Ohio EPA, Central Office before they can be used.

Analyses for the purpose of determining the sulfur content of the natural gas may be performed by the permittee, the fuel vendor, or any other qualified agency in accordance with the analytical methods specified in 40 CFR Part 60, Subpart GG, Section 60.335(d) or equivalent methods as approved by the Administrator.

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

**4.** The permittee shall maintain records of the diesel fuel burned in this emissions unit in accordance with either Alternative 1 or Alternative 2 described below:

a. Alternative 1:

For each shipment of oil received for burning in this emissions unit, the permittee shall collect or require the oil supplier to collect a representative grab sample of oil and maintain records of the total quantity of oil received, the permittee's or oil supplier's analyses for sulfur content and heat content, and the calculated sulfur dioxide emission rate (in lbs/mmBtu). (The sulfur dioxide emission rate shall be calculated in accordance with the formula specified in OAC rule 3745-18-04(F).) 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 may be represented by a single batch analysis from the supplier.

b. Alternative 2:

The permittee shall collect a representative grab sample of oil that is burned in this emissions unit for each day when the emission unit is in operation. If additional fuel oil is added to the tank serving this emissions unit on a day when the emissions unit is in operation, the permittee shall collect a sufficient number of grab samples to develop a composite sample representative of the fuel oil burned in this emissions unit. A representative grab sample of oil does not need to be collected on days when this emissions unit is only operated for the purpose of "test-firing". The permittee shall maintain records of the total quantity of oil burned each day (except for the purpose of test-firing), the permittee's analyses for sulfur content and heat content, and the calculated sulfur dioxide emission rate (in lbs/mmBtu). [The sulfur dioxide emission rate shall be calculated in accordance with the formula specified in OAC rule 3745-18-04(F).]

The permittee shall perform or require the supplier to perform the analyses for sulfur content and heat content in accordance with the following ASTM methods: ASTM method D4294 for sulfur content and ASTM method D240 for heat content. The newest or most recent revisions to the applicable test method shall be used for analyses. Alternative, equivalent methods may be used upon written approval by the Hamilton County Department of Environmental Services - Air Quality Control Division.

**5.** The permittee shall operate and maintain equipment to continuously monitor and record the actual fuel flow to this emissions unit when it is in operation. Such continuous monitoring and recording equipment shall comply with the requirements specified in 40 CFR Part 75. If the fuel flow monitoring and/or recording equipment is (are) not in service when the emissions unit is in operation, the permittee shall comply with the appropriate missing data procedures specified in 40 CFR Part 75.

**6.** The permittee shall operate and maintain equipment to continuously monitor and record the percent oxygen (as a 1-hr average) in the stack serving this emissions unit when the emissions unit is in operation. Such continuous monitoring and recording equipment shall comply with the requirements specified in 40 CFR Part 75. The monitoring and recording equipment shall be installed, calibrated, operated and maintained in accordance with the manufacturer's recommendations, with any modifications deemed necessary by the permittee.

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

**7.** The permittee shall operate and maintain equipment to continuously monitor and record NOx emissions from this emissions unit in units of the applicable standard(s). Such continuous monitoring and recording equipment shall comply with the applicable requirements specified in 40 CFR Part 60 and Part 75.

Each continuous monitoring system consists of all the equipment used to acquire and record data and includes the sample extraction and transport hardware, sample conditioning hardware, analyzers, and data processing hardware and software.

The permittee shall maintain on-site documentation from the USEPA or the Ohio EPA that the continuous NOx monitoring system has been certified in accordance with the applicable requirements specified in 40 CFR Part 60 and Part 75. The letter of certification shall be made available to the Director upon request.

The permittee shall maintain records of the following data obtained by the continuous NOx monitoring system: emissions of NOx in ppmvd at 15% oxygen on an hourly average basis, emissions of NOx in lbs/hr, results of daily zero/span calibration checks, results of quarterly cylinder gas audits, linearity checks, or relative accuracy test audits, and magnitude of manual calibration adjustments.

The permittee shall develop a written quality assurance/quality control plan for the continuous NOx monitoring system designed to ensure continuous valid and representative readings of NOx emissions in units of the applicable standard(s). The plan shall follow the applicable requirements of 40 CFR Part 60, Appendix F and 40 CFR Part 75, Appendix B. The quality assurance/quality control plan and a logbook documenting the activities related to the continuous NOx monitoring system must be kept on site and available for inspection during regular office hours.

The permittee may conduct the relative accuracy test audits for the continuous nitrogen oxides monitoring system in accordance with the frequencies required for monitoring systems subject to 40 CFR Part 75, Appendix B; however, the permittee is still required to provide the audit results in units of the applicable standard(s), in accordance with 40 CFR Part 60. In addition, linearity checks conducted pursuant to 40 CFR Part 75, Appendix B, may be used in place of quarterly cylinder gas audits, as required in 40 CFR Part 60.

**8.** The permittee shall operate and maintain equipment to continuously monitor and record CO emissions from this emissions unit in units of the applicable standard(s). Such continuous monitoring and recording equipment shall comply with the requirements specified in 40 CFR Part 60.

Each continuous monitoring system consists of all the equipment used to acquire and record data and includes the sample extraction and transport hardware, sample conditioning hardware, analyzers, and data processing hardware and software.

The permittee shall maintain on-site documentation from the USEPA or the Ohio EPA that the continuous CO monitoring system has been certified in accordance with 40 CFR Part 60. The letter of certification shall be made available to the Director upon request.

The permittee shall maintain records of the following data obtained by the continuous CO monitoring system: emissions of CO in lbs/hr, results of daily zero/span calibration checks, results of quarterly cylinder gas audits or relative accuracy test audits, and magnitude of manual calibration adjustments.

The permittee shall develop a written quality assurance/quality control plan for the continuous CO monitoring system designed to ensure continuous valid and representative readings of CO emissions in units of the applicable standard(s). The plan shall follow the requirements of 40 CFR Part 60, Appendix F. The quality assurance/quality control plan and a logbook documenting the activities related to the continuous CO monitoring system must be kept on site and available for inspection during regular office hours.

The permittee may conduct the relative accuracy test audits for the continuous carbon monoxide monitoring system in accordance with the frequencies required for monitoring systems subject to 40 CFR Part 75, Appendix B; however, the permittee is still required to provide the audit results in units of the applicable standard(s), in accordance with 40 CFR Part 60. Cylinder gas audits may be conducted in accordance with the frequencies specified in 40 CFR Part 75, Appendix B for linearity checks.

## IV. Reporting Requirements

**1.** 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.

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

a. all exceedances of the rolling, 12-month natural gas usage limitation for emissions units P001 through P008, combined;

b. all exceedances of the rolling, 12-month emission limitations for PE/PM10, SO2, NOx, CO, H2SO4 mist, VOC, benzene, beryllium and arsenic for emissions units P001 through P008, combined;

c. all exceedances of the sulfur content restriction (i.e., 0.05%, by weight) for the fuels (natural gas and diesel fuel) received for burning in this emissions unit;

d. all exceedances of the SO2 lbs/mmBtu emission limitation when burning diesel fuel in this emissions unit;

e. all exceedances of the 1.0 hour startup and shutdown cycle operational restriction;

f. all exceedances of the rolling, 12-month diesel fuel usage limitation for emissions units P001 through P008, combined;

g. all exceedances of the startup and shutdown emission limitations specified in Section A.I.1 when burning natural gas;

h. all exceedances of the startup and shutdown emission limitations specified in Section A.I.1 when burning diesel fuel; and

i. each day when a fuel other than natural gas or diesel fuel was burned in this emissions unit.

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

**4.** 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 Control Division documenting the date, commencement and completion times, duration, magnitude, reason (if known), and corrective actions taken (if any), of all instances of NOx values in excess of the applicable emission limitations (emissions of NOx in ppmvd at 15% oxygen on an hourly average basis and emissions of NOx in lbs/hr) specified in the terms and conditions of this permit.

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 Control Division documenting any continuous NOx 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 analyzer 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 analyzer 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 31, April 30, July 31, and October 31 of each year and shall address the data obtained during the previous calendar quarter.

The permittee shall submit a summary of the excess emission report. The summary shall be submitted to the Hamilton County Department of Environmental Services - Air Quality Control Division within 30 days following the end of each calendar quarter in a manner prescribed by the Director.

## IV. Reporting Requirements (continued)

**5.** 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 Control Division documenting the date, commencement and completion times, duration, magnitude, reason (if known), and corrective actions taken (if any) of all instances of CO values in excess of any applicable emission limitations (emissions of CO in lbs/hr) specified in the terms and conditions of this permit.

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 Control Division documenting any continuous CO 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 analyzer 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 analyzer while the emissions unit was on line shall also be included in the quarterly report. These quarterly excess emission reports shall be submitted by January 31, April 30, July 31, and October 31 of each year and shall address the data obtained during the previous calendar quarter.

The permittee shall submit a summary of the excess emission report. The summary shall be submitted to the Hamilton County Department of Environmental Services - Air Quality Control Division within 30 days following the end of the calendar quarter.

**6.** The permittee shall submit annual reports that specify the total mercury and lead emissions from this emissions unit for the previous calendar year. The reports shall be submitted by April 15 of each year. This reporting requirement may be satisfied by including and identifying the specific emission data for this emissions unit in the annual Fee Emission Report.

## V. Testing Requirements

**1.** Compliance with the emission limitations, fuel usage restrictions, and fuel sulfur content restriction specified in Sections A.I and A.II shall be determined by the following methods:

**1.a** Emission Limitations:
Emissions from startup and shutdown operations shall not exceed the following emission limitations:

when burning natural gas

83 lbs of NOx/startup and shutdown cycle
308 lbs of CO/startup and shutdown cycle

when burning diesel fuel

130 lbs of NOx/startup and shutdown cycle
354 lbs of CO/startup and shutdown cycle

Applicable Compliance Method:
The lbs/cycle emission limitations were established based on emission data contained in the PTI modification application (PTI 14-04682) submitted March, 2001 and the emission factors from the background document, Reference 16, for Stationary Gas Turbines in AP-42, Fifth Edition, Section 3.1, dated April 2000.

Compliance with the NOx and CO emission limitations shall be determined by the continuous emission monitoring data collected pursuant to the record keeping requirements specified in Sections A.III.2, A.III.7, and A.III.8.

## V. Testing Requirements (continued)

**1.b** Emission Limitations:
The hourly emissions from this emissions unit shall not exceed the following limitations:

i. 58.0 lbs of SO2 emissions/hour;
ii. 54.0 lbs of CO emissions/hour;
iii. 196.0 lbs of NOx emissions/hour;
iv. 6.0 lbs of H2SO4 mist emissions/hour; and
v. 10.0 lbs of VOC emissions/hour.

Applicable Compliance Method:
The hourly emission limitations are based upon the emissions unit's potentials to emit and the manufacturer's guaranteed emission data found in PTI 14-4682 submitted April 26, 1999.

Compliance with the NOx emission limitation shall be determined by the continuous emission monitoring data collected pursuant to the record keeping requirements specified in Section A.III.8.

Compliance with the CO emission limitation shall be determined by the continuous emission monitoring data collected pursuant to the record keeping requirements specified in Section A.III.9.

If required, the permittee shall demonstrate compliance with the hourly NOx emission limitation through emission tests performed in accordance with Methods 1 through 4 and 7 of 40 CFR Part 60, Appendix A.

If required, the permittee shall demonstrate compliance with the hourly SO2 emission limitation through emission tests performed in accordance with Methods 1 through 4 and 6 of 40 CFR Part 60, Appendix A.

If required, the permittee shall demonstrate compliance with the hourly CO emission limitation through emission tests performed in accordance with Methods 1 through 4 and 10 of 40 CFR Part 60, Appendix A.

If required, the permittee shall demonstrate compliance with the hourly H2SO4 mist emission limitation through emission tests performed in accordance with Methods 1 through 4 and 8 of 40 CFR Part 60, Appendix A.

If required, the permittee shall demonstrate compliance with the hourly VOC emission limitation through emission tests performed in accordance with Methods 1 through 4 and 25 of 40 CFR Part 60, Appendix A.

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

## V. Testing Requirements (continued)

**1.c** Emission Limitations:
The total emissions from emissions units P001 through P008, combined, shall not exceed the following emission limitations:

i. 60.5 tons of PE/PM10 emissions per rolling, 12-month period;
ii. 120.8 tons of SO2 emissions per rolling, 12-month period;
iii. 733.3 tons of NOx emissions per rolling, 12-month period;
iv. 541.0 tons of CO emissions per rolling, 12-month period;
v. 36.4 tons of VOC emissions per rolling, 12-month period;
vi. 12.2 tons of H2SO4 mist emissions per rolling, 12-month period;
vii. 7.7 tons of benzene* emissions per rolling, 12-month period;
viii. 0.00084 ton of beryllium* emissions per rolling, 12-month period; and
ix. 0.012 ton of arsenic* emissions per rolling, 12-month period.

Applicable Compliance Method:
Compliance with the rolling, 12-month PE/PM10, SO2, NOx, CO and VOC, H2SO4, benzene, beryllium and arsenic emission limitations specified above shall be determined by the record keeping requirements specified in Section A.III.2.j.

Emission factors for PE/PM10, VOC, SO2, and H2SO4 are specified in the manufacturers guaranteed performance data contained in the application for PTI 14-4682 submitted to the Hamilton County Department of Environmental Services on April 26, 1999.

* The emission factors as specified in AP-42, Fifth Edition, Section 3.1 "Stationary Gas Turbines", updated 4/00 are 0.000011 lb.mmBtu for arsenic, 0.000055 lb/mmBtu for benzene, and 0.00000031 lb/mmBtu for beryllium, from diesel fuel-fired turbines.

The emission factor as specified in AP-42 Fifth Edition, Section 3.1 "Stationary Gas Turbines", updated 4/00 is 0.000012 lb/mmBtu for benzene, from natural gas-fired turbines.

The emission factor for beryllium and arsenic when natural gas is burned is insignificant based upon the manufacturer's guaranteed emission data contained in the application for PTI 14-4682 submitted to the Hamilton County Department of Environmental Services on April 26, 1999.

**1.d** Emission Limitations:
0.15 ton per year of lead emissions and 0.0023 ton per year of mercury emissions.

Applicable Compliance Method:
The lead and mercury emission limitations specified above were determined by multiplying the maximum fuel usage capacity of the equipment, as provided by the manufacturer in PTI 14-4682 submitted April 26, 1999, by the pollutant specific emission factor found in AP-42, Fifth Edition, Section 3.1 "Stationary Gas Turbines," updated 4/00, by the maximum heat content of the fuel, and dividing by 2,000 lbs/ton. The emission factor as specified in the above referenced AP-42 is 0.000014 lbs/mmBtu for lead and 0.0000012 lbs/mmBtu for mercury, from diesel fuel-fired turbines.

The emission factor for mercury and lead when natural gas is burned is insignificant based upon the manufacturer's guaranteed emission data contained in the application for PTI 14-4682 submitted to the Hamilton County Department of Environmental Services on April 26, 1999.

## V. Testing Requirements (continued)

**1.e** Emission Limitations:
when burning natural gas, 15 ppm of NOx, by volume, at 15% oxygen, on a dry basis, (as a 1-hour average, at full load)

when burning diesel fuel, 42 ppm of NOx, by volume, at 15% oxygen, on a dry basis (as a 1-hour average, at full load)

when burning natural gas at full load, 12 ppm of NOx, by volume, at 15% oxygen, on a dry basis (based on a rolling, 12-month summation of the average monthly NOx emissions, in ppm)

Applicable Compliance Method:
Compliance with the NOx emission limitations shall be determined by the continuous emission monitoring data collected pursuant to the record keeping requirements specified in Sections A.III.6 and A.III.7 and the record keeping requirements specified in Section A.III.2.

If required, the permittee shall demonstrate compliance with the non-rolling ppm NOx emission limitations through emission tests performed in accordance with Methods 1 through 4 and 7 of 40 CFR Part 60, Appendix A.

**1.f** Emission Limitation:
0.008 lb of PE/PM10 emissions/mmBtu

Applicable Compliance Method:
The lb/mmBtu emission limitation represents the emissions unit's potential to emit and is based upon the manufacturer's guaranteed emission data contained in the application for PTI 14-4682 submitted to the Hamilton County Department of Environmental Services on April 26, 1999. The total PM10 emissions were evaluated and did not trigger any additional federal requirements, therefore, the emissions are being regulated as particulate emissions (PE) and are subject to the PE compliance demonstration as noted below.

If required, the permittee shall demonstrate compliance with the PE/PM10 emission limitation through emission tests performed in accordance with Methods 1 through 5 of 40 CFR Part 60, Appendix A.

**1.g** Emission Limitation:
Visible particulate emissions from any stack shall not exceed 20% opacity, as a 6-minute average, except as specified by rule, when burning diesel fuel.

Applicable Compliance Method:
If required, compliance with the visible particulate emission limitation shall be determined 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).

**1.h** Emission Limitation:
Visible particulate emissions from any stack shall not exceed 10% opacity, as a 6-minute average, when burning natural gas.

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

## V. Testing Requirements (continued)

**1.i** Emission Limitation:
0.0456 lb of SO2 emissions/mmBtu when burning diesel fuel;

Applicable Compliance Method:
Compliance with the SO2 emission limitation shall be determined by the sulfur analysis of the fuels burned pursuant to the requirements specified in Section A.lll.4 and by documenting that the sulfur content of each shipment of oil received during a calendar month or each daily sample meets the 0.05%, by weight, sulfur content restriction.

If required, the permittee shall demonstrate compliance with the SO2 emission limitation through emission tests performed in accordance with Methods 1 through 4 and 6 of 40 CFR Part 60, Appendix A.

**1.j** Sulfur Content Restriction:
The sulfur content of the natural gas and diesel fuel burned in this emissions unit shall not exceed 0.05% sulfur, by weight.

Applicable Compliance Method:
Compliance with the sulfur content restriction shall be determined by the record keeping requirements specified in Sections A.III.3 and A.III.4.

**1.k** Natural Gas and Diesel Fuel Usage Restrictions:
The maximum annual natural gas usage rate for emissions units P001 through P008, combined, shall not exceed 20,300,000,000 cubic feet per rolling, 12-month period.

The maximum annual diesel fuel usage rate for emissions units P001 through P008, combined, shall not exceed 34,000,000 gallons per rolling, 12-month period.

Applicable Compliance Method:
Compliance with the natural gas and diesel fuel usage restrictions shall be determined by the record keeping requirements specified in Section A.III.2.

## 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 |
|---|---|---|
| 84.65 megawatt (nominal) natural gas/diesel fuel-fired simple cycle combustion turbine using dry low NOx combustors (natural gas firing) or water injection (diesel fuel firing) to control NOx emissions. | OAC rule 3745-31-28 | The requirements established pursuant to this rule are equivalent to the requirements established pursuant to 40 CFR Parts 63.41 through 63.44. This regulation has been promulgated in the Ohio Administrative Code; however, it has not yet been approved as part of the Ohio State Implementation Plan. |

**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:** #7 Turbine (P007)

**Activity Description:** 84.65 Megawatt (Nominal) Simple-Cycle Combustion Turbine #7

## 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 |
|---|---|---|
| 84.65 megawatt (nominal) natural gas/diesel fuel-fired simple cycle combustion turbine using dry low NOx combustors (natural gas firing) or water injection (diesel fuel firing) to control NOx emissions. | OAC rules 3745-31-11 through 3745-31-20<br>(PTI 14-04682) | This emissions unit shall not exceed the following emission limitations:<br><br>58.0 lbs of sulfur dioxide (SO2) emissions/hour*<br><br>6.0 lbs of sulfuric acid (H2SO4) mist emissions/hour*<br><br>0.008 lb of particulate emissions (PE)/particulate matter with a diameter of 10 microns or less (PM10** emissions)/mmBtu*<br><br>* The hourly emission limitations and the lb of PE/PM10 emissions/mmBtu emission limitation specified above represent this emissions unit's potentials to emit for all operating conditions, including startup and shutdown. Therefore, no additional monitoring, record keeping or reporting requirements are required to demonstrate compliance with these emission limitations.<br><br>**The total PM10 emissions were evaluated and did not trigger any additional federal requirements, therefore, the emissions are being regulated as particulate emissions (PE). |

| Operations, Property, and/or Equipment | Applicable Rules/ Requirements | Applicable Emissions Limitations/Control Measures |
|---|---|---|
| | | 196.0 lbs of NOx emissions/hour, excluding startup and shutdown periods<br><br>54.0 lbs of CO emissions/hour, excluding startup and shutdown periods<br><br>when burning natural gas, 15 ppm of NOx, by volume, at 15% oxygen, on a dry basis, (as a 1-hour average, at full load)<br><br>when burning diesel fuel, 42 ppm of NOx, by volume, at 15% oxygen, on a dry basis (as a 1-hour average, at full load)<br><br>when burning natural gas at full load, 12 ppm of NOx, by volume, at 15% oxygen, on a dry basis (based on a rolling, 12-month average summation of the monthly NOx emissions, in ppm)<br><br>when burning diesel fuel, 0.0456 lb of SO2 emissions/mmBtu of actual heat input<br><br>The sulfur content of the natural gas and diesel fuel burned in this emissions unit shall not exceed 0.05% sulfur, by weight.<br><br>Emissions from startup and shutdown operations shall not exceed the following emission limitations:<br><br>when burning natural gas<br><br>83 lbs of NOx/startup and shutdown cycle<br>308 lbs of CO/startup and shutdown cycle<br><br>when burning diesel fuel<br><br>130 lbs of NOx/startup and shutdown cycle<br>354 lbs of CO/startup and shutdown cycle<br><br>See Section A.I.2.c below. |

| Operations, Property, and/or Equipment | Applicable Rules/ Requirements | Applicable Emissions Limitations/Control Measures |
|---|---|---|
| | | Emissions units P001 through P008, combined, shall not exceed the following emission limitations:<br><br>60.5 tons of PE/PM10 emissions per rolling, 12-month period<br><br>120.8 tons of SO2 emissions per rolling, 12-month period<br><br>733.3 tons of nitrogen oxides (NOx) emissions per rolling, 12-month period<br><br>541.0 tons of carbon monoxide (CO) emissions per rolling, 12-month period<br><br>12.2 tons of H2SO4 mist emissions per rolling, 12-month period<br><br>7.7 tons of benzene emissions per rolling, 12-month period<br><br>0.00084 ton of beryllium emissions per rolling, 12-month period<br><br>0.012 ton of arsenic emissions per rolling, 12-month period<br><br>The rolling, 12-month emission limitations are based upon a summation of the pollutant-specific emissions generated under all operating conditions, including startup and shutdown periods, for both natural gas and diesel fuel. |

| Operations, Property, and/or Equipment | Applicable Rules/ Requirements | Applicable Emissions Limitations/Control Measures |
|---|---|---|
| | OAC rule 3745-31-05(A)(3) (PTI 14-04682) | This emissions unit shall not exceed the following emission limitations:<br><br>10.0 lbs of volatile organic compound (VOC) emissions/hour*<br>0.15 ton per year of lead emissions<br>0.0023 ton per year of mercury emissions<br><br>See Section A.I.2.b below.<br><br>Compliance with this rule also includes compliance with the requirements of OAC rule 3745-31-05(C) and OAC rule 3745-17-07(A) when burning diesel fuel.<br><br>* The hourly VOC emission limitation specified above represent this emissions unit's potential to emit for all operating conditions, including startup and shutdown. Therefore, no additional monitoring, record keeping or reporting requirements are required to demonstrate compliance with this emission limitation. |
| | OAC rule 3745-31-05(C) | 36.4 tons of VOC emissions per rolling, 12-month period from emissions units P001 through P008, combined. |
| | OAC rule 3745-17-07(A) | See Section A.I.2.a below. |
| | 40 CFR Part 60, Subpart GG | The emission limitations established in 40 CFR Part 60, Subpart GG for SO2 and NOx are less stringent than those established pursuant to OAC rule 3745-31-05(C). |
| | OAC rule 3745-17-11(B)(4) | The PE limitation specified by this rule is less stringent the PE limitation established pursuant to OAC rule 3745-31-05(C). |
| | OAC rule 3745-18-06(F) | The SO2 emission limitation specified by this rule (0.5 lb of SO2 emissions/mmBtu) is less stringent than the SO2 emission limitation established pursuant to OAC rule 3745-31-05(C). |
| | OAC rules 3745-21-08(B) and 3745-23-06(B) | See Section A.I.2.j below. |

## 2. Additional Terms and Conditions

**2.a** Visible PE from any stack shall not exceed 20% opacity, as a 6-minute average, except as specified by rule when burning diesel fuel.

**2.b** Visible PE from any stack shall not exceed 10% opacity, as a 6-minute average when burning natural gas.

**2.c** The permittee shall operate and maintain dry low NOx burners when burning natural gas and operate and maintain a water injection system when burning diesel fuel.

**2.d** "Full load" shall be defined as the nameplate electrical output of 84.65 megawatts. Any load that is greater than or equal to 90% of the nameplate electrical output shall be considered full load.

**2.e** "Normal operation" shall be defined as the period when the combustion turbine achieves dry low NOx mode (GE Mode 6). GE Mode 6 is defined by the manufacturer as the low emissions mode during which all burner nozzles are in use, burning a lean pre-mixed gas for steady-state operation. The continuous emissions monitoring system will indicate and record the GE Mode 6 status of the combustion turbine, including when the emissions unit is shutdown and when operating in startup and shutdown modes.

**2.f** "Startup" shall be defined as the period between when the combustion turbine is initially started (initial fuel light-off) until the combustion turbine completes transition to GE Mode 6. "Shutdown" shall be defined as the period beginning when the combustion turbine leaves the GE Mode 6 and ending when combustion has ceased.

**2.g** "Startup and shutdown cycle" shall be defined as a startup period followed by a consecutive shutdown period.

**2.h** For the purpose of this permit, the term "diesel fuel" shall be considered to be any low sulfur fuel oil that is burned in this emissions unit, as defined in 40 CFR Part 72.2.

**2.i** Compliance with the startup and shutdown NOx and CO lbs/cycle emission limitations, the NOx and CO emission limitations during steady-state operations, and the NOx ppm emission limitations during full load operations shall be demonstrated by the use of dual range NOx and CO continuous emission monitoring systems (CEMs). For CEM systems with dual ranges, certification testing shall be performed on the range normally used for measuring emissions.

**2.j** 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 technology requirements established pursuant to OAC rule 3745-31-05(A)(3) in Permit to Install 14-4682.

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 technology requirements established pursuant to OAC rule 3745-31-05(A)(3) in Permit to Install 14-4682.

**2.k** For the purposes of this permit and for the hazardous air pollutants (HAPs) emitted from this emissions unit, the best available control technology determination to satisfy the requirements of 40 CFR Part 52.21 is equivalent to the maximum achievable control technology determination used to satisfy the requirements of 40 CFR Parts 63.41 through 63.44.

**2. Additional Terms and Conditions (continued)**

**2.l** In lieu of the requirements of 40 CFR Part 60.334(a) to install and operate a continuous monitoring system to monitor and record the fuel consumption and the ratio of water to fuel being fired in this emissions unit, the permittee shall operate and maintain systems to continuously monitor and record emissions of NOx for this emissions unit in accordance with this permit.

In lieu of the excess emissions reports required under 40 CFR Part 60.334, the permittee shall submit excess emissions reports for this emissions unit in accordance with this permit.

In lieu of the test methods and procedures required under 40 CFR Part 60.335, the permittee shall follow the monitoring and testing requirements for this emissions unit in accordance with this permit.

## II. Operational Restrictions

**1.** The maximum annual natural gas usage rate for emissions units P001 through P008, combined, shall not exceed 20,300,000,000 cubic feet per rolling, 12-month period.

**2.** The maximum annual diesel fuel usage rate for emissions units P001 through P008, combined, shall not exceed 34,000,000 gallons per rolling, 12-month period.

**3.** The permittee shall burn only pipeline quality natural gas or diesel fuel in this emissions unit.

**4.** The quality of diesel fuel burned in this emissions unit shall have a combination of heat and sulfur content which is sufficient to comply with the allowable SO2 emission limitation of 0.0456 lb of SO2/mmBtu of actual heat input. The diesel fuel shall have a sulfur content of 0.05%, by weight, or less.

**5.** When the emissions unit is operating in startup and shutdown conditions, as defined in Section A.I.2.f above, each startup and shutdown cycle shall not exceed 1.0 hour in duration.

**6.** With the exception of startup and shutdown, this emissions unit shall be operated in GE Mode 6, defined as normal or full load operation (see Sections A.I.2.d and A.I.2.e above).

## III. Monitoring and/or Record Keeping Requirements

**1.** The permittee shall maintain daily records of the following information:

a. the emissions unit's actual electrical output for each operating hour; and

b. for each day during which the permittee burns a fuel other than pipeline quality natural gas and/or diesel fuel, the permittee shall maintain a record of the type and quantity of fuel burned in this emissions unit.

**2.** The permittee shall maintain monthly records of the following information:

a. the total amount of natural gas burned, in cubic feet, for emissions units P001 through P008, combined;

b. the total amount of diesel fuel burned, in gallons, for emissions units P001 through P008, combined;

c. the rolling, 12-month summation of the total amount of natural gas burned, in cubic feet, for emissions units P001 through P008, combined (the amount of natural gas burned for the current month plus the total amount of natural gas burned for the previous 11 calendar months);

d. the rolling, 12-month summation of the total amount of diesel fuel burned, in gallons, for emissions units P001 through P008, combined (the amount of diesel fuel burned for the current month plus the total amount of diesel fuel burned for the previous 11 calendar months);

e. the date and duration, in minutes, of each startup and shutdown cycle;

f. the emissions, in pounds, for NOx* and CO* when burning natural gas for each startup and shutdown cycle;

g. the emissions, in pounds, for NOx* and CO* when burning diesel fuel for each startup and shutdown cycle;

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

h. the total emissions, in tons, for NOx*, CO*, PE/PM10, SO2 , VOC, H2SO4, and benzene when burning natural gas for all operating conditions;

i. the total emissions, in tons, for NOx*, CO*, PE/PM10, SO2, VOC, H2SO4, benzene, beryllium and arsenic when burning diesel fuel for all operating conditions;

j. the rolling, 12-month emissions, in tons, for NOx*, CO*, PE/PM10, SO2, VOC, H2SO4, benzene, beryllium and arsenic for emissions units P001 through P008, combined, when burning natural gas and diesel fuel (the total emissions calculated in (h) + (i)) for the current month plus the total emissions for the previous 11 calendar months); and

k. the rolling, 12-month average of NOx* emissions, in ppm, when burning natural gas at full load for this emissions unit (the NOx ppm average for the current month (from the CEMs data) plus the total NOx ppm average for the previous 11 calendar months).

* The permittee shall use the continuous NOx and CO emissions monitoring data to determine the NOx and CO emissions for these emissions units. During any period when the NOx and/or the CO emissions monitoring systems are not operational, the permittee shall use the appropriate missing data procedures specified in 40 CFR Part 75 to determine NOx and CO emissions or an approved data substitution protocol for the purpose of calculating the rolling, 12-month emission rates. The data substitution values shall not be used to demonstrate compliance with the hourly NOx and CO emission limitations applicable during normal operation of this emissions unit.

**3.** The permittee shall monitor and record the sulfur content of the natural gas being burned in this emissions unit or make the demonstration that the sulfur content of the natural gas does not need to be monitored and recorded in accordance with the provisions specified in 40 CFR Part 60.334(b). Owners, operators or fuel vendors may develop custom fuel schedules for the determination of the sulfur content based on the design and operation of the affected facility and the characteristics of the fuel supply. Except as provided in 40 CFR Parts 60.334(i)(3)(i) and 60.334(i)(3)(ii), these custom schedules shall be substantiated with data and must be approved by the Ohio EPA, Central Office before they can be used.

Analyses for the purpose of determining the sulfur content of the natural gas may be performed by the permittee, the fuel vendor, or any other qualified agency in accordance with the analytical methods specified in 40 CFR Part 60, Subpart GG, Section 60.335(d) or equivalent methods as approved by the Administrator.

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

**4.** The permittee shall maintain records of the diesel fuel burned in this emissions unit in accordance with either Alternative 1 or Alternative 2 described below:

a. Alternative 1:

For each shipment of oil received for burning in this emissions unit, the permittee shall collect or require the oil supplier to collect a representative grab sample of oil and maintain records of the total quantity of oil received, the permittee's or oil supplier's analyses for sulfur content and heat content, and the calculated sulfur dioxide emission rate (in lbs/mmBtu). (The sulfur dioxide emission rate shall be calculated in accordance with the formula specified in OAC rule 3745-18-04(F).) 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 may be represented by a single batch analysis from the supplier.

b. Alternative 2:

The permittee shall collect a representative grab sample of oil that is burned in this emissions unit for each day when the emission unit is in operation. If additional fuel oil is added to the tank serving this emissions unit on a day when the emissions unit is in operation, the permittee shall collect a sufficient number of grab samples to develop a composite sample representative of the fuel oil burned in this emissions unit. A representative grab sample of oil does not need to be collected on days when this emissions unit is only operated for the purpose of "test-firing". The permittee shall maintain records of the total quantity of oil burned each day (except for the purpose of test-firing), the permittee's analyses for sulfur content and heat content, and the calculated sulfur dioxide emission rate (in lbs/mmBtu). [The sulfur dioxide emission rate shall be calculated in accordance with the formula specified in OAC rule 3745-18-04(F).]

The permittee shall perform or require the supplier to perform the analyses for sulfur content and heat content in accordance with the following ASTM methods: ASTM method D4294 for sulfur content and ASTM method D240 for heat content. The newest or most recent revisions to the applicable test method shall be used for analyses. Alternative, equivalent methods may be used upon written approval by the Hamilton County Department of Environmental Services - Air Quality Control Division.

**5.** The permittee shall operate and maintain equipment to continuously monitor and record the actual fuel flow to this emissions unit when it is in operation. Such continuous monitoring and recording equipment shall comply with the requirements specified in 40 CFR Part 75. If the fuel flow monitoring and/or recording equipment is (are) not in service when the emissions unit is in operation, the permittee shall comply with the appropriate missing data procedures specified in 40 CFR Part 75.

**6.** The permittee shall operate and maintain equipment to continuously monitor and record the percent oxygen (as a 1-hr average) in the stack serving this emissions unit when the emissions unit is in operation. Such continuous monitoring and recording equipment shall comply with the requirements specified in 40 CFR Part 75. The monitoring and recording equipment shall be installed, calibrated, operated and maintained in accordance with the manufacturer's recommendations, with any modifications deemed necessary by the permittee.

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

**7.** The permittee shall operate and maintain equipment to continuously monitor and record NOx emissions from this emissions unit in units of the applicable standard(s). Such continuous monitoring and recording equipment shall comply with the applicable requirements specified in 40 CFR Part 60 and Part 75.

Each continuous monitoring system consists of all the equipment used to acquire and record data and includes the sample extraction and transport hardware, sample conditioning hardware, analyzers, and data processing hardware and software.

The permittee shall maintain on-site documentation from the USEPA or the Ohio EPA that the continuous NOx monitoring system has been certified in accordance with the applicable requirements specified in 40 CFR Part 60 and Part 75. The letter of certification shall be made available to the Director upon request.

The permittee shall maintain records of the following data obtained by the continuous NOx monitoring system: emissions of NOx in ppmvd at 15% oxygen on an hourly average basis, emissions of NOx in lbs/hr, results of daily zero/span calibration checks, results of quarterly cylinder gas audits, linearity checks, or relative accuracy test audits, and magnitude of manual calibration adjustments.

The permittee shall develop a written quality assurance/quality control plan for the continuous NOx monitoring system designed to ensure continuous valid and representative readings of NOx emissions in units of the applicable standard(s). The plan shall follow the applicable requirements of 40 CFR Part 60, Appendix F and 40 CFR Part 75, Appendix B. The quality assurance/quality control plan and a logbook documenting the activities related to the continuous NOx monitoring system must be kept on site and available for inspection during regular office hours.

The permittee may conduct the relative accuracy test audits for the continuous nitrogen oxides monitoring system in accordance with the frequencies required for monitoring systems subject to 40 CFR Part 75, Appendix B; however, the permittee is still required to provide the audit results in units of the applicable standard(s), in accordance with 40 CFR Part 60. In addition, linearity checks conducted pursuant to 40 CFR Part 75, Appendix B, may be used in place of quarterly cylinder gas audits, as required in 40 CFR Part 60.

**8.** The permittee shall operate and maintain equipment to continuously monitor and record CO emissions from this emissions unit in units of the applicable standard(s). Such continuous monitoring and recording equipment shall comply with the requirements specified in 40 CFR Part 60.

Each continuous monitoring system consists of all the equipment used to acquire and record data and includes the sample extraction and transport hardware, sample conditioning hardware, analyzers, and data processing hardware and software.

The permittee shall maintain on-site documentation from the USEPA or the Ohio EPA that the continuous CO monitoring system has been certified in accordance with 40 CFR Part 60. The letter of certification shall be made available to the Director upon request.

The permittee shall maintain records of the following data obtained by the continuous CO monitoring system: emissions of CO in lbs/hr, results of daily zero/span calibration checks, results of quarterly cylinder gas audits or relative accuracy test audits, and magnitude of manual calibration adjustments.

The permittee shall develop a written quality assurance/quality control plan for the continuous CO monitoring system designed to ensure continuous valid and representative readings of CO emissions in units of the applicable standard(s). The plan shall follow the requirements of 40 CFR Part 60, Appendix F. The quality assurance/quality control plan and a logbook documenting the activities related to the continuous CO monitoring system must be kept on site and available for inspection during regular office hours.

The permittee may conduct the relative accuracy test audits for the continuous carbon monoxide monitoring system in accordance with the frequencies required for monitoring systems subject to 40 CFR Part 75, Appendix B; however, the permittee is still required to provide the audit results in units of the applicable standard(s), in accordance with 40 CFR Part 60. Cylinder gas audits may be conducted in accordance with the frequencies specified in 40 CFR Part 75, Appendix B for linearity checks.

## IV. Reporting Requirements

**1.** 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.

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

a. all exceedances of the rolling, 12-month natural gas usage limitation for emissions units P001 through P008, combined;

b. all exceedances of the rolling, 12-month emission limitations for PE/PM10, SO2, NOx, CO, H2SO4 mist, VOC, benzene, beryllium and arsenic for emissions units P001 through P008, combined;

c. all exceedances of the sulfur content restriction (i.e., 0.05%, by weight) for the fuels (natural gas and diesel fuel) received for burning in this emissions unit;

d. all exceedances of the SO2 lbs/mmBtu emission limitation when burning diesel fuel in this emissions unit;

e. all exceedances of the 1.0 hour startup and shutdown cycle operational restriction;

f. all exceedances of the rolling, 12-month diesel fuel usage limitation for emissions units P001 through P008, combined;

g. all exceedances of the startup and shutdown emission limitations specified in Section A.I.1 when burning natural gas;

h. all exceedances of the startup and shutdown emission limitations specified in Section A.I.1 when burning diesel fuel; and

i. each day when a fuel other than natural gas or diesel fuel was burned in this emissions unit.

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

**4.** 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 Control Division documenting the date, commencement and completion times, duration, magnitude, reason (if known), and corrective actions taken (if any), of all instances of NOx values in excess of the applicable emission limitations (emissions of NOx in ppmvd at 15% oxygen on an hourly average basis and emissions of NOx in lbs/hr) specified in the terms and conditions of this permit.

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 Control Division documenting any continuous NOx 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 analyzer 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 analyzer 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 31, April 30, July 31, and October 31 of each year and shall address the data obtained during the previous calendar quarter.

The permittee shall submit a summary of the excess emission report. The summary shall be submitted to the Hamilton County Department of Environmental Services - Air Quality Control Division within 30 days following the end of each calendar quarter in a manner prescribed by the Director.

## IV. Reporting Requirements (continued)

**5.** 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 Control Division documenting the date, commencement and completion times, duration, magnitude, reason (if known), and corrective actions taken (if any) of all instances of CO values in excess of any applicable emission limitations (emissions of CO in lbs/hr) specified in the terms and conditions of this permit.

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 Control Division documenting any continuous CO 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 analyzer 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 analyzer while the emissions unit was on line shall also be included in the quarterly report. These quarterly excess emission reports shall be submitted by January 31, April 30, July 31, and October 31 of each year and shall address the data obtained during the previous calendar quarter.

The permittee shall submit a summary of the excess emission report. The summary shall be submitted to the Hamilton County Department of Environmental Services - Air Quality Control Division within 30 days following the end of the calendar quarter.

**6.** The permittee shall submit annual reports that specify the total mercury and lead emissions from this emissions unit for the previous calendar year. The reports shall be submitted by April 15 of each year. This reporting requirement may be satisfied by including and identifying the specific emission data for this emissions unit in the annual Fee Emission Report.

## V. Testing Requirements

**1.** Compliance with the emission limitations, fuel usage restrictions, and fuel sulfur content restriction specified in Sections A.I and A.II shall be determined by the following methods:

**1.a** Emission Limitations:
Emissions from startup and shutdown operations shall not exceed the following emission limitations:

when burning natural gas

83 lbs of NOx/startup and shutdown cycle
308 lbs of CO/startup and shutdown cycle

when burning diesel fuel

130 lbs of NOx/startup and shutdown cycle
354 lbs of CO/startup and shutdown cycle

Applicable Compliance Method:
The lbs/cycle emission limitations were established based on emission data contained in the PTI modification application (PTI 14-04682) submitted March, 2001 and the emission factors from the background document, Reference 16, for Stationary Gas Turbines in AP-42, Fifth Edition, Section 3.1, dated April 2000.

Compliance with the NOx and CO emission limitations shall be determined by the continuous emission monitoring data collected pursuant to the record keeping requirements specified in Sections A.III.2, A.III.7, and A.III.8.

## V. Testing Requirements (continued)

**1.b** Emission Limitations:
The hourly emissions from this emissions unit shall not exceed the following limitations:

i. 58.0 lbs of SO2 emissions/hour;
ii. 54.0 lbs of CO emissions/hour;
iii. 196.0 lbs of NOx emissions/hour;
iv. 6.0 lbs of H2SO4 mist emissions/hour; and
v. 10.0 lbs of VOC emissions/hour.

Applicable Compliance Method:
The hourly emission limitations are based upon the emissions unit's potentials to emit and the manufacturer's guaranteed emission data found in PTI 14-4682 submitted April 26, 1999.

Compliance with the NOx emission limitation shall be determined by the continuous emission monitoring data collected pursuant to the record keeping requirements specified in Section A.III.8.

Compliance with the CO emission limitation shall be determined by the continuous emission monitoring data collected pursuant to the record keeping requirements specified in Section A.III.9.

If required, the permittee shall demonstrate compliance with the hourly NOx emission limitation through emission tests performed in accordance with Methods 1 through 4 and 7 of 40 CFR Part 60, Appendix A.

If required, the permittee shall demonstrate compliance with the hourly SO2 emission limitation through emission tests performed in accordance with Methods 1 through 4 and 6 of 40 CFR Part 60, Appendix A.

If required, the permittee shall demonstrate compliance with the hourly CO emission limitation through emission tests performed in accordance with Methods 1 through 4 and 10 of 40 CFR Part 60, Appendix A.

If required, the permittee shall demonstrate compliance with the hourly H2SO4 mist emission limitation through emission tests performed in accordance with Methods 1 through 4 and 8 of 40 CFR Part 60, Appendix A.

If required, the permittee shall demonstrate compliance with the hourly VOC emission limitation through emission tests performed in accordance with Methods 1 through 4 and 25 of 40 CFR Part 60, Appendix A.

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

## V. Testing Requirements (continued)

**1.c** Emission Limitations:
The total emissions from emissions units P001 through P008, combined, shall not exceed the following emission limitations:

i. 60.5 tons of PE/PM10 emissions per rolling, 12-month period;
ii. 120.8 tons of SO2 emissions per rolling, 12-month period;
iii. 733.3 tons of NOx emissions per rolling, 12-month period;
iv. 541.0 tons of CO emissions per rolling, 12-month period;
v. 36.4 tons of VOC emissions per rolling, 12-month period;
vi. 12.2 tons of H2SO4 mist emissions per rolling, 12-month period;
vii. 7.7 tons of benzene* emissions per rolling, 12-month period;
viii. 0.00084 ton of beryllium* emissions per rolling, 12-month period; and
ix. 0.012 ton of arsenic* emissions per rolling, 12-month period.

Applicable Compliance Method:
Compliance with the rolling, 12-month PE/PM10, SO2, NOx, CO and VOC, H2SO4, benzene, beryllium and arsenic emission limitations specified above shall be determined by the record keeping requirements specified in Section A.III.2.j.

Emission factors for PE/PM10, VOC, SO2, and H2SO4 are specified in the manufacturers guaranteed performance data contained in the application for PTI 14-4682 submitted to the Hamilton County Department of Environmental Services on April 26, 1999.

* The emission factors as specified in AP-42, Fifth Edition, Section 3.1 "Stationary Gas Turbines", updated 4/00 are 0.000011 lb.mmBtu for arsenic, 0.000055 lb/mmBtu for benzene, and 0.00000031 lb/mmBtu for beryllium, from diesel fuel-fired turbines.

The emission factor as specified in AP-42 Fifth Edition, Section 3.1 "Stationary Gas Turbines", updated 4/00 is 0.000012 lb/mmBtu for benzene, from natural gas-fired turbines.

The emission factor for beryllium and arsenic when natural gas is burned is insignificant based upon the manufacturer's guaranteed emission data contained in the application for PTI 14-4682 submitted to the Hamilton County Department of Environmental Services on April 26, 1999.

**1.d** Emission Limitations:
0.15 ton per year of lead emissions and 0.0023 ton per year of mercury emissions.

Applicable Compliance Method:
The lead and mercury emission limitations specified above were determined by multiplying the maximum fuel usage capacity of the equipment, as provided by the manufacturer in PTI 14-4682 submitted April 26, 1999, by the pollutant specific emission factor found in AP-42, Fifth Edition, Section 3.1 "Stationary Gas Turbines," updated 4/00, by the maximum heat content of the fuel, and dividing by 2,000 lbs/ton. The emission factor as specified in the above referenced AP-42 is 0.000014 lbs/mmBtu for lead and 0.0000012 lbs/mmBtu for mercury, from diesel fuel-fired turbines.

The emission factor for mercury and lead when natural gas is burned is insignificant based upon the manufacturer's guaranteed emission data contained in the application for PTI 14-4682 submitted to the Hamilton County Department of Environmental Services on April 26, 1999.

## V. Testing Requirements (continued)

**1.e** Emission Limitations:
when burning natural gas, 15 ppm of NOx, by volume, at 15% oxygen, on a dry basis, (as a 1-hour average, at full load)

when burning diesel fuel, 42 ppm of NOx, by volume, at 15% oxygen, on a dry basis (as a 1-hour average, at full load)

when burning natural gas at full load, 12 ppm of NOx, by volume, at 15% oxygen, on a dry basis (based on a rolling, 12-month summation of the average monthly NOx emissions, in ppm)

Applicable Compliance Method:
Compliance with the NOx emission limitations shall be determined by the continuous emission monitoring data collected pursuant to the record keeping requirements specified in Sections A.III.6 and A.III.7 and the record keeping requirements specified in Section A.III.2.

If required, the permittee shall demonstrate compliance with the non-rolling ppm NOx emission limitations through emission tests performed in accordance with Methods 1 through 4 and 7 of 40 CFR Part 60, Appendix A.

**1.f** Emission Limitation:
0.008 lb of PE/PM10 emissions/mmBtu

Applicable Compliance Method:
The lb/mmBtu emission limitation represents the emissions unit's potential to emit and is based upon the manufacturer's guaranteed emission data contained in the application for PTI 14-4682 submitted to the Hamilton County Department of Environmental Services on April 26, 1999. The total PM10 emissions were evaluated and did not trigger any additional federal requirements, therefore, the emissions are being regulated as particulate emissions (PE) and are subject to the PE compliance demonstration as noted below.

If required, the permittee shall demonstrate compliance with the PE/PM10 emission limitation through emission tests performed in accordance with Methods 1 through 5 of 40 CFR Part 60, Appendix A.

**1.g** Emission Limitation:
Visible particulate emissions from any stack shall not exceed 20% opacity, as a 6-minute average, except as specified by rule, when burning diesel fuel.

Applicable Compliance Method:
If required, compliance with the visible particulate emission limitation shall be determined 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).

**1.h** Emission Limitation:
Visible particulate emissions from any stack shall not exceed 10% opacity, as a 6-minute average, when burning natural gas.

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

## V. Testing Requirements (continued)

**1.i** Emission Limitation:
0.0456 lb of SO2 emissions/mmBtu when burning diesel fuel;

Applicable Compliance Method:
Compliance with the SO2 emission limitation shall be determined by the sulfur analysis of the fuels burned pursuant to the requirements specified in Section A.lll.4 and by documenting that the sulfur content of each shipment of oil received during a calendar month or each daily sample meets the 0.05%, by weight, sulfur content restriction.

If required, the permittee shall demonstrate compliance with the SO2 emission limitation through emission tests performed in accordance with Methods 1 through 4 and 6 of 40 CFR Part 60, Appendix A.

**1.j** Sulfur Content Restriction:
The sulfur content of the natural gas and diesel fuel burned in this emissions unit shall not exceed 0.05% sulfur, by weight.

Applicable Compliance Method:
Compliance with the sulfur content restriction shall be determined by the record keeping requirements specified in Sections A.III.3 and A.III.4.

**1.k** Natural Gas and Diesel Fuel Usage Restrictions:
The maximum annual natural gas usage rate for emissions units P001 through P008, combined, shall not exceed 20,300,000,000 cubic feet per rolling, 12-month period.

The maximum annual diesel fuel usage rate for emissions units P001 through P008, combined, shall not exceed 34,000,000 gallons per rolling, 12-month period.

Applicable Compliance Method:
Compliance with the natural gas and diesel fuel usage restrictions shall be determined by the record keeping requirements specified in Section A.III.2.

## 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 |
|---|---|---|
| 84.65 megawatt (nominal) natural gas/diesel fuel-fired simple cycle combustion turbine using dry low NOx combustors (natural gas firing) or water injection (diesel fuel firing) to control NOx emissions. | OAC rule 3745-31-28 | The requirements established pursuant to this rule are equivalent to the requirements established pursuant to 40 CFR Parts 63.41 through 63.44. This regulation has been promulgated in the Ohio Administrative Code; however, it has not yet been approved as part of the Ohio State Implementation Plan. |

**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:** #8 Turbine (P008)

**Activity Description:** 84.65 Megawatt (Nominal) Simple-Cycle Combustion Turbine #8

## 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 |
|---|---|---|
| 84.65 megawatt (nominal) natural gas/diesel fuel-fired simple cycle combustion turbine using dry low NOx combustors (natural gas firing) or water injection (diesel fuel firing) to control NOx emissions. | OAC rules 3745-31-11 through 3745-31-20<br>(PTI 14-04682) | This emissions unit shall not exceed the following emission limitations:<br><br>58.0 lbs of sulfur dioxide (SO2) emissions/hour*<br><br>6.0 lbs of sulfuric acid (H2SO4) mist emissions/hour*<br><br>0.008 lb of particulate emissions (PE)/particulate matter with a diameter of 10 microns or less (PM10** emissions)/mmBtu*<br><br>* The hourly emission limitations and the lb of PE/PM10 emissions/mmBtu emission limitation specified above represent this emissions unit's potentials to emit for all operating conditions, including startup and shutdown. Therefore, no additional monitoring, record keeping or reporting requirements are required to demonstrate compliance with these emission limitations.<br><br>**The total PM10 emissions were evaluated and did not trigger any additional federal requirements, therefore, the emissions are being regulated as particulate emissions (PE). |

| Operations, Property, and/or Equipment | Applicable Rules/ Requirements | Applicable Emissions Limitations/Control Measures |
|---|---|---|
| | | 196.0 lbs of NOx emissions/hour, excluding startup and shutdown periods<br><br>54.0 lbs of CO emissions/hour, excluding startup and shutdown periods<br><br>when burning natural gas, 15 ppm of NOx, by volume, at 15% oxygen, on a dry basis, (as a 1-hour average, at full load)<br><br>when burning diesel fuel, 42 ppm of NOx, by volume, at 15% oxygen, on a dry basis (as a 1-hour average, at full load)<br><br>when burning natural gas at full load, 12 ppm of NOx, by volume, at 15% oxygen, on a dry basis (based on a rolling, 12-month average summation of the monthly NOx emissions, in ppm)<br><br>when burning diesel fuel, 0.0456 lb of SO2 emissions/mmBtu of actual heat input<br><br>The sulfur content of the natural gas and diesel fuel burned in this emissions unit shall not exceed 0.05% sulfur, by weight.<br><br>Emissions from startup and shutdown operations shall not exceed the following emission limitations:<br><br>when burning natural gas<br><br>83 lbs of NOx/startup and shutdown cycle<br>308 lbs of CO/startup and shutdown cycle<br><br>when burning diesel fuel<br><br>130 lbs of NOx/startup and shutdown cycle<br>354 lbs of CO/startup and shutdown cycle<br><br>See Section A.I.2.c below. |

| Operations, Property, and/or Equipment | Applicable Rules/ Requirements | Applicable Emissions Limitations/Control Measures |
|---|---|---|
| | | Emissions units P001 through P008, combined, shall not exceed the following emission limitations:<br><br>60.5 tons of PE/PM10 emissions per rolling, 12-month period<br><br>120.8 tons of SO2 emissions per rolling, 12-month period<br><br>733.3 tons of nitrogen oxides (NOx) emissions per rolling, 12-month period<br><br>541.0 tons of carbon monoxide (CO) emissions per rolling, 12-month period<br><br>12.2 tons of H2SO4 mist emissions per rolling, 12-month period<br><br>7.7 tons of benzene emissions per rolling, 12-month period<br><br>0.00084 ton of beryllium emissions per rolling, 12-month period<br><br>0.012 ton of arsenic emissions per rolling, 12-month period<br><br>The rolling, 12-month emission limitations are based upon a summation of the pollutant-specific emissions generated under all operating conditions, including startup and shutdown periods, for both natural gas and diesel fuel. |

| Operations, Property, and/or Equipment | Applicable Rules/ Requirements | Applicable Emissions Limitations/Control Measures |
|---|---|---|
| | OAC rule 3745-31-05(A)(3) (PTI 14-04682) | This emissions unit shall not exceed the following emission limitations:<br><br>10.0 lbs of volatile organic compound (VOC) emissions/hour*<br>0.15 ton per year of lead emissions<br>0.0023 ton per year of mercury emissions<br><br>See Section A.I.2.b below.<br><br>Compliance with this rule also includes compliance with the requirements of OAC rule 3745-31-05(C) and OAC rule 3745-17-07(A) when burning diesel fuel.<br><br>* The hourly VOC emission limitation specified above represent this emissions unit's potential to emit for all operating conditions, including startup and shutdown. Therefore, no additional monitoring, record keeping or reporting requirements are required to demonstrate compliance with this emission limitation. |
| | OAC rule 3745-31-05(C) | 36.4 tons of VOC emissions per rolling, 12-month period from emissions units P001 through P008, combined. |
| | OAC rule 3745-17-07(A) | See Section A.I.2.a below. |
| | 40 CFR Part 60, Subpart GG | The emission limitations established in 40 CFR Part 60, Subpart GG for SO2 and NOx are less stringent than those established pursuant to OAC rule 3745-31-05(C). |
| | OAC rule 3745-17-11(B)(4) | The PE limitation specified by this rule is less stringent the PE limitation established pursuant to OAC rule 3745-31-05(C). |
| | OAC rule 3745-18-06(F) | The SO2 emission limitation specified by this rule (0.5 lb of SO2 emissions/mmBtu) is less stringent than the SO2 emission limitation established pursuant to OAC rule 3745-31-05(C). |
| | OAC rules 3745-21-08(B) and 3745-23-06(B) | See Section A.I.2.j below. |

## 2. Additional Terms and Conditions

**2.a** Visible PE from any stack shall not exceed 20% opacity, as a 6-minute average, except as specified by rule when burning diesel fuel.

**2.b** Visible PE from any stack shall not exceed 10% opacity, as a 6-minute average when burning natural gas.

**2.c** The permittee shall operate and maintain dry low NOx burners when burning natural gas and operate and maintain a water injection system when burning diesel fuel.

**2.d** "Full load" shall be defined as the nameplate electrical output of 84.65 megawatts. Any load that is greater than or equal to 90% of the nameplate electrical output shall be considered full load.

**2.e** "Normal operation" shall be defined as the period when the combustion turbine achieves dry low NOx mode (GE Mode 6). GE Mode 6 is defined by the manufacturer as the low emissions mode during which all burner nozzles are in use, burning a lean pre-mixed gas for steady-state operation. The continuous emissions monitoring system will indicate and record the GE Mode 6 status of the combustion turbine, including when the emissions unit is shutdown and when operating in startup and shutdown modes.

**2.f** "Startup" shall be defined as the period between when the combustion turbine is initially started (initial fuel light-off) until the combustion turbine completes transition to GE Mode 6. "Shutdown" shall be defined as the period beginning when the combustion turbine leaves the GE Mode 6 and ending when combustion has ceased.

**2.g** "Startup and shutdown cycle" shall be defined as a startup period followed by a consecutive shutdown period.

**2.h** For the purpose of this permit, the term "diesel fuel" shall be considered to be any low sulfur fuel oil that is burned in this emissions unit, as defined in 40 CFR Part 72.2.

**2.i** Compliance with the startup and shutdown NOx and CO lbs/cycle emission limitations, the NOx and CO emission limitations during steady-state operations, and the NOx ppm emission limitations during full load operations shall be demonstrated by the use of dual range NOx and CO continuous emission monitoring systems (CEMs). For CEM systems with dual ranges, certification testing shall be performed on the range normally used for measuring emissions.

**2.j** 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 technology requirements established pursuant to OAC rule 3745-31-05(A)(3) in Permit to Install 14-4682.

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 technology requirements established pursuant to OAC rule 3745-31-05(A)(3) in Permit to Install 14-4682.

**2.k** For the purposes of this permit and for the hazardous air pollutants (HAPs) emitted from this emissions unit, the best available control technology determination to satisfy the requirements of 40 CFR Part 52.21 is equivalent to the maximum achievable control technology determination used to satisfy the requirements of 40 CFR Parts 63.41 through 63.44.

**2. Additional Terms and Conditions (continued)**

**2.l** In lieu of the requirements of 40 CFR Part 60.334(a) to install and operate a continuous monitoring system to monitor and record the fuel consumption and the ratio of water to fuel being fired in this emissions unit, the permittee shall operate and maintain systems to continuously monitor and record emissions of NOx for this emissions unit in accordance with this permit.

In lieu of the excess emissions reports required under 40 CFR Part 60.334, the permittee shall submit excess emissions reports for this emissions unit in accordance with this permit.

In lieu of the test methods and procedures required under 40 CFR Part 60.335, the permittee shall follow the monitoring and testing requirements for this emissions unit in accordance with this permit.

## II. Operational Restrictions

**1.** The maximum annual natural gas usage rate for emissions units P001 through P008, combined, shall not exceed 20,300,000,000 cubic feet per rolling, 12-month period.

**2.** The maximum annual diesel fuel usage rate for emissions units P001 through P008, combined, shall not exceed 34,000,000 gallons per rolling, 12-month period.

**3.** The permittee shall burn only pipeline quality natural gas or diesel fuel in this emissions unit.

**4.** The quality of diesel fuel burned in this emissions unit shall have a combination of heat and sulfur content which is sufficient to comply with the allowable SO2 emission limitation of 0.0456 lb of SO2/mmBtu of actual heat input. The diesel fuel shall have a sulfur content of 0.05%, by weight, or less.

**5.** When the emissions unit is operating in startup and shutdown conditions, as defined in Section A.I.2.f above, each startup and shutdown cycle shall not exceed 1.0 hour in duration.

**6.** With the exception of startup and shutdown, this emissions unit shall be operated in GE Mode 6, defined as normal or full load operation (see Sections A.I.2.d and A.I.2.e above).

## III. Monitoring and/or Record Keeping Requirements

**1.** The permittee shall maintain daily records of the following information:

a. the emissions unit's actual electrical output for each operating hour; and

b. for each day during which the permittee burns a fuel other than pipeline quality natural gas and/or diesel fuel, the permittee shall maintain a record of the type and quantity of fuel burned in this emissions unit.

**2.** The permittee shall maintain monthly records of the following information:

a. the total amount of natural gas burned, in cubic feet, for emissions units P001 through P008, combined;

b. the total amount of diesel fuel burned, in gallons, for emissions units P001 through P008, combined;

c. the rolling, 12-month summation of the total amount of natural gas burned, in cubic feet, for emissions units P001 through P008, combined (the amount of natural gas burned for the current month plus the total amount of natural gas burned for the previous 11 calendar months);

d. the rolling, 12-month summation of the total amount of diesel fuel burned, in gallons, for emissions units P001 through P008, combined (the amount of diesel fuel burned for the current month plus the total amount of diesel fuel burned for the previous 11 calendar months);

e. the date and duration, in minutes, of each startup and shutdown cycle;

f. the emissions, in pounds, for NOx* and CO* when burning natural gas for each startup and shutdown cycle;

g. the emissions, in pounds, for NOx* and CO* when burning diesel fuel for each startup and shutdown cycle;

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

h. the total emissions, in tons, for NOx*, CO*, PE/PM10, SO2 , VOC, H2SO4, and benzene when burning natural gas for all operating conditions;

i. the total emissions, in tons, for NOx*, CO*, PE/PM10, SO2, VOC, H2SO4, benzene, beryllium and arsenic when burning diesel fuel for all operating conditions;

j. the rolling, 12-month emissions, in tons, for NOx*, CO*, PE/PM10, SO2, VOC, H2SO4, benzene, beryllium and arsenic for emissions units P001 through P008, combined, when burning natural gas and diesel fuel (the total emissions calculated in (h) + (i)) for the current month plus the total emissions for the previous 11 calendar months); and

k. the rolling, 12-month average of NOx* emissions, in ppm, when burning natural gas at full load for this emissions unit (the NOx ppm average for the current month (from the CEMs data) plus the total NOx ppm average for the previous 11 calendar months).

* The permittee shall use the continuous NOx and CO emissions monitoring data to determine the NOx and CO emissions for these emissions units. During any period when the NOx and/or the CO emissions monitoring systems are not operational, the permittee shall use the appropriate missing data procedures specified in 40 CFR Part 75 to determine NOx and CO emissions or an approved data substitution protocol for the purpose of calculating the rolling, 12-month emission rates. The data substitution values shall not be used to demonstrate compliance with the hourly NOx and CO emission limitations applicable during normal operation of this emissions unit.

**3.** The permittee shall monitor and record the sulfur content of the natural gas being burned in this emissions unit or make the demonstration that the sulfur content of the natural gas does not need to be monitored and recorded in accordance with the provisions specified in 40 CFR Part 60.334(b). Owners, operators or fuel vendors may develop custom fuel schedules for the determination of the sulfur content based on the design and operation of the affected facility and the characteristics of the fuel supply. Except as provided in 40 CFR Parts 60.334(i)(3)(i) and 60.334(i)(3)(ii), these custom schedules shall be substantiated with data and must be approved by the Ohio EPA, Central Office before they can be used.

Analyses for the purpose of determining the sulfur content of the natural gas may be performed by the permittee, the fuel vendor, or any other qualified agency in accordance with the analytical methods specified in 40 CFR Part 60, Subpart GG, Section 60.335(d) or equivalent methods as approved by the Administrator.

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

**4.** The permittee shall maintain records of the diesel fuel burned in this emissions unit in accordance with either Alternative 1 or Alternative 2 described below:

a. Alternative 1:

For each shipment of oil received for burning in this emissions unit, the permittee shall collect or require the oil supplier to collect a representative grab sample of oil and maintain records of the total quantity of oil received, the permittee's or oil supplier's analyses for sulfur content and heat content, and the calculated sulfur dioxide emission rate (in lbs/mmBtu). (The sulfur dioxide emission rate shall be calculated in accordance with the formula specified in OAC rule 3745-18-04(F).) 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 may be represented by a single batch analysis from the supplier.

b. Alternative 2:

The permittee shall collect a representative grab sample of oil that is burned in this emissions unit for each day when the emission unit is in operation. If additional fuel oil is added to the tank serving this emissions unit on a day when the emissions unit is in operation, the permittee shall collect a sufficient number of grab samples to develop a composite sample representative of the fuel oil burned in this emissions unit. A representative grab sample of oil does not need to be collected on days when this emissions unit is only operated for the purpose of "test-firing". The permittee shall maintain records of the total quantity of oil burned each day (except for the purpose of test-firing), the permittee's analyses for sulfur content and heat content, and the calculated sulfur dioxide emission rate (in lbs/mmBtu). [The sulfur dioxide emission rate shall be calculated in accordance with the formula specified in OAC rule 3745-18-04(F).]

The permittee shall perform or require the supplier to perform the analyses for sulfur content and heat content in accordance with the following ASTM methods: ASTM method D4294 for sulfur content and ASTM method D240 for heat content. The newest or most recent revisions to the applicable test method shall be used for analyses. Alternative, equivalent methods may be used upon written approval by the Hamilton County Department of Environmental Services - Air Quality Control Division.

**5.** The permittee shall operate and maintain equipment to continuously monitor and record the actual fuel flow to this emissions unit when it is in operation. Such continuous monitoring and recording equipment shall comply with the requirements specified in 40 CFR Part 75. If the fuel flow monitoring and/or recording equipment is (are) not in service when the emissions unit is in operation, the permittee shall comply with the appropriate missing data procedures specified in 40 CFR Part 75.

**6.** The permittee shall operate and maintain equipment to continuously monitor and record the percent oxygen (as a 1-hr average) in the stack serving this emissions unit when the emissions unit is in operation. Such continuous monitoring and recording equipment shall comply with the requirements specified in 40 CFR Part 75. The monitoring and recording equipment shall be installed, calibrated, operated and maintained in accordance with the manufacturer's recommendations, with any modifications deemed necessary by the permittee.

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

**7.** The permittee shall operate and maintain equipment to continuously monitor and record NOx emissions from this emissions unit in units of the applicable standard(s). Such continuous monitoring and recording equipment shall comply with the applicable requirements specified in 40 CFR Part 60 and Part 75.

Each continuous monitoring system consists of all the equipment used to acquire and record data and includes the sample extraction and transport hardware, sample conditioning hardware, analyzers, and data processing hardware and software.

The permittee shall maintain on-site documentation from the USEPA or the Ohio EPA that the continuous NOx monitoring system has been certified in accordance with the applicable requirements specified in 40 CFR Part 60 and Part 75. The letter of certification shall be made available to the Director upon request.

The permittee shall maintain records of the following data obtained by the continuous NOx monitoring system: emissions of NOx in ppmvd at 15% oxygen on an hourly average basis, emissions of NOx in lbs/hr, results of daily zero/span calibration checks, results of quarterly cylinder gas audits, linearity checks, or relative accuracy test audits, and magnitude of manual calibration adjustments.

The permittee shall develop a written quality assurance/quality control plan for the continuous NOx monitoring system designed to ensure continuous valid and representative readings of NOx emissions in units of the applicable standard(s). The plan shall follow the applicable requirements of 40 CFR Part 60, Appendix F and 40 CFR Part 75, Appendix B. The quality assurance/quality control plan and a logbook documenting the activities related to the continuous NOx monitoring system must be kept on site and available for inspection during regular office hours.

The permittee may conduct the relative accuracy test audits for the continuous nitrogen oxides monitoring system in accordance with the frequencies required for monitoring systems subject to 40 CFR Part 75, Appendix B; however, the permittee is still required to provide the audit results in units of the applicable standard(s), in accordance with 40 CFR Part 60. In addition, linearity checks conducted pursuant to 40 CFR Part 75, Appendix B, may be used in place of quarterly cylinder gas audits, as required in 40 CFR Part 60.

**8.** The permittee shall operate and maintain equipment to continuously monitor and record CO emissions from this emissions unit in units of the applicable standard(s). Such continuous monitoring and recording equipment shall comply with the requirements specified in 40 CFR Part 60.

Each continuous monitoring system consists of all the equipment used to acquire and record data and includes the sample extraction and transport hardware, sample conditioning hardware, analyzers, and data processing hardware and software.

The permittee shall maintain on-site documentation from the USEPA or the Ohio EPA that the continuous CO monitoring system has been certified in accordance with 40 CFR Part 60. The letter of certification shall be made available to the Director upon request.

The permittee shall maintain records of the following data obtained by the continuous CO monitoring system: emissions of CO in lbs/hr, results of daily zero/span calibration checks, results of quarterly cylinder gas audits or relative accuracy test audits, and magnitude of manual calibration adjustments.

The permittee shall develop a written quality assurance/quality control plan for the continuous CO monitoring system designed to ensure continuous valid and representative readings of CO emissions in units of the applicable standard(s). The plan shall follow the requirements of 40 CFR Part 60, Appendix F. The quality assurance/quality control plan and a logbook documenting the activities related to the continuous CO monitoring system must be kept on site and available for inspection during regular office hours.

The permittee may conduct the relative accuracy test audits for the continuous carbon monoxide monitoring system in accordance with the frequencies required for monitoring systems subject to 40 CFR Part 75, Appendix B; however, the permittee is still required to provide the audit results in units of the applicable standard(s), in accordance with 40 CFR Part 60. Cylinder gas audits may be conducted in accordance with the frequencies specified in 40 CFR Part 75, Appendix B for linearity checks.

## IV. Reporting Requirements

**1.** 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.

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

a. all exceedances of the rolling, 12-month natural gas usage limitation for emissions units P001 through P008, combined;

b. all exceedances of the rolling, 12-month emission limitations for PE/PM10, SO2, NOx, CO, H2SO4 mist, VOC, benzene, beryllium and arsenic for emissions units P001 through P008, combined;

c. all exceedances of the sulfur content restriction (i.e., 0.05%, by weight) for the fuels (natural gas and diesel fuel) received for burning in this emissions unit;

d. all exceedances of the SO2 lbs/mmBtu emission limitation when burning diesel fuel in this emissions unit;

e. all exceedances of the 1.0 hour startup and shutdown cycle operational restriction;

f. all exceedances of the rolling, 12-month diesel fuel usage limitation for emissions units P001 through P008, combined;

g. all exceedances of the startup and shutdown emission limitations specified in Section A.I.1 when burning natural gas;

h. all exceedances of the startup and shutdown emission limitations specified in Section A.I.1 when burning diesel fuel; and

i. each day when a fuel other than natural gas or diesel fuel was burned in this emissions unit.

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

**4.** 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 Control Division documenting the date, commencement and completion times, duration, magnitude, reason (if known), and corrective actions taken (if any), of all instances of NOx values in excess of the applicable emission limitations (emissions of NOx in ppmvd at 15% oxygen on an hourly average basis and emissions of NOx in lbs/hr) specified in the terms and conditions of this permit.

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 Control Division documenting any continuous NOx 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 analyzer 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 analyzer 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 31, April 30, July 31, and October 31 of each year and shall address the data obtained during the previous calendar quarter.

The permittee shall submit a summary of the excess emission report. The summary shall be submitted to the Hamilton County Department of Environmental Services - Air Quality Control Division within 30 days following the end of each calendar quarter in a manner prescribed by the Director.

## IV. Reporting Requirements (continued)

**5.** 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 Control Division documenting the date, commencement and completion times, duration, magnitude, reason (if known), and corrective actions taken (if any) of all instances of CO values in excess of any applicable emission limitations (emissions of CO in lbs/hr) specified in the terms and conditions of this permit.

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 Control Division documenting any continuous CO 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 analyzer 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 analyzer while the emissions unit was on line shall also be included in the quarterly report. These quarterly excess emission reports shall be submitted by January 31, April 30, July 31, and October 31 of each year and shall address the data obtained during the previous calendar quarter.

The permittee shall submit a summary of the excess emission report. The summary shall be submitted to the Hamilton County Department of Environmental Services - Air Quality Control Division within 30 days following the end of the calendar quarter.

**6.** The permittee shall submit annual reports that specify the total mercury and lead emissions from this emissions unit for the previous calendar year. The reports shall be submitted by April 15 of each year. This reporting requirement may be satisfied by including and identifying the specific emission data for this emissions unit in the annual Fee Emission Report.

## V. Testing Requirements

**1.** Compliance with the emission limitations, fuel usage restrictions, and fuel sulfur content restriction specified in Sections A.I and A.II shall be determined by the following methods:

**1.a** Emission Limitations:
Emissions from startup and shutdown operations shall not exceed the following emission limitations:

when burning natural gas

83 lbs of NOx/startup and shutdown cycle
308 lbs of CO/startup and shutdown cycle

when burning diesel fuel

130 lbs of NOx/startup and shutdown cycle
354 lbs of CO/startup and shutdown cycle

Applicable Compliance Method:
The lbs/cycle emission limitations were established based on emission data contained in the PTI modification application (PTI 14-04682) submitted March, 2001 and the emission factors from the background document, Reference 16, for Stationary Gas Turbines in AP-42, Fifth Edition, Section 3.1, dated April 2000.

Compliance with the NOx and CO emission limitations shall be determined by the continuous emission monitoring data collected pursuant to the record keeping requirements specified in Sections A.III.2, A.III.7, and A.III.8.

## V. Testing Requirements (continued)

**1.b** Emission Limitations:
The hourly emissions from this emissions unit shall not exceed the following limitations:

i. 58.0 lbs of SO2 emissions/hour;
ii. 54.0 lbs of CO emissions/hour;
iii. 196.0 lbs of NOx emissions/hour;
iv. 6.0 lbs of H2SO4 mist emissions/hour; and
v. 10.0 lbs of VOC emissions/hour.

Applicable Compliance Method:
The hourly emission limitations are based upon the emissions unit's potentials to emit and the manufacturer's guaranteed emission data found in PTI 14-4682 submitted April 26, 1999.

Compliance with the NOx emission limitation shall be determined by the continuous emission monitoring data collected pursuant to the record keeping requirements specified in Section A.III.8.

Compliance with the CO emission limitation shall be determined by the continuous emission monitoring data collected pursuant to the record keeping requirements specified in Section A.III.9.

If required, the permittee shall demonstrate compliance with the hourly NOx emission limitation through emission tests performed in accordance with Methods 1 through 4 and 7 of 40 CFR Part 60, Appendix A.

If required, the permittee shall demonstrate compliance with the hourly SO2 emission limitation through emission tests performed in accordance with Methods 1 through 4 and 6 of 40 CFR Part 60, Appendix A.

If required, the permittee shall demonstrate compliance with the hourly CO emission limitation through emission tests performed in accordance with Methods 1 through 4 and 10 of 40 CFR Part 60, Appendix A.

If required, the permittee shall demonstrate compliance with the hourly H2SO4 mist emission limitation through emission tests performed in accordance with Methods 1 through 4 and 8 of 40 CFR Part 60, Appendix A.

If required, the permittee shall demonstrate compliance with the hourly VOC emission limitation through emission tests performed in accordance with Methods 1 through 4 and 25 of 40 CFR Part 60, Appendix A.

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

## V. Testing Requirements (continued)

**1.c** Emission Limitations:
The total emissions from emissions units P001 through P008, combined, shall not exceed the following emission limitations:

i. 60.5 tons of PE/PM10 emissions per rolling, 12-month period;
ii. 120.8 tons of SO2 emissions per rolling, 12-month period;
iii. 733.3 tons of NOx emissions per rolling, 12-month period;
iv. 541.0 tons of CO emissions per rolling, 12-month period;
v. 36.4 tons of VOC emissions per rolling, 12-month period;
vi. 12.2 tons of H2SO4 mist emissions per rolling, 12-month period;
vii. 7.7 tons of benzene* emissions per rolling, 12-month period;
viii. 0.00084 ton of beryllium* emissions per rolling, 12-month period; and
ix. 0.012 ton of arsenic* emissions per rolling, 12-month period.

Applicable Compliance Method:
Compliance with the rolling, 12-month PE/PM10, SO2, NOx, CO and VOC, H2SO4, benzene, beryllium and arsenic emission limitations specified above shall be determined by the record keeping requirements specified in Section A.III.2.j.

Emission factors for PE/PM10, VOC, SO2, and H2SO4 are specified in the manufacturers guaranteed performance data contained in the application for PTI 14-4682 submitted to the Hamilton County Department of Environmental Services on April 26, 1999.

* The emission factors as specified in AP-42, Fifth Edition, Section 3.1 "Stationary Gas Turbines", updated 4/00 are 0.000011 lb.mmBtu for arsenic, 0.000055 lb/mmBtu for benzene, and 0.00000031 lb/mmBtu for beryllium, from diesel fuel-fired turbines.

The emission factor as specified in AP-42 Fifth Edition, Section 3.1 "Stationary Gas Turbines", updated 4/00 is 0.000012 lb/mmBtu for benzene, from natural gas-fired turbines.

The emission factor for beryllium and arsenic when natural gas is burned is insignificant based upon the manufacturer's guaranteed emission data contained in the application for PTI 14-4682 submitted to the Hamilton County Department of Environmental Services on April 26, 1999.

**1.d** Emission Limitations:
0.15 ton per year of lead emissions and 0.0023 ton per year of mercury emissions.

Applicable Compliance Method:
The lead and mercury emission limitations specified above were determined by multiplying the maximum fuel usage capacity of the equipment, as provided by the manufacturer in PTI 14-4682 submitted April 26, 1999, by the pollutant specific emission factor found in AP-42, Fifth Edition, Section 3.1 "Stationary Gas Turbines," updated 4/00, by the maximum heat content of the fuel, and dividing by 2,000 lbs/ton. The emission factor as specified in the above referenced AP-42 is 0.000014 lbs/mmBtu for lead and 0.0000012 lbs/mmBtu for mercury, from diesel fuel-fired turbines.

The emission factor for mercury and lead when natural gas is burned is insignificant based upon the manufacturer's guaranteed emission data contained in the application for PTI 14-4682 submitted to the Hamilton County Department of Environmental Services on April 26, 1999.

## V. Testing Requirements (continued)

**1.e** Emission Limitations:
when burning natural gas, 15 ppm of NOx, by volume, at 15% oxygen, on a dry basis, (as a 1-hour average, at full load)

when burning diesel fuel, 42 ppm of NOx, by volume, at 15% oxygen, on a dry basis (as a 1-hour average, at full load)

when burning natural gas at full load, 12 ppm of NOx, by volume, at 15% oxygen, on a dry basis (based on a rolling, 12-month summation of the average monthly NOx emissions, in ppm)

Applicable Compliance Method:
Compliance with the NOx emission limitations shall be determined by the continuous emission monitoring data collected pursuant to the record keeping requirements specified in Sections A.III.6 and A.III.7 and the record keeping requirements specified in Section A.III.2.

If required, the permittee shall demonstrate compliance with the non-rolling ppm NOx emission limitations through emission tests performed in accordance with Methods 1 through 4 and 7 of 40 CFR Part 60, Appendix A.

**1.f** Emission Limitation:
0.008 lb of PE/PM10 emissions/mmBtu

Applicable Compliance Method:
The lb/mmBtu emission limitation represents the emissions unit's potential to emit and is based upon the manufacturer's guaranteed emission data contained in the application for PTI 14-4682 submitted to the Hamilton County Department of Environmental Services on April 26, 1999. The total PM10 emissions were evaluated and did not trigger any additional federal requirements, therefore, the emissions are being regulated as particulate emissions (PE) and are subject to the PE compliance demonstration as noted below.

If required, the permittee shall demonstrate compliance with the PE/PM10 emission limitation through emission tests performed in accordance with Methods 1 through 5 of 40 CFR Part 60, Appendix A.

**1.g** Emission Limitation:
Visible particulate emissions from any stack shall not exceed 20% opacity, as a 6-minute average, except as specified by rule, when burning diesel fuel.

Applicable Compliance Method:
If required, compliance with the visible particulate emission limitation shall be determined 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).

**1.h** Emission Limitation:
Visible particulate emissions from any stack shall not exceed 10% opacity, as a 6-minute average, when burning natural gas.

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

## V. Testing Requirements (continued)

**1.i** Emission Limitation:
0.0456 lb of SO2 emissions/mmBtu when burning diesel fuel;

Applicable Compliance Method:
Compliance with the SO2 emission limitation shall be determined by the sulfur analysis of the fuels burned pursuant to the requirements specified in Section A.lll.4 and by documenting that the sulfur content of each shipment of oil received during a calendar month or each daily sample meets the 0.05%, by weight, sulfur content restriction.

If required, the permittee shall demonstrate compliance with the SO2 emission limitation through emission tests performed in accordance with Methods 1 through 4 and 6 of 40 CFR Part 60, Appendix A.

**1.j** Sulfur Content Restriction:
The sulfur content of the natural gas and diesel fuel burned in this emissions unit shall not exceed 0.05% sulfur, by weight.

Applicable Compliance Method:
Compliance with the sulfur content restriction shall be determined by the record keeping requirements specified in Sections A.III.3 and A.III.4.

**1.k** Natural Gas and Diesel Fuel Usage Restrictions:
The maximum annual natural gas usage rate for emissions units P001 through P008, combined, shall not exceed 20,300,000,000 cubic feet per rolling, 12-month period.

The maximum annual diesel fuel usage rate for emissions units P001 through P008, combined, shall not exceed 34,000,000 gallons per rolling, 12-month period.

Applicable Compliance Method:
Compliance with the natural gas and diesel fuel usage restrictions shall be determined by the record keeping requirements specified in Section A.III.2.

## 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 |
|---|---|---|
| 84.65 megawatt (nominal) natural gas/diesel fuel-fired simple cycle combustion turbine using dry low NOx combustors (natural gas firing) or water injection (diesel fuel firing) to control NOx emissions. | OAC rule 3745-31-28 | The requirements established pursuant to this rule are equivalent to the requirements established pursuant to 40 CFR Parts 63.41 through 63.44. This regulation has been promulgated in the Ohio Administrative Code; however, it has not yet been approved as part of the Ohio State Implementation Plan. |

**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:** #1 EDG (P009)

**Activity Description:** 1.5 Megawatt Emergency Diesel Generator #1

## 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 |
|---|---|---|
| 17.21 mmBtu/hour (1.5 megawatt) emergency diesel fuel-fired generator | OAC rule 3745-31-05(A)(3) (PTI 14-04682) | See Section A.I.2.a below.<br><br>The requirements of this rule also include compliance with the requirements of OAC rules 3745-17-07(A), 3745-17-11(B)(5)(b), 3745-18-06(G), 3745-31-05(C). |
| | OAC rule 3745-31-05(C) | See Section A.II.1 below. |
| | OAC rules 3745-31-11 through 3745-31-20 | See Section A.I.2.b below. |
| | OAC rule 3745-17-07(A) | Visible particulate emissions (PE) from any stack shall not exceed 20% opacity, as a 6-minute average, except as specified by rule. |
| | OAC rule 3745-17-11(B)(5)(b) | Particulate emissions shall not exceed 0.35 lb/mmBtu actual heat input.<br><br>See Section A.I.2.d below. |
| | OAC rule 3745-17-11(B)(5)(b) | Particulate emissions shall not exceed 0.062 lb/mmBtu actual heat input.<br><br>See Section A.I.2.e below. |
| | OAC rule 3745-18-06(G) | Sulfur dioxide (SO2) emissions shall not exceed 0.5 lb/mmBtu of actual heat input. |
| | OAC rules 3745-21-08(B) and 3745-23-06(B) | See Section A.I.2.f below. |

**2. Additional Terms and Conditions**

**2.a** The permittee shall not exceed the following hourly emission limitations:

i. 8.61 lbs of SO2 emissions/hour;
ii. 55.07 lbs of nitrogen oxides (NOx) emissions/hour;
iii. 14.63 lbs of carbon monoxide (CO) emissions/hour; and
iv. 1.55 lbs of volatile organic compound (VOC) emissions/hour.

**2.b** The permittee shall not exceed the following emission limitations:

i. 0.27 ton of PE per rolling, 12-month period;
ii. 2.15 tons of SO2 emissions per rolling, 12-month period;
iii. 13.77 tons of NOx emissions per rolling, 12-month period;
iv. 3.66 tons of CO emissions per rolling, 12-month period; and
v. 0.39 ton of VOC emissions per rolling, 12-month period.

**2.c** The hourly emission limitations specified above are 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.d** The requirement to comply with this particulate emission limitation shall terminate on the date the U.S. EPA approves the 0.062 lb/mmBtu actual heat input emission limitation as a revision to the Ohio SIP for particulate matter.

**2.e** This particulate emission limitation shall be effective and federally enforceable on the date the U.S. EPA approves this particulate emission limitation as a revision to the Ohio SIP for particulate matter.

**2.f** 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 technology requirements established pursuant to OAC rule 3745-31-05(A)(3) in Permit to Install 14-04682.

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 technology requirements established pursuant to OAC rule 3745-31-05(A)(3) in Permit to Install 14-04682.

**II. Operational Restrictions**

**1.** The maximum annual operating hours for this emissions unit shall not exceed 499 hours per rolling, 12-month period.

**2.** The quality of diesel fuel burned in this emissions unit shall have a combination of heat and sulfur content that is sufficient to comply with the allowable SO2 emission limitation.

Compliance with the above-mentioned specification shall be determined by using analytical results provided by the permittee or oil supplier for each shipment or daily sample of diesel fuel.

**3.** The permittee shall burn only diesel fuel in this emissions unit.

## III. Monitoring and/or Record Keeping Requirements

**1.** The permittee shall collect and record the following information each month for this emissions unit:

a. the total hours of operation for this emissions unit; and

b. the rolling, 12-month summation of the total hours of operation for this emissions unit (the total number of operating hours for the current month plus the total number of operating hours for the previous 11 calendar months).

**2.** For each day during which the permittee burns a fuel other than diesel fuel, the permittee shall maintain a record of the type and quantity of the fuel burned in this emissions unit.

**3.** The permittee shall maintain records of the diesel fuel burned in this emissions unit in accordance with either Alternative 1 or Alternative 2 described below:

a. Alternative 1:

For each shipment of oil received for burning in this emissions unit, the permittee shall collect or require the oil supplier to collect a representative grab sample of oil and maintain records of the total quantity of oil received, the permittee's or oil supplier's analyses for sulfur content and heat content, and the calculated sulfur dioxide emission rate (in lbs/mmBtu). (The sulfur dioxide emission rate shall be calculated in accordance with the formula specified in OAC rule 3745-18-04(F).) 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 may be represented by a single batch analysis from the supplier.

b. Alternative 2:

The permittee shall collect a representative grab sample of oil that is burned in this emissions unit for each day when the emission unit is in operation. If additional fuel oil is added to the tank serving this emissions unit on a day when the emissions unit is in operation, the permittee shall collect a sufficient number of grab samples to develop a composite sample representative of the fuel oil burned in this emissions unit. A representative grab sample of oil does not need to be collected on days when this emissions unit is only operated for the purpose of "test-firing". The permittee shall maintain records of the total quantity of oil burned each day (except for the purpose of test-firing), the permittee's analyses for sulfur content and heat content, and the calculated sulfur dioxide emission rate (in lbs/mmBtu). [The sulfur dioxide emission rate shall be calculated in accordance with the formula specified in OAC rule 3745-18-04(F).]

The permittee shall perform or require the supplier to perform the analyses for sulfur content and heat content in accordance with the following ASTM methods: ASTM method D4294 for sulfur content and ASTM method D240 for heat content. The newest or most recent revisions to the applicable test method shall be used for analyses. Alternative, equivalent methods may be used upon written approval by the Hamilton County Department of Environmental Services - Air Quality Control Division.

## IV. Reporting Requirements

**1.** The permittee shall submit quarterly deviation (excursion) reports to the Hamilton County Department of Environmental Services that identify the following:

a. each day when a fuel other than diesel fuel was burned in this emissions unit;

b. all exceedances of the rolling, 12-month hours of operation limitation; and

c. all exceedances of the lb of SO2/mmBtu emission limitation.

**2.** 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.** Compliance with the emission limitations and the hours of operation restriction specified in Sections A.I.1, A.I.2, and A.II shall be determined by the following methods:

**1.a** Emission Limitations:

8.61 lbs of SO2 emissions/hour;
55.07 lbs of NOx emissions/hour;
14.63 lbs of CO emissions/hour; and
1.55 lbs of VOC emissions/hour.

Applicable Compliance Method:

i. The hourly SO2 emission limitation was established by multiplying the emission factor of 1.01(S) lbs of SO2/mmBtu (where "S" is the % sulfur in the fuel oil) by the emissions unit's maximum heat input capacity of 17.21 mmBtu/hour.

If required, the permittee shall demonstrate compliance with the hourly SO2 emission limitation through emission tests performed in accordance with Methods 1 through 4 and 6 of 40 CFR Part 60, Appendix A.

ii. The hourly NOx emission limitation was established by multiplying the emission factor of 3.2 lbs of NOx emissions/mmBtu by the emissions unit's maximum heat input capacity of 17.21 mmBtu/hour.

If required, the permittee shall demonstrate compliance with the hourly NOx emission limitation through emission tests performed in accordance with Methods 1 through 4 and 7 of 40 CFR Part 60, Appendix A.

iii. The hourly CO emission limitation was established by multiplying the emission factor of 0.85 lb of CO emissions/mmBtu by the emissions unit's maximum heat input capacity of 17.21 mmBtu/hour.

If required, the permittee shall demonstrate compliance with the hourly CO emission limitation through emission tests performed in accordance with Methods 1 through 4 and 10 of 40 CFR Part 60, Appendix A.

iv. The hourly VOC emission limitation was established by multiplying the emission factor of 0.09 lb of VOC emissions/mmBtu by the emissions unit's maximum heat input capacity of 17.21 mmBtu/hour.

If required, the permittee shall demonstrate compliance with the hourly VOC emission limitation through emission tests performed in accordance with Methods 1 through 4 and 25 of 40 CFR Part 60, Appendix A.

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

Note: The emission factors specified above for each pollutant, including SO2, were obtained from AP-42, Fifth Edition, Chapter 3, Section 3.4, "Large Stationary Diesel Engines", Table 3.4-1, dated 10/96.

**1.b** Emission Limitations:

0.27 ton of PE/rolling, 12-month period;
2.15 tons of SO2 emissions/rolling, 12-month period;
13.77 tons of NOx emissions/rolling, 12-month period;
3.66 tons of CO emissions/rolling, 12-month period; and
0.39 tons of VOC emissions/rolling, 12-month period.

Applicable Compliance Method:

Compliance with the annual emission limitations for the pollutants specified above are ensured if compliance is maintained with the restricted annual hours of operation (i.e., 499 hours per rolling, 12-month period). The annual emission limitations were calculated by multiplying the hourly emission limitations (for each pollutant respectively), by the restricted annual hours of operation, and dividing by 2,000 lbs/ton.

## V. Testing Requirements (continued)

**1.c** Emission Limitation:

PE shall not exceed 0.35 lb/mmBtu actual heat input.

Applicable Compliance Method:

Compliance may be based upon an emission factor of 0.062 lb of PE/mmBtu. This emission factor is specified in the U.S. EPA reference document AP-42, Fifth Edition, Chapter 3, Section 3.4, "Large Stationary Diesel Engines", Table 3.4-2, dated 10/96.

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 and and the procedures specified in OAC rule 3745-17-03(B)(10).

**1.d** Emission Limitation:

PE shall not exceed 0.062 lb/mmBtu actual heat input.

Applicable Compliance Method:

Compliance may be based upon an emission factor of 0.062 lb of PE/mmBtu. This emission factor is specified in the U.S. EPA reference document AP-42, Fifth Edition, Chapter 3, Section 3.4, "Large Stationary Diesel Engines", Table 3.4-2, dated 10/96.

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 and and the procedures specified in OAC rule 3745-17-03(B)(10).

**1.e** Emission Limitation:

SO2 emissions shall not exceed 0.5 lb/mmBtu of actual heat input.

Applicable Compliance Method:

Compliance with the SO2 emission limitation may be determined by the record keeping requirements specified in Section A.III.3.

If required, the permittee shall demonstrate compliance with the SO2 emission limitation through emission tests performed in accordance with Methods 1-4 and 6 of 40 CFR Part 60, Appendix A.

**1.f** Emission Limitation:

Visible PE from any stack shall not exceed 20% opacity, as a 6-minute average, except as specified by rule.

Applicable Compliance Method:

If required, compliance with the visible PE limitation shall be determined 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).

**1.g** Operating Hours Restriction:

499 hours per rolling, 12-month period

Applicable Compliance Method:

Compliance with the operating hours restriction shall be determined by the record keeping requirements specified in Section A.lll.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 |
|---|---|---|
| 17.21 mmBtu/hour (1.5 megawatt) emergency diesel fuel-fired generator | | |

**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:** #2 EDG (P010)

**Activity Description:** 1.5 Megawatt Emergency Diesel Generator #2

## 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 |
|---|---|---|
| 17.21 mmBtu/hour (1.5 megawatt) emergency diesel fuel-fired generator | OAC rule 3745-31-05(A)(3) (PTI 14-04682) | See Section A.I.2.a below.<br><br>The requirements of this rule also include compliance with the requirements of OAC rules 3745-17-07(A), 3745-17-11(B)(5)(b), 3745-18-06(G), 3745-31-05(C). |
| | OAC rule 3745-31-05(C) | See Section A.II.1 below. |
| | OAC rules 3745-31-11 through 3745-31-20 | See Section A.I.2.b below. |
| | OAC rule 3745-17-07(A) | Visible particulate emissions (PE) from any stack shall not exceed 20% opacity, as a 6-minute average, except as specified by rule. |
| | OAC rule 3745-17-11(B)(5)(b) | Particulate emissions shall not exceed 0.35 lb/mmBtu actual heat input.<br><br>See Section A.I.2.d below. |
| | OAC rule 3745-17-11(B)(5)(b) | Particulate emissions shall not exceed 0.062 lb/mmBtu actual heat input.<br><br>See Section A.I.2.e below. |
| | OAC rule 3745-18-06(G) | Sulfur dioxide (SO2) emissions shall not exceed 0.5 lb/mmBtu of actual heat input. |
| | OAC rules 3745-21-08(B) and 3745-23-06(B) | See Section A.I.2.f below. |

**2. Additional Terms and Conditions**

**2.a** The permittee shall not exceed the following hourly emission limitations:

i. 8.61 lbs of SO2 emissions/hour;
ii. 55.07 lbs of nitrogen oxides (NOx) emissions/hour;
iii. 14.63 lbs of carbon monoxide (CO) emissions/hour; and
iv. 1.55 lbs of volatile organic compound (VOC) emissions/hour.

**2.b** The permittee shall not exceed the following emission limitations:

i. 0.27 ton of PE per rolling, 12-month period;
ii. 2.15 tons of SO2 emissions per rolling, 12-month period;
iii. 13.77 tons of NOx emissions per rolling, 12-month period;
iv. 3.66 tons of CO emissions per rolling, 12-month period; and
v. 0.39 ton of VOC emissions per rolling, 12-month period.

**2.c** The hourly emission limitations specified above are 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.d** The requirement to comply with this particulate emission limitation shall terminate on the date the U.S. EPA approves the 0.062 lb/mmBtu actual heat input emission limitation as a revision to the Ohio SIP for particulate matter.

**2.e** This particulate emission limitation shall be effective and federally enforceable on the date the U.S. EPA approves this particulate emission limitation as a revision to the Ohio SIP for particulate matter.

**2.f** 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 technology requirements established pursuant to OAC rule 3745-31-05(A)(3) in Permit to Install 14-04682.

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 technology requirements established pursuant to OAC rule 3745-31-05(A)(3) in Permit to Install 14-04682.

**II. Operational Restrictions**

**1.** The maximum annual operating hours for this emissions unit shall not exceed 499 hours per rolling, 12-month period.

**2.** The quality of diesel fuel burned in this emissions unit shall have a combination of heat and sulfur content that is sufficient to comply with the allowable SO2 emission limitation.

Compliance with the above-mentioned specification shall be determined by using analytical results provided by the permittee or oil supplier for each shipment or daily sample of diesel fuel.

**3.** The permittee shall burn only diesel fuel in this emissions unit.

## III. Monitoring and/or Record Keeping Requirements

**1.** The permittee shall collect and record the following information each month for this emissions unit:

a. the total hours of operation for this emissions unit; and

b. the rolling, 12-month summation of the total hours of operation for this emissions unit (the total number of operating hours for the current month plus the total number of operating hours for the previous 11 calendar months).

**2.** For each day during which the permittee burns a fuel other than diesel fuel, the permittee shall maintain a record of the type and quantity of the fuel burned in this emissions unit.

**3.** The permittee shall maintain records of the diesel fuel burned in this emissions unit in accordance with either Alternative 1 or Alternative 2 described below:

a. Alternative 1:

For each shipment of oil received for burning in this emissions unit, the permittee shall collect or require the oil supplier to collect a representative grab sample of oil and maintain records of the total quantity of oil received, the permittee's or oil supplier's analyses for sulfur content and heat content, and the calculated sulfur dioxide emission rate (in lbs/mmBtu). (The sulfur dioxide emission rate shall be calculated in accordance with the formula specified in OAC rule 3745-18-04(F).) 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 may be represented by a single batch analysis from the supplier.

b. Alternative 2:

The permittee shall collect a representative grab sample of oil that is burned in this emissions unit for each day when the emission unit is in operation. If additional fuel oil is added to the tank serving this emissions unit on a day when the emissions unit is in operation, the permittee shall collect a sufficient number of grab samples to develop a composite sample representative of the fuel oil burned in this emissions unit. A representative grab sample of oil does not need to be collected on days when this emissions unit is only operated for the purpose of "test-firing". The permittee shall maintain records of the total quantity of oil burned each day (except for the purpose of test-firing), the permittee's analyses for sulfur content and heat content, and the calculated sulfur dioxide emission rate (in lbs/mmBtu). [The sulfur dioxide emission rate shall be calculated in accordance with the formula specified in OAC rule 3745-18-04(F).]

The permittee shall perform or require the supplier to perform the analyses for sulfur content and heat content in accordance with the following ASTM methods: ASTM method D4294 for sulfur content and ASTM method D240 for heat content. The newest or most recent revisions to the applicable test method shall be used for analyses. Alternative, equivalent methods may be used upon written approval by the Hamilton County Department of Environmental Services - Air Quality Control Division.

## IV. Reporting Requirements

**1.** The permittee shall submit quarterly deviation (excursion) reports to the Hamilton County Department of Environmental Services that identify the following:

a. each day when a fuel other than diesel fuel was burned in this emissions unit;

b. all exceedances of the rolling, 12-month hours of operation limitation; and

c. all exceedances of the lb of SO2/mmBtu emission limitation.

**2.** 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.** Compliance with the emission limitations and the hours of operation restriction specified in Sections A.I.1, A.I.2, and A.II shall be determined by the following methods:

**1.a** Emission Limitations:

8.61 lbs of SO2 emissions/hour;
55.07 lbs of NOx emissions/hour;
14.63 lbs of CO emissions/hour; and
1.55 lbs of VOC emissions/hour.

Applicable Compliance Method:

i. The hourly SO2 emission limitation was established by multiplying the emission factor of 1.01(S) lbs of SO2/mmBtu (where "S" is the % sulfur in the fuel oil) by the emissions unit's maximum heat input capacity of 17.21 mmBtu/hour.

If required, the permittee shall demonstrate compliance with the hourly SO2 emission limitation through emission tests performed in accordance with Methods 1 through 4 and 6 of 40 CFR Part 60, Appendix A.

ii. The hourly NOx emission limitation was established by multiplying the emission factor of 3.2 lbs of NOx emissions/mmBtu by the emissions unit's maximum heat input capacity of 17.21 mmBtu/hour.

If required, the permittee shall demonstrate compliance with the hourly NOx emission limitation through emission tests performed in accordance with Methods 1 through 4 and 7 of 40 CFR Part 60, Appendix A.

iii. The hourly CO emission limitation was established by multiplying the emission factor of 0.85 lb of CO emissions/mmBtu by the emissions unit's maximum heat input capacity of 17.21 mmBtu/hour.

If required, the permittee shall demonstrate compliance with the hourly CO emission limitation through emission tests performed in accordance with Methods 1 through 4 and 10 of 40 CFR Part 60, Appendix A.

iv. The hourly VOC emission limitation was established by multiplying the emission factor of 0.09 lb of VOC emissions/mmBtu by the emissions unit's maximum heat input capacity of 17.21 mmBtu/hour.

If required, the permittee shall demonstrate compliance with the hourly VOC emission limitation through emission tests performed in accordance with Methods 1 through 4 and 25 of 40 CFR Part 60, Appendix A.

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

Note: The emission factors specified above for each pollutant, including SO2, were obtained from AP-42, Fifth Edition, Chapter 3, Section 3.4, "Large Stationary Diesel Engines", Table 3.4-1, dated 10/96.

**1.b** Emission Limitations:

0.27 ton of PE/rolling, 12-month period;
2.15 tons of SO2 emissions/rolling, 12-month period;
13.77 tons of NOx emissions/rolling, 12-month period;
3.66 tons of CO emissions/rolling, 12-month period; and
0.39 tons of VOC emissions/rolling, 12-month period.

Applicable Compliance Method:

Compliance with the annual emission limitations for the pollutants specified above are ensured if compliance is maintained with the restricted annual hours of operation (i.e., 499 hours per rolling, 12-month period). The annual emission limitations were calculated by multiplying the hourly emission limitations (for each pollutant respectively), by the restricted annual hours of operation, and dividing by 2,000 lbs/ton.

## V. Testing Requirements (continued)

**1.c** Emission Limitation:

PE shall not exceed 0.35 lb/mmBtu actual heat input.

Applicable Compliance Method:

Compliance may be based upon an emission factor of 0.062 lb of PE/mmBtu. This emission factor is specified in the U.S. EPA reference document AP-42, Fifth Edition, Chapter 3, Section 3.4, "Large Stationary Diesel Engines", Table 3.4-2, dated 10/96.

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 and and the procedures specified in OAC rule 3745-17-03(B)(10).

**1.d** Emission Limitation:

PE shall not exceed 0.062 lb/mmBtu actual heat input.

Applicable Compliance Method:

Compliance may be based upon an emission factor of 0.062 lb of PE/mmBtu. This emission factor is specified in the U.S. EPA reference document AP-42, Fifth Edition, Chapter 3, Section 3.4, "Large Stationary Diesel Engines", Table 3.4-2, dated 10/96.

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 and and the procedures specified in OAC rule 3745-17-03(B)(10).

**1.e** Emission Limitation:

SO2 emissions shall not exceed 0.5 lb/mmBtu of actual heat input.

Applicable Compliance Method:

Compliance with the SO2 emission limitation may be determined by the record keeping requirements specified in Section A.III.3.

If required, the permittee shall demonstrate compliance with the SO2 emission limitation through emission tests performed in accordance with Methods 1-4 and 6 of 40 CFR Part 60, Appendix A.

**1.f** Emission Limitation:

Visible PE from any stack shall not exceed 20% opacity, as a 6-minute average, except as specified by rule.

Applicable Compliance Method:

If required, compliance with the visible PE limitation shall be determined 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).

**1.g** Operating Hours Restriction:

499 hours per rolling, 12-month period

Applicable Compliance Method:

Compliance with the operating hours restriction shall be determined by the record keeping requirements specified in Section A.lll.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 |
|---|---|---|
| 17.21 mmBtu/hour (1.5 megawatt) emergency diesel fuel-fired generator | | |

**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:** Fire Pump (P011)

**Activity Description:** 140 Kilowatt Emergency Diesel Fire Pump

## 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 |
|---|---|---|
| 1.6 mmBtu/hour (140 kilowatt) emergency diesel fuel-fired pump | OAC rule 3745-31-05(A)(3) (PTI 14-04682) | See Section A.I.2.a below.<br><br>The requirements of this rule also include compliance with the requirements of OAC rules 3745-17-07(A), 3745-17-11(B)(5)(a), 3745-18-06(G), and 3745-31-05(C). |
| | OAC rule 3745-31-05(C) | See Section A.ll.1 below. |
| | OAC rules 3745-31-11 through 3745-31-20 | See Section A.I.2.b below. |
| | OAC rule 3745-17-07(A) | Visible particulate emissions (PE) from any stack shall not exceed 20% opacity, as a 6-minute average, except as specified by rule. |
| | OAC rule 3745-17-11(B)(5)(a) | Particulate emissions shall not exceed 0.25 lb/mmBtu actual heat input.<br><br>See A.I.2.d below. |
| | OAC rule 3745-17-11(B)(5)(a) | Particulate emissions shall not exceed 0.310 lb/mmBtu actual heat input.<br><br>See A.I.2.e below. |
| | OAC rule 3745-18-06(G) | Exempt, pursuant to the provisions of OAC rule 3745-18-06(B). See Section A.I.2.f below. |
| | OAC rules 3745-21-08(B) and 3745-23-06(B) | See Section A.I.2.g below. |

**2. Additional Terms and Conditions**

**2.a** The permittee shall not exceed the following hourly emission limitations:

i. 0.80 lb of sulfur dioxide (SO2) emissions/hour;
ii. 5.14 lbs of nitrogen oxides (NOx) emissions/hour;
iii. 1.37 lbs of carbon monoxide (CO) emissions/hour; and
iv. 0.14 lb of volatile organic compound (VOC) emissions/hour.

**2.b** The permittee shall not exceed the following emission limitations:

i. 0.12 ton of PE per rolling, 12-month period;
ii. 0.20 ton of SO2 emissions per rolling, 12-month period;
iii. 1.28 tons of NOx emissions per rolling, 12-month period;
iv. 0.34 ton of CO emissions per rolling, 12-month period; and
v. 0.04 ton of VOC emissions per rolling, 12-month period.

**2.c** The hourly emission limitations specified above are 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.d** The requirement to comply with this particulate emission limitation shall terminate on the date the U.S. EPA approves the 0.310 lb/mmBtu actual heat input emission limitation as a revision to the Ohio SIP for particulate matter.

**2.e** This particulate emission limitation shall be effective and federally enforceable on the date the U.S. EPA approves this particulate emission limitation as a revision to the Ohio SIP for particulate matter.

**2.f** The rated heat input capacity of this emissions unit is equal to or less than 10 mmBtu/hour. Therefore, pursuant to OAC rule 3745-18-06(B), this emissions unit is exempt from the requirements of OAC rule 3745-18-06(G).

**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 technology requirements established pursuant to OAC rule 3745-31-05(A)(3) in Permit to Install 14-04682.

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 technology requirements established pursuant to OAC rule 3745-31-05(A)(3) in Permit to Install 14-04682.

**II. Operational Restrictions**

**1.** The maximum annual operating hours for this emissions unit shall not exceed 499 hours per rolling, 12-month period.

**2.** The quality of diesel fuel burned in this emissions unit shall have a combination of heat and sulfur content that is sufficient to comply with the allowable SO2 emission limitation.

Compliance with the above-mentioned specification shall be determined by using analytical results provided by the permittee or oil supplier for each shipment or daily sample of diesel fuel.

**3.** The permittee shall burn only diesel fuel in this emissions unit.

## III. Monitoring and/or Record Keeping Requirements

**1.** The permittee shall collect and record the following information each month for this emissions unit:

a. the total hours of operation for this emissions unit; and

b. the rolling, 12-month summation of the total hours of operation for this emissions unit (the total number of operating hours for the current month plus the total number of operating hours for the previous 11 calendar months).

**2.** For each day during which the permittee burns a fuel other than diesel fuel, the permittee shall maintain a record of the type and quantity of the fuel burned in this emissions unit.

**3.** The permittee shall maintain records of the diesel fuel burned in this emissions unit in accordance with either Alternative 1 or Alternative 2 described below:

a. Alternative 1:

For each shipment of oil received for burning in this emissions unit, the permittee shall collect or require the oil supplier to collect a representative grab sample of oil and maintain records of the total quantity of oil received, the permittee's or oil supplier's analyses for sulfur content and heat content, and the calculated sulfur dioxide emission rate (in lbs/mmBtu). (The sulfur dioxide emission rate shall be calculated in accordance with the formula specified in OAC rule 3745-18-04(F).) 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 may be represented by a single batch analysis from the supplier.

b. Alternative 2:

The permittee shall collect a representative grab sample of oil that is burned in this emissions unit for each day when the emission unit is in operation. If additional fuel oil is added to the tank serving this emissions unit on a day when the emissions unit is in operation, the permittee shall collect a sufficient number of grab samples to develop a composite sample representative of the fuel oil burned in this emissions unit. A representative grab sample of oil does not need to be collected on days when this emissions unit is only operated for the purpose of "test-firing". The permittee shall maintain records of the total quantity of oil burned each day (except for the purpose of test-firing), the permittee's analyses for sulfur content and heat content, and the calculated sulfur dioxide emission rate (in lbs/mmBtu). [The sulfur dioxide emission rate shall be calculated in accordance with the formula specified in OAC rule 3745-18-04(F).]

The permittee shall perform or require the supplier to perform the analyses for sulfur content and heat content in accordance with the following ASTM methods: ASTM method D4294 for sulfur content and ASTM method D240 for heat content. The newest or most recent revisions to the applicable test method shall be used for analyses. Alternative, equivalent methods may be used upon written approval by the Hamilton County Department of Environmental Services - Air Quality Control Division.

## IV. Reporting Requirements

**1.** The permittee shall submit quarterly deviation (excursion) reports to the Hamilton County Department of Environmental Services that identify the following:

a. each day when a fuel other than diesel fuel was burned in this emissions unit;

b. all exceedances of the rolling, 12-month hours of operation limitation; and

c. all exceedances of the lb of SO2/mmBtu emission limitation.

**2.** 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.** Compliance with the emission limitations and the hours of operation restriction specified in Sections A.I.1, A.I.2, and A.II shall be determined by the following methods:

**1.a** Emission Limitations:

0.80 lb of SO2 emissions/hour;
5.14 lbs of NOx emissions/hour;
1.37 lbs of CO emissions/hour; and
0.14 lb of VOC emissions/hour.

Applicable Compliance Method:

The hourly emission limitations specified above are based upon the emissions unit's potentials to emit and were established by the following methodology:

i. The hourly SO2 emission limitation was established by multiplying the emission factor of 1.01(S) lbs of SO2/mmBtu (where "S" is the % sulfur in the fuel oil) by the maximum heat input of 1.6 mmBtu/hour.

If required, the permittee shall demonstrate compliance with the hourly SO2 emission limitation through emission tests performed in accordance with Methods 1 through 4 and 6 of 40 CFR Part 60, Appendix A.

ii. The hourly NOx emission limitation was established by multiplying the emission factor of 3.2 lbs of NOx emissions/mmBtu by the maximum heat input of 1.6 mmBtu/hour.

If required, the permittee shall demonstrate compliance with the hourly NOx emission limitation through emission tests performed in accordance with Methods 1 through 4 and 7 of 40 CFR Part 60, Appendix A.

iii. The hourly CO emission limitation was established by multiplying the emission factor of 0.85 lb of CO emissions/mmBtu by the maximum heat input of 1.6 mmBtu/hour.

If required, the permittee shall demonstrate compliance with the hourly CO emission limitation through emission tests performed in accordance with Methods 1 through 4 and 10 of 40 CFR Part 60, Appendix A.

iv. The hourly VOC emission limitation was established by multiplying the emission factor of 0.09 lb of VOC emissions/mmBtu by the maximum heat input of 1.6 mmBtu/hour.

If required, the permittee shall demonstrate compliance with the hourly VOC emission limitation through emission tests performed in accordance with Methods 1 through 4 and 25 of 40 CFR Part 60, Appendix A.

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

Note: The emission factors specified above for each pollutant, including SO2, were obtained from AP-42, Fifth Edition, Chapter 3, Section 3.4, "Large Stationary Diesel Engines", Table 3.4-1, dated 10/96.

**1.b** Emission Limitations:

0.12 ton of PE/rolling, 12-month period;
0.20 ton of SO2 emissions/rolling, 12-month period;
1.28 ton of NOx emissions/rolling, 12-month period;
0.34 tons of CO emissions/rolling, 12-month period; and
0.04 ton of VOC emissions/rolling, 12-month period.

Applicable Compliance Method:

Compliance with the annual emission limitations for the pollutants specified above are ensured if compliance is maintained with the restricted annual operating hours (i.e., 500 hours per rolling, 12-month period). The annual emission limitations were calculated by multiplying the hourly emission limitations (for each pollutant respectively), by the restricted annual hours of operation, and dividing by 2,000 lbs/ton.

## V. Testing Requirements (continued)

**1.c** Emission Limitation:

PE shall not exceed 0.25 lb/mmBtu actual heat input.

Applicable Compliance Method:

The permittee cannot demonstrate compliance with this emission limitation based upon the current emission factor contained in the U.S. EPA reference document AP-42, Fifth Edition, Compilation of Air Pollution Emission Factors, Section 3.3, Table 3.3-1 (10/96). The Ohio EPA revised the emission limitation specified in this rule citation based upon the currently applicable emission factor. The revised rule was adopted by the Director of Ohio EPA in December of 1997, and has been submitted to the U.S. EPA as a proposed revision to the Ohio SIP for particulate matter. When the SIP revision is approved by the U.S. EPA, the 0.25 lb/mmBtu actual heat input emission limitation will no longer be applicable, and the permittee will be able to demonstrate compliance with the new emission limitation (0.310 lb/mmBtu actual heat input) using the current emission factor.

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 and the procedures specified in OAC rule 3745-17-03(B)(10).

**1.d** Emission Limitation:

PE shall not exceed 0.310 lb/mmBtu actual heat input.

Applicable Compliance Method:

Compliance with this emission limitation may be based upon an emission factor of 0.31 lb/mmBtu. This emission factor is specified in the U.S. EPA reference document AP-42, Fifth Edition, Compilation of Air Pollution Emission Factors, Section 3.3, Table 3.3-1 (10/96).

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 and the procedures specified in OAC rule 3745-17-03(B)(10).

**1.e** Emission Limitation:

Visible PE from any stack shall not exceed 20% opacity, as a 6-minute average, except as specified by rule.

Applicable Compliance Method:

If required, compliance with the visible PE limitation shall be determined 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).

**1.f** Operating Hours Restriction:

499 hours per rolling, 12-month period

Applicable Compliance Method:

Compliance with the operating hours restriction shall be determined by the record keeping requirements specified in Section A.lll.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 |
|---|---|---|
| 1.6 mmBtu/hour (140 kilowatt) emergency diesel fuel-fired pump | | |

**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**

**********

## THIS IS THE LAST PAGE OF THE PERMIT

**********

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
A. What is the Source of Authority for Development of NESHAP?
B. What Criteria are Used in the Development of NESHAP?
C. What are the Health Effects Associated with HAP from Stationary Combustion Turbines?
D. What is the Regulatory Development Background of the Source Category?
II. Summary of the Final Rule
A. What Sources are Subject to the Final Rule?
B. What Source Categories and Subcategories are Affected by the Final Rule?
C. What are the Primary Sources of HAP Emissions and What are the Emissions?
D. What are the Emission Limitations and Operating Limitations?
E. What are the Initial Compliance Requirements?
F. What are the Continuous Compliance Provisions?
G. What are the Notification, Recordkeeping and Reporting Requirements?
III. Summary of Responses to Major Comments
A. Applicability
B. Definitions
C. Dates
D. MACT
E. Emission Limitations
F. Monitoring, Recordkeeping, and Reporting
G. Test Methods
H. Risk-Based Approaches
I. Other
IV. Rationale for Selecting the Final Standards
A. How did we Select the Source Category and any Subcategories?
B. What are the Requirements for Stationary Combustion Turbines Located at Area Sources?
C. What is the Affected Source?
D. How did we Determine the Basis and Level of the Emission Limitations for Existing Sources?
E. How did we Determine the Basis and Level of the Emission Limitations and Operating Limitations for New Sources?
F. How did we Select the Initial Compliance Requirements?
G. How did we Select the Continuous Compliance Requirements?
H. How did we Select the Testing Methods to Measure these Low Concentrations of Formaldehyde?
I. How did we Select the Notification, Recordkeeping and Reporting Requirements?
V. Summary of Environmental, Energy and Economic Impacts
A. What are the Air Quality Impacts?
B. What are the Cost Impacts?
C. What are the Economic Impacts?
D. What are the Non-air Health, Environmental and Energy Impacts?
VI. Statutory and Executive Order Reviews
A. Executive Order 12866: Regulatory Planning and Review
B. Paperwork Reduction Act
C. Regulatory Flexibility Act
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

### *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


Attachment 1
Attachment 1

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


Attachment 1
Attachment 1

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


Attachment 1
Attachment 1

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.


Attachment 1
Attachment 1

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


Attachment 1
Attachment 1

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

Sec.

**What This Subpart Covers**

63.6080 What is the purpose of subpart YYYY?
63.6085 Am I subject to this subpart?
63.6090 What parts of my plant does this subpart cover?
63.6092 Are duct burners and waste heat recovery units covered by subpart YYYY?
63.6095 When do I have to comply with this subpart?

**Emission and Operating Limitations**

63.6100 What emission and operating limitations must I meet?

**General Compliance Requirements**

63.6105 What are my general requirements for complying with this subpart?

**Testing and Initial Compliance Requirements**

63.6110 By what date must I conduct the initial performance tests or other initial compliance demonstrations?
63.6115 When must I conduct subsequent performance tests?
63.6120 What performance tests and other procedures must I use?
63.6125 What are my monitor installation, operation, and maintenance requirements?
63.6130 How do I demonstrate initial compliance with the emission and operating limitations?

**Continuous Compliance Requirements**

63.6135 How do I monitor and collect data to demonstrate continuous compliance?
63.6140 How do I demonstrate continuous compliance with the emission and operating limitations?

**Notifications, Reports, and Records**

63.6145 What notifications must I submit and when?
63.6150 What reports must I submit and when?
63.6155 What records must I keep?
63.6160 In what form and how long must I keep my records?

**Other Requirements and Information**

63.6165 What parts of the General Provisions apply to me?
63.6170 Who implements and enforces this subpart?
63.6175 What definitions apply to this subpart?

**Tables to Subpart YYYY of Part 63**

Table 1 to Subpart YYYY of Part 63.—Emission Limitations
Table 2 to Subpart YYYY of Part 63.—Operating Limitations
Table 3 to Subpart YYYY of Part 63.—Requirements for Performance Tests and Initial Compliance Demonstrations
Table 4 to Subpart YYYY of Part 63.—Initial Compliance with Emission Limitations
Table 5 to Subpart YYYY of Part 63.—Continuous Compliance with Operating Limitations
Table 6 to Subpart YYYY of Part 63.—Requirements for Reports
Table 7 to Subpart YYYY of Part 63.—Applicability of General Provisions to Subpart YYYY

### 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,<br>2. a lean premix oil-fired stationary combustion turbine as defined in this subpart,<br>3. a diffusion flame gas-fired stationary combustion turbine as defined in this subpart, or<br>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. | |

[FR Doc. 04–4530 Filed 3–4–04; 8:45 am]

**BILLING CODE 6560–50–P**

6560-50-P

**ENVIRONMENTAL PROTECTION AGENCY**

**40 CFR Part 63**

**[OAR-2002-0059; FRL- ]**

**RIN 2060-AG-63**

# National Emission Standards for Hazardous Air Pollutants for Stationary Reciprocating Internal Combustion Engines

**AGENCY:** Environmental Protection Agency (EPA).

**ACTION:** Final rule.

**SUMMARY:** This action promulgates national emission standards for hazardous air pollutants (NESHAP) for stationary reciprocating internal combustion engines (RICE) with a site-rating of more than 500 brake horsepower (HP). We have identified stationary RICE as major sources of hazardous air pollutants (HAP) emissions such as formaldehyde, acrolein, methanol, 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 RICE. We estimate that 40 percent of stationary RICE will be located at major sources and thus, subject to the final rule. 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 5,600 tons per year (tpy) in the 5th year after the rule is promulgated. The emissions reductions achieved by these standards will provide protection to the public and achieve a primary goal of the CAA.

**EFFECTIVE DATE:** [INSERT DATE 60 DAYS AFTER PUBLICATION OF THIS FINAL RULE IN THE FEDERAL REGISTER]

**ADDRESSES:** Docket. Docket ID No. OAR-2002-0059 and Docket ID No. A-95-35 contain supporting information used in developing the standards. The dockets are 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[1] | NAICS[2] | Examples of regulated entities |
|---|---|---|---|
| Any industry using a stationary RICE as defined in the final rule | 4911 | 2211 | Electric power generation, transmission, or distribution |
| | 4922 | 48621 | Natural gas transmission |
| | 1311 | 211111 | Crude petroleum and natural gas production |
| | 1321 | 211112 | Natural gas liquids producers |
| | 9711 | 92811 | National security |

[1] Standard Industrial Classification
[2] North American Industry Classification System

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 §63.6585 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 including both Docket ID No. OAR-2002-0059 and Docket ID No. A-95-35. 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

 Attachment 2 Attachment 2

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 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. 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 [INSERT DATE 60 DAYS AFTER DATE OF PUBLICATION OF FINAL RULE IN FEDERAL REGISTER]. 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 RICE on December 19, 2002 (67 FR 77830), and received 64 comment letters on the proposal. A background information document (BID) ("National Emission Standards for Stationary Reciprocating Internal Combustion Engines, Summary of Public Comments and Responses,")

containing EPA's responses to each public comment is available in Docket ID Nos. OAR-2002-0059 and A-95-35.

Outline. The information presented in this preamble is organized as follows:

I. Background
A. What is the source of authority for development of NESHAP?
B. What criteria are used in the development of NESHAP?
C. What are the health effects associated with HAP from stationary RICE?
D. What is the regulatory development background of the source category?
II. Summary of the Final Rule
A. What sources are subject to the final rule?
B. What source categories and subcategories are affected by the final rule?
C. What are the primary sources of HAP emissions and what are the emissions?
D. What are the emission limitations and operating limitations?
E. What are the initial compliance requirements?
F. What are the continuous compliance provisions?
G. What are the notification, recordkeeping and reporting requirements?
III. Summary of Significant Changes Since Proposal
A. Emission Limitations
B. Operating Limitations
C. Testing and Monitoring
D. Other
IV. Summary of Responses to Major Comments
A. Applicability
B. Definitions
C. Dates
D. Emission Limitations
E. Monitoring, Recordkeeping, and Reporting
F. Testing
G. Risk-Based Approaches
H. Other
V. Summary of Environmental, Energy and Economic Impacts
A. What are the air quality impacts?
B. What are the cost impacts?
C. What are the economic impacts?
D. What are the non-air health, environmental and energy impacts?

 Attachment 2 Attachment 2

VI. Statutory and Executive Order Reviews
A. Executive Order 12866: Regulatory Planning and Review
B. Paperwork Reduction Act
C. Regulatory Flexibility Act
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

### 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 RICE source category was listed as a major source category 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 sources in listed source categories. The CAA requires the NESHAP to reflect the maximum degree of reduction in

 Attachment 2 Attachment 2

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 regulated 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.

 Attachment 2 Attachment 2

C. <u>What are the health effects associated with HAP from stationary RICE?</u>

Emission data collected during development of the NESHAP show that several HAP are emitted from stationary RICE. These HAP emissions are formed during combustion or result from HAP compounds contained in the fuel burned.

The HAP which have been measured in emission tests conducted on natural gas fired and distillate oil fired RICE include: 1,1,2,2-tetrachloroethane, 1,3-butadiene, 2,2,4-trimethylpentane, acetaldehyde, acrolein, benzene, chlorobenzene, chloroethane, ethylbenzene, formaldehyde, methanol, methylene chloride, n-hexane, naphthalene, polycyclic aromatic hydrocarbons, polycyclic organic matter, styrene, tetrachloroethane, toluene, and xylene. Metallic HAP from distillate oil fired stationary RICE that have been measured are: cadmium, chromium, lead, manganese, mercury, nickel, and selenium.

Although numerous HAP may be emitted from RICE, only a few account for essentially all of the mass of HAP emissions from stationary RICE. These HAP are: formaldehyde, acrolein, methanol, and acetaldehyde.

The HAP emitted in the largest quantities from stationary RICE is formaldehyde. Formaldehyde is a probable human carcinogen and can cause irritation of the eyes and

 Attachment 2 Attachment 2

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.

Acrolein is a cytotoxic agent, a powerful lacrimating agent, and a severe tissue irritant. Acute exposure to acrolein can cause severe irritation or corrosion of the eyes, nose, throat, and lungs, with tearing, pain in the chest, and delayed-onset pulmonary injury with depressed pulmonary function. Chronic exposure to acrolein can cause skin sensitization and contact dermatitis. Acrolein is not considered carcinogenic to humans.

Humans are very sensitive to the toxic effects of methanol including formic acidaemia, metabolic acidosis, ocular toxicity, nervous system depression, blindness, coma, and death. A majority of the available information on methanol toxicity in humans is based on acute rather than long-term exposure. However, recent animal studies also indicate potential reproductive and developmental health consequences following chronic exposure to methanol in both mice and primates. Methanol has not been classified with respect to carcinogenicity.

 Attachment 2 Attachment 2

The health effects for acetaldehyde are irritation of the eye mucous membranes, skin, and upper respiratory tract, and a central nervous system (CNS) depressant in humans. Acute exposure can cause conjunctivitis, coughing, difficult breathing, and dermatitis. Chronic exposure may cause heart and kidney damage, embryotoxicity, and teratogenic effects. Acetaldehyde is a probable carcinogen in humans.

We recently reviewed health effects associated with emissions of particulates from diesel engines in the context of regulating heavy duty motor vehicles and engines (66 FR 5001, January 18, 2001). Diesel particulate matter (PM) is not currently listed as a hazardous air pollutant for stationary sources under section 112 of the CAA and was not specifically reviewed under the rule, though constituent parts of diesel PM are subject to the final rule. We are continuing to review this issue in the context of regulating stationary RICE.

D. <u>What is the regulatory development background of the source category?</u>

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

 Attachment 2 Attachment 2

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 RICE Work Group, was formed to research issues related to stationary RICE. The RICE Work Group submitted recommendations, information, and data analyses to the Coordinating Committee, which in turn considered them and submitted recommendations and information to EPA. The Committee's 2-year charter expired in September 1998. We considered the Committee's recommendations in developing the final rule for stationary RICE.

## 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 stationary RICE which are located at a major source of HAP emissions, except if your stationary RICE all have a site-rating of 500 brake HP or less. A major source of HAP emissions is a plant site that emits or has the potential to emit any single HAP at a rate of 10 tons (9.07 megagrams) or more per year or any combination of HAP at a rate of 25 tons (22.68 megagrams) or more per year.

Section 112(n)(4) of the CAA requires that the

 Attachment 2 Attachment 2

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 RICE 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, RICE, 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.

While all stationary RICE with a site-rating of more than 500 brake HP located at major sources are subject to the final rule, there are distinct requirements for

 Attachment 2 Attachment 2

regulated stationary RICE depending on their design, use, and fuel. The standards in the final rule have specific requirements for all new or reconstructed stationary RICE and for existing spark ignition 4 stroke rich burn (4SRB) stationary RICE located at a major source of HAP emissions, except that stationary RICE with a site-rating of 500 brake HP or less are not addressed in the final rule. New or reconstructed stationary RICE which operate exclusively as emergency or limited use units are subject only to initial notification requirements. New or reconstructed stationary RICE which combust landfill gas or digester gas equivalent to 10 percent or more of the gross heat input on an annual basis are subject only to initial notification requirements and to monitoring, recording, and reporting of fuel usage requirements. With the exception of existing spark ignition 4SRB stationary RICE, other types of existing stationary RICE (i.e., spark ignition 2 stroke lean burn (2SLB), spark ignition 4 stroke lean burn (4SLB), compression ignition (CI), stationary RICE that combust landfill or digester gas equivalent to 10 percent or more of the gross heat input on an annual basis, emergency, and limited use units) located at a major source of HAP emissions are not subject to any specific requirement under the final rule. You must determine your source's subcategory to determine which

 Attachment 2 Attachment 2

requirements apply to your source.

The final rule does not apply to stationary RICE 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.

Finally, the final rule does not apply to stationary RICE test cells/stands since these facilities are covered by another NESHAP, subpart PPPPP of 40 CFR part 63.

B. <u>What source categories and subcategories are affected by the final rule?</u>

The final rule covers stationary RICE. A stationary RICE is any RICE which uses reciprocating motion to convert heat energy into mechanical work and is not mobile. Stationary RICE differ from mobile RICE in that a stationary RICE is not a non-road engine as defined at 40 CFR 1068.30, and is not used to propel a motor vehicle or a vehicle used solely for competition.

We divided the stationary RICE source category into five subcategories: (1) stationary RICE with a site-rating of 500 brake HP or less, (2) emergency stationary RICE, (3) limited use stationary RICE, (4) stationary RICE that combust landfill gas or digester gas equivalent to 10 percent or more of the gross heat input on an annual basis, and (5) other stationary RICE. We further divided the last

 Attachment 2 Attachment 2

subcategory into four subcategories: (1) 2SLB stationary RICE, (2) 4SLB stationary RICE, (3) 4SRB stationary RICE, and (4) CI stationary RICE.

The final rule does not apply to stationary RICE test cells/stands since these facilities are covered by another NESHAP, subpart PPPPP of 40 CFR part 63.

The final rule also does not apply to stationary RICE with a site-rating of 500 brake HP or less. In reviewing the population database to identify stationary RICE with a site-rating of 500 brake HP or less, we found extremely little information. In discussions with State and local permitting officials, the manufacturers, and some of the owners and operators of stationary RICE, we found that such small stationary RICE have generally not been regarded as significant sources of air pollutant emissions. As a result, the small stationary RICE have not been subjected to the same level of scrutiny, examination, or review as larger stationary RICE. Little information has been gathered or compiled by anyone for this subcategory of stationary RICE.

Thus, at this point, we know very little about stationary RICE with a site-rating of 500 brake HP or less. For example, we do not know how many of the small stationary RICE exist. In addition, we know little about the operating characteristics and emissions, the current use of, as well

 Attachment 2 Attachment 2

as the applicability of, emission control technologies, the costs of emission control for the small stationary RICE, or the economic impacts and benefits associated with regulation. In the absence of such information, we have concerns with the applicability of HAP emission control technology to these stationary RICE. As a result, we feel it is appropriate to defer a decision on regulation of stationary RICE with a site-rating of 500 brake HP or less until further information on the engines can be obtained and analyzed.

We feel this subcategory of stationary RICE is likely to be more similar to stationary RICE located at area sources than to stationary RICE located at major sources. Thus, we plan to include this subcategory of stationary RICE in our considerations to develop regulations for stationary RICE located at area sources.

C. <u>What are the primary sources of HAP emissions and what are the emissions?</u>

The primary sources of HAP emissions are exhaust gases from combustion of gaseous fuels and liquid fuels in stationary RICE. Formaldehyde, acrolein, methanol, and acetaldehyde are HAP that are present in significant quantities from stationary RICE.

D. <u>What are the emission limitations and operating</u>

 Attachment 2 Attachment 2

limitations?

As the owner or operator of an affected source, you must do one of the following: (1) each existing, new, or reconstructed 4SRB stationary RICE must comply with each emission limitation in Table 1(a) of subpart ZZZZ, 40 CFR part 63, and each operating limitation in Table 1(b) of subpart ZZZZ that apply; or (2) each new or reconstructed 2SLB stationary RICE, new or reconstructed 4SLB stationary RICE, or new or reconstructed CI stationary RICE must comply with each emission limitation in Table 2(a) of subpart ZZZZ and operating limitation in Table 2(b) of subpart ZZZZ that apply. These tables can be found after the definitions in §63.6675 of subpart ZZZZ.

Existing 2SLB stationary RICE, existing 4SLB stationary RICE, existing CI stationary RICE, stationary RICE that operate exclusively as emergency or limited use units, or stationary RICE that combust landfill gas or digester gas equivalent to 10 percent or more of the gross heat input on an annual basis have an emission standard of no emission reduction, and will not be tested to meet any specific emission limitation or operating limitation. In addition, any stationary RICE located at an area source of HAP emissions, any stationary RICE with a site-rating of 500 brake HP or less, or stationary RICE that are being tested

 Attachment 2 Attachment 2

at stationary RICE test cells/stands are not addressed in the final rule and, therefore, do not need to comply with any emission limitation or operating limitation.

E. What are the initial compliance requirements?

If your stationary RICE must meet specific emission limitations and operating limitations, then you must meet the following initial compliance requirements. The testing and initial compliance requirements are different, depending on whether you demonstrate compliance with the carbon monoxide (CO) emission reduction requirement, formaldehyde emission reduction requirement, or the requirement to limit the formaldehyde concentration in the stationary RICE exhaust.

If you own or operate a 2SLB or 4SLB stationary RICE or a CI stationary RICE complying with the requirement to reduce CO emissions, you must conduct an initial performance test to demonstrate that you are achieving the required CO percent reduction, corrected to 15 percent oxygen, dry basis. The initial performance test must be conducted at high load conditions, defined as 100 percent ±10 percent.

If you own or operate a 2SLB or 4SLB stationary RICE or a CI stationary RICE complying with the requirement to reduce CO emissions and you are using an oxidation catalyst, you must also install a continuous parameter monitoring

 Attachment 2 Attachment 2

system (CPMS) to continuously monitor the catalyst inlet temperature. During the initial performance test, you must record the initial pressure drop across the catalyst and the catalyst inlet temperature.

If you own or operate a 2SLB or 4SLB stationary RICE or a CI stationary RICE complying with the requirement to reduce CO emissions and you are not using an oxidation catalyst, you must also petition the Administrator for approval of operating limitations or approval or no operating limitations. You must also install a CPMS to continuously monitor the operating parameters (if any) approved by the Administrator. During the initial performance test, you must record the initial values of the approved operating parameters (if any).

As an alternative, you may elect to install a continuous emissions monitoring system (CEMS) to measure CO and either carbon dioxide or oxygen simultaneously at the inlet and outlet of the oxidation catalyst. To demonstrate initial compliance, you must conduct an initial performance evaluation using Performance Specifications (PS) 3 and 4A of 40 CFR part 60, appendix B. The initial performance test must be conducted at high load conditions, defined as 100 percent ±10 percent. You must demonstrate that the reduction of CO emissions meets the required percent

 Attachment 2 Attachment 2

reduction using the first 4-hour average after a successful performance evaluation. Your measurements at the inlet and the outlet of the oxidation catalyst must be on a dry basis and corrected to 15 percent oxygen or equivalent carbon dioxide content.

If you own or operate 4SRB stationary RICE complying with the requirement to reduce formaldehyde emissions, you must conduct an initial performance test using Test Method 320 or 323 of 40 CFR part 63, appendix A, or ASTM D6348-03 to demonstrate that you are achieving the required formaldehyde percent reduction, corrected to 15 percent oxygen, dry basis. The initial performance test must be conducted at high load conditions, defined as 100 percent ±10 percent.

If you own or operate a 4SRB stationary RICE complying with the requirement to reduce formaldehyde emissions and you are using non-selective catalytic reduction (NSCR), you must also install a CPMS to continuously monitor the catalyst inlet temperature. During the initial performance test, you must record the initial values of the pressure drop across the catalyst and the catalyst inlet temperature.

If you own or operate a 4SRB stationary RICE complying with the requirement to reduce formaldehyde emissions and you are not using NSCR, you must also petition the

Administrator for approval of operating limitations or approval or no operating limitations. You must also install a CPMS to continuously monitor the operating parameters (if any) approved by the Administrator. During the initial performance test, you must record the initial values of the approved operating parameters (if any).

If you are complying with the requirement to limit the concentration of formaldehyde in the stationary RICE exhaust, you must conduct an initial performance test using Test Method 320 or 323 of 40 CFR part 63, appendix A, or ASTM D6348-03 to demonstrate that the concentration of formaldehyde in the stationary RICE exhaust is less than or equal to the emission limit, corrected to 15 percent oxygen, dry basis, that applies to you. 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 measure moisture using Method 4 of 40 CFR part 60, appendix A; or 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 own or operate a 2SLB or 4SLB stationary RICE or a CI stationary RICE complying with the emission limitation to limit the concentration of formaldehyde in the stationary RICE exhaust and you are using an oxidation catalyst or if

 Attachment 2 Attachment 2

you own or operate a 4SRB stationary RICE complying with the emission limitation to limit the concentration of formaldehyde in the stationary RICE exhaust and you are using NSCR, you must also install a CPMS to continuously monitor the catalyst inlet temperature. During the initial performance test, you must record the initial pressure drop across the catalyst and the catalyst inlet temperature.

If you choose to comply with the emission limitation to limit the concentration of formaldehyde in the stationary RICE exhaust and you are not an using oxidation catalyst or NSCR, you must also petition the Administrator for approval of operating limitations or approval of no operating limitations. If the Administrator approves your petition for operating limitations, the operating limitations must also be established during the initial performance test.

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 the parameters and HAP emissions, identifying how HAP emissions change with changes in the parameters, and how limitations on the parameters will serve to limit HAP emissions; (3) a discussion of how you will establish the upper and/or lower

values for the parameters which will establish the limits on the parameters in the operating limitations; (4) a discussion identifying the methods you will use to measure and the instruments you will use to monitor the parameters, as well as the relative accuracy and precision of the methods and instruments; and (5) a discussion identifying the frequency and methods for recalibrating the instruments you will use for monitoring the 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 RICE and any emission control device which could change intentionally (e.g., operator adjustment, automatic controller adjustment, etc.) or unintentionally (e.g., wear and tear, error, etc.) on a routine basis or over time; (2) a discussion of the relationship, if any, between changes in the parameters and changes in HAP emissions; (3) for those parameters with a relationship to HAP emissions, a discussion of whether establishing limitations on the 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 the parameters which would establish limits on these parameters in operating

 Attachment 2 Attachment 2

limitations; (5) for the parameters with a relationship to HAP emissions, a discussion identifying the methods you could use to measure the parameters and the instruments you could use to monitor them, as well as the relative accuracy and precision of the methods and instruments; (6) for the parameters, a discussion identifying the frequency and methods for recalibrating the instruments you could use to monitor them; and (7) a discussion of why, from your point of view, it is infeasible or unreasonable to adopt the parameters as operating limitations.

F. <u>What are the continuous compliance provisions?</u>

Several general continuous compliance requirements apply to all stationary RICE meeting various specified emission and operating limitations. If your stationary RICE is required to meet specific emission and operating limitations, then you are required to comply with the emission and operating limitations at all times, except during startup, shutdown, and malfunction of your stationary RICE. You must also operate and maintain your stationary RICE, 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 all monitoring at all times that the stationary RICE is operating, except during periods of

 Attachment 2 Attachment 2

malfunction of the monitoring equipment or necessary repairs or quality assurance or control activities, such as calibration checks.

For 2SLB and 4SLB stationary RICE and CI stationary RICE complying with the requirement to reduce CO emissions, unless you are using a CEMS, you must conduct semiannual performance tests for CO and oxygen using a portable CO monitor to demonstrate that the required CO percent reduction is achieved. The performance tests must be conducted at high load conditions, defined as 100 percent ±10 percent. If you demonstrate compliance with the percent reduction requirement for two successive performance tests, you may reduce the frequency of performance testing to annually. However, if an annual performance test indicates a deviation from the percent reduction requirement, you must return to semiannual performance tests.

If you are using an oxidation catalyst, you must continuously monitor and record the catalyst inlet temperature to demonstrate continuous compliance with the CO percent reduction requirement. The 4-hour rolling average of the valid data must be within the operating limitation. You must also measure the pressure drop across the catalyst monthly. If you replace your oxidation catalyst, you must reestablish your pressure drop and catalyst inlet

 Attachment 2 Attachment 2

temperature.

If you are not using an oxidation catalyst, you must continuously monitor and record the operating parameters (if any) approved by the Administrator to demonstrate continuous compliance with the CO percent reduction requirement. The 4-hour rolling average of the valid data must be within the operating limitation.

If you elect to demonstrate continuous compliance using a CEMS, you must calibrate and operate your CEMS according to the requirements in 40 CFR 63.8. You must continuously monitor and record the CO concentration at the inlet and outlet of the oxidation catalyst and calculate the percent reduction of CO emissions hourly. The reduction of CO must be at least the required percent reduction, based on a rolling 4-hour average, averaged every hour. You must also conduct an annual relative accuracy test audit (RATA) of your CEMS using PS 3 and 4A of 40 CFR part 60, appendix B, as well as daily and periodic data quality checks in accordance with 40 CFR part 60, appendix F, procedure 1.

For existing, new, or reconstructed 4SRB stationary RICE complying with the requirement to reduce formaldehyde emissions using NSCR, you must demonstrate continuous compliance by continuously monitoring the catalyst inlet temperature. The 4-hour rolling average of the valid data

must be within the operating limitation. You must also measure the pressure drop across the catalyst monthly. If you replace your NSCR, you must reestablish the values of the pressure drop across the catalyst and the catalyst inlet temperature.

For existing, new, or reconstructed 4SRB stationary RICE complying with the requirement to reduce formaldehyde emissions and not using NSCR, you must continuously monitor and record the operating parameters (if any) approved by the Administrator. The 4-hour rolling average of the valid data must be within the operating limitation.

The 4SRB stationary RICE with a site-rating greater than or equal to 5,000 brake HP must also conduct semiannual performance tests to demonstrate that the percent reduction for formaldehyde emissions is achieved. The performance tests must be conducted at high load conditions, defined as 100 percent ±10 percent. If you demonstrate compliance with the percent reduction requirement for two successive performance tests, you may reduce the frequency of performance testing to annually. However, if an annual performance test indicates a deviation from the percent reduction requirement, you must return to semiannual performance tests.

If you are complying with the requirement to limit the

concentration of formaldehyde in the stationary RICE exhaust, the following requirements must be met.

Proper maintenance. At all times, the owner or operator shall maintain the monitoring equipment including, but not limited to, maintaining necessary parts for routine repairs of the monitoring equipment.

Continued operation. Except for, as applicable, monitoring malfunctions, associated repairs, and required quality assurance or control activities (including, as applicable, calibration checks and required zero and span adjustments), the owner or operator shall conduct all monitoring in continuous operation at all times that the unit is operating. Data recorded during monitoring malfunctions, associated repairs, out-of-control periods, and required quality assurance or control activities shall not be used for purposes of calculating data averages. The owner or operator shall use all the data collected during all other periods in assessing compliance. A monitoring malfunction is any sudden, infrequent, not reasonably preventable failure of the monitoring equipment to provide valid data. Monitoring failures that are caused in part by poor maintenance or careless operation are not malfunctions. Any period for which the monitoring system is out of control and data are not available for required calculations

 Attachment 2 Attachment 2

constitutes a deviation from the monitoring requirements.

After completion of the initial performance test, you must demonstrate that formaldehyde emissions remain at or below the formaldehyde concentration limit by performing semiannual performance tests. The performance tests must be conducted at high load conditions, defined as 100 percent ±10 percent. If you demonstrate compliance with the requirement to limit the concentration of formaldehyde in the stationary RICE exhaust for two successive performance tests, you may reduce the frequency of performance testing to annually. However, if an annual performance test indicates a deviation of formaldehyde emissions from the formaldehyde concentration limit, you must return to semiannual performance tests.

If you choose to comply with the emission limitation to limit the concentration of formaldehyde in the stationary RICE exhaust and you are using an oxidation catalyst or NSCR, you must demonstrate continuous compliance by continuously monitoring the catalyst inlet temperature. The 4-hour rolling average of the valid data must be within the operating limitation. You must also measure the pressure drop across the catalyst monthly. If you replace your oxidation catalyst or NSCR, you must reestablish the values of the pressure drop across the catalyst and the catalyst

inlet temperature.

If you choose to comply with the emission limitation to limit the concentration of formaldehyde in the stationary RICE exhaust and you are not using an oxidation catalyst or NSCR, you must demonstrate continuous compliance by continuously monitoring and recording the values of any parameters which have been approved by the Administrator as operating limitations.

G. <u>What are the notification, recordkeeping and reporting requirements?</u>

If you own or operate a stationary RICE with a site-rating of more than 500 brake HP which is located at a major source of HAP emissions, 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 RICE which must comply with the specified emission and operating limitations. In addition, you must submit an initial notification for each existing 4SRB stationary RICE and each new stationary RICE which operates exclusively as an emergency unit, limited use unit, or a stationary RICE which combusts digester gas or landfill gas equivalent to 10 percent or more of the gross heat input on

an annual basis.

You must record all of the data necessary to determine if you are in compliance with the emission limitations and operating limitations (if applicable) as required by the final rule. 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, corrective action, 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.

You must submit a compliance report semiannually. This report should contain information including company name and address, a statement by a responsible official that the report is accurate, and a statement of compliance or documentation of any deviation from the requirements of the final rule during the reporting period.

## III. Summary of Significant Changes Since Proposal

Most of the rationale used to develop the proposed rule remains the same for the final rule. Therefore, the rationale previously provided in the proposed rule is not repeated in the final rule and the Rationale for Selecting the Proposed Standards section of the proposed rule should be referred to. Changes that have been made to the final

 Attachment 2 Attachment 2

rule are discussed in this section with rationale following in the Summary of Responses to Major Comments section.

A. Emission Limitations

In the proposed NESHAP, new 2SLB stationary RICE were required to either reduce CO emissions by 60 percent or more, or limit the concentration of formaldehyde to 17 parts per million by volume dry basis (ppmvd) or less at 15 percent oxygen. Existing and new 4SRB stationary RICE were required to either reduce formaldehyde emissions by 75 percent or more, or limit the concentration of formaldehyde to 350 parts per billion by volume dry basis (ppbvd) or less at 15 percent oxygen. The final rule requires new 2SLB stationary RICE to either reduce CO emissions by 58 percent or more, or limit the concentration of formaldehyde to 12 ppmvd or less at 15 percent oxygen. Existing and new 4SRB stationary RICE must either reduce formaldehyde emissions by 76 percent or more, or limit the concentration of formaldehyde to 350 ppbvd or less at 15 percent oxygen.

In the proposed rule, sources were required to meet one of two emission limitations, depending on the type of control device being used. In the final rule, we have allowed sources the flexibility to meet either emission limitation, regardless of the type of emission control.

B. Operating Limitations

 Attachment 2 Attachment 2

We have made several revisions to the operating limitations that we proposed. The minimum value for the catalyst inlet temperature for new 2SLB, new 4SLB, and new CI stationary RICE complying with the requirement to reduce CO emissions and using an oxidation catalyst has decreased from 500°F to 450°F and the maximum value has increased from 1250°F to 1350°F. For 4SRB stationary RICE, we have removed the requirement to maintain the temperature rise across the catalyst. For stationary RICE complying with the requirement to limit the concentration of formaldehyde, we have removed the proposed requirement to maintain either an operating load or fuel flow rate equal to or greater than 95 percent of the value established during the initial performance test.

C. Testing and Monitoring

In the final rule, we did not include EPA SW-846 Method 0011 or California Air Resources Board (CARB) Method 430 as appropriate methods for measuring formaldehyde. We also specified that performance testing should be conducted at high load, defined as 100 ±10 percent. In the final rule, we have included ASTM D6348-03 as an acceptable method for formaldehyde and moisture.

The proposed rule required new 2SLB, new 4SLB, and new CI stationary RICE with a brake HP greater than or equal to

5,000 complying with the CO emission reduction requirement to install a CEMS to continuously monitor CO, whereas those with a brake HP less than 5,000 demonstrated compliance with continuous parametric monitoring and quarterly CO performance testing. The final rule requires that new 2SLB, new 4SLB, and new CI engines use continuous parametric monitoring and semiannual CO performance testing to demonstrate continuous compliance. Sources may still elect to use a CO CEMS, but it is not required.

In the final rule, we specified that the pressure drop across the catalyst must be measured monthly for sources complying with the requirement to reduce CO emissions and using an oxidation catalyst and for sources complying with the requirement to reduce formaldehyde emissions and using NSCR, instead of continuously monitored as specified in the proposed rule.

D. Other

The proposed rule specified that stationary RICE that combust landfill gas or digester gas as primary fuel did not have to meet the requirements of the rule, except for initial notification requirements. In the final rule, we redefined the subcategory as those engines with annual landfill gas or digester gas consumption of 10 percent or more of the gross heat input on an annual basis. We have

 Attachment 2 Attachment 2

specified that new and reconstructed stationary RICE with annual landfill gas or digester gas consumption of 10 percent or more have to submit an initial notification and must also meet monitoring, recording, and reporting requirements associated with fuel usage. Existing stationary RICE with annual landfill gas or digester gas consumption of 10 percent or more do not have to meet any requirements.

The definition of emergency and limited use stationary RICE has been separated in the final rule. Limited use stationary RICE means any stationary RICE that operates less than 100 hours per year.

The definition of emergency stationary RICE was written to indicate that loss of power that constitutes an emergency can include power supplied to portions of a facility, and that emergency operation is not limited to only times when the primary power source has been interrupted and is not limited to a specific number of hours. Routine testing and maintenance to ensure operational readiness has been included in the definition of emergency operation.

We included a provision in the final rule allowing new or rebuilt engines to operate for up to 200 hours prior to installing the catalyst; this will not be considered a violation.

 Attachment 2 Attachment 2

In the final rule, we specified that an existing area source that increases its emissions or its potential to emit such that it becomes a major source must be in compliance within 3 years after becoming a major source. Potential to emit is defined in §63.6675 of the final stationary RICE NESHAP. The proposed rule stipulated that an existing area source that became a major source must be in compliance immediately after becoming a major source.

## IV. 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: One commenter requested clarification on what is considered an existing RICE unit for purposes of compliance. According to the commenter, using a date as a determination whether an engine is existing is confusing. The commenter stated that an engine takes on its identity when first assembled into an engine or when modified to be a different kind of engine, regardless of where that engine is ultimately installed or whether it is a spare on the shelf awaiting installation. Another commenter asked that EPA clarify that an existing RICE unit is any engine that was

assembled as a final unit before December 19, 2002, regardless of whether it was or has been installed in a stationary location.

One commenter stated that the criteria that makes a RICE unit affected by the proposed rule does not limit the rule's effects to only units that operate. The proposed factors that determine applicability are construction date, site-rating, and specific inherent designs of units. None of these criteria as applied in the proposal include a requirement that the engine be operational. It is not uncommon for an owner or operator to have idle engines. Some may be installed and not in use. Others may be stored for later use as replacements or spare engines. Importantly, idle units are distinct from emergency units because an idle unit is not in any use. The commenter expressed that an idle RICE unit should have no compliance obligations imposed by the final RICE rule.

Response: We disagree with the first set of comments and feel that the date an engine was constructed is the date it was installed at the operator site and not when it was assembled as a final unit at the manufacturer. Thus, any engine constructed (i.e., installed at the site of the operator) prior to December 19, 2002, is an existing engine for purposes of the final rule, while any engine constructed

on or after that date is a new engine. For purposes of the final rule, the term "on-site fabrication" in the definition of construction in 40 CFR §63.2 shall refer to the final installation at the site of the final operator. This definition of construction is in line with how EPA generally defines construction, i.e., it is defined by when the unit is installed at the operator's location, rather than where it is first assembled.

We feel it is appropriate to define "on-site fabrication" as the final site of installation because even after a unit has been manufactured, several components necessary in order to be able to operate the unit must be considered and added. The owner or operator cannot go directly from purchasing the unit from the manufacturer to operation. The owner or operator must typically have a building to house the unit in, construct a pad for the unit, run utilities, install fuel supply tanks or run the natural gas line, have the catalyst vendor install the pollution control equipment, and finally test the unit on-site. For larger engines (e.g., 5,000 HP or greater), the installation process is even more pronounced. For these reasons, we find it appropriate that the date that final installation of the unit at the site of operation is commenced should be considered the construction date.

 Attachment 2 Attachment 2

Engines manufactured prior to December 19, 2002, but where installation was not commenced until after that date, are considered new engines and must comply with the requirements for new engines. We expect that these units will be able to comply with the requirements especially since the control equipment is typically installed on the engine at the site of operation and does not come with the engine purchased from the manufacturer. Finally, no problems are expected to occur with retrofit controls because the control technology is relatively easy to retrofit, especially in units that are being installed initially at a site. If owners or operators anticipate problems, they can elect to purchase a new engine meeting the requirements if it is installed after that date.

With regard to the next comment, we disagree with the commenter's proposition that EPA needs to have a special provision to deal with engines that are installed but not in use. For new engines covered by the final rule, which will be the vast majority of the engines, the final rule does not apply until startup of the engine, which is when the engine begins operation. Therefore, new engines are not covered until they are operational, which already accomplishes the goal of the commenter. For existing engines, we feel that any engine that does not meet the definition of limited use

 Attachment 2 Attachment 2

engine, which includes any engine that operates less than 100 hours per year, should not be relieved of compliance obligations. We have written our definitions to distinguish emergency engines from limited use engines, which should reduce some confusion. An engine that does not operate at all is clearly a limited use engine, which by definition includes engines that operate 0 hours per year.

Comment: Several commenters expressed that EPA should include an alternative applicability criteria based on 1 tpy actual formaldehyde emissions.

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 megagrams per year (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

 Attachment 2 Attachment 2

HAP emissions and is, therefore, based on equivalence, not risk. The information in the docket does not support a decision to provide an alternative applicability cutoff in this case. Our decision to defer regulation of engines 500 HP or less was based on questions regarding how accurately the database reflected such engines. There were no such concerns raised based on whether an engine emitted formaldehyde above 1 tpy.

Comment: Five commenters stated that the applicability limit for 2SLB should be increased to 1100 HP to be consistent with the MACT floor. One commenter stated that the small engine size cutoff should be changed from 500 HP to 650 HP. The commenter said that while EPA appropriately reasoned that small engines should not be subject to the requirements of the rule, EPA provided no explicit rationale for the selection of 500 HP as the appropriate small engine size cutoff. Ranking all engines in EPA's database from smallest to largest, the first engine size that has controls is 650 HP. Thus, the appropriate small engine size cutoff supported by the record is less than 650 HP instead of less than or equal to 500 HP.

Response: First, we need to clarify that engines 500 brake HP or less have not been exempted from regulation. Because we determined at the time of proposal that we did

not have enough information to go forward with regulation of those engines at this time, we have deferred regulatory activity with regard to those engines. Pursuant to a consent decree signed on May 22, 2003, Sierra Club v. Whitman, Case Number 1:01CV01537 (D.C.D.C), a notice of proposed rulemaking regarding regulation of these engines under CAA section 112 is scheduled for October 31, 2006, with a final rule by December 20, 2007. At this time, it would be inappropriate to speculate on what level of control would be promulgated for these engines.

We are aware of stationary engines as small as 650 HP that are equipped with add-on HAP control devices. We feel our database represented the population of engines between 500 HP and 1100 HP reasonably well, so we do not feel it is appropriate to defer regulation of these engines to a later rule. Therefore, we do not feel it is appropriate to defer the regulation of engines up to 1100 HP for 2SLB engines, or to include such engines in a separate subcategory. Although 650 HP is the smallest size unit that is known to have add-on HAP control, we feel it is appropriate to limit the deferral to engines 500 HP or less because the control technology used for 650 HP units can be transferred to units at least as small as 500 HP in size. Oxidation catalyst technology is not limited to engines greater than 650 HP in

size. In fact, information received during the public comment period supports our conclusion, where several engines rated at 400 HP were equipped with oxidation catalyst control. Our deferral of engine regulation was based on the type of engines used below 500 HP and whether our database was adequate for such engines. We feel our database for engines above 500 HP was adequate and that, in any case, the final rule for these engines is adequately justified in the record. The commenter does not adequately provide particular reasons to justify placing engines between 500 and 650 HP in a different subcategory from larger engines, and we do not feel such subcategorization has been shown to be appropriate.

Comment: One commenter asserted that the rule should be more explicit as to whether the 500 HP capacity level for exception from the rule and 5,000 HP capacity level for enhanced monitoring applies to an individual engine or applies to the aggregate capacity of a group of engines.

Response: We intended for the 500 HP capacity level to apply to an individual engine, not the aggregate capacity of a group of engines. Similarly, the 5,000 HP capacity level for enhanced monitoring was intended to apply to an individual engine. However, we have not included a CO CEMS requirement in the final rule. Sources are free to use CO

 Attachment 2 Attachment 2

CEMS to demonstrate compliance; however, CO CEMS are not required.

Comment: One commenter contended that the MACT should consider exempting any RICE using landfill gas. A diesel engine can operate at a landfill in a dual fuel mode using fuel oil and landfill gas. Tests have shown that a catalytic converter cannot be used because of siloxanes in the landfill gas, even if the engine operates with more than half the energy being supplied by the liquid fuel.

Response: In the proposed rule, we established a subcategory for landfill or digester gas fired units and defined the subcategory as those stationary RICE that combust digester gas or landfill gas as the primary fuel. In the proposed rule, these units did not have to meet any emission limitation requirements but were subject to the initial notification requirements. We agree with the commenters supporting the proposed approach to landfill and digester gas fired engines. We agree that neither control technology, fuel switching, or other practices would be an appropriate or workable strategy for reducing HAP from these engines. We agree with the commenter that problems will occur when using landfill gas because of siloxanes in the fuel, even if the engine operates with more than half the energy being supplied by the liquid fuel. Therefore, we

 Attachment 2 Attachment 2

contacted sanitation districts and catalyst vendors for information. Based on the information obtained, we feel that firing greater than 10 percent landfill gas or digester gas will cause fouling of the oxidation catalyst, rendering the control device inoperable within a short period of time. All the sources we contacted indicated that there would be problems associated with catalyst deactivation due to siloxanes present in landfill gas and digester gas. Information regarding landfill and digester gas is presented in a memorandum included in the rule docket (Docket ID Nos. OAR-2002-0059 and A-95-35). While most units will operate using landfill or digester gas consumption above 50 percent of the time, there are times when such units may need to operate significantly below 50 percent landfill or digester gas consumption. We feel a cut-off level of 10 percent of gross heat input is an appropriate level for defining these units, because operation below that percentage raises significant questions regarding whether the unit is still appropriately considered to be operating as a landfill or digester gas burning unit, and would raise concerns regarding circumvention of the requirements for other new units. In the final rule, we have redefined the subcategory as those engines with annual landfill gas or digester gas consumption of 10 percent or more of the gross heat input on

 Attachment 2 Attachment 2

an annual basis. New and reconstructed engines in this subcategory must only comply with limited requirements of the final rule. Engines with an annual landfill gas or digester gas consumption of less than 10 percent of the gross heat input on an annual basis are subject to applicable emission limitations of the final rule in addition to other requirements.

Comment: Multiple commenters stated that a limited use category with a capacity utilization of 10 percent or less (876 or fewer hours of annual operation) should be included. One commenter suggested using a flat annual threshold level of 1,000 hours per year in lieu of 10 percent usage. Another commenter recommended that the category include all units, not only peak shaving units. Several commenters argued that the 50 hours per year may not be sufficient. Some commenters noted that testing and maintenance should be included and not counted towards the 50 hours per year. Two commenters recommended at least 250 hours per year. One commenter recommended a 52 hour limit for routine maintenance and testing, then have no limit for true emergency use. Similarly, other commenters expressed that since routine or unscheduled maintenance and testing could require unknown time to complete, there should be no time limits on the use of emergency stationary RICE. Several

 Attachment 2 Attachment 2

commenters suggested 100 hours per year for emergency generators. One commenter stated that the subcategory should be redefined to include RICE that operate less than 500 hours per year. Two commenters remarked that setting this exemption at 50 hours per year down from the 100 or 200 hours per year commonly seen in many State air pollution regulations, could have the net effect of increasing pollution by not allowing sufficient operating time for the engine to burn off hard deposits. Several commenters stated that the limited use definition for RICE should be separated from the emergency power definition since these are really different applications. Two commenters stated that the operation of emergency power units should not be limited to only those times when the primary power source has been interrupted, but rather not time-restricted at all, providing the primary design purpose of the unit is to provide emergency backup services, fire water, etc. One commenter asked that EPA clarify the definition of emergency/limited use engines as to whether loss power that constitutes an emergency is limited to power supplied to the facility as a whole or includes power supplied to portions of the facility. One commenter suggested that EPA revise the definition of emergency power RICE to clarify the intent of the rule as the current definition does not adequately

 Attachment 2 Attachment 2

encompass the wide array of emergency uses of engines. One commenter felt that the description of an emergency engine is too restrictive. The emergency use description should describe more power loss emergencies than those affecting an entire facility at once. The definition should also include uses for additional emergency types beyond power loss emergencies, e.g., fuel and raw material curtailments or fuel shortage emergencies applied by governments, utilities, or other suppliers may require the need to temporarily operate an engine, or some equipment may be operated to fight fires (firewater pumps). Neither of these examples represent loss of power, but are still unplanned events. One commenter stated that the definition should be clarified, or extended, to allow for operations in anticipation of an emergency situation. One commenter remarked that this class of RICE (engines having a capacity utilization of less than 10 percent) would operate mostly in the summer months when the public is more likely to be impacted by the emissions. Acetaldehyde, acrolein, and formaldehyde all have documented short-term acute health effects. The EPA has failed to identify short-term health effects throughout any of the risk analysis proposals. The commenter asserted that any subcategorization of these engines without controls is not protective of public health.

 Attachment 2 Attachment 2

One commenter suggested eliminating from the definition the reference to "when the primary power source has been rendered inoperable." There are emergency conditions where the primary power source is still operable, but the emergency condition necessitates the startup of engines (e.g., firewater pumps during a unit fire, instrument air back-up engines). Another option would be to add the words "or is insufficient for an emergency situation" after the primary power source comment.

Response: The preamble to the proposed rule proposed a subcategory for limited use stationary RICE and defined them as operating 50 hours or less per year. Comments received indicated that the proposed 50 hours per year for limited use units was not sufficient and that many limited use engines would exceed the 50 hours per year just by routine testing and maintenance of the engine for readiness purposes. For this reason, we feel that few owners and operators would find this allowance useful and would not serve a purpose except to cover periods of testing and maintenance. We have, therefore, found it appropriate to increase the number of hours for limited use operation. We have specified in the final rule that limited use stationary RICE are stationary RICE that operate less than 100 hours per year. For limited use units, operation during routine

 Attachment 2 Attachment 2

testing and maintenance is counted towards the 100 hours per year.

In the preamble to the proposed rule, we solicited comments on creating a subcategory of limited use engines with capacity utilization of 10 percent or less (876 or fewer hours of annual operation). These units would have included engines used for electric power peak shaving. As a result of soliciting comments, we received several comments regarding the possibility of establishing a limited use subcategory with capacity utilization of 10 percent or less; some for and some against. We considered all comments received and have decided not to include a subcategory of limited use stationary RICE with a capacity utilization of 10 percent or less in the final rule. Limited use units operating 876 hours per year are similar to other sources 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. Those commenters supporting a longer time period for the limited use engines did not provide persuasive arguments for such a subcategory. The commenters have not provided significant data indicating that engines operating up to 10 percent of the time (or longer, as some commenters suggested) are unable to take steps similar to other RICE to

reduce HAP. On the contrary, as stated previously, such engines are similar to other stationary RICE that can be and have been equipped with add-on oxidation catalyst control, and their operation only during peak periods does not preclude them from being equipped with workable add-on control or from using other methods of emission control to reduce HAP. The 10 percent time limit would allow over a month of usage per year, which we feel is substantial enough both to be of concern environmentally and to take advantage of emission control strategies. Significant operation of these engines is expected and should be accounted for in the final rule.

By contrast, a limited use exemption covering only 100 hours per year of use is justified because usage in these cases in clearly exceptional and these engines would have the technical and usage concerns similar to emergency engines discussed in the proposed rule. These engines are categorically different from other engines in that they are only used in truly exceptional situations. For these reason, we have not established a limited use subcategory of units operating 876 hours per year in the final rule, but have included a limited use subcategory allowing engines to operate up to 100 hours per year.

We agree with the comment that the emergency and

limited use stationary RICE definition should be separated. We have established separate definitions for emergency stationary RICE and limited use stationary RICE in the final rule.

In addition, in the final rule, the definition of emergency engine was written to indicate that loss of power that constitutes an emergency can include power supplied to portions of a facility. We intended that the definition of emergency engine include operation during emergency situations, including times when the primary power source has been interrupted as well as other situations such as pumping water in the case of fire or flood, which was given as an example of emergency operation in the definition in the proposed rule. The definition has been clarified to clearly indicate that emergency operation is not limited to only times when the primary power source has been interrupted. We contacted the commenter for more information about the types of curtailments with which they were concerned. The commenter provided only one example, which was shutdown of offshore wells during a hurricane. We feel that the definition of emergency stationary combustion engine is sufficient to cover this particular scenario and it is not necessary to include more examples of emergency operation. It would be nearly impossible to provide

examples of every potential type of emergency situation. The operation of emergency engines is not limited to a specific number of hours. Also, routine testing and maintenance to ensure operational readiness have been included in the definition of emergency engine. However, the routine testing and maintenance must be within limits recommended by the engine manufacturer or other entity such as an insurance company. Emergency stationary RICE may also operate an additional 50 hours per year in non-emergency situations. As stated previously, routine testing and maintenance have been included in the definition of emergency stationary RICE and, therefore, are not counted towards the 50 hours per year. We do not agree that operation in anticipation of an emergency situation should be included in the definition of emergency engine and have not made this change.

Comment: One commenter requested a subcategory for new and reconstructed stationary CI RICE located in the State of Alaska that exempts the engines from the control requirements of this proposed rule. The commenter stated that EPA has overlooked the fact that low sulfur fuels (less than 500 ppm (0.05 weight percent)) are necessary for CO oxidation catalysts to operate properly and that these fuels are not available in several areas of the United States

including the State of Alaska. Sulfur can quickly degrade oxidation catalyst performance for controlling CO (or formaldehyde) emissions by poisoning the precious metal substrate of the catalyst. In one study it was found that increasing the diesel sulfur content from 3 ppm to 350 ppm by weight resulted in a three-fold increase in catalyst-out PM emissions. In the same study, the performance of the diesel oxidation catalyst for controlling CO emissions from the higher sulfur fuel degraded by an average of 10 percent after the short-term (250-hour) aging tests. In Alaska meeting the proposed MACT floor (oxidation catalyst) for new CI RICE sources will be problematic because of the non-availability of low sulfur diesel fuels (300 to 500 ppm sulfur content by weight). The permitted diesel fuel sulfur content, by weight, for most permitted stationary CI sources is between 0.1 percent and 0.5 percent (1,000 ppm to 5,000 ppm by weight). The Trans Alaska Pipeline System facilities operated by the commenter have permitted sulfur fuel content limits between 0.24 percent to 0.5 percent. The lowest fuel sulfur diesel that is available in the State of Alaska is an arctic grade fuel that has a sulfur content of approximately 0.1 percent. Petroleum refineries in the State are not required to produce lower sulfur fuels because Alaska is exempted (see 40 CFR part 69 of 69 FR 34126) from EPA's low

sulfur highway diesel fuel standards.

Response: We feel it is unnecessary to establish a subcategory for new and reconstructed CI RICE located in the State of Alaska. Information received from the Alaska Department of Environmental Conservation (DEC) indicated that there is a refinery in Alaska that can produce low sulfur fuel (300 to 500 ppm sulfur content by weight). The refinery can make low sulfur diesel that meets arctic pour point specifications. The information from the Alaska DEC also indicated that low sulfur fuel is generally available where there are roads in Anchorage, but not generally available on other parts of the road system, such as Fairbanks. Some remote villages do have low sulfur fuel. We expect availability to grow further as EPA's final rule implementing new sulfur limits for highway fuel, including fuel in Alaska (68 FR 5002, January 18, 2001), is implemented beginning in 2006. The Alaska DEC said that Alaska has 200 small villages that are remote, and it may be difficult for these small villages to always have low sulfur fuel available. These villages tend to employ RICE to generate electricity and have between two to four stationary RICE in their power plants. These engines range from 6 to 4000 kilowatt (kW), with an average of 300 kW. The Alaska DEC said that these engines are below the threshold for

major sources, and that is also confirmed by HAP emission calculations. Since these villages would not be major HAP sites they would not be affected by the final rule. The non-availability of low sulfur fuel at these remote villages would therefore not be an issue since these villages would not be subject to the rule since they are located at non major HAP sites. Finally, we have received information from catalyst vendors indicating that there are sulfur tolerant catalysts that have been commercialized and are suitable for use with fuels having a sulfur content between 3,000 and 5,000 ppm sulfur by weight. Sources that may not be able to obtain low sulfur fuel could use such catalysts to comply with the requirements of the final rule. For these reasons, we do not feel it is necessary to establish a separate subcategory for stationary RICE located in Alaska.

B. Definitions

Comment: Several commenters stated that EPA should revise the definition of rich burn engine to eliminate engines that have been converted to operate as lean burn engines and to address older engines (e.g., horizontal), where there is no recommended air/fuel ratio. One commenter recommended that EPA adopt the following definition into the final rule: "Rich burn engine means four-stroke spark ignited engine where the manufacturer's recommended air/fuel

 Attachment 2 Attachment 2

ratio divided by the stoichiometric air/fuel ratio at full conditions is #1.1. Engines originally manufactured as rich burn engines, but modified prior to [INSERT DATE 60 DAYS AFTER PUBLICATION OF THIS FINAL RULE IN THE FEDERAL REGISTER] with passive emission control technology for nitrogen oxides ($NO_X$) (such as pre-combustion chambers) shall be considered lean burn engines. Horizontal engines shall be considered lean burn engines. Also, older engines where there are no manufacturer's recommendations regarding air/fuel ratio will be considered a rich burn engine if the excess oxygen content of the exhaust at full load conditions is #2 percent."

Response: We agree with the commenter that it is necessary to address engines that have been converted from 4SRB engines to 4SLB engines and to also address older engines such as horizontal engines. We have, therefore, adjusted the definition of rich burn engine and have written the rich burn definition in the final rule as follows: "Rich burn engine means any four-stroke spark ignited engine where the manufacturer's recommended operating air/fuel ratio divided by the stoichiometric air/fuel ratio at full load conditions is less than or equal to 1.1. Engines originally manufactured as rich burn engines, but modified prior to December 19, 2002 with passive emission control

technology for $NO_x$ (such as pre-combustion chambers) will be considered lean burn engines. Also, existing engines where there are no manufacturer's recommendations regarding air/fuel ratio will be considered a rich burn engine if the excess oxygen content of the exhaust at full load conditions is less than or equal to 2 percent." In addition, to avoid conflict with the definition of lean burn engine, the lean burn engine definition has also been adjusted and reads as follows in the final rule: "Lean burn engine means any two-stroke or four-stroke spark ignited engine that does not meet the definition of a rich burn engine."

Comment: One commenter asserted that the definition of a reconstructed source should be modified to exclude any cost incurred with the installation of a control device required by State and local emission standards. The addition of diesel particulate filters (DPF) could exceed the reconstruction cost threshold (50 percent of fixed capital cost to construct a comparable new source).

Response: Based on the information we have available on costs of DPF systems and costs of engines, we feel that the addition of DPF would not exceed the reconstruction threshold of 50 percent of the capital cost of a new engine. Information received from CARB indicates that the total cost of a DPF including equipment and installation is around

 Attachment 2 Attachment 2

$38/HP. Engine costs estimated by CARB are $93/HP for a new engine. Comparing the cost of a DPF system to the cost of a new engine shows that the addition of such a filter system would be less than 50 percent. Engine cost information available to us obtained from other sources indicate that engine costs are between $150-$270/HP. Using these engine costs, the addition of a DPF system would be an even lower percentage of the cost of a new engine. Engine costs are presented in a memorandum included in the rule docket (Docket ID Nos. OAR-2002-0059 and A-95-35). We have, therefore, concluded that based on both information received from CARB and information we already have, the addition of a DPF would be less than 50 percent of the cost of a new engine.

In any case, our policy regarding the inclusion of air pollution control equipment in determining reconstruction is that the costs associated with the purchase and installation of air pollution control equipment are included in the fixed capital cost to the extent that the equipment is required as part of the manufacturing or operating process. Therefore, it is our policy not to include the fixed capital cost of air pollution control equipment that is not part of the operating process. Since DPF is not required in order to operate an engine, the cost for purchase and installation of

 Attachment 2 Attachment 2

DPF would not be included in determining whether a source is reconstructed. The commenter does not explain why we should deviate from the General Provisions based on compliance with State or local regulations. A source that is spending more than 50 percent of the capital cost needed for a new engine to meet the requirements should be in a position to make appropriate changes in its source at that time to meet the standards promulgated today. Moreover, the source may be able to comply with both requirements at the same time and may be able to meet the requirements using integrated controls (if not the same controls) that would be best implemented at the same time.

Comment: Several commenters requested that EPA write the definitions of affected source, existing stationary RICE, new stationary RICE, and reconstructed stationary RICE such that they represent the "collection" of each type of source at a site, consistent with General Provisions §63.2.

Response: Although §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

 Attachment 2 Attachment 2

significant administrative, practical, or implementation problems" and "the different definition would resolve those problems." This is such an instance. There are several subcategories of stationary RICE, and a site could have engines from multiple subcategories, each having different compliance requirements. Use of the broader definition of affected source specified by the General Provisions would require very complex aggregate compliance determinations. We feel such complicated compliance determinations to be impractical, and, therefore, have decided to adopt a definition which establishes each individual RICE as the affected source.

Comment: One commenter recommended that the preamble should clarify that the definition of major source in the RICE MACT does not alter the definition of a major source in subpart HH of 40 CFR part 63 (Oil and Natural Gas Production Facilities) and, therefore, does not affect subpart HH applicability.

Response: We recognize the commenter’s concern regarding the definition of major source in the RICE NESHAP and its difference from the definition of major source in 40 CFR subpart HH. We have, therefore, clarified in the preamble to the final rule that the definition of major source in the RICE NESHAP does not alter the definition of

major source in subpart HH (or any other subpart) and, therefore, does not affect subpart HH applicability.

Comment: One commenter recommended that the definitions from 40 CFR subpart HH and 40 CFR subpart HHH for glycol dehydration unit, storage vessel with the potential for flash emissions, and production well should be included.

Response: We agree with the commenter that the definitions should be included in the RICE NESHAP. The definitions from 40 CFR subpart HH and 40 CFR subpart HHH for glycol dehydration unit, storage vessel with the potential for flash emissions, and production well have been added to the final rule.

C. Dates

Comment: A few commenters remarked that EPA should provide 1 year for initial notification as in the glycol dehydration MACT.

Response: An initial notification is not a time consuming activity, and we do not feel that 1 year is necessary to submit an initial notification.

Comment: Multiple commenters expressed the view that immediate compliance for new and reconstructed engines is unreasonable. The commenters felt that 1 year compliance time frame is more reasonable.

 Attachment 2 Attachment 2

Response: We feel that immediate compliance is appropriate for new or reconstructed engines and is consistent with the General Provisions of part 63. See also CAA section 112(i)(1). The requirements of CAA section 112 contemplate that sources will be aware of their requirements at the time of proposal and, excluding requirements that are made more stringent between proposal and promulgation, new or reconstructed sources should be prepared to meet such requirements immediately, at the time of the final rule. 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. In addition, because two of our emission requirements have been made more stringent since proposal, sources subject to those requirements that commence operation in between proposal and the final rule may show compliance with the proposed requirements for the first 3 years of the program.

Comment: Several commenters stated that for area sources becoming major sources, the requirement to be in compliance at the time of the switch is unreasonable. Two commenters suggested allowing 1 year for the unit to come into compliance. One commenter suggested that all area sources that become major should be allowed 3 years to

achieve compliance or change the definition of a new stationary RICE to "A stationary RICE is new if you commenced construction of the stationary RICE after December 19, 2002, and you meet the applicability criteria for the subpart at the time you commenced construction." Five commenters suggested 3 years.

Response: We agree with the commenters that it is appropriate to allow existing area sources that become major sources 3 years to comply with the final rule. This has been specified in the final rule in §63.6595(b)(2). However, we do not agree with the commenters that immediate compliance is unreasonable for new and reconstructed RICE located at area sources that are constructed or reconstructed at the same time the area source becomes a major source. These sources are aware in advance of their change in status from area source to major source, and therefore, should have sufficient time to plan for immediate compliance with the final rule. This has been specified in the final rule in §63.6595(b)(1). A period of 180 days is allowed to demonstrate compliance.

Comment: Some commenters requested that EPA provide 1 year to conduct the initial performance test, rather than 180 days provided by the General Provisions. One commenter indicated that seasonal operations, such as storage

 Attachment 2 Attachment 2

facilities or compressor stations used in peak demand only, may not be operational during the 180 days provided to conduct the performance test. All existing 4SRB engines must conduct formaldehyde testing as a part of the initial performance test. It may be difficult to secure appropriate testing firms within the 180 days provided, especially since many may depend on Fourier Transform Infrared (FTIR) testing.

Response: We feel the time we have allowed sources to conduct the initial performance test is appropriate. Existing sources that must meet the requirements of the final rule have 3 years and 180 days to conduct the initial performance test and to demonstrate compliance. Therefore, existing 4SRB engines that must meet the formaldehyde emission limitations have sufficient of time to secure an appropriate testing firm. In addition, the final rule does not only specify that FTIR can be used for formaldehyde testing, but that also Method 323 can be used. This means it may not be necessary to secure testing firms specializing in FTIR measurements, and should increase the number of available testing firms. New sources that must meet the requirements of the final rule are aware in advance that their source will be covered by the final rule. We feel that 180 days is sufficient time to secure appropriate

testing firms and to conduct the initial performance test and feel that 1 year to conduct the initial performance test is not necessary. Regarding the comment concerning seasonal operations, new sources do not have to test until the unit is operating, so seasonal operation should not be a concern for new units. Also, for existing sources, we feel that seasonal operation should not be a problem since the unit has 3 years and 180 days to conduct the initial performance test, and surely the unit would be operational within that timeframe. Finally, the 180 day time period for new sources is consistent with the General Provisions of part 63.

D. Emission Limitations

Comment: One commenter asserted that the emission limitations are too stringent. The commenter stated that the proposed emission standards were based on information from only five engines and does not believe that the proposed percent reductions and emission standards reflect the actual performance possible from the wide array of engine designs and sizes in the marketplace. For example, the formaldehyde reduction standard for rich burn engines in the proposed rule is set at 75 percent. However, the data in the docket show that results from eight test runs on two rich burn engines varied from 73 to 80 percent. If the reduction efficiency on two test engines under highly-

controlled conditions can vary by such a significant amount (and to a level that does not meet the proposed standard), then it is highly likely that rich burn engines of different size and using different NSCR technology also would not be able to meet the standard. The EPA must consider the significant variability in RICE and adjust all final emissions standards and reduction percentages accordingly. The commenter recommended that the formaldehyde emission limits be revised upward by 10 percent to allow for variability in the RICE and aftertreatment system populations.

Three commenters asserted that the MACT floor for existing 4SRB is not representative of the average emission limit achieved by the best performing 12 percent of existing sources.

One commenter stated that the emission standard for existing 4SRB engines should be reassessed to be consistent with the requirements of CAA section 112(d). The commenter remarked that the Agency used the incorrect approach to set the emission limit for existing 4SRB engines, which logically should be lower percent removal than for new 4SRB engines. It was the commenter’s opinion that the Agency should revisit the analysis and establish an emission limit for 4SRB engines more consistent with the required floor-

setting methodology.

Five commenters expressed that the same emission limitation for existing and new 4SRB is unrealistic. One commenter recommended considering 10 percent less restrictive emission reduction requirement for existing units. Another commenter indicated that practically speaking, retrofitting existing equipment rarely achieves the optimum design available in new equipment.

One commenter contended that 350 ppbvd is too low. The chosen limit was achieved by the best performing engine during Colorado State University (CSU) testing while for other types of engines the highest emissions from the performance range had been chosen as the emissions limit.

Response: We disagree with comments that the MACT floor level proposed for existing 4SRB engines is inconsistent with the statute or not representative of the average emission level achieved by the best performing 12 percent of existing sources. The commenters do not dispute the accuracy of the data used or the representativeness of the engines tested. The commenters instead believe the manner in which we used the data is not reflective of the average of the best performing 12 percent of existing sources. To clarify our approach in the proposal, we found the lowest percent reduction value for each of the two

sources tested, which accounts for variability in results for each source. However, as we found that 27 percent of the engines in the subcategory use NSCR, we felt that it was appropriate to use only the higher of the two values to determine the MACT floor for existing engines. In essence, this treated the top performer as a surrogate for the top half of the population using NSCR or the top 13.5 percent of the population. This is more closely analogous to the level of the top 12 percent of sources than is a straight average of the two sources.

However, in reviewing our method in response to these comments, we feel that it would be more appropriate to include in the analysis the data from the lower performing of the two engines tested, thus using more than a single data point in determining the MACT floor for existing engines. Because the test calculation for the MACT floor for existing engines is supposed to be based on the average of the top performing 12 percent of sources, it would be better to rely on a formula that does not rely solely on the highest performer. Also, it would not be appropriate to use a straight average between the two sources, because that would not be a fair approximation of the average of the top 12 percent of sources. Instead, it would approximate the average of the best performing 27 percent of sources.

 Attachment 2 Attachment 2

Therefore, we feel a reasonable approach is to discount the lower performing source by 12/27, thus reducing the influence of that data point by the ratio of controlled sources (27 percent of the population) compared to the statutory level (12 percent). This leads to a weighted average where the data point for the lower performer will be worth 22 percent (50 percent) (12/27) and the level for the higher performer will be worth 78 percent.

To be consistent with the approach followed for other engine types, i.e., establish emission limitations based on test results conducted at high loads, we found it appropriate to exclude runs conducted at low loads in determining the lower and higher performer. This leads to a final MACT floor of 76 percent control efficiency or 350 ppbvd.[1] Though the formaldehyde reduction number differs slightly from the proposed level, it is very close. The proposed level for the alternative formaldehyde concentration emission limitation remains the same even

---

[1] The calculation of percentage reduction is as follows: (lowest tested percentage reduction of the lower performing engine) * (.222) + (lowest tested percentage reduction of the higher performing engine) * (.778) = (75.5)(.222) + (76.2)(.778) = 76.0. The calculation of parts per billion is as follows: (highest tested parts per billion of the lower performing engine) * (.222) + (highest tested parts per billion of the higher performing engine) * (.778) = (355)(.222) + (348)(.778) = 350.

 Attachment 2 Attachment 2

after following the revised approach. This should not be particularly surprising. Though the emission values of the two engines were not identical, they were very close and the final values for either engines generally round to the same value.

For new 4SRB engines, we proposed a formaldehyde reduction requirement of 75 percent and an alternative formaldehyde concentration emission limitation of 350 ppbvd. In reviewing the 4SRB emissions data we used to set the standard, we observed that the minimum percent efficiency achieved by the best performing engine was actually 76.2 percent formaldehyde reduction. Therefore, we acknowledge that the proposed formaldehyde reduction should have been set at 76 percent reduction for new 4SRB engines and not 75 percent formaldehyde reduction and have written this in the final rule.

The commenters also seem to argue that the MACT floor levels for existing engines must be less stringent than those for new engines. While the criteria for the MACT floor for new engines is in some cases more stringent than for existing engines, it is not impossible, or even illogical, for the result to be the same, or at least very close. In this case, the best performing 12 percent of engines use the same control technology, and the emission

 Attachment 2 Attachment 2

values, as well as the emission reduction values, appear to be very close for these engines. Therefore, it is not surprising that the levels for the MACT floor for new and existing engines should be close. Moreover, we were using a very small data set in setting the final emission limits, thus limiting the variation in the data used. This led to a proposed level that used the same calculations for determining the MACT floor for both existing and new engines. We have changed the manner of calculating the MACT floor for existing engines for the final rule, but the result is still very close to that for new engines. Again, this is because the results for both engines were very close.

Regarding the comment referring to the use of the average of the best five performing sources, this is only permitted when the category or subcategory has less than 30 sources. This is not the case with this subcategory. Given that we had usable data from only two sources, it is not clear that averaging the two sources would be appropriate to meet that requirement.

Regarding the comment that retrofitting existing equipment rarely achieved the optimum design available in new equipment, the commenters provide no data showing that emissions reductions from retrofitting existing engines

 Attachment 2 Attachment 2

would be reduced compared to those from new engines. Regardless, the MACT floor for new engines is not based on the optimum possible design for a new engine, but on the best level of control achieved in practice by the best controlled similar source, whether retrofitted or not. Similarly, the MACT floor for existing engines is based on a specific formula. We based the MACT floor for new engines on the information available to us from existing engines. While individual existing sources may have some design constraints in installing the emission control technology, there is no evidence that the MACT floor is not achievable. The suggestion that is provided, a 10 percent discount for existing units, without a basis in the existing data, does not appear consistent with the requirements of CAA section 112(d).

Comment: One commenter indicated that there is considerable doubt about the ability of an oxidation catalyst to reduce the formaldehyde concentration over long periods of time. A technical paper presented at the 2002 Gas Machinery Conference found that the catalyst efficiency for the Waukesha GL engine for formaldehyde reduces from 100 percent to 67 percent in only 150 hours of operation.

Response: We accounted for catalyst aging in setting the standard. In fact, the oxidation catalysts used during

 Attachment 2 Attachment 2

EPA's testing at CSU were sufficiently aged prior to testing. The 2SLB engine catalyst was aged for 236 hours, the 4SLB engine catalyst was aged for 140 hours, and the CI engine catalyst was aged for 100 hours. Industry representatives were in agreement that the catalysts were adequately aged. The industry testing we used in setting the standard for 4SRB engines was based on testing of two 4SRB engines equipped with NSCR. The NSCR catalysts used were appropriately aged by more than 2 years prior to testing. Information regarding catalyst aging at CSU is presented in a memorandum included in the rule docket (OAR-2002-0059 and A-95-35).

Comment: One commenter said that the 14 ppmvd formaldehyde limit for new 4SLB engines is not achievable and should be increased. The commenter stated that EPA based its proposed limit on a small number of tests on a newly rebuilt engine over a test period of 8.8 hours. Only a single 4SLB was tested, and it may not be representative of engines of the same type from different manufacturers. The period of catalyst aging was very short compared to typical catalyst maintenance intervals, so results may not be representative of catalyst performance during normal catalyst maintenance intervals; and the tests were performed within only a single catalyst that may not be representative

of catalysts from different manufacturers. Clearly, all 4SLB stationary RICE cannot meet the emissions limits set by EPA in the proposed rule, particularly over normal catalyst life intervals of 2 to 3 years. The EPA should incorporate other available test data in the final emission limits for 4SLB engines to accommodate the degradation in catalyst performance over the useful lifetime of the catalyst.

Response: The MACT floor for new sources cannot be less stringent that the emission control that is achieved in practice by the best controlled similar source. The alternative formaldehyde standard for 4SLB engines is based on the minimum level of control achieved by the best controlled source. This approach takes into account variability of the best performing engine. Furthermore, EPA and industry representatives were in agreement that the engines and catalysts tested at CSU were representative of engine and catalyst operation across the U.S. We discussed catalyst aging during the EPA testing at CSU in response to the previous comment. We feel the catalyst was sufficiently aged prior to testing at CSU. Industry representatives also agreed that the catalyst was adequately aged. For the reasons provided, we feel that the 14 ppmvd formaldehyde limit that was proposed for 4SLB is appropriate and achievable. We recognize that the alternative formaldehyde

 Attachment 2 Attachment 2

emission limitation is based on a limited amount of data. However, we feel that sources with a well designed oxidation catalyst that operate the equipment properly will be able to meet the formaldehyde concentration.

Comment: Several commenters expressed that 93 percent CO reduction is not achievable. During the public hearing a commenter stated that a specific CO limit is more reasonable. Two commenters suggested reducing the limit to require 60 percent CO reduction. One commenter recommended that the value be set between 70 and 80 percent comparable to 2SLB and CI engines. Another commenter stated that EPA has not demonstrated that the catalyst will perform at this level on a continuous basis considering fuel and lubrication poisoning. Finally, one commenter said that American Petroleum Institute/Gas Research Institute testing indicated a 53 to 63 percent performance. The commenter also said that the percent reduction likely will not be achievable with aged catalysts.

One commenter had several concerns with establishing the CO reduction limit based on the testing conducted at CSU. The concerns stated by the commenter include: only a single engine for each type was tested and it may not be representative of engines of the same type from different manufacturers; the variables consisted only of parameters

affecting HAP formation in the engine and not necessarily those affecting CO reduction across the catalyst; the engines were rebuilt prior to testing to represent new engines and may not represent engine condition between routine maintenance intervals; the period of catalyst aging was very short compared to typical catalyst maintenance intervals, hence results may not be representative of catalyst performance during normal catalyst maintenance intervals; and the tests were performed with only a single catalyst that may not be representative of catalysts from different manufacturers.

One commenter stated catalyst performance degrades over time due to gas species and concentrations, thermal cycling, chemical poisoning and/or physical blocking caused by sulfur, lubricants, silica, etc. that enter the exhaust from the fuel, crankcase and/or combustion air. Catalyst life is the dominant factor in the cost of the control technology, since the cost of replacement catalyst modules is large relative to other operating and maintenance costs. Typically, oxidation catalysts undergo two stages of deactivation: a period of rapid deactivation as the catalyst adjusts to the thermal and gas conditions, typically over a period on the order of 100 hours; followed by a period of slow deactivation that occurs over thousands

 Attachment 2 Attachment 2

or tens of thousands of hours. The duration of the CSU tests was clearly insufficient to address long-term catalyst deactivation, and perhaps not even fully accounting for initial deactivation. For example, CO reduction efficiency during the 140 hours of catalyst aging during the 4SLB engine test at CSU was still declining at the end of that period, suggesting that further deactivation would likely occur over time.

Response: We disagree with the commenter that 93 percent reduction for CO is not achievable for 4SLB engines. The 93 percent CO reduction emission limitation is based on the minimum level of control achieved by the 4SLB engine tested at CSU. We chose the minimum efficiency achieved as this value takes into account variability in performance of the engine and engines operating across the U.S., therefore, we feel we have appropriately set the emission limitation for 4SLB engines.

As rationale for setting the limit at 60 percent, the commenter cited a recent field test of a 4SLB engine where the measured CO reduction efficiency was 53 to 60 percent. However, the commenter did not provide any indication of what reduction efficiency the catalyst was designed for, or whether the catalyst had been properly maintained and cleaned. The commenter also did not identify the operating

 Attachment 2 Attachment 2

conditions under which the test was conducted, for example if the test was conducted during high load operation. Moreover, given the results of the CSU testing, and the standard-setting requirements for new engines under CAA section 112(d), it is not clear that the results in that test would be relevant for standard-setting for new engines.

Regarding the concerns expressed by one commenter, EPA and industry representatives were in agreement that the engines and catalysts tested at CSU were representative of engine and catalyst operation across the U.S. As explained in the preamble to the proposed rule, the testing conducted at CSU to obtain HAP and CO emissions data was a joint EPA-industry effort. Prior to testing, EPA and industry developed a list of engine operating parameters that were known to vary throughout the U.S. for each type of engine. The engines and control devices were tested at typical engine conditions in which these operating parameters were varied. The variations in the emission reduction results for each engine type are due to the variability of the engine and control system and include a representation of the performance of the best controlled source for new engines. Equipment manufacturers, catalyst vendors, owners and operators, and EPA agreed that the tests conducted at CSU were representative of typical engine operating

 Attachment 2 Attachment 2

conditions in the field for varied engine and catalyst manufacturers. It is believed that the variations in the operating parameters affect both HAP formation and CO reduction across the catalyst. For additional information regarding the CSU testing, please refer to the rule docket (Docket ID Nos. OAR-2002-0059 and A-95-35).

We disagree that the catalyst will not perform at this level on a continuous basis or when it is aged. The CSU testing was funded by several different agencies, and several stakeholders participated in the planning, preparation and execution of the tests. All stakeholders agreed that the catalyst was properly aged before testing was initiated on each engine. We discussed catalyst aging during the testing at CSU in response to a previous comment. We feel the catalyst was sufficiently aged prior to testing at CSU. It should be noted, as discussed below, that sources may meet the formaldehyde concentration standard to meet the requirements as well as the 93 percent CO reduction requirement.

In response to the comment regarding long-term catalyst deactivation, we reemphasize that industry representatives that were involved in the testing at CSU agreed that the testing would be representative for catalyst performance, both short-term and long-term. We agree with the commenter

that there may be two stages of deactivation. The first stage of deactivation may occur during the first 100 hours, or might occur as early as after 20 hours of operation. A second stage of deactivation may occur over a period of more than a 1,000 hours of operation. However, information received from catalyst vendors indicate that they are able to design the catalyst to achieve the guaranteed percent reduction at the end of the catalyst life (warranty period). The percent reduction may decline slightly in the beginning but the catalyst can be designed to stabilize at the desired percent reduction. Catalysts that can achieve emissions reductions of 93 percent or more for the life of the catalyst are within the technological limits of this technology. For these reasons, we feel the CO percent reduction requirement of the final rule is appropriate and justified.

Comment: Multiple commenters asked that EPA allow sources to choose either percent reduction or final concentration to comply with irrespective of the control technique employed.

Response: We agree with the commenters, and we feel it is appropriate to allow sources to choose either the percent reduction or formaldehyde concentration outlet limit to demonstrate compliance irrespective of the control technique

 Attachment 2 Attachment 2

employed. We have specified this flexibility in the final rule.

Comment: Two commenters argued that the proposed rule does not recognize DPF as a significantly more effective control device for reducing diesel exhaust emissions compared to diesel oxidation catalysts. One commenter asked that the final rule require the use of particulate traps on diesel engines. Another commenter expressed concern with the interaction of control equipment with diesel particulate traps. One commenter indicated that DPF can reduce diesel PM by at least 80 percent. According to the commenter, these traps can reduce CO by at least 90 percent.

Response: The commenters indicate that DPF are effective at reducing diesel exhaust emissions or diesel particulates. These are not HAP listed pursuant to section 112(b) of the CAA and, therefore, are not the pollutants that the final rule is targeting specifically. The EPA has recently received a request to list diesel exhaust pursuant to section 112(b) of the CAA and is currently reviewing that request. At the time of proposal, we investigated DPF. However, at the time of this investigation, the effectiveness of DPF on listed HAP emissions from stationary sources had not been demonstrated, and the technology had only been applied to a handful of stationary RICE. They,

therefore, were not appropriate as a MACT floor technology. We examined DPF for their ability to reduce listed HAP and their cost effectiveness. We concluded that there were no data to show that this technology would be more effective at reducing listed HAP than oxidation catalysts. We also noted that this technology was more expensive than oxidation catalysts, so we did not use this technology as a basis for the proposed MACT levels. However, the proposal did allow the use of technologies other than oxidation catalysts, including DPF, to meet the MACT requirements, which are generally numerical, though there were certain compliance options that differed depending on the emission control used on the engine. Since proposal, we have received new information regarding DPF resulting in reevaluating the feasibility of applying DPF to stationary RICE. (See Docket ID Nos. OAR-2002-0059 and A-95-35.) In addition, the final rule eliminates all provisions linking the standard to any particular control technology. Sources are free to choose any compliance option irrespective of the control technique applied. We have no reason to believe that DPF are incompatible with oxidation catalysts or that they cannot be used instead of oxidation catalysts. In the context of its mobile source regulations, we have found that DPF can be incorporated with other emission control devices without

 Attachment 2 Attachment 2

compatibility problems. We agree with the commenter that DPF may be able to reduce PM by at least 80 percent and they might be able to also reduce CO by at least 90 percent, at least in certain instances, though EPA has determined that these reductions can only be reliably achieved using ultra low sulfur fuel (15 ppm sulfur content by weight). However, we do not have any actual test data showing that DPF can reliably reduce HAP emissions from stationary CI engines at a level beyond that already required by the final rule. In particular, we do not have data regarding actual use of these devices on stationary RICE, or under the range of operating parameters reasonably expected for such engines. Also, the ultra low sulfur fuel (15 ppm sulfur content by weight) needed for this technology is not yet available in sufficient quantities in the U.S. We, therefore, have determined that there is currently not enough information regarding DPF as applied to HAP emissions from stationary CI engines on which to base the standard for the final rule.

Comment: One commenter urged EPA to rationalize its policy and address the serious public health impacts associated with diesel-powered RICE by establishing rigorous PM and clean fuel requirements in the final rule.

Response: We appreciate the comments regarding pollution from diesel-powered stationary RICE. While we

agree that diesel engines emit pollutants of concern beyond those covered in the final rule, we do not feel it would be appropriate to establish diesel PM or clean fuel requirements in the rule. The final rule is a relatively narrow rule, regulating only listed HAP from stationary RICE. Diesel PM is not currently listed as a HAP under section 112 of the CAA. While regulation of diesel PM may be appropriate in the long-term, either as a criteria pollutant or as a listed HAP, we do not feel that the final rule, which proposed only to regulate HAP already listed under CAA section 112, is the appropriate place to promulgate final rules affecting criteria pollutants and precursors (like PM or $NO_x$). Similarly, the commenter does not provide an explanation of the need to regulate diesel fuel, except as it affects PM emissions. Therefore, we are not taking any final action with regard to these issues in the final rule.

Comment: Several commenters sought adjustment of the MACT emission limitations to reflect fully the test results that are the basis for the standard. One commenter indicated that the CO percent reduction standard for 2SLB engines should be adjusted to 58 percent to reflect the lowest percent reduction achieved during the EPA-sponsored emission testing at the CSU Engine Lab, which is the basis

for the 2SLB standards. The formaldehyde percent reduction standard for 4SRB engines should be adjusted to 73 percent to reflect the lowest percent reduction achieved during the industry-sponsored testing, which is the basis for the 4SRB emission standards. Similarly, the formaldehyde concentration standard for 4SRB engines should be adjusted to 370 ppbvd at 15 percent oxygen to reflect the highest post-NSCR concentration of formaldehyde.

Response: We agree with the commenter that the CO percent reduction standard for 2SLB should be adjusted to 58 percent to fully reflect the possible variation for the best performing source for these engines. We have made this adjustment in the final rule to fully reflect the test results obtained for the 2SLB engine tested at CSU. We proposed an alternative formaldehyde emission limitation of 17 ppmvd for new 2SLB engines in the proposal. The concentration for the formaldehyde emission limitation was based on the minimum level of control achieved by the best controlled source. This approach takes into account the variability of the best performing engine. The formaldehyde emissions at CSU ranged from 7.5 ppmvd to 17 ppmvd. Therefore, we chose 17 ppmvd at proposal. The 17 ppmvd formaldehyde concentration was based on a run conducted at low load (69 percent). After reviewing our approach at

 Attachment 2 Attachment 2

proposal, we have found it inconsistent to establish the alternative formaldehyde emission limitation based on the level achieved during a low load test. The approach that we have used for other engine types in establishing the alternative emission limitations was to establish the limits based on high loads and to require compliance at high loads. The expected trend is for emissions to generally increase with decreasing load; however, we do not have sufficient data to take the effect of load into account in establishing the alternative emission limitations. Because of this, the emission limitations are based on performance at high loads. We expect that if the emission limitations are achieved at high load then the technology will be operating appropriately and will also operate appropriately at lower loads. To be consistent, we have established in the final rule an alternative formaldehyde emission limit for new 2SLB engines of 12 ppmvd. This number is based on the minimum level of control achieved by the best performing engine at high load conditions. We have specified in the final rule that performance tests must be conducted at high load conditions, defined as 100 percent ±10 percent. If a source has demonstrated compliance with the emission limit at high loads it is assumed that the technology is operating appropriately and will also operate appropriately at lower

 Attachment 2 Attachment 2

loads. Sources are not required to meet the emission limitation at low load.

As described in the preamble to the proposed rule, we reviewed emissions data from an industry sponsored formaldehyde emission test conducted on two 4SRB engines. We selected the best performing engine based on the highest average formaldehyde percent reduction. The average reduction was 79 percent for that engine; however, to establish variability we looked at each of the 12 individual test runs performance on that engine. The percent reduction varied from 75 percent to 81 percent. At proposal, we selected 75 percent for the MACT floor. However, since proposal, we have reviewed the method we used to set the MACT floor for existing 4SRB engines. We feel it would be more appropriate to include in the analysis the data from the lower performing engine, thus using more than a single data point in determining the MACT floor for existing 4SRB engines. The revised approach was discussed in detail in response to a previous comment. In that response, we described our revised approach which takes into account the performance of both engines tested, using a weighted average where the data point for the lower performer will be worth 22 percent and the level for the higher performer will be worth 78 percent. In addition, to be consistent with the

approach followed for other engine types, we have excluded runs conducted at low loads in setting the MACT floor. As previously indicated elsewhere in this document, since the MACT floor is based on emissions data from runs at high loads, performance tests must be conducted at high load conditions, defined as 100 percent load, ±10 percent. The commenter stated that the formaldehyde percent reduction standard for existing 4SRB engines should be adjusted to 73 percent to reflect the lowest percent reduction achieved during the industry-sponsored testing. Although the commenter is correct in stating that 73 percent formaldehyde reduction was the lowest average reduction, 73 percent reduction was achieved during a run that was not conducted at high load. For this reason, it is not appropriate to use the 73 percent formaldehyde reduction in the MACT floor analysis. Similarly, the run where the formaldehyde concentration was measured at 370 ppbvd was also not conducted at high load, and was, therefore, not used in our analysis of the MACT floor for existing 4SRB engines.

Comment: One commenter requested that the "burn-in" period during commissioning of new or rebuilt engines should be exempted from emission limits. Catalyst manufacturer warrantees typically require a "burn-in period" for new and rebuilt engines prior to placing the catalyst on stream.

 Attachment 2 Attachment 2

This is intended to allow seating of critical engine components (e.g., piston rings). Catalyst placed on stream before this burn-in period is subject to physical damage from engine backfire and poisoning and or fouling from crankcase oil blow-by. The EPA has acknowledged this need in a prevention of significant deterioration and title V Permit by including the following language: "The permittee shall be allowed to operate the replacement/overhauled engine without the use of the catalytic converter assembly for a period not to exceed 200 hours from the engine startup, unless a longer time period has been approved by EPA, in writing." The commenter recommended that deviating from the emissions limits during the burn-in period or the first 200 hours of operation of a new or rebuilt RICE not be considered a violation. The commenter recommended that a statement be added at §63.6640(d) that deviating from the emissions limits during the burn-in period or the first 200 hours of operation of a new or rebuilt RICE is not a violation.

Response: We agree with the commenter that an engine burn-in period of 200 hours is appropriate prior to installing the catalyst to prevent damage to the catalyst. We have, therefore, specified that new or rebuilt engines may operate for up to 200 hours prior to installing the

catalyst in the final rule and that this will not be considered a violation. However, sources have 180 days after the compliance date specified for their source to conduct the performance test and initial compliance demonstration and the 200 hours of burn-in time must be conducted within the these 180 days.

Comment: One commenter did not agree with EPA's determination of the MACT floor for 4SLB RICE. The database used to determine the MACT floor is based on pre-1999 information and includes 542 engines from Wyoming. Since 1999, Wyoming has permitted 2,100 4SLB engines. Approximately 62 percent of the greater than 500 HP 4SLB permitted since 1999 have been required to be equipped with oxidation catalyst to control formaldehyde. The EPA reports the number of existing 4SLB used in determining the MACT floor at 4,149. Including the 4SLB engines greater than 500 HP permitted since 1999 in Wyoming, the total is 5,664. Of this total, 935 engines have permit conditions requiring oxidation catalyst to control formaldehyde, which is 16.5 percent of the total. Section 112(d) of the CAA requires the emission standard for existing sources be no less stringent than the emission limitation achieved by the best performing 12 percent of existing sources. The commenter contended that the database used to determine the MACT floor

is incomplete, and EPA must reevaluate the MACT floor including permitting actions post 1998.

Response: We contacted the commenter who submitted this comment. The commenter stated that mostly all of the engines that have been permitted are minor sources of HAP. Since the 4SLB engines permitted in Wyoming are nearly all at minor sources of HAP, it is not accurate to add these sources to the determination of the average of the best performing 12 percent of existing sources from the source category. The determination of the average of the best performing 12 percent of existing sources must be based on the sources regulated. Since the final rule only covers major sources, it is not appropriate to include the minor source engines permitted to require oxidation catalyst in Wyoming. Moreover, the calculation of the MACT floor does not require that we include reductions that were implemented within 18 months of the proposal, or 30 months of the final rule. It is not clear how many of the engines the commenter discusses were equipped with oxidation catalysts during that period. Therefore, we have not reevaluated the floor for existing 4SLB engines. The MACT floor of existing 4SLB engines remains at no emissions reductions.

E. Monitoring, Recordkeeping, and Reporting

Comment: Multiple commenters contended that the CO

CEMS requirement for large lean burn engines is unreasonable. The commenters stated that parameter monitoring and periodic testing should be offered to CO monitoring on all lean burn engines. One commenter noted that given that the best available emissions control technology for RICE is a passive catalyst system and that the operator cannot reduce or improve HAP removal efficiency, simplified and less costly environmental monitoring requirements should be adopted.

Response: We now feel that the proposed requirement for 2SLB, 4SLB, and CI engines 5,000 HP or above complying with the requirement to reduce CO emissions using an oxidation catalyst to use CO CEMS is unnecessary and inappropriate. The costs associated with a CO CEMS is estimated to be over $200,000 in capital costs and nearly $60,000 in annual costs. We consider these costs to be excessive. For these reasons, we feel it is not appropriate to include a requirement for large lean burn and large CI engines to install CO CEMS in the final rule. We feel that the combination of periodic stack testing and parameter monitoring is a proper and reasonable alternative for large engines. The testing of CO will ensure, on an ongoing basis, that the source is meeting the CO percent reduction requirement. In addition to stack testing, 2SLB, 4SLB, and

CI engines meeting the CO percent reduction requirement and using an oxidation catalyst must continuously monitor and maintain the catalyst inlet temperature as well as maintain and monitor the pressure drop across the catalyst monthly. These parameters serves as surrogates of the oxidation catalyst performance and by monitoring and maintaining these parameters, continuous compliance between stack testing will be ensured. Stationary RICE meeting the CO percent reduction requirement that are not using an oxidation catalyst must petition the Administrator for approval of operating limitations and must continuously monitor and maintain the operating parameters that are approved (if any).

We are including CO CEMS as an option to periodic stack testing and parametric monitoring for all lean burn and CI engines in the final rule, but it is not required.

Comment: One commenter observed that deficiencies noted in the proposed rule with regard to the test methods and performance protocols render CO CEMS infeasible for the RICE MACT. While CO CEMS have been demonstrated on some facility types, their application to RICE is very limited. 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. While it may be appropriate for EPA to solicit comments on its test methods and technical monitoring requirements, the commenter found that it is inappropriate to propose requirements for measurement systems prior to resolving the current deficiencies with the EPA protocols.

Response: We disagree with the commenter that the application of CO CEMS must be considered infeasible for all RICE unless accompanied by emission test data obtained under known and controlled conditions applicable to the subject source category. Since we have previously established acceptable CEMS performance specifications, we can allow the RICE source owner and operator the optional use of CO CEMS within such performance standards as an effective parameter monitor. However, as discussed above, we do agree that we should not require the installation of CEMS at all affected facilities.

Comment: Many commenters asserted that the fuel flow and HP limits should be removed. Five commenters recommended that EPA specify that the emission standards only apply within a 60 to 100 percent load range and performance testing should be conducted within that load range. One commenter suggested revising MACT requirements

to have emission limits and performance testing applicable at higher load conditions instead of establishing the lowest load to be operated in the future. Another commenter recommended that the final standards only apply down to the lowest load for which EPA has data and should specify that the performance test be conducted in that load range. One commenter stated that should EPA pursue minimum load testing and compliance in the final rule, the owner and operators should be allowed to retest the unit at some time later than the initial performance test to enlarge the operating range. The lower operating load and fuel range should then be based on the lowest load that has demonstrated compliance irrespective of whether the demonstration occurred in the initial or later performance tests.

One commenter stated that the NESHAP provide two options. One is to use a catalyst and the other is to limit the formaldehyde. If the formaldehyde limit is chosen, however, the engine must maintain an operating load of 95 percent or more of the load established in the initial testing, which under many circumstances is impractical. For example, this option cannot be chosen for the commonly used variable-load application engine. For variable load engines, there is no choice but to use a catalyst. The commenter believed that this approach limits the flexibility

in controlling these engines.

Response: In the proposed rule, we required sources complying with the alternative formaldehyde limit to maintain an operating load equal to or greater than 95 percent of the operating load established during the initial performance test or maintain a fuel flow rate equal to or greater than 95 percent of the fuel flow rate established during the initial performance test. These sources were also required to comply with any additional operating limitations approved by the Administrator. Based on information received during the public comment period, we have reached the conclusion that maintaining the load or fuel flow rate within 95 percent of that established during the initial performance test may be impractical for many applications, especially those in load following applications. Therefore, we have not included the requirement to maintain load or fuel flow rate in the final rule. Sources complying with the alternative formaldehyde limit that use an oxidation catalyst or NSCR must continuously maintain and monitor the catalyst inlet temperature and measure the pressure drop across the catalyst monthly. Sources complying with the alternative formaldehyde limit that do not use an oxidation catalyst or NSCR must petition the Administrator for operating

 Attachment 2 Attachment 2

limitations to be continuously monitored. In the petition for approval of operating limitations, we recommend that sources consider establishing load or fuel flow rate as possible operating parameters to continuously monitor. Finally, we have based the emission standard on test results from high load tests only. Typically, as load decreases, the concentration of HAP increases. Comments received support this trend. Therefore, we have specified in the final rule that performance tests must be conducted at high load conditions, defined as 100 percent ±10 percent.

Comment: Several commenters contended that the temperature ranges at the catalyst inlet should be revised. Six commenters supported an operating range of 450°F to 1350°F for lean burn engines and the ability to develop customized catalyst inlet temperature ranges based on specific engine operating parameters. One commenter recommended using 450°F minimum catalyst inlet temperature for 2SLB. One commenter also said that owners and operators should be allowed to identify more appropriate temperature ranges based on performance testing, control device design specifications, manufacturer recommendations, or other applicable information (such as a performance test on a similar unit).

Response: We proposed that lean burn and CI engines

complying with the requirement to reduce CO emissions maintain the temperature of the stationary RICE exhaust so that the catalyst inlet temperature is greater than or equal to 500°F and less than or equal to 1250°F. We required the catalyst inlet temperature to be maintained to ensure proper operation of the oxidation catalyst. We stated in the preamble to the proposed rule that, in general, the oxidation catalyst performance will decrease as the catalyst inlet temperature decreases. Also, if the catalyst inlet temperature is too high, oxidation catalyst performance could be affected. Finally, the oxidation catalyst inlet temperature cannot be too low, or the reduction of HAP emissions may be compromised. For these reasons, we proposed that sources complying with the CO reduction requirement using an oxidation catalyst maintain the catalyst inlet temperature within 500°F and 1250°F. Several comments received during the public comment period indicated that the temperature range we proposed for catalyst inlet temperature should be expanded. Commenters suggested that the lower end of the temperature range should start at 450°F. The level of the standard for 2SLB engines is 58 percent CO reduction. Similar CO reduction was seen at CSU for 2SLB engines where the exhaust temperature was 450°F. For this reason, we agree with the commenters that the

 Attachment 2 Attachment 2

catalyst inlet lower temperature should be set at 450°F. Furthermore, we feel that the oxidation catalyst will perform adequately at a temperature of 1350°F. This was discussed in a memorandum included in the rule docket (Docket ID Nos. OAR-2002-0059 and A-95-35). Commenters also stated that Waukesha Pearce Industries, Inc. includes 1350°F in their limited warranty statements for oxidation catalysts. Therefore, we have written the temperature range requirement for catalyst inlet temperatures to be between 450°F and 1350°F in the final rule. Regarding the comment that owners and operators should be allowed to identify more appropriate temperature ranges, we feel that requiring a catalyst inlet temperature range of 450°F to 1350°F is appropriate. Based on information from the testing at CSU, information from catalyst vendors, and information provided in comment letters submitted to the docket, we feel we have adequate information that supports requiring a catalyst inlet temperature range of 450°F to 1350°F, and we do not feel it is necessary to allow owners and operators the ability to identify and define other temperature ranges. Owners and operators have the option to petition the Administrator for other operating parameters following the procedures in section 63.8 for alternative monitoring procedures.

 Attachment 2 Attachment 2

Comment: Many commenters stated that the requirement to measure pressure drop should be removed. One commenter indicated that the operating limitation not to exceed a pressure change of 2 inches of water column from the initial performance test has the potential to be problematic in practice. Another commenter stated that there is no need for continuous pressure drop measurements on engines running exclusively on natural gas and at high loads. The commenter has seen very little problems with catalyst fouling on their lean burn RICE equipped with oxidation catalysts. The commenter understood that it is an issue in some installations, but concludes that they would be applications either running on other fuels or where engines are run at idle or very low load for long periods of time. One commenter stated that the proposed requirements to continuously monitor and maintain a prescribed pressure differential across the catalyst should be removed from the final rule for the following reasons: (1) although significant change in differential pressure across the catalyst may provide an indication that the catalyst has become fouled, EPA has presented no evidence to suggest that an increase in 2 inches of water column means that catalyst performance is impacted; (2) industry data demonstrates that the pressure drop can increase more than 2 inches of water

column without impacting catalyst performance. Such increases may even occur because of engine operating conditions. For that reason, EPA's proposed 2 inches of water column condition might forbid engines to operate within part of their normal operating range; and (3) vendors do not treat pressure differential as a continuous operating parameter requirement. Rather it is presented as a maintenance requirement for catalysts on some engines. The general duty clause of §63.6(e)(1)(i) is sufficient to address pressure drop issues. Finally, one commenter stated that the uniqueness of the installation should be given consideration in whether or not pressure drop is required to be monitored.

Response: We proposed a requirement for 4SRB engines complying with the requirement to reduce formaldehyde emissions using NSCR and 2SLB, 4SLB, and CI engines less than 5,000 HP complying with the requirement to reduce CO emissions using an oxidation catalyst to maintain the catalyst so that the pressure drop across the catalyst does not change by more than 2 inches of water from the pressure drop across the catalyst measured during the initial performance test. Catalyst vendors have indicated to EPA that the pressure drop across the catalyst may be a good parameter to indicate catalyst performance and that an

increase in pressure drop is an indication of poor catalyst performance. The pressure drop across the catalyst can indicate if the catalyst is damaged or fouled. If the catalyst is damaged or becomes fouled, the catalyst performance would decrease. For the reasons provided, we feel it is appropriate to use the pressure drop as it serves as a surrogate of the catalyst performance.

We determined at proposal that if the pressure drop across the catalyst deviates by more than 2 inches of water from the pressure drop across the catalyst measured during the initial performance test, the catalyst might be damaged or fouled. This was based on information received from catalyst vendors which indicated that if the pressure drop changes by more than 2 inches of water column, the catalyst should be inspected for damage or fouling. For this reason, we feel it was appropriate to specify that the pressure drop across the catalyst should not change by more than 2 inches from the pressure drop measured during the initial performance test. Anything higher than 2 inches might indicate damage or fouling of the catalyst. We feel it is appropriate to maintain the pressure drop requirement as proposed. However, we have reevaluated our position regarding requiring sources to monitor the pressure drop across the oxidation catalyst on a continuous basis and are

no longer requiring sources to install a CPMS to monitor this parameter continuously. The pressure drop across the catalyst is not likely to change within short periods of time, but is a parameter the owner and operator might see changing over a longer period of time, not within hours or days. This is consistent with comments that stated that vendors do not treat pressure differential as a continuous operating parameter requirement. Rather it is presented as a maintenance requirement for catalysts on some engines. For this reason, we feel it is appropriate to require sources that must comply with the pressure drop requirement to measure this parameter monthly, as we do not expect the pressure drop across the catalyst to change significantly more frequently than monthly. Regarding the comment that the uniqueness of the installation should be given consideration in whether or not pressure drop is required to be monitored, we feel that we have gathered sufficient information from catalyst vendors that supports requiring the pressure drop to be monitored and maintained monthly. In addition, the commenter did not describe or provide information regarding how the uniqueness of the installation would affect whether or not monitoring and maintaining the pressure drop should be required.

Comment: Many commenters stated that the requirement

 Attachment 2 Attachment 2

to measure the temperature rise for rich burn RICE should be removed. One commenter had the opinion that 5 percent difference in temperature is not feasible or workable in practice. While a NSCR catalyst is more likely to show a positive temperature change across the catalyst, very low, or even negative, temperature changes are possible while the catalyst is functioning normally. One commenter did not think it is appropriate to specify that the temperature rise across a NSCR catalyst has to stay within 5 percent of the temperature rise (or any other specific value) measured at the initial source test. The commenter believed that this seems arbitrary. At one facility, the commenter has seen zero temperature change across the catalyst. Yet, $NO_X$, CO and volatile organic compounds (VOC) reductions were all occurring at high efficiency and in full compliance with requirements. It would be more appropriate to simply require that NSCR be operated in conjunction with an air-to-fuel ratio controller and that the catalyst inlet temperature simply be hot enough to ensure it is working, but not too hot to damage the catalyst.

One commenter said that Table 1b of the proposed rule stipulates that 4SRB RICE must ensure that the temperature rise across the catalyst is no more than 5 percent different. The commenter asked what if the temperature is

10 percent different and would this not represent a higher degree of oxidation. The commenter questioned why this should not be allowed.

Response: As summarized above, we received several comments regarding the requirement in the proposed rule that 4SRB engines monitor and maintain the temperature rise across the NSCR. Based on the information received, we agree with the commenters that such a requirement would be inappropriate and most likely would not provide an accurate representation of how the catalyst is performing. We are including the requirement to measure the catalyst pressure drop monthly and to maintain and continuously monitor the catalyst inlet temperature to ensure that it remains between 750°F and 1250°F. It is our opinion that monitoring and maintaining these two parameters is sufficient to ensure proper catalyst operation. Therefore, we have not included the requirement to maintain the catalyst such that the temperature rise across the catalyst stays within 5 percent of the temperature rise measured during the initial performance test in the final rule.

Comment: One commenter argued that the requirement for an immediate startup, shutdown, and malfunction (SSM) report should indicate that this is required only when the actions addressing the malfunction were inconsistent with the

startup, shutdown, and malfunction report (SSMP).

Two commenters stated that EPA should eliminate the immediate SSM report indicated in Table 7, item 2, of the proposed rule. One commenter further noted that any reporting requirements should be consistent with the General Provisions and the December 2002 proposal relating to reporting malfunctions only versus startups and shutdowns.

Two commenters recommended eliminating the requirement for an immediate SSMP in Table 7 of the proposed rule.

Response: We agree that immediate SSMP reports are unnecessary and have the potential of becoming a burdensome activity for sources with frequent startups and shutdowns. We have specified in the final rule that an immediate SSMP report is only required when actions addressing the startup, shutdown, or malfunction were inconsistent with the SSMP.

Comment: Two commenters requested annual compliance reports instead of the requirement of semiannual reporting of compliance reports in §63.6650(3). One of the commenters asked that the language in this paragraph be modified to allow the flexibility for annual compliance reports in order to make the final rule consistent with other MACT standards. The commenter noted that they are seeing in the various State and Federal regulations the requirements for monthly, quarterly, semiannual, and annual reports, and keeping track

of these is becoming quite difficult. One of the commenters stated that this will create an unnecessary paperwork burden for both the regulated community as well as for the regulatory agencies. A more reasonable approach would be to require an annual compliance report timed concurrently with the state EPA's typical emissions reporting requirement.

Response: We disagree that semiannual compliance reports are a burden. We feel that the submittal of semiannual reports will assist in identifying problem areas within a reasonable period of time. The requirement for semiannual compliance reporting is not inconsistent with previous MACT standards. Several MACT standards require compliance reports to be prepared and submitted semiannually. Enforcing agencies have been requiring semiannual compliance reports for a long time, and this has worked well and has helped EPA enforce rules appropriately. We feel the submittal of semiannual compliance reports is appropriate for stationary RICE complying with the final rule.

Comment: One commenter stated that readily available electronic records do not have to be stored on-site. In §63.6660(c), the proposed RICE MACT requires that records be kept on-site for the first 2 years following the date of each occurrence, measurement, maintenance, corrective

action, report or record. This requirement does not recognize the trend toward computerization of monitoring records. Many sites are making an intentional effort to move away from paper records of air compliance critical data whenever the opportunity presents itself. These electronic records reside on hardware referred to as servers. For a variety of reasons, these servers are not always located at the major source that would be affected by the RICE MACT. There are cases at companies where the server for an affected source is not located in the same State as the affected source. The concept of "readily accessible" should be more important, relative to current records, than the need for them to be on-site at the major source. The commenter urges EPA to recognize the trend to electronic record keeping by changing §63.6660(c) to read as follows: "(c) Each record must be readily accessible in hard copy or electronic form 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 may keep the records off-site for the remaining 3 years."

Response: We agree with the commenter and feel that records that can be accessed on-site by a computer are valid and should be considered on-site records. Our understanding of the General Provisions is that it allows the

interpretation that records that can be accessed on-site are acceptable. In any case, we have written §63.6660(c) in the final rule according to the commenter's suggestion.

F. Testing

Comment: Several commenters pointed out that there is a 50 parts per million (ppm) $NO_x$ limit advisory with the use of CARB Method 430. The commenters asked EPA to follow the direction of the CARB advisory. One commenter added that due to concerns about matrix interferences with CARB Method 430, as expressed in an advisory released by CARB, the commenter believed that it is inappropriate to include CARB Method 430 as a candidate method until its governing agency has more thoroughly researched method deficiencies and revised the method or rescinded the advisory.

Response: We agree that CARB Method 430 use should not be cited in the final rule. Therefore, we have not included CARB Method 430 as a test method in the final rule.

Comment: A few commenters recommended that EPA include proposed Method 323. One commenter felt that it is imperative that multiple test methods and technological approaches be available for formaldehyde measurement from engines. The EPA Method 323 addresses this need and appears to offer a reasonable alternative to FTIR for formaldehyde testing of engines. The method detection limits are within

the range necessary to demonstrate compliance with a formaldehyde based limit. This method was investigated and developed by the Gas Technology Institute (GTI) as a low-cost alternative for engine formaldehyde measurement and has been validated for application to internal combustion engines in research conducted by GTI.

One commenter said that this method has the advantage of actually having been field-validated at the required concentration. Furthermore, it is simpler and less costly than the other methods. It is the commenter's experience that with a similar chilled-impinger method for VOC (Method 25.3), they found it was critical to maintain near-ice-water temperatures in order to achieve 100 percent capture. The method might be modified by adding a final impinger and having that analyzed separately for breakthrough. Sulfur dioxide is listed as an interference, possibly because of its ability to bond with aldehydes. This bond is broken under acidic conditions. If this is found to be a problem, perhaps the sample can be acidified more to break up any complexes.

Response: We agree with the commenter and have included Method 323 as an optional method for natural gas-fired units in the final rule. We plan to develop a FAQ sheet for Method 323. We may include the commenter's

suggestion for analyzing for breakthrough with another impinger and a caution to check the impinger exhaust temperature when assessing the data quality.

Comment: One commenter expressed the view that since EPA SW-846 Method 0011 uses a similar analytical approach as CARB Method 430, has not been validated for application to engines, and has quality assurance requirements considered less thorough than CARB Method 430, it should be excluded from the list of acceptable methods.

Response: We agree with the commenter that this method should not be specified as an acceptable method for this application. This method has not been included in the final rule.

Comment: A few commenters stated that EPA should allow ASTM Method D6348 as equivalent to Method 320. One commenter stated that the method is self-validating and includes clarity that the commenter believed will provide better consistency and reduce the likelihood of errors as FTIR becomes more widely implemented by the source test community. The ASTM method was developed and approved following a refereed process and considering the input and review of leading experts in the field.

Response: We identified ASTM D6348-03 as a potential national consensus based method in addition to Method 320

and Method 323. Upon review, we approved this method as an alternative to Method 320 for formaldehyde measurement provided in ASTM D6348-03, Annex 5 (Analyte Spiking Technique), percent R must be greater than or equal to 70 and less than or equal to 130.

Comment: Some commenters stated that quarterly emission testing with CO portable units should not be full performance tests. This provision is burdensome and unnecessary. The final rule should not require that the quarterly emission tests be full performance tests for the following reasons: (1) for full performance tests, engines in load-following applications may need to conduct emissions testing at multiple operating conditions, in accordance with the General Provisions' requirement that performance tests be conducted for representative conditions; (2) facilities with load-following operations, such as natural gas transmission and storage, may not be able to operate the engines over the full range of operating conditions on a quarterly basis; (3) full performance tests impose significant burden on the owner or operator to develop site-specific test plans, provide notification to the permitting authority 60 days in advance of the test, and submit the full results within 60 days of completion of the testing; and (4) review of other MACT standards indicates that full

 Attachment 2 Attachment 2

performance tests are not required more frequently than annually.

Response: We agree with the commenters that requiring full performance tests quarterly for sources complying with CO reduction requirement may impose significant burden on the owner or operator to develop site-specific test plans, provide notification to the permitting authority 60 days in advance of the test, and submit the full results within 60 days of completion of the testing. We now feel that quarterly testing for CO is unnecessary and inappropriate. In the final rule, we have specified that new 2SLB, new 4SLB, and new CI engines complying with requirement to reduce CO emissions must conduct semiannual performance tests for CO to demonstrate that the required CO percent reduction is achieved. Semiannual performance testing for CO in addition to monitoring and maintaining operating parameters will ensure, on an ongoing basis, that the applicable CO percent reduction requirement is being met. After demonstrating compliance for two consecutive tests, the frequency can be reduced to annually. However, if an annual performance test indicates a deviation of CO emissions from the CO reduction requirement, you must return to semiannual performance tests.

Comment: Some commenters contended that additional

 Attachment 2 Attachment 2

performance tests should not be required when NSCR or oxidation catalysts are replaced with identical units.

Response: We disagree. Additional performance tests are required to be performed even though an emission control device is replaced with an identical unit. The performance of identical catalysts can vary significantly, and it is not guaranteed that the NSCR or oxidation catalyst will achieve the same performance levels.

Comment: One commenter asked that EPA include similar language as in the Petroleum Refinery MACT for Catalytic Cracking Units which has the provision to make adjustments to one of the monitored operating parameters to acknowledge that it may not be possible to achieve worst-case operation during the performance test. In this scenario, the testing of a similar unit should be allowed to serve as the basis for establishing acceptable inlet temperatures.

One commenter remarked that initial performance tests should only have to be performed on one engine when an installation is provided with several identical engines.

Response: We do not agree that it is appropriate to allow a facility with identical engines to conduct testing on only one of the units to establish operating parameters. Although the units are identical, operating parameters, as well as emissions, could vary significantly from unit to

 Attachment 2 Attachment 2

unit. We do not agree that it is appropriate to allow a facility with identical engines to conduct performance tests on only one of the units to demonstrate compliance with the emission limits for all of the identical units. It is our experience that emissions from identical units can vary significantly.

Comment: One commenter stated that manufacturer's performance data should be allowable in lieu of an initial performance test.

Response: We are not allowing manufacturer's performance data in lieu of an initial performance test. Performance data provided by the manufacturer may not be representative of how the engine will perform in the field and may overestimate the engine's performance.

Comment: One commenter contended that the stack testing should be no more frequent than semiannual for CO. The stack testing for formaldehyde should be no more frequent than annual. The commenter added that both should also include the ability to go to even less frequent testing based upon good performance.

Response: We agree with the commenter and feel that it is appropriate to require semiannual performance tests for CO for sources meeting the CO percent reduction requirement. This has been specified in the final rule. The rationale

 Attachment 2 Attachment 2

for reducing the CO testing requirement was previously discussed. For CO stack testing, we also agree with the commenter that it is appropriate to allow sources that demonstrate compliance for two consecutive tests, to reduce the frequency of subsequent performance tests to annually. However, if an annual performance test indicates a deviation of CO emissions from the CO reduction requirement, sources must return to semiannual performance tests. Regarding formaldehyde testing, we disagree with the commenter and feel that we have appropriately set the testing requirements for formaldehyde at semiannual performance tests. Periodic stack testing for CO and formaldehyde will ensure, on an ongoing basis, that the source is meeting the emission limitation requirements. For formaldehyde stack testing, if you have demonstrated compliance for two consecutive tests, you may reduce the frequency of subsequent performance tests to annually. However, if the results of any subsequent annual performance test indicate that the stationary engine is not in compliance with the formaldehyde emission limitation, or you deviate from any of your operating limitations, you must resume semiannual performance tests.

Comment: One commenter was of the opinion that EPA should allow facilities complying with the formaldehyde emission limitation to use existing performance test data to

 Attachment 2 Attachment 2

demonstrate initial compliance with the emission limit.

Response: We agree with the commenter that existing performance test data can be used to demonstrate compliance with the emission limit. 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 is of good quality and is less than 2 years old. Existing test data can only be used to demonstrate initial compliance; after the initial compliance demonstration, facilities must then begin to follow the semiannual compliance test schedule. This has been specified in the final rule.

G. 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.[2]

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 feel that it is not appropriate to include any risk-based approaches in today's final rule.

---

[2] See 68 FR 1276 (January 9, 2003) (Plywood and Composite Wood Products Proposed NESHAP) and Docket ID No. A-98-44 (White Papers submitted to EPA outlining the risk-based approaches).

H. Other

Comment: One commenter stated that $NO_x$ increases due to oxidation catalysts for 2SLB and 4SLB engines should be considered in evaluating the cost and benefits of the proposed rule. Test results for 2SLB and 4SLB engines (Docket ID Nos. OAR-2002-0059 and A-95-35) equipped with oxidation catalysts indicate an increase of $NO_x$ emissions up to about 15 percent and 12 percent for 2SLB and 4SLB engines, respectively. It is not clear that the impacts of this $NO_x$ increase has been addressed with respect to the ability of sources to comply with State and local $NO_x$ limits or impacts on the environment.

Response: We did consider $NO_x$ increases due to oxidation catalysts for 2SLB and 4SLB engines. However, the $NO_x$ increases resulting from 2SLB and 4SLB installing oxidation catalyst controls to comply with the final rule are far less than the $NO_x$ decreases resulting from 4SRB engines installing NSCR controls to comply with the final rule, resulting in a net decrease in $NO_x$ emissions due to the final rule and a benefit to the environment overall. In addition, oxidation catalysts are not specifically required by the final rule and as only new 2SLB and new 4SLB engines are affected by the final rule, sources that are concerned about $NO_x$ emissions can use other methods of HAP

emission control that are less problematic from a $NO_x$ control perspective (like in-cylinder controls), or they can use $NO_x$ control to reduce $NO_x$ from engines using oxidation catalysts.

Comment: One commenter contended that data from testing of 2SLB and 4SLB should be disallowed. The commenter provided the following reasons: (1) The range of engine operating conditions in the testing of the 2SLB engine and quite probably the 4SLB engine are far leaner than the leanest engine in the pipeline RICE fleet. This is indicated by the extremely low $NO_x$ emissions. (2) engines equipped with pre-combustion chambers operating extremely lean are not typical examples of the 2SLB and 4SLB fleet. (3) the range of exhaust temperatures, air-to-fuel ratios, and exhaust oxygen are not typical of 2SLB and 4SLB. (4) Engines were laboratory research engines. They were not equipped with turbochargers, but with turbocharger simulators that do not have the same traits as a turbocharger. (5) Found no information in the piping diagrams of insulation on the ducting and manifolds leading from the engine to the catalyst. Certainly all ducting is insulated in industry. The EPA needs to determine if any insulation was in place. (6) The following excerpt from page 77840 of the proposed rule is not true: "In general,

higher exhaust temperatures lead to better catalyst performance. This difference in temperatures is a function of the inherent design of these engine types and cannot be controlled by the operator." By controlling the air-to-fuel ratio of the engine, the exhaust gas temperature, and thus the catalyst inlet temperature, can be precisely controlled. (7) If HAP data from the 2SLB and 4SLB testing is allowed to stand, then this testing must become the definitive work on all pollutants tested as well, including $NO_x$. The $NO_x$ data should be forwarded to the criteria pollutant group.

One commenter disagreed that the engine at CSU is representative of 2SLB engines in the industry due to low $NO_x$ levels, high levels of oxygen, and low exhaust temperatures. The 2SLB engine was running considerably leaner than similar model engines at similar conditions.

Response: We compared these parameters to other 2SLB and 4SLB engines for which we have information in the emissions database. The $NO_x$ and oxygen levels and exhaust temperatures for the 2SLB and 4SLB engines tested at CSU are similar to those observed for other non-CSU 2SLB and 4SLB engines in the emissions database. This analysis is presented in a memorandum included in the rule docket (Docket ID Nos. OAR-2002-0059 and A-95-35). We feel that the 2SLB and 4SLB engines tested at CSU are representative

of 2SLB and 4SLB engines in the industry. As far as insulation is concerned, the catalyst inlet temperature recorded should represent catalyst performance at that temperature regardless of insulation presence or absence. It should be remembered that the MACT standard for new sources under CAA section 112(d) is based on the level of control of the best controlled similar source.

Comment: One commenter stated that the testing did not include in its test protocol dynamic spiking that is required in Method 320 which leaves some question to the integrity of the sample measured in the test program.

Response: An alternative quality assurance procedure was proposed and followed resulting in data of sufficient quality. The entire FTIR sampling analysis system was validated on a 2SLB engine by a dynamic spiking of formaldehyde, acrolein, and acetaldehyde. The data were assessed following Method 301 criteria. Then, on a daily basis, the analyzer was checked for linearity and alignment, a diagnostic or transfer standard consisting of the CO was used to confirm accuracy, a second diagnostic standard consisting of $CO_2$, CO, methane, and $NO_x$ was introduced using the same procedure. Then to check sampling system integrity, a formaldehyde standard was introduced directly into the instrument and a reading obtained, then it was

 Attachment 2 Attachment 2

introduced into the sampling system at the sample probe upstream of the filter and another reading obtained. The sampling system pass/fail criterion was 100 percent ±10 percent of the direct-to-the-analyzer reading. Finally, the diagnostic and system integrity procedures were repeated at the end of each day testing. This procedure resulted in data of sufficient quality.

Comment: One commenter asked that EPA clarify retesting requirements on new sources. Section 63.6610 of the proposed rule is ambiguous on the General Provisions requirement for some new sources to retest 3 years after promulgation in §63.7(a)(2)(ix). Table 8, item 24, or the proposed rule does not clarify the issue.

Response: Section 63.7(a)(2)(ix) of the General Provisions discusses performance test dates if the promulgated standard is more stringent that the proposed standard. Sources that commenced construction or reconstruction between the proposal and promulgation have the option to demonstrate compliance with either the proposed or the promulgated standard. If the owner or operator chooses to comply with the proposed standard initially, the owner or operator must conduct a second performance test within 3 years to demonstrate compliance with the promulgated standard. Since the promulgated

standard is in some cases more stringent than the proposed standard, we have specified in §63.6610(c) of the final rule that sources that commenced construction or reconstruction between the proposal and promulgated have this option.

Comment: A few commenters asserted that the basis for any size threshold should be expressed in site-rated HP as opposed to manufacturer's nameplate HP. One commenter gave the following reasons: (1) the database used by EPA to determine the MACT floor provisions likely includes the site-rated HP, based on the facility's air permit; (2) stationary RICE are typically identified by site-rated HP, rather than manufacturer's nameplate HP in the facility's title V permit and not all engines have HP on the nameplate; and (3) the Federal Energy Regulatory Commission certified HP for natural gas transmission facilities are issued based on site-rated HP.

Response: We contacted one of the commenters who submitted this comment and also an engine manufacturer. Information received from both sources indicated that there may be differences between site-rated HP and the manufacturer's nameplate rating. Factors such as altitude, temperature, fuel, etc. affect what the site-rated HP will be for the engine at a specific location. Some manufacturers include the specific site-rating on the

nameplate of the engine, which is a HP rating which has been adjusted to account for the characteristics of the location the engine is installed at as well as other parameters affecting the engine rating. For these reasons, we agree with the commenters that it is appropriate to use the site-rated HP as opposed to the manufacturer's nameplate rating for the size applicability criteria, because relying on the manufacturer's nameplate rating may not be representative of the capability of the engine on-site. This has been specified in the final rule.

Comment: Some commenters asked that EPA include non-aggregation provisions for transmission and storage facilities for the Transmission & Storage (T&S) MACT.

Response: We have incorporated this comment in the final rule. The non-aggregation provisions for transmission and storage facilities from the Natural Gas Transmission and Storage MACT (40 CFR part 63, subpart HHH), which are found in the definition of major source in that subpart, are as follows: (1) emissions from any pipeline compressor station or pump station shall not be aggregated with emissions from other similar units, whether or not such units are in a contiguous area or under common control; and (2) emissions from processes, operations, and equipment that are not part of the same natural gas transmission and storage facility,

 Attachment 2 Attachment 2

as defined in this section, shall not be aggregated.

The non-aggregation provisions in (1) above were already included in the proposed definition of major source for the RICE NESHAP and have been retained in the final rule. The non-aggregation provisions in (2) above have also been added to the definition of major source for the RICE NESHAP.

Comment: Some commenters requested that EPA include the provisions to calculate potential emissions for storage facilities from the T&S MACT.

Response: We agree with the commenters and have incorporated their comment in the final rule by modifying the definition of potential to emit in the final rule to include the following: "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 may be determined according to §63.1270(a)(2)."

Comment: Two commenters asked that EPA list diesel PM as a HAP. One of the commenters stated that if EPA fails to

act on its own initiative, the commenter will submit a formal listing petition to EPA. One commenter recommended including diesel PM in this MACT and including limits and control measures.

Response: We acknowledge the comments on this issue. However, we are not prepared at this time to list diesel PM as a regulated HAP, at least not in the context of the final rule. We proposed the rule for the purposes of promulgating regulations for emissions from stationary RICE that were already listed under section 112 of the CAA. While we did mention the diesel exhaust issue, we did not include any detailed discussion on the separate issue of whether any additional pollutants should be added to the list of regulated pollutants under CAA section 112. The decision regarding whether to list diesel PM entails several significant issues that have not been discussed in the context of the final rule. Therefore, it would be inappropriate to take final action on this comment in the context of the final rule.

## V. Summary of Environmental, Energy and Economic Impacts

### A. What are the air quality impacts?

The final rule will reduce total HAP emissions from stationary RICE by an estimated 5,600 tpy in the 5th year after the standards are implemented. We estimate that

approximately 1,800 existing 4SRB stationary RICE will be affected by the final rule. In addition, we estimate that approximately 1,600 new 2SLB, 4SLB and 4SRB stationary RICE, and CI stationary RICE will be affected by the final rule each year for the next 5 years. At the end of the 5th year, it is estimated that 8,100 new stationary RICE will be subject to the final rule.

To estimate air impacts, HAP emissions from stationary RICE were estimated using average emission factors from the emissions database. It was also assumed that each stationary RICE is operated for 6,500 hours annually. The total national HAP emissions reductions are the sum of formaldehyde, acetaldehyde, acrolein, and methanol emissions reductions.

In addition to HAP emissions reductions, the final rule will reduce criteria pollutant emissions including CO, VOC, $NO_x$, and PM. The application of NSCR controls to 4SRB engines (the technology on which MACT for 4SRB engines is based) will also reduce $NO_x$ emissions by 90 percent. It is possible that oxidation catalyst controls could be used to meet the 4SRB emission standards, but it is expected that the costs of controls will be similar for both systems. Assuming that 60 percent of the 4SRB (new and existing) engines that are covered by the emission standards will use

 Attachment 2 Attachment 2

NSCR, the emissions reductions of $NO_x$ in the 5th year after promulgation are calculated to be about 167,900 tpy.

B. What are the cost impacts?

A list of 26 model stationary RICE was developed to represent the range of existing stationary RICE. Information was obtained from catalyst vendors on equipment costs for oxidation catalyst and NSCR. This information was then used to estimate the costs of the final rule for each model stationary RICE following methodologies from the Office of Air Quality Planning and Standards (OAQPS) Control Cost Manual. These cost estimates for model stationary RICE were extrapolated to the national population of stationary RICE in the United States, and national impacts were determined.

The total national capital cost for the final rule for existing stationary RICE is estimated to be approximately $68 million, with a total national annual cost of $35 million in the 5th year. The total national capital cost for the final rule for new stationary RICE by the 5th year is estimated to be approximately $371 million, with a total national annual cost of $213 million in the 5th year.

C. What are the economic impacts?

We prepared an economic impact analysis to evaluate the primary and secondary impacts the final rule would have on

 Attachment 2 Attachment 2

the producers and consumers of RICE, and society as a whole. The affected engines operate in over 30 different manufacturing markets, but a large portion are located in the oil and gas exploration industry, the oil and gas pipeline (transmission) industry, the mining and quarrying of non-metallic minerals industry, the chemicals and allied products industry, and the electricity and gas services industry. Taken together, these industries can have an influence on the price and demand for fuels used in the energy market (i.e., petroleum, natural gas, electricity, and coal). Therefore, our analysis evaluates the impacts on each of the 30 different manufacturing markets affected by the final rule, as well as the combined effect on the market for energy. The total annualized social cost (in 1998 dollars) of the final rule is $248 million but this cost is spread across all 30 markets and the fuel markets. Overall, our analysis indicates a minimal change in prices and quantity produced in most of the fuel markets. The distribution of impacts on the fuel markets and the specific manufacturing market segments evaluated are summarized in Table 1 of this preamble.

Table 1: Economic Impact of Final RICE Rule on Affected Market Sectors

 Attachment 2 Attachment 2

| Market Sector | Change in Price | Change in Market Output | Total Social Cost (millions of 1998$) |
|---|---|---|---|
| Fuel Markets:[a]<br>Petroleum<br>Natural Gas<br>Electricity<br>Coal<br>Subtotal: | <br>0.015%<br>0.300%<br>0.040%<br>0.008% | <br>-0.003%<br>-0.040%<br>0.009%<br>0.008% | <br>-$15.7<br>-$102.5<br>$26.6<br>$1.1<br>-$90.4 |
| Sectors of Energy Consumption:[b]<br>Commercial Sector<br>Residential Sector<br>Transportation Sector | <br>–<br>–<br>– | <br>–<br>–<br>– | <br>-$161.6<br>-$98.9<br>-$47.0 |
| Mining and Quarrying | 0.050% | -0.001% | -$52.6 |
| Food and Kindred Products | 0.002% | -0.002% | -$16.2 |
| Paper and Allied Products | 0.002% | -0.003% | -$14.5 |
| Chemicals and Allied Products | 0.004% | -0.006% | -$49.8 |
| Primary Metals | 0.004% | -0.004% | -18.9 |
| Fabricated Metal Products | 0.002% | -0.000% | 5.0 |
| Nonmetallic Mineral Products | 0.005% | -0.005% | -$9.9 |
| Other Manufacturing Markets | 0.0%-0.001% | 0.0%-0.001% | -$53.8 |

[a] Only changes in producer surplus (i.e., producer's share of regulatory costs) are reported for the Fuel Markets which represent the producers of energy. Sectors of energy consumption - commercial, residential, and transportation - have reported changes in consumer surplus only, and thus do not have reported changes in price and output. A combination of these costs will represent total social costs for the energy market in the economy.

 Attachment 2 Attachment 2

Because a significant portion of the engines affected by the final rule use natural gas as a fuel source, it is not surprising to see the natural gas fuel market with the largest portion of the social costs. Although the natural gas market has a greater share of the regulatory burden, the overall impact on prices and output is about three-tenths of one percent, which is considered to be a minor economic impact on this industry. The change in the price of natural gas is not expected to influence the purchase decisions for new engines. Our analysis indicates that at most, five fewer engines out of over 20,000 engines will be purchased as a result of economic impacts associated with the final rule. The electricity and coal markets may experience a slight gain in revenues due to some fuel switching from natural gas to coal or electricity.

The total welfare loss for the manufacturing industries affected by the final rule is estimated to be approximately $103.0 million for consumers and $117.7 million for producers in the aggregate. In comparison to the energy expenditures of these industries (estimated to be $101.2 billion), the cost of the final rule to producers as a percentage of their fuel expenditures is 0.12 percent. For consumers, the total value of shipments for the affected industries is $3.95 trillion in 1998, so the cost to

 Attachment 2 Attachment 2

consumers as a percentage of spending on the outputs from these industries is nearly zero, or 0.003 percent.

The cost to residential consumers at $98.9 million is larger than for any individual manufacturing market, but less than the total consumer surplus losses in the manufacturing industries. In comparison, the social cost burden to residential consumers of fuel is 0.08 percent of residential energy expenditures ($98.9 million/$131.06 billion). The commercial sector of energy users also experiences a moderate portion of total social costs at an estimated $69.3 million. This amount is also larger than for any individual manufacturing sector, but is an aggregate across all commercial NAICS codes. As a percentage of fuel expenditures by this sector of fuel consumers, the regulatory burden is 0.07 percent ($69.3 million/$96.86 billion). The cost to transportation consumers is estimated to be $47.0 million. This cost represents 0.02 percent ($47.0 million/$188.13 billion) of energy expenditures for the transportation sector.

Therefore, giving consideration to the minimal changes in prices and output in nearly all markets, and the fact that the regulatory costs that are shared by commercial, residential, and transportation users of fuel energy are a small fraction of typical energy expenditures in these

 Attachment 2 Attachment 2

sectors each year, we conclude that the economic impacts of the final rule will not be significant to any one sector of the economy.

The economic analysis described above assumed that all existing 4SRB engines and all new engines were located at major HAP emission sources and are required to install controls. However, as stated previously, we anticipate that at least 60 percent of the stationary RICE will be located at area sources which are not affected by the final rule. Therefore, the economic impacts described above would be reduced.

D. What are the non-air health, environmental and energy impacts?

We do not expect any significant wastewater, solid waste, or energy impacts resulting from the final rule. Energy impacts associated with the final rule would be due to additional energy consumption that the final rule would require by installing and operating control equipment. The only energy requirement for the operation of the control technologies is a very small increase in fuel consumption resulting from back pressure caused by the emission control system.

## 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 obligations 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" because it could have an annual effect on the economy of over $100 million. Consequently, this action

 Attachment 2 Attachment 2

was submitted to OMB for review under Executive Order 12866. Any written comments from OMB and written EPA responses are available in the docket.

As stipulated in Executive Order 12866, in deciding how or whether to regulate, EPA is required to assess all costs and benefits of available regulatory alternatives, including the alternative of not regulating. To this end, EPA prepared a detailed benefit-cost analysis in the "Regulatory Impact Analysis of the Reciprocating Internal Combustion Engines NESHAP" which is contained in the docket. The following is a summary of the benefit-cost analysis.

It is estimated that 5 years after implementation of the final rule, HAP will be reduced by 5,600 tpy due to reductions in formaldehyde, acetaldehyde, acrolein, methanol, and several other HAP from some existing and all new internal combustion engines. Formaldehyde and acetaldehyde have been classified as "probable human carcinogens" based on scientific studies conducted over the past 20 years. These 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. Acrolein, methanol and the other HAP emitted from RICE sources are not considered carcinogenic

but have been reported to cause several noncarcinogenic effects.

The control technology to reduce the level of HAP emitted from RICE are also expected to reduce emissions of criteria pollutants, primarily CO, $NO_x$, and PM, however, VOC are also reduced to a minor extent. It is estimated that CO emissions reductions totals approximately 234,400 tpy, $NO_x$ emissions reductions total approximately 167,900 tpy, and PM emissions reductions total approximately 3,700 tpy. These reductions occur from new and existing engines in operation 5 years after the implementation of the rule and are expected to continue throughout the life of the engines and continue to grow as new engines (that otherwise would not be controlled) are purchased for operation.

Human health effects associated with exposure to CO include cardiovascular system and CNS effects, which are directly related to reduced oxygen content of blood and which can result in modification of visual perception, hearing, motor and sensorimotor performance, vigilance, and cognitive ability. Emissions of $NO_x$ can transform into PM in the atmosphere which produces a variety of health and welfare effects. In general, exposure to high concentrations of $PM_{2.5}$ may aggravate existing respiratory and cardiovascular disease including asthma, bronchitis and

emphysema, especially in children and the elderly. Nitrogen oxides are also contributors 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 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 $NO_x$ emissions transform into PM, they can lead to the same health and welfare effects listed above.

At the present time, the Agency cannot provide a monetary estimate for the benefits associated with the reductions in CO. For $NO_x$ and PM, we conducted an air quality assessment to determine the change in concentrations of PM that result from reductions of $NO_x$ and direct emissions of PM at all sources of RICE. Because we are unable to identify the location of all affected existing and

new sources of RICE, our analysis is conducted in two phases. In the first phase, we conduct an air quality analysis assuming a 50 percent reduction of 1996-levels of $NO_x$ emissions and a 100 percent reduction of $PM_{10}$ emissions for all RICE sources throughout the country. The results of this analysis serve as a reasonable approximation of air quality changes to transfer to the final rule's emissions reductions at affected sources. The results of the air quality assessment served as input to a model that estimates the benefits related to the health effects listed above. In the second phase of our analysis, the value of the benefits per ton of $NO_x$ and PM reduced (e.g., $ benefit/ton reduced) associated with the air quality scenarios are then applied to the tons of $NO_x$ and PM emissions expected to be reduced by the final rule. We also used the benefit transfer method to value improvements in ozone based on the transfer of benefit values from an analysis of the 1998 $NO_x$ SIP call. In addition, although the benefits of the welfare effects of $NO_x$ are monetized in other Agency analyses, we chose not to do an analysis of the improvements in welfare effects that will result from the final rule. Alternatively, we could transfer the estimates of welfare benefits from these other studies to this analysis, but chose not to do so because these studies with estimated welfare benefits differ in the

 Attachment 2 Attachment 2

source and location of emissions and associated impacted populations.

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 CAA. We used many of the same models and assumptions used in the Nonroad Diesel and IAQR analyses as well as other Regulatory Impact Analyses (RIA) 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 RIA, 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 Industrial Boilers and Process Heaters NESHAP. A similar method has also been used in recent benefits analyses for the proposed Nonroad Large Spark-Ignition Engines and Recreational

 Attachment 2 Attachment 2

Engines rule (67 FR 68241, November 8, 2002).

The sum of benefits from the two phases of analysis and the ozone benefit transfer estimate provide an estimate of the total benefits of the final rule. Total benefits of the final rule are approximately $280 million (1998$).

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 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

 Attachment 2 Attachment 2

reduction in HAP 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

(6) Uncertainties associated with the benefit transfer approach.

Despite these uncertainties, we have determined that the benefit-cost analysis provides a reasonable indication of the expected economic benefits of the final rule under a given set of assumptions.

In addition to the presentation of quantified health benefits, our estimate also includes a “B” to represent those additional health and environmental benefits which could not be expressed in quantitative incidence and/or economic value terms. A full appreciation of the overall economic consequences of the RICE NESHAP requires

consideration of all benefits and costs expected to result from the new standards, not just those benefits and costs which could be expressed here in dollar terms. A full listing of the benefit categories that could not be quantified or monetized in our estimate are provided in Table 2 of this preamble.

| **Table 2. Unquantified Benefit Categories from RICE Emissions Reductions** | | | |
|---|---|---|---|
| | **Unquantified Benefit Categories Associated with HAP** | **Unquantified Benefit Categories Associated with Ozone** | **Unquantified Benefit Categories Associated with PM** |

 Attachment 2 Attachment 2

| | | | |
|---|---|---|---|
| Health Categories | Carcinogenicity mortality<br>Genotoxicity mortality<br>Non-Cancer lethality<br>Pulmonary function decrement<br>Dermal irritation<br>Eye irritation<br>Neurotoxicity<br>Immunotoxicity<br>Pulmonary function decre-ment<br>Liver damage Gastrointestinal toxicity<br>Kidney damage<br>Cardiovascular impairment<br>Hematopoietic (Blood disorders)<br>Reproductive/ Developmental toxicity | Airway responsiveness<br>Pulmonary inflammation<br>Increased susceptibility to respiratory infection<br>Acute inflammation and respiratory cell damage<br>Chronic respiratory damage/Premature aging of lungs<br>Emergency room visits for asthma | Changes in pulmonary function<br>Morphological changes<br>Altered host defense mechanisms<br>Cancer<br>Other chronic respiratory disease<br>Emergency room visits for asthma<br>Lower and upper respiratory symptoms<br>Acute bronchitis<br>Shortness of breath |

 Attachment 2 Attachment 2

| | | | |
|---|---|---|---|
| Welfare Categories | Corrosion/ Deterioration<br>Unpleasant odors<br>Transportation safety concerns<br>Yield reductions/ Foliar injury<br>Biomass decrease<br>Species richness decline<br>Species diversity decline<br>Community size decrease<br>Organism lifespan decrease<br>Trophic web shortening | Ecosystem and vegetation effects in Class I areas (e.g., national parks)<br>Damage to urban ornamentals (e.g.,grass, flowers, shrubs, and trees in urban areas)<br>Commercial field crops<br>Fruit and vegetable crops<br>Reduced yields of tree seedlings, commercial and non-commercial forests<br>Damage to ecosystems<br>Materials damage | Materials damage<br>Damage to ecosystems (e.g., acid sulfate deposition)<br>Nitrates in drinking water |

Benefit-cost comparison (or net benefits) is another tool used to evaluate the reallocation of society's resources needed to address the pollution externality created by the operation of RICE units. The additional costs of internalizing the pollution produced at major sources of emissions from RICE units is 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 case of the RICE NESHAP, we are specifying only one option, the minimal level of control mandated by the CAA, or the MACT floor.

Based on estimated compliance costs (control + administrative costs associated with Paperwork Reduction Act requirements associated with the final rule and predicted changes in the price and output of electricity and other affected products), the estimated social costs of the RICE NESHAP are $248 million (1998$). 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 $280 million in benefits from the final rule, compared to $248 million in costs. Thus, the total benefits (associated with $NO_x$ and PM reductions) exceed the estimated total costs of the final rule by $30 million + B. 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 HAP that are reduced by the final rule. It arises from ancillary reductions in PM and $NO_x$ that result from controls aimed at complying with the NESHAP. Although consideration of ancillary benefits is

 Attachment 2 Attachment 2

reasonable, we note that these benefits are not uniquely attributable to the final rule. The Agency has determined that the key rationale for controlling formaldehyde, acetaldehyde, acrolein, methanol, and the other HAP associated with the final rule is to reduce public and environmental exposure to these HAP, thereby reducing risk to public health and wildlife. Although the available science does not support quantification of these benefits at this time, the Agency has determined that the qualitative benefits are large enough to justify substantial investment in these emissions reductions.

It should be recognized, however, that this analysis does not account for many of the potential benefits that may result from these actions. 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 $SO_2$.

Table 3 of this preamble presents a summary of the costs, emissions reductions, and quantifiable benefits by engine type. Table 4 of this preamble presents a summary of net benefits. Approximately 90 percent of the total

 Attachment 2 Attachment 2

benefits ($255 million + B) are associated with $NO_x$ reductions from the 4SRB subcategory for new and existing engines. Approximately 10 percent of the total benefits ($25 million + B) are associated with the PM reductions from the compression ignition engine subcategory at new sources.

In both cases, net benefits would be greater if all the benefits of the HAP and other pollutant reductions could be quantified. Notable omissions to the net benefits include all benefits of HAP and CO reductions, including reduced cancer incidences, toxic morbidity effects, and cardiovascular and CNS effects. It is also important to note that not all benefits of $NO_x$ reductions have been monetized. Categories which have contributed significantly to monetized benefits in past analyses (see the RIA for the Heavy Duty Engine/Diesel standards) include commercial agriculture and forestry, recreational and residential visibility improvements, and estuarine improvements.

**Table 3. Summary of Costs, Emission Reductions, and Quantifiable Benefits by Engine Type**

| Type of Engine | Total Annualized Cost (million $/yr in 2005) | Emission Reductions[a] (tons/yr in 2005) | | | | Quantifiable Annual Monetized Benefits[b] (million $/yr in 2005) |
|---|---|---|---|---|---|---|
| | | HAP | CO | $NO_x$ | PM | |
| 2SLB - New | $3 | 250 | 2,025 | 0 | 0 | $B_1$ |

| | | | | | | |
|---|---|---|---|---|---|---|
| 4SLB - New | $64 | 4,035 | 36,240 | 0 | 0 | $B_3$ |
| 4SRB - Existing | $37 | 230 | 98,040 | 69,900 | 0 | $105 + $B_5$ |
| 4SRB - New | $47 | 215 | 91,820 | 98,000 | 0 | $150 + $B_9$ |
| CI - New | $96 | 305 | 6,320 | 0 | 3,700 | $25 + $B_{13}$ |
| Total | $248 | 5,035 | 234,445 | 167,900 | 3,700 | $280 + B |

[a] All benefits values are rounded to the nearest $5 million.
[b] Benefits of HAP and CO emissions reductions are not quantified in this analysis and, therefore, are not presented in this table. The quantifiable benefits are from emissions reductions of $NO_x$ and PM only. For notational purposes, unquantified benefits are indicated with a "B" to represent monetary benefits. A detailed listing of unquantified $NO_x$, PM, and HAP related health effects is provided in Table 2 of this preamble.

| **Table 4. Annual Net Benefits of the RICE NESHAP in 2005** | |
|---|---|
| | **Million 1998$[a]** |
| Social Costs[b] | $250 |
| Social Benefits[b,c]: | |
| HAP-related benefits | Not monetized |
| CO-related benefits | Not monetized |
| Ozone- and PM-related Welfare benefits | Not monetized |
| Ozone- and PM-related health benefits: | $280 + B |
| Net Benefits (Benefits-Costs)[c]: | $30 + B |

[a] All costs and benefits are rounded to the nearest $5 million.
[b] Note that costs are the total costs of reducing all pollutants, including HAP and CO, as well as $NO_x$ and $PM_{10}$. Benefits in this table are associated only with PM and $NO_x$ reductions.
[c] Not all possible benefits or disbenefits are quantified

and monetized in this analysis. Potential benefit categories that have not been quantified and monetized are listed in Table 2 of this preamble. B is the sum of all unquantified benefits and disbenefits.

B. Paperwork Reduction Act

The information collection requirements in the final rule have been submitted for approval to OMB 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

 Attachment 2 Attachment 2

burden for this collection (averaged over the first 3 years after the effective date of the final rule) is estimated to be 141,984 labor hours per year at a total annual cost of $11,377,592. 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 information collection request (ICR) are estimated at $5,302,416 (an average of $1,767,472 per year), with operation and maintenance costs of $1,206,212/yr.

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 the 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 the final rule.

C. Regulatory Flexibility Act

We have determined that it is not necessary to prepare a regulatory flexibility analysis in connection with the final rule.

For purposes of assessing the impacts of the final rule on small entities, "small entity" is defined as: (1) a small business whose parent company has fewer than 500 employees (for most affected industries); (2) a small governmental jurisdiction that is a government or 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 the final rule covers more than 25

 Attachment 2 Attachment 2

different industries. For each industry, we applied the definition of a small business provided by the Small Business Administration (SBA) at 13 CFR 121, classified by the NAICS. The SBA defines small businesses in most industries affected by the final rule as those with fewer than 500 employees. However, SBA has defined "small business" differently for a limited number of industries, either through reference to another employment cap or through the substitution of total yearly revenues in place of an employment limit. For more information on the size standards for particular industries, please refer to the regulatory impact analysis in the docket.

After considering the economic impacts of today's final rule on small entities, we have concluded that this action will not have a significant economic impact on a substantial number of small entities. In support of this conclusion, we examined the percentage of annual revenues that compliance costs may consume if small entities must absorb all of the compliance costs associated with the final rule. Since many firms will be able to pass along some or all compliance costs to customers, actual impacts to affected firms will frequently be lower than those analyzed here.

As is mentioned in section II.A of this preamble, the final rule will set standards for new and existing 4SRB

units. We identified a total of 26,832 existing engines located at commercial, industrial, and government facilities. From this initial population of 26,832 engines, 10,118 engines were excluded because the final rule will not cover engines 500 brake HP or less, emergency, or limited use engines. Of the 16,714 units remaining, 2,645 units had sufficient information to assign to model unit numbers developed during the cost analysis. These 2,645 units were linked to 834 existing facilities, owned by 153 parent companies. Sales and employment information was unavailable for 12 of the 153 parent companies. A total of 47 companies linked to engines with sufficient information to be included in the cost analysis were identified as small entities, and 13 of them own 4SRB engines. These small entities own a total of 39 4SRB units at 21 facilities.

Based on a technical support document in the docket (Docket ID Nos. OAR-2002-0059 and A-95-35) discussing the distribution of major and area sources of RICE units, we anticipate that about 60 percent of existing and future stationary RICE units will be located at area sources. This is because most RICE engines or groups of RICE engines are not major sources of HAP emissions by themselves, but may be major because they are co-located at major HAP sites. Because area sources are not covered by the NESHAP, engines

located at area sources will not incur any compliance costs associated with the RICE NESHAP. Thus, 40 percent of the existing 4SRB engines that are above 500 HP and are not backup/emergency units (the only existing engines that receive costs under the rule) and 40 percent of all new RICE projected to be added in the future (above 500 HP that are not backup/emergency units) are expected to be subject to today's action. Based on this assumption, about 16 of the 39 4SRB units identified at facilities owned by small businesses would be located at major sources.

In applying the compliance costs to our modeling for generating economic impact and small business analyses, we calculate impacts (as mentioned in Section 6 of the economic impact analysis) presuming that all 39 4SRB engines are located at major sources and hence will bear compliance costs associated with this action. We make this presumption because it is highly uncertain which facilities are major sources and which are area sources. Thus, we assume a worst case scenario that all existing 4SRB owned by small businesses are located at major sources and subject to the rule to provide a conservative or high estimate of the small business impacts. This is called an "upper bound cost scenario" because only 40 percent and not 100 percent of all RICE units are estimated to be at major sources, and

 Attachment 2 Attachment 2

therefore subject to the rule. It is reasonable to expect that the percentage of facilities owned by small businesses that are major sources would be lower than the average for the whole source category, so even fewer existing 4SRB owned by small businesses may be affected.

Under the upper bound cost scenario, there are no small firms that have compliance costs above 3 percent of firm revenues and two small firms owning 4SRB engines that have impacts between 1 and 3 percent of revenues. In addition to 12 small firms with 4SRB engines, there is one small government in the population database affected by the final rule. The costs to this city are approximately $3 per capita annually assuming their engine is affected by the final rule, less than 0.01 percent of median household income.

Based on this subset of the existing engines population, the final rule will not affect small entities owning RICE at a cost to sales ratio (CSR) greater than 3 percent, while potentially up to 15 percent (2/13) of those small entities owning RICE greater than 500 HP will have compliance costs between 1 and 3 percent of sales under an upper bound cost scenario.

Assuming the same breakdown of large and small company ownership of engines in the total population of existing

 Attachment 2 Attachment 2

engines as in the subset with parent company information identified, the Agency expects that approximately 82 (13 * 16,714/2,645) small entities in the existing population of RICE owners would have CSR between 1 and 3 percent under the upper bound cost scenario described earlier in this preamble section.

In addition, because many small entities owning RICE will not be affected because of the exclusion of engines 500 brake HP or less, the percentage of all small companies owning RICE that are affected by the final rule is even smaller. Based on the proportion of engines in the population database that are greater than 500 brake HP and are not backup units (16,714/26,832, or 62.3 percent) and assuming that small companies own the same proportion of small engines (500 brake HP or less) as they do of engines greater than 500 brake HP, the Agency estimates that 628 small companies own RICE. Of all small companies owning RICE, 13 percent (82/628) are expected to have CSR between 1 and 3 percent under the upper bound cost scenario described earlier in this preamble section and in the economic impact analysis report. If the percentage of RICE owned by small companies that are located at major sources is the same as the engine population overall (40 percent), about 5 percent of small companies owning RICE would be expected to have CSR

greater than 1 percent.

The median profit margin for the industries in our analysis is approximately 2 to 7 percent. Therefore, based on this median profit margin data, it seems reasonable to consider the number of small firms with CSR above 3 percent in screening for significant economic impacts on small businesses.

This screening analysis shows that none of the small entities in the population database have impacts greater than 3 percent and two small firms that we were able to analyze with the available data have impacts between 1 and 3 percent even under the upper bound cost scenario described earlier in this preamble section and in the economic impact analysis report.

Section II.A also states that new 4SRB engines will be affected by today's action. For new sources, it can be reasonably assumed that the investment decision to purchase a new engine may be slightly altered as a result of the final rule. In fact, as shown in section 6 of the economic impact analysis, for the entire population of affected engines (approximately 20,000 new engines over a 5-year period), 2 fewer engines (0.01 percent) may be purchased due to changes in costs of the engines and market responses to the final rule. It is not possible, however, to determine

 Attachment 2 Attachment 2

future investment decisions by the small entities in the affected industries, so we cannot link these 2 engines to any one firm (small or large). Overall, it is very unlikely that a substantial number of small firms who may consider purchasing a new engine will be significantly impacted, because the decision to purchase new engines is not altered to a large extent. In addition to this consideration of costs on some firms attributable to the final rule, we note the final rule is likely to increase revenues for many small firms, including those not regulated by the final rule, due to a predictable increase in prices of natural gas in the industry. An increase in natural gas prices is expected since the compliance costs of today's action will lead to market adjustments such as decreased output, thereby leading to increased prices. Concurrent with this increase in natural gas prices will be some increase in revenues for those small firms in affected industries that are not subject to this action, for they experience revenues due to the increased natural gas prices without bearing any of the compliance costs.

Although the final rule will not have a significant economic impact on a substantial number of small entities, we nonetheless have tried to reduce the impact of the final rule on small entities. In the final rule, we are applying

 Attachment 2 Attachment 2

the minimum level of control allowed by the CAA (i.e., the MACT floor), and the minimum level of monitoring, recordkeeping, and reporting by affected sources. In addition, as mentioned section II of the preamble, new RICE units with capacities 500 brake HP or less and those that operate as emergency and limited use units are not covered by the final rule, provisions that should greatly 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 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 under section 202 of the UMRA which is summarized below. The written statement is in the docket.

Statutory Authority

 Attachment 2 Attachment 2

As discussed previously in this preamble, the statutory authority for the final rule is section 112 of the CAA. Section 112(b) lists the 189 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 based on MACT which require existing and new major sources to control emissions of HAP. These NESHAP apply to all stationary RICE located at major sources of HAP emissions, however, only certain existing and new or reconstructed stationary RICE have substantive regulatory requirements.

In compliance with section 205(a), we identified and considered a reasonable number of regulatory alternatives. The regulatory alternative upon which the rule is based represents the MACT floor for stationary RICE and, as a result, it is the least costly and least burdensome alternative.

Social Costs and Benefits

The RIA prepared for the final rule, including the Agency's assessment of costs and benefits, is detailed in the "Regulatory Impact Analysis for the Final RICE NESHAP" in the docket. Based on estimated compliance costs on all sources associated with the final rule and the predicted change in prices and production in the affected industries,

 Attachment 2 Attachment 2

the estimated social costs of the final rule are $248 million (1998$).

It is estimated that 5 years after implementation of the final rule, HAP will be reduced by 5,600 tpy due to reductions in formaldehyde, acetaldehyde, acrolein, methanol and other HAP from existing and new stationary RICE. Formaldehyde and acetaldehyde have been classified as "probable human carcinogens." Acrolein, methanol and the other HAP are not considered carcinogenic, but produce several other toxic effects. The final rule will also achieve reductions in 234,400 tons of CO, approximately 167,900 tons of $NO_x$ per year, and approximately 3,700 tons of PM per year. Exposure to CO can effect the cardiovascular system and the central nervous system. Emissions of $NO_x$ can transform into PM, which can result in fatalities and many respiratory problems (such as asthma or bronchitis); and $NO_x$ can also transform into ozone causing several respiratory problems to affected populations.

At the present time, the Agency cannot provide a monetary estimate for the benefits associated with the reductions in HAP and CO. For $NO_x$ and PM, we estimated the benefits associated with health effects of PM directly and secondary PM that is formed from NOx, but were unable to quantify all categories of benefits of $NO_x$ (particularly

 Attachment 2 Attachment 2

those associated with ecosystem and environmental effects). Unquantified benefits are noted with "B" in the estimates presented below. Total monetized benefits are approximately $280 million + B (1998$). These monetized benefits should be considered along with the many categories of benefits that we are unable to place a dollar value on to consider the total benefits of the final rule.

Future and Disproportionate Costs

The UMRA 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.

Effects on the National Economy

The UMRA requires that we estimate the effect of the final rule on the national economy. To the 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

 Attachment 2 Attachment 2

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 "Regulatory Impact Analysis for RICE NESHAP" in the docket. This analysis provides estimates of the effect of the final rule on most of the categories mentioned above. The results of the economic impact analysis are summarized previously in this preamble.

Consultation with Government Officials

The UMRA requires that we describe the extent of our 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 UMRA requires that we develop a plan for informing and advising small governments that may be significantly or uniquely impacted by a proposal. Although the final rule does not 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.

 Attachment 2 Attachment 2

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

 Attachment 2 Attachment 2

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

The final rule is not a "significant energy action" as defined in Executive Order 13211 (66 FR 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 Regulatory Impact Analysis (RIA) estimates changes in prices and production levels for all energy markets (i.e., petroleum, natural gas, electricity, and coal). We also estimate how changes in the energy markets will impact other users of energy, such as manufacturing markets and residential, industrial and commercial consumers of energy. The results of the economic impact analysis for the final rule are shown for 2005, for this is the year in which full implementation of the final rule is expected to occur. These results show that there will be minimal changes in price, if any, for most energy products affected by

 Attachment 2 Attachment 2

implementation of the final rule. Only a slight price increase (about 0.008 percent to 0.04 percent) may occur in three of the energy sectors: petroleum, electricity, and coal products nationwide; and approximately a three-tenths of one percent (i.e., 0.30 percent) change in natural gas prices. The change in energy costs associated with the final rule, however, represents only 0.08 percent of expected annual energy expenditures by residential consumers in 2005, a 0.02 percent change for transportation consumers of energy, and about 0.07 percent of energy expenditures in the commercial sector. In addition, no discernable impact on exports or imports of energy products is expected. Therefore, the impacts on energy markets and users will be relatively small nationwide as a result of implementation of the final rule. In addition, as is discussed in previous sections of this preamble, the economic analysis for RICE assumed that all existing 4SRB engines and all new engines were located at major HAP emission sources and are required to install controls. However, we anticipate that at least 60 percent of the stationary RICE will be located at area sources which are not affected by the final rule. Therefore, the economic impacts on the energy sector as described above would be reduced.

Therefore, we conclude that the final rule when

 Attachment 2 Attachment 2

implemented will not 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 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 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 methods in the final rule: EPA Methods 1, 1A, 3A, 3B, 4, 10 of 40 CFR part 60, appendix A; EPA Methods 320 and 323 of 40 CFR part 63, appendix A; and PS 3, and PS 4A, of 40 CFR part 60, appendix B. Consistent with the NTTAA, EPA conducted searches to identify voluntary consensus standards in addition to these EPA methods/performance specifications. No applicable voluntary consensus standards were identified for EPA Methods 1A, PS

3, and PS 4A. The search and review results have been documented and are placed in the docket (Docket ID Nos. OAR-2002-0059 and A-95-35) for the final rule.

Two voluntary consensus standards were identified as acceptable alternatives to the EPA methods specified in the final rule. One 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 cited in the final rule as an acceptable alternative to EPA Methods 3A and 10 for identifying carbon monoxide and oxygen concentrations for the final rule when the fuel is natural gas.

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 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.

In addition to the voluntary consensus standards EPA uses in the final rule, the search for emissions measurement

procedures identified six other 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/performance specifications for the purposes of the final rule. Therefore, the EPA does not intend to adopt these standards. The reasons for the determinations of these five methods are discussed below.

The voluntary consensus standard ASTM D3154-00, "Standard Method for Average Velocity in a Duct (Pitot Tube Method)," is impractical as an alternative to EPA Methods 1, 3B, and 4 for the purposes of the final rule since the standard appears to lack in quality control and quality assurance requirements. Specifically, ASTM D3154-00 does not include the following: (1) proof that openings of standard pitot tube have not plugged during the test; (2) if differential pressure gauges other than inclined manometers (*e.g.*, magnehelic gauges) are used, their calibration must be checked after each test series; and (3) the frequency and validity range for calibration of the temperature sensors.

The voluntary consensus standard, CAN/CSA Z223.2-M86(1986), "Method for the Continuous Measurement of Oxygen, Carbon Dioxide, Carbon Monoxide, Sulphur Dioxide, and Oxides

 Attachment 2 Attachment 2

of Nitrogen in Enclosed Combustion Flue Gas Streams," is unacceptable as a substitute for EPA Method 3A since it does not include quantitative specifications for measurement system performance, most notably the calibration procedures and instrument performance characteristics. The instrument performance characteristics that are provided are nonmandatory and also do not provide the same level of quality assurance as the EPA methods. For example, the zero and span/calibration drift is only checked weekly, whereas the EPA methods requires drift checks after each run.

Two very similar standards, ASTM D5835-95, "Standard Practice for Sampling Stationary Source Emissions for Automated Determination of Gas Concentration," and ISO 10396:1993, "Stationary Source Emissions: Sampling for the Automated Determination of Gas Concentrations," are impractical alternatives to EPA Method 3A for the purposes of the final rule because they lack in detail and quality assurance/quality control requirements. Specifically, these two standards do not include the following: (1) sensitivity of the method; (2) acceptable levels of analyzer calibration error; (3) acceptable levels of sampling system bias; (4) zero drift and calibration drift limits, time span, and required testing frequency; (5) a method to test the interference response of the analyzer; (6) procedures to

 Attachment 2 Attachment 2

determine the minimum sampling time per run and minimum measurement time; and (7) specifications for data recorders, in terms of resolution (all types) and recording intervals (digital and analog recorders, only).

The voluntary consensus standard ISO 12039:2001, "Stationary Source Emissions--Determination of Carbon Monoxide, Carbon Dioxide, and Oxygen--Automated Methods," is not acceptable as an alternative to EPA Method 3A. This ISO standard is similar to EPA Method 3A, but is missing some key features. In terms of sampling, the hardware required by ISO 12039:2001 does not include a 3-way calibration valve assembly or equivalent to block the sample gas flow while calibration gases are introduced. In its calibration procedures, ISO 12039:2001 only specifies a two-point calibration while EPA Method 3A specifies a three-point calibration. Also, ISO 12039:2001 does not specify performance criteria for calibration error, calibration drift, or sampling system bias tests as in the EPA method, although checks of these quality control features are required by the ISO standard.

One of the six voluntary consensus standards identified in this search, ASME/BSR MFC 13M, "Flow Measurement by Velocity Traverse" (for EPA Method 2 and possibly 1), was not available at the time the review was conducted for the

purposes of the final rule because it was under development by a voluntary consensus body.

Tables 4, 5, and 6 to 40 CFR part 60, subpart ZZZZ, list the EPA testing methods included in the final rule. 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 a "major rule" as defined by 5 U.S.C. 804(2). The final rule will be effective on [INSERT DATE 60 DAYS AFTER DATE OF PUBLICATION IN THE FEDERAL REGISTER].

**List of Subjects in 40 CFR Part 63**

 Attachment 2 Attachment 2

Environmental protection, Administrative practice and procedure, Air pollution control, Hazardous substances, Intergovernmental relations, Reporting and recordkeeping requirements.

February 26, 2004

Dated:

/s/

_____

Michael O. Leavitt,
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 ZZZZ to read as follows:

**Subpart ZZZZ — National Emission Standards for Hazardous Air Pollutants for Stationary Reciprocating Internal Combustion Engines**

Sec.

**WHAT THIS SUBPART COVERS**

63.6580 What is the purpose of subpart ZZZZ?
63.6585 Am I subject to this subpart?
63.6590 What parts of my plant does this subpart cover?
63.6595 When do I have to comply with this subpart?

**EMISSION LIMITATIONS**

63.6600 What emission limitations and operating limitations must I meet?

**GENERAL COMPLIANCE REQUIREMENTS**

63.6605 What are my general requirements for complying with this subpart?

**TESTING AND INITIAL COMPLIANCE REQUIREMENTS**

63.6610 By what date must I conduct the initial performance tests or other initial compliance

demonstrations?
63.6615 When must I conduct subsequent performance tests?
63.6620 What performance tests and other procedures must I use?
63.6625 What are my monitoring, installation, operation, and maintenance requirements?
63.6630 How do I demonstrate initial compliance with the emission limitations and operating limitations?

**CONTINUOUS COMPLIANCE REQUIREMENTS**

63.6635 How do I monitor and collect data to demonstrate continuous compliance?
63.6640 How do I demonstrate continuous compliance with the emission limitations and operating limitations?

**NOTIFICATION, REPORTS, AND RECORDS**

63.6645 What notifications must I submit and when?
63.6650 What reports must I submit and when?
63.6655 What records must I keep?
63.6660 In what form and how long must I keep my records?

**OTHER REQUIREMENTS AND INFORMATION**

63.6665 What parts of the General Provisions apply to me?
63.6670 Who implements and enforces this subpart?
63.6675 What definitions apply to this subpart?

**TABLES TO SUBPART ZZZZ OF PART 63**

Table 1a to Subpart ZZZZ of Part 63.
Emission Limitations for Existing, New, and Reconstructed Spark Ignition, 4SRB Stationary RICE
Table 1b to Subpart ZZZZ of Part 63.
Operating Limitations for Existing, New, and Reconstructed Spark Ignition, 4SRB Stationary RICE
Table 2a to Subpart ZZZZ of Part 63.
Emission Limitations for New and Reconstructed Lean Burn and Compression Ignition Stationary RICE
Table 2b to Subpart ZZZZ of Part 63.
Operating Limitations for New and Reconstructed Lean Burn and Compression Ignition Stationary RICE
Table 3 to Subpart ZZZZ of Part 63.
Subsequent Performance Tests
Table 4 to Subpart ZZZZ of Part 63.
Requirements for Performance Tests

Table 5 to Subpart ZZZZ of Part 63.
Initial Compliance with Emission Limitations and Operating Limitations
Table 6 to Subpart ZZZZ of Part 63.
Continuous Compliance with Emission Limitations and Operating Limitations
Table 7 to Subpart ZZZZ of Part 63.
Requirements for Reports
Table 8 to Subpart ZZZZ of Part 63.
Applicability of General Provisions to Subpart ZZZZ

**WHAT THIS SUBPART COVERS**

§63.6580 What is the purpose of subpart ZZZZ?

Subpart ZZZZ establishes national emission limitations and operating limitations for hazardous air pollutants (HAP) emitted from stationary reciprocating internal combustion engines (RICE) located at major sources of HAP emissions. This subpart also establishes requirements to demonstrate initial and continuous compliance with the emission limitations and operating limitations.

§63.6585 Am I subject to this subpart?

You are subject to this subpart if you own or operate a stationary RICE at a major source of HAP emissions, except if the stationary RICE is being tested at a stationary RICE test cell/stand.

(a) A stationary RICE is any internal combustion engine which uses reciprocating motion to convert heat energy into mechanical work and which is not mobile. Stationary RICE differ from mobile RICE in that a stationary RICE is not a non-road engine as defined at 40 CFR 1068.30,

and is not used to propel a motor vehicle or a vehicle used solely for competition.

(b) A major source of HAP emissions is a plant site that emits or has the potential to emit any single HAP at a rate of 10 tons (9.07 megagrams) or more per year or any combination of HAP at a rate of 25 tons (22.68 megagrams) or more per year, except that for oil and gas production facilities, a major source of HAP emissions is determined for each surface site.

§63.6590 What parts of my plant does this subpart cover?

This subpart applies to each affected source.

(a) Affected source. An affected source is any existing, new, or reconstructed stationary RICE with a site-rating of more than 500 brake horsepower located at a major source of HAP emissions, excluding stationary RICE being tested at a stationary RICE test cell/stand.

(1) Existing stationary RICE. A stationary RICE is existing if you commenced construction or reconstruction of the stationary RICE before December 19, 2002. A change in ownership of an existing stationary RICE does not make that stationary RICE a new or reconstructed stationary RICE.

(2) New stationary RICE. A stationary RICE is new if you commenced construction of the stationary RICE on or after December 19, 2002.

 Attachment 2 Attachment 2

(3) Reconstructed stationary RICE. A stationary RICE is reconstructed if you meet the definition of reconstruction in §63.2 and reconstruction is commenced on or after December 19, 2002.

(b) Stationary RICE subject to limited requirements.

(1) An affected source which meets either of the criteria in paragraph (b)(1)(i) through (ii) of this section does not have to meet the requirements of this subpart and of subpart A of this part except for the initial notification requirements of §63.6645(d).

(i) The stationary RICE is a new or reconstructed emergency stationary RICE; or

(ii) The stationary RICE is a new or reconstructed limited use stationary RICE.

(2) A new or reconstructed stationary RICE which combusts landfill or digester gas equivalent to 10 percent or more of the gross heat input on an annual basis must meet the initial notification requirements of §63.6645(d) and the requirements of §§63.6625(c), 63.6650(g), and 63.6655(c). These stationary RICE do not have to meet the emission limitations and operating limitations of this subpart.

(3) A stationary RICE which is an existing spark ignition 2 stroke lean burn (2SLB) stationary RICE, an existing spark ignition 4 stroke lean burn (4SLB) stationary

 Attachment 2 Attachment 2

RICE, an existing compression ignition (CI) stationary RICE, an existing emergency stationary RICE, an existing limited use stationary RICE, or an existing stationary RICE that combusts landfill gas or digester gas equivalent to 10 percent or more of the gross heat input on an annual basis, does not have to meet the requirements of this subpart and of subpart A of this part. No initial notification is necessary.

§63.6595 When do I have to comply with this subpart?

(a) Affected sources.

(1) If you have an existing stationary RICE, you must comply with the applicable emission limitations and operating limitations no later than [3 YEARS AFTER THE DATE THE FINAL RULE IS PUBLISHED IN THE FEDERAL REGISTER].

(2) If you start up your new or reconstructed stationary RICE before [60 DAYS AFTER THE DATE THE FINAL RULE IS PUBLISHED IN THE FEDERAL REGISTER], you must comply with the applicable emission limitations and operating limitations in this subpart no later than [60 DAYS AFTER THE DATE THE FINAL RULE IS PUBLISHED IN THE FEDERAL REGISTER].

(3) If you start up your new or reconstructed stationary RICE after [60 DAYS AFTER THE DATE THE FINAL RULE IS PUBLISHED IN THE FEDERAL REGISTER], you must comply with the applicable emission limitations and operating

limitations in this subpart upon startup of your affected source.

(b) Area sources that become major sources. If you have an area source that increases its emissions or its potential to emit such that it becomes a major source of HAP, the compliance dates in paragraphs (b)(1) and (2) of this section apply to you.

(1) Any stationary RICE for which construction or reconstruction is commenced after the date when your area source becomes a major source of HAP must be in compliance with this subpart upon startup of your affected source.

(2) Any stationary RICE for which construction or reconstruction is commenced before your area source becomes a major source of HAP must be in compliance with this subpart within 3 years after your area source becomes a major source of HAP.

(c) If you own or operate an affected source, you must meet the applicable notification requirements in §63.6645 and in 40 CFR part 63, subpart A.

**EMISSION AND OPERATING LIMITATIONS**

§63.6600 What emission limitations and operating limitations must I meet?

(a) If you own or operate an existing, new, or reconstructed spark ignition 4 stroke rich burn (4SRB)

stationary RICE located at a major source of HAP emissions, you must comply with the emission limitations in Table 1(a) of this subpart and the operating limitations in Table 1(b) of this subpart which apply to you.

(b) If you own or operate a new or reconstructed 2SLB or 4SLB stationary RICE or a new or reconstructed CI stationary RICE located at a major source of HAP emissions, you must comply with the emission limitations in Table 2(a) of this subpart and the operating limitations in Table 2(b) of this subpart which apply to you.

(c) If you own or operate: an existing 2SLB stationary RICE, an existing 4SLB stationary RICE, or an existing CI stationary RICE; a stationary RICE that combusts landfill gas or digester gas equivalent to 10 percent or more of the gross heat input on an annual basis; an emergency stationary RICE; or a limited use stationary RICE, you do not need to comply with the emission limitations in Tables 1(a) and 2(a) of this subpart or operating limitations in Tables 1(b) and 2(b) of this subpart.

**GENERAL COMPLIANCE REQUIREMENTS**

<u>§63.6605 What are my general requirements for complying with this subpart?</u>

(a) You must be in compliance with the emission limitations and operating limitations in this subpart that

apply to you at all times, except during periods of startup, shutdown, and malfunction.

(b) If you must comply with emission limitations and operating limitations, you must operate and maintain your stationary RICE, including air pollution control 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**

<u>§63.6610 By what date must I conduct the initial performance tests or other initial compliance demonstrations?</u>

(a) You must conduct the initial performance test or other initial compliance demonstrations in Table 4 of this subpart that apply to you within 180 days after the compliance date that is specified for your stationary RICE in §63.6595 and according to the provisions in §63.7(a)(2).

(b) If you commenced construction or reconstruction between December 19, 2002 and [DATE THE FINAL RULE IS PUBLISHED IN THE FEDERAL REGISTER], you must demonstrate initial compliance with either the proposed emission limitations or the promulgated emission limitations no later than [240 DAYS AFTER THE DATE THE FINAL RULE IS PUBLISHED IN THE FEDERAL REGISTER] or no later than 180 days after

startup of the source, whichever is later, according to §63.7(a)(2)(ix).

(c) If you commenced construction or reconstruction between December 19, 2002 and [DATE THE FINAL RULE IS PUBLISHED IN THE FEDERAL REGISTER], and you chose to comply with the proposed emission limitations when demonstrating initial compliance, you must conduct a second performance test to demonstrate compliance with the promulgated emission limitations by [3 YEARS AND 180 DAYS AFTER THE DATE THE FINAL RULE IS PUBLISHED IN THE FEDERAL REGISTER] or after startup of the source, whichever is later, according to §63.7(a)(2)(ix).

(d) An owner or operator is not required to conduct an initial performance test on units for which a performance test has been previously conducted, but the test must meet all of the conditions described in paragraphs (d)(1) through (5) of this section.

(1) The test must have been conducted using the same methods specified in this subpart, and these methods must have been followed correctly.

(2) The test must not be older than 2 years.

(3) The test must be reviewed and accepted by the Administrator.

(4) Either no process or equipment changes must have

been made since the test was performed, or the owner or operator must be able to demonstrate that the results of the performance test, with or without adjustments, reliably demonstrate compliance despite process or equipment changes.

(5) The test must be conducted at any load condition within plus or minus 10 percent of 100 percent load.

§63.6615 When must I conduct subsequent performance tests?

If you must comply with the emission limitations and operating limitations, you must conduct subsequent performance tests as specified in Table 3 of this subpart.

§63.6620 What performance tests and other procedures must I use?

(a) You must conduct each performance test in Tables 3 and 4 of this subpart that applies to you.

(b) Each performance test must be conducted according to the requirements in §63.7(e)(1) and under the specific conditions that this subpart specifies in Table 4. The test must be conducted at any load condition within plus or minus 10 percent of 100 percent load.

(c) You may not conduct performance tests during periods of startup, shutdown, or malfunction, as specified in §63.7(e)(1).

(d) You must conduct three separate test runs for each performance test required in this section, as specified in

 Attachment 2 Attachment 2

§63.7(e)(3). Each test run must last at least 1 hour.

(e) You must use Equation 1 of this section to determine compliance with the percent reduction requirement:

$$\frac{C_i - C_o}{C_i} \times 100 = R \qquad (Eq.\ 1)$$

Where:

$C_i$ = concentration of CO or formaldehyde at the control device inlet,
$C_o$ = concentration of CO or formaldehyde at the control device outlet, and
R = percent reduction of CO or formaldehyde emissions.

You must normalize the carbon monoxide (CO) or formaldehyde concentrations at the inlet and outlet of the control device to a dry basis and to 15 percent oxygen, or an equivalent percent carbon dioxide ($CO_2$). If pollutant concentrations are to be corrected to 15 percent oxygen and $CO_2$ concentration is measured in lieu of oxygen concentration measurement, a $CO_2$ correction factor is needed. Calculate the $CO_2$ correction factor as described in paragraphs (e)(1) through (3) of this section.

(1) Calculate the fuel-specific $F_o$ value for the fuel burned during the test using values obtained from Method 19, Section 5.2, and the following equation:

$$F_o = \frac{0.209\ F_d}{F_c} \qquad (Eq.\ 2)$$

Where:

$F_o$ = Fuel factor based on the ratio of oxygen volume to the ultimate $CO_2$ volume produced by the fuel at zero percent excess air.
0.209 = Fraction of air that is oxygen, percent/100.
$F_d$ = Ratio of the volume of dry effluent gas to the gross calorific value of the fuel from Method 19, $dsm^3/J$ ($dscf/10^6$ Btu).
$F_c$ = Ratio of the volume of $CO_2$ produced to the gross calorific value of the fuel from Method 19, $dsm^3/J$ ($dscf/10^6$ Btu).

(2) Calculate the $CO_2$ correction factor for correcting measurement data to 15 percent oxygen, as follows:

$$X_{CO2} = \frac{5.9}{F_o} \qquad (Eq.\ 3)$$

Where:

$X_{CO2}$ = $CO_2$ correction factor, percent.
5.9 = 20.9 percent $O_2$ - 15 percent $O_2$, the defined $O_2$ correction value, percent.

(3) Calculate the $NO_x$ and $SO_2$ gas concentrations adjusted to 15 percent $O_2$ using $CO_2$ as follows:

$$C_{adj} = C_d\ \frac{X_{CO2}}{\%CO_2} \qquad (Eq.\ 4)$$

Where:

$\%CO_2$ = Measured $CO_2$ concentration measured, dry basis, percent.

(f) If you comply with the emission limitation to reduce CO and you are not using an oxidation catalyst, if you comply with the emission limitation to reduce formaldehyde and you are not using NSCR, or if you comply with the emission limitation to limit the concentration of formaldehyde in the stationary RICE exhaust and you are not using an oxidation catalyst or NSCR, you must petition the Administrator for operating limitations to be established during the initial performance test and continuously monitored thereafter; or for approval of no operating limitations. You must not conduct the initial performance test until after the petition has been approved by the Administrator.

(g) If you petition the Administrator for approval of operating limitations, your petition must include the information described in paragraphs (g)(1) through (5) of this section.

(1) Identification of the specific parameters you propose to use as operating limitations;

(2) A discussion of the relationship between these parameters and HAP emissions, identifying how HAP emissions change with changes in these parameters, and how limitations on these parameters will serve to limit HAP emissions;

 Attachment 2 Attachment 2

(3) A discussion of how you will establish the upper and/or lower values for these parameters which will establish the limits on these parameters in the operating limitations;

(4) A discussion identifying the methods you will use to measure and the instruments you will use to monitor these parameters, as well as the relative accuracy and precision of these methods and instruments; and

(5) A discussion identifying the frequency and methods for recalibrating the instruments you will use for monitoring these parameters.

(h) If you petition the Administrator for approval of no operating limitations, your petition must include the information described in paragraphs (h)(1) through (7) of this section.

(1) Identification of the parameters associated with operation of the stationary RICE and any emission control device which could change intentionally (e.g., operator adjustment, automatic controller adjustment, etc.) or unintentionally (e.g., wear and tear, error, etc.) on a routine basis or over time;

(2) A discussion of the relationship, if any, between changes in the parameters and changes in HAP emissions;

(3) For the parameters which could change in such a

way as to increase HAP emissions, a discussion of whether establishing limitations on the parameters would serve to limit HAP emissions;

(4) For the parameters which could change in such a way as to increase HAP emissions, a discussion of how you could establish upper and/or lower values for the parameters which would establish limits on the parameters in operating limitations;

(5) For the parameters, a discussion identifying the methods you could use to measure them and the instruments you could use to monitor them, as well as the relative accuracy and precision of the methods and instruments;

(6) For the parameters, a discussion identifying the frequency and methods for recalibrating the instruments you could use to monitor them; and

(7) A discussion of why, from your point of view, it is infeasible or unreasonable to adopt the parameters as operating limitations.

(i) The engine percent load during a performance test must be determined by documenting the calculations, assumptions, and measurement devices used to measure or estimate the percent load in a specific application. A written report of the average percent load determination must be included in the notification of compliance status.

 Attachment 2 Attachment 2

The following information must be included in the written report: the engine model number, the engine manufacturer, the year of purchase, the manufacturer's site-rated brake horsepower, the ambient temperature, pressure, and humidity during the performance test, and all assumptions that were made to estimate or calculate percent load during the performance test must be clearly explained. If measurement devices such as flow meters, kilowatt meters, beta analyzers, stain gauges, etc. are used, the model number of the measurement device, and an estimate of its accurate in percentage of true value must be provided.

§63.6625 What are my monitoring, installation, operation, and maintenance requirements?

(a) If you elect to install a CEMS as specified in Table 5 of this subpart, you must install, operate, and maintain a CEMS to monitor CO and either oxygen or $CO_2$ at both the inlet and the outlet of the control device according to the requirements in paragraphs (a)(1) through (4) of this section.

(1) Each CEMS must be installed, operated, and maintained according to the applicable performance specifications of 40 CFR part 60, appendix B.

(2) You must conduct an initial performance evaluation and an annual relative accuracy test audit (RATA) of each

CEMS according to the requirements in §63.8 and according to the applicable performance specifications of 40 CFR part 60, appendix B as well as daily and periodic data quality checks in accordance with 40 CFR part 60, appendix F, procedure 1.

(3) As specified in §63.8(c)(4)(ii), each CEMS must complete a minimum of one cycle of operation (sampling, analyzing, and data recording) for each successive 15-minute period. You must have at least two data points, with each representing a different 15-minute period, to have a valid hour of data.

(4) The CEMS data must be reduced as specified in §63.8(g)(2) and recorded in parts per million or parts per billion (as appropriate for the applicable limitation) at 15 percent oxygen or the equivalent $CO_2$ concentration.

(b) If you are required to install a continuous parameter monitoring system (CPMS) as specified in Table 5 of this subpart, you must install, operate, and maintain each CPMS according to the requirements in §63.8.

(c) If you are operating a new or reconstructed stationary RICE which fires landfill gas or digester gas equivalent to 10 percent or more of the gross heat input on an annual basis, you must monitor and record your fuel usage daily with separate fuel meters to measure the volumetric flow rate of each fuel. In addition, you must operate your

 Attachment 2 Attachment 2

stationary RICE in a manner which reasonably minimizes HAP emissions.

§63.6630 How do I demonstrate initial compliance with the emission limitations and operating limitations?

(a) You must demonstrate initial compliance with each emission and operating limitation that applies to you according to Table 5 of this subpart.

(b) During the initial performance test, you must establish each operating limitation in Tables 1(b) and 2(b) of this subpart that applies to you.

(c) You must submit the Notification of Compliance Status containing the results of the initial compliance demonstration according to the requirements in §63.6645.

**CONTINUOUS COMPLIANCE REQUIREMENTS**

§63.6635 How do I monitor and collect data to demonstrate continuous compliance?

(a) If you must comply with emission and operating limitations, you must monitor and collect data according to this section.

(b) Except for monitor malfunctions, associated repairs, and required quality assurance or control activities (including, as applicable, calibration checks and required zero and span adjustments), you must monitor continuously at all times that the stationary RICE is

operating.

(c) You may not use data recorded during monitoring malfunctions, associated repairs, and required quality assurance or control activities in data averages and calculations used to report emission or operating levels. You must, however, use all the valid data collected during all other periods.

§63.6640 How do I demonstrate continuous compliance with the emission limitations and operating limitations?

(a) You must demonstrate continuous compliance with each emission limitation and operating limitation in Tables 1(a) and 1(b) and Tables 2(a) and 2(b) of this subpart that apply to you according to methods specified in Table 6 of this subpart.

(b) You must report each instance in which you did not meet each emission limitation or operating limitation in Tables 1(a) and 1(b) and Tables 2(a) and 2(b) 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 §63.6650. If you change your catalyst, you must reestablish the values of the operating parameters measured during the initial performance test. When you reestablish the values of your operating parameters, you

must also conduct a performance test to demonstrate that you are meeting the required emission limitation applicable to your stationary RICE.

(c) During periods of startup, shutdown, and malfunction, you must operate in accordance with your startup, shutdown, and malfunction plan.

(d) Consistent with §§63.6(e) and 63.7(e)(1), deviations from the emission or operating limitations that occur during a period of startup, shutdown, or malfunction are not violations if you demonstrate to the Administrator's satisfaction that you were operating in accordance with the startup, shutdown, and malfunction plan. For new and reconstructed stationary RICE, deviations from the emission or operating limitations that occur during the first 200 hours of operation from engine startup (engine burn-in period) are not violations.

(e) You must also report each instance in which you did not meet the requirements in Table 8 of this subpart that apply to you. If you own or operate an existing 2SLB stationary RICE, an existing 4SLB stationary RICE, an existing CI stationary RICE, an existing emergency stationary RICE, an existing limited use emergency stationary RICE, or an existing stationary RICE which fires landfill gas or digester gas equivalent to 10 percent or

 Attachment 2 Attachment 2

more of the gross heat input on an annual basis, you do not need to comply with the requirements in Table 8 of this subpart. If you own or operate a new or reconstructed stationary RICE that combusts landfill gas or digester gas equivalent to 10 percent or more of the gross heat input on an annual basis, a new or reconstructed emergency stationary RICE, or a new or reconstructed limited use stationary RICE, you do not need to comply with the requirements in Table 8 of this subpart, except for the initial notification requirements.

**NOTIFICATIONS, REPORTS, AND RECORDS**

<u>§63.6645 What notifications must I submit and when?</u>

(a) You must submit all of the notifications in §§63.7(b) and (c), 63.8(e), (f)(4) and (f)(6), 63.9(b) through (e), and (g) and (h) that apply to you by the dates specified.

(b) As specified in §63.9(b)(2), if you must comply with the emission and operating limitations, and you start up your stationary RICE before the effective date of this subpart, you must submit an Initial Notification not later than [120 DAYS AFTER DATE THE FINAL RULE IS PUBLISHED IN THE FEDERAL REGISTER].

(c) If you start up your new or reconstructed stationary RICE on or after the [DATE THE FINAL RULE IS

PUBLISHED IN THE FEDERAL REGISTER], you must submit an Initial Notification not later than 120 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 requirements of this subpart, in accordance with §63.6590(b), your notification should include the information in §63.9(b)(2)(i) through (v), and a statement that your stationary RICE has no additional requirements and explain the basis of the exclusion (for example, that it operates exclusively as an emergency stationary RICE).

(e) If you are required to conduct a performance test, you must submit a Notification of Intent to conduct a performance test at least 60 days before the performance test is scheduled to begin as required in §63.7(b)(1).

(f) If you are required to conduct a performance test or other initial compliance demonstration as specified in Tables 4 and 5 to this subpart, you must submit a Notification of Compliance Status according to §63.9(h)(2)(ii).

(1) For each initial compliance demonstration required in Table 5 of this subpart that does not include a performance test, you must submit the Notification of Compliance Status before the close of business on the 30th

day following the completion of the initial compliance demonstration.

(2) For each initial compliance demonstration required in Table 5 of this subpart that includes a performance test conducted according to the requirements in Table 4 to this subpart, you must submit the Notification of Compliance Status, including the performance test results, before the close of business on the 60th day following the completion of the performance test according to §63.10(d)(2).

§63.6650 What reports must I submit and when?

(a) You must submit each report in Table 7 of this subpart that applies to you.

(b) Unless the Administrator has approved a different schedule for submission of reports under §63.10(a), you must submit each report by the date in Table 7 of this subpart and according to the requirements in paragraphs (b)(1) through (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 §63.6595 and ending on June 30 or December 31, whichever date is the first date following the end of the first calendar half after the compliance date that is specified for your source in §63.6595.

(2) The first Compliance report must be postmarked or

delivered no later than July 31 or January 31, whichever date follows the end of the first calendar half after the compliance date that is specified for your affected source in §63.6595.

(3) 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 stationary RICE that is subject to permitting regulations pursuant to 40 CFR part 70 or 71, and if the permitting authority has established dates for submitting semiannual reports pursuant to 40 CFR 70.6 (a)(3)(iii)(A) or 40 CFR 71.6 (a)(3)(iii)(A), you may submit the first and subsequent Compliance reports according to the dates the permitting authority has established instead of according to the dates in paragraphs (b)(1) through (4) of this section.

(c) The Compliance report must contain the information in paragraphs (c)(1) through (6) of this section.

(1) Company name and address.

 Attachment 2 Attachment 2

(2) Statement by a responsible official, with that official's name, title, and signature, certifying the accuracy of the content of the report.

(3) Date of report and beginning and ending dates of the reporting period.

(4) If you had a startup, shutdown, or malfunction during the reporting period, the compliance report must include the information in §63.10(d)(5)(i).

(5) If there are no deviations from any emission or operating limitations that apply to you, a statement that there were no deviations from the emission or operating limitations during the reporting period.

(6) If there were no periods during which the continuous monitoring system (CMS), including CEMS and CPMS, was out-of-control, as specified in §63.8(c)(7), a statement that there were no periods during which the CMS was out-of-control during the reporting period.

(d) For each deviation from an emission or operating limitation that occurs for a stationary RICE where you are not using a CMS to comply with the emission or operating limitations in this subpart, the Compliance report must contain the information in paragraphs (c)(1) through (4) of this section and the information in paragraphs (d)(1) and (2) of this section.

 Attachment 2 Attachment 2

(1) The total operating time of the stationary RICE at which the deviation occurred during the reporting period.

(2) Information on the number, duration, and cause of deviations (including unknown cause, if applicable), as applicable, and the corrective action taken.

(e) For each deviation from an emission or operating limitation occurring for a stationary RICE where you are using a CMS to comply with the emission and operating limitations in this subpart, you must include information in paragraphs (c)(1) through (4) and (e)(1) through (12) of this section.

(1) The date and time that each malfunction started and stopped.

(2) The date, time, and duration that each CMS was inoperative, except for zero (low-level) and high-level checks.

(3) The date, time, and duration that each CMS was out-of-control, including the information in §63.8(c)(8).

(4) The date and time that each deviation started and stopped, and whether each deviation occurred during a period of malfunction or during another period.

(5) A summary of the total duration of the deviation during the reporting period, and the total duration as a percent of the total source operating time during that

 Attachment 2 Attachment 2

reporting period.

(6) A breakdown of the total duration of the deviations during the reporting period into those that are due to control equipment problems, process problems, other known causes, and other unknown causes.

(7) A summary of the total duration of CMS downtime during the reporting period, and the total duration of CMS downtime as a percent of the total operating time of the stationary RICE at which the CMS downtime occurred during that reporting period.

(8) An identification of each parameter and pollutant (CO or formaldehyde) that was monitored at the stationary RICE.

(9) A brief description of the stationary RICE.

(10) A brief description of the CMS.

(11) The date of the latest CMS certification or audit.

(12) A description of any changes in CMS, processes, or controls since the last reporting period.

(f) Each affected source that has obtained a title V operating permit pursuant to 40 CFR part 70 or 71 must report all deviations as defined in this subpart in the semiannual monitoring report required by 40 CFR 70.6 (a)(3)(iii)(A) or 40 CFR 71.6(a)(3)(iii)(A). If an affected

source submits a Compliance report pursuant to Table 7 of this subpart along with, or as part of, the semiannual monitoring report required by 40 CFR 70.6(a)(3)(iii)(A) or 40 CFR 71.6(a)(3)(iii)(A), and the Compliance report includes all required information concerning deviations from any emission or operating limitation in this subpart, submission of the Compliance report shall be deemed to satisfy any obligation to report the same deviations in the semiannual monitoring report. However, submission of a Compliance report shall not otherwise affect any obligation the affected source may have to report deviations from permit requirements to the permit authority.

(g) If you are operating as a new or reconstructed stationary RICE which fires landfill gas or digester gas equivalent to 10 percent or more of the gross heat input on an annual basis, you must submit an annual report according to Table 7 of this subpart by the date specified unless the Administrator has approved a different schedule, according to the information described in paragraphs (b)(1) through (b)(5) of this section. You must report the data specified in (g)(1) through (g)(3) of this section.

(1) Fuel flow rate of each fuel and the heating values that were used in your calculations. You must also demonstrate that the percentage of heat input provided by

landfill gas or digester gas is equivalent to 10 percent or more of the total fuel consumption on an annual basis.

(2) The operating limits provided in your federally enforceable permit, and any deviations from these limits.

(3) Any problems or errors suspected with the meters.

§63.6655 What records must I keep?

(a) If you must comply with the emission and operating limitations, you must keep the records described in paragraphs (a)(1) through (a)(3), (b)(1) through (b)(3) and (c) of this section.

(1) A copy of each notification and report that you submitted to comply with this subpart, including all documentation supporting any Initial Notification or Notification of Compliance Status that you submitted, according to the requirement in §63.10(b)(2)(xiv).

(2) The records in §63.6(e)(3)(iii) through (v) related to startup, shutdown, and malfunction.

(3) Records of performance tests and performance evaluations as required in §63.10(b)(2)(viii).

(b) For each CEMS or CPMS, you must keep the records listed in paragraphs (b)(1) through (3) of this section.

(1) Records described in §63.10(b)(2)(vi) through (xi).

(2) Previous (i.e., superseded) versions of the

performance evaluation plan as required in §63.8(d)(3).

(3) Requests for alternatives to the relative accuracy test for CEMS or CPMS as required in §63.8(f)(6)(i), if applicable.

(c) If you are operating a new or reconstructed stationary RICE which fires landfill gas or digester gas equivalent to 10 percent or more of the gross heat input on an annual basis, you must keep the records of your daily fuel usage monitors.

(d) You must keep the records required in Table 6 of this subpart to show continuous compliance with each emission or operating limitation that applies to you.

§63.6660 In what form and how long must I keep my records?

(a) Your records must be in a form suitable and readily available for expeditious review according to §63.10(b)(1).

(b) As specified in §63.10(b)(1), you must keep each record for 5 years following the date of each occurrence, measurement, maintenance, corrective action, report, or record.

(c) You must keep each record readily accessible in hard copy or electronic form 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**

§63.6665 What parts of the General Provisions apply to me?

Table 8 of this subpart shows which parts of the General Provisions in §§63.1 through 63.15 apply to you. If you own or operate an existing 2SLB, an existing 4SLB stationary RICE, an existing CI stationary RICE, an existing stationary RICE that combusts landfill gas or digester gas equivalent to 10 percent or more of the gross heat input on an annual basis, an existing emergency stationary RICE, or an existing limited use stationary RICE, you do not need to comply with any of the requirements of the General Provisions. If you own or operate a new stationary RICE that combusts landfill gas or digester gas equivalent to 10 percent or more of the gross heat input on an annual basis, a new emergency stationary RICE, or a new limited use stationary RICE, you do not need to comply with the requirements in the General Provisions except for the initial notification requirements.

§63.6670 Who implements and enforces this subpart?

(a) This subpart is implemented and enforced by the U.S. EPA, or a delegated authority such as your State, local, or tribal agency. If the U.S. EPA Administrator has

delegated authority to your State, local, or tribal agency, then that agency (as well as the U.S. EPA) has the authority to implement and enforce this subpart. You should contact your U.S. EPA Regional Office to find out whether this subpart is delegated to your State, local, or tribal agency.

(b) In delegating implementation and enforcement authority of this subpart to a State, local, or tribal agency under 40 CFR part 63, subpart E, the authorities contained in paragraph (c) of this section are retained by the Administrator of the U.S. EPA and are not transferred to the State, local, or tribal agency.

(c) The authorities that will not be delegated to State, local, or tribal agencies are:

(1) Approval of alternatives to the non-opacity emission limitations and operating limitations in §63.6600 under §63.6(g).

(2) Approval of major alternatives to test methods under §63.7(e)(2)(ii) and (f) and as defined in §63.90.

(3) Approval of major alternatives to monitoring under §63.8(f) and as defined in §63.90.

(4) Approval of major alternatives to recordkeeping and reporting under §63.10(f) and as defined in §63.90.

(5) Approval of a performance test which was conducted prior to the effective date of the rule, as specified in

 Attachment 2 Attachment 2

§63.6610(b).

§63.6675 What definitions apply to this subpart?

Terms used in this subpart are defined in the Clean Air Act (CAA); in 40 CFR 63.2, the General Provisions of this part; and in this section as follows:

Area source means any stationary source of HAP that is not a major source as defined in part 63.

Associated equipment as used in this subpart and as referred to in section 112(n)(4) of the CAA, means equipment associated with an oil or natural gas exploration or production well, and includes all equipment from the well bore to the point of custody transfer, except glycol dehydration units, storage vessels with potential for flash emissions, combustion turbines, and stationary RICE.

CAA means the Clean Air Act (42 U.S.C. 7401 et seq., as amended by Public Law 101-549, 104 Stat. 2399).

Compression ignition engine means any stationary RICE in which a high boiling point liquid fuel injected into the combustion chamber ignites when the air charge has been compressed to a temperature sufficiently high for auto-ignition, including diesel engines, dual-fuel engines, and engines that are not spark ignition.

Custody transfer means the transfer of hydrocarbon liquids or natural gas: after processing and/or treatment

in the producing operations, or from storage vessels or automatic transfer facilities or other such equipment, including product loading racks, to pipelines or any other forms of transportation. For the purposes of this subpart, the point at which such liquids or natural gas enters a natural gas processing plant is a point of custody transfer.

Deviation means any instance in which an affected source subject to this subpart, or an owner or operator of such a source:

(1) Fails to meet any requirement or obligation established by this subpart, including but not limited to any emission limitation or operating limitation;

(2) Fails to meet any term or condition that is adopted to implement an applicable requirement in this subpart and that is included in the operating permit for any affected source required to obtain such a permit; or

(3) Fails to meet any emission limitation or operating limitation in this subpart during malfunction, regardless or whether or not such failure is permitted by this subpart.

(4) Fails to 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).

Diesel engine means any stationary RICE in which a high

boiling point liquid fuel injected into the combustion chamber ignites when the air charge has been compressed to a temperature sufficiently high for auto-ignition. This process is also known as compression ignition.

Diesel fuel means any liquid obtained from the distillation of petroleum with a boiling point of approximately 150 to 360 degrees Celsius. One commonly used form is fuel oil number 2.

Digester gas means any gaseous by-product of wastewater treatment typically formed through the anaerobic decomposition of organic waste materials and composed principally of methane and $CO_2$.

Dual-fuel engine means any stationary RICE in which a liquid fuel (typically diesel fuel) is used for compression ignition and gaseous fuel (typically natural gas) is used as the primary fuel.

Emergency stationary RICE means any stationary RICE that operates in an emergency situation. Examples include stationary RICE used to produce power for critical networks or equipment (including power supplied to portions of a facility) when electric power from the local utility is interrupted, or stationary RICE used to pump water in the case of fire or flood, etc. Emergency stationary RICE may be operated for the purpose of maintenance checks and

 Attachment 2 Attachment 2

readiness testing, provided that the tests are recommended by the manufacturer, the vendor, or the insurance company associated with the engine. Required testing of such units should be minimized, but there is no time limit on the use of emergency stationary RICE in emergency situations and for routine testing and maintenance. Emergency stationary RICE may also operate an additional 50 hours per year in non-emergency situations.

Four-stroke engine means any type of engine which completes the power cycle in two crankshaft revolutions, with intake and compression strokes in the first revolution and power and exhaust strokes in the second revolution.

Gaseous fuel means a material used for combustion which is in the gaseous state at standard atmospheric temperature and pressure conditions.

Glycol dehydration unit means a device in which a liquid glycol (including, but not limited to, ethylene glycol, diethylene glycol, or triethylene glycol) absorbent directly contacts a natural gas stream and absorbs water in a contact tower or absorption column (absorber). The glycol contacts and absorbs water vapor and other gas stream constituents from the natural gas and becomes "rich" glycol. This glycol is then regenerated in the glycol dehydration unit reboiler. The "lean" glycol is then recycled.

Hazardous air pollutants (HAP) means any air pollutants listed in or pursuant to section 112(b) of the CAA.

ISO standard day conditions means 288 degrees Kelvin (15 degrees Celsius), 60 percent relative humidity and 101.3 kilopascals pressure.

Landfill gas means a gaseous by-product of the land application of municipal refuse typically formed through the anaerobic decomposition of waste materials and composed principally of methane and $CO_2$.

Lean burn engine means any two-stroke or four-stroke spark ignited engine that does not meet the definition of a rich burn engine.

Limited use stationary RICE means any stationary RICE that operates less than 100 hours per year.

Liquid fuel means any fuel in liquid form at standard temperature and pressure, including but not limited to diesel, residual/crude oil, kerosene/naphtha (jet fuel), and gasoline.

Liquefied petroleum gas means any liquefied hydrocarbon gas obtained as a by-product in petroleum refining of natural gas production.

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. Failures that are caused in part by poor maintenance or careless operation are not malfunctions.

Natural gas means a naturally occurring mixture of

 Attachment 2 Attachment 2

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.

Non-selective catalytic reduction (NSCR) means an add-on catalytic nitrogen oxides ($NO_x$) control device for rich burn engines that, in a two-step reaction, promotes the conversion of excess oxygen, $NO_x$, CO, and volatile organic compounds (VOC) into $CO_2$, nitrogen, and water.

Oil and gas production facility as used in this subpart means any grouping of equipment where hydrocarbon liquids are processed, upgraded (i.e., remove impurities or other constituents to meet contract specifications), or stored prior to the point of custody transfer; or where natural gas is processed, upgraded, or stored prior to entering the natural gas transmission and storage source category. For purposes of a major source determination, facility (including a building, structure, or installation) means oil and natural gas production and processing equipment that is located within the boundaries of an individual surface site as defined in this section. Equipment that is part of a facility will typically be located within close proximity to other equipment located at the same facility. Pieces of production equipment or groupings of equipment located on

different oil and gas leases, mineral fee tracts, lease tracts, subsurface or surface unit areas, surface fee tracts, surface lease tracts, or separate surface sites, whether or not connected by a road, waterway, power line or pipeline, shall not be considered part of the same facility. Examples of facilities in the oil and natural gas production source category include, but are not limited to, well sites, satellite tank batteries, central tank batteries, a compressor station that transports natural gas to a natural gas processing plant, and natural gas processing plants.

Oxidation catalyst means an add-on catalytic control device that controls CO and VOC by oxidation.

Peaking unit or engine means any standby engine intended for use during periods of high demand that are not emergencies.

Percent load means the fractional power of an engine compared to its maximum manufacturer's design capacity at engine site conditions. Percent load may range between 0 percent to above 100 percent.

Potential to emit means the maximum capacity of a stationary source to emit a pollutant under its physical and operational design. Any physical or operational limitation on the capacity of the stationary source to emit a pollutant, including air pollution control equipment and

 Attachment 2 Attachment 2

restrictions on hours of operation or on the type or amount of material combusted, stored, or processed, shall be treated as part of its design if the limitation or the effect it would have on emissions is federally enforceable. For oil and natural gas production facilities subject to subpart HH of this part, the potential to emit provisions in §63.760(a) may be used. For natural gas transmission and storage facilities subject to subpart HHH of this part, the maximum annual facility gas throughput for storage facilities may be determined according to §63.1270(a)(1) and the maximum annual throughput for transmission facilities may be determined according to §63.1270(a)(2).

Production field facility means those oil and gas production facilities located prior to the point of custody transfer.

Production well means any hole drilled in the earth from which crude oil, condensate, or field natural gas is extracted.

Propane means a colorless gas derived from petroleum and natural gas, with the molecular structure $C_3H_8$.

Responsible official means responsible official as defined in 40 CFR 70.2.

Rich burn engine means any four-stroke spark ignited engine where the manufacturer's recommended operating

air/fuel ratio divided by the stoichiometric air/fuel ratio at full load conditions is less than or equal to 1.1. Engines originally manufactured as rich burn engines, but modified prior to December 19, 2002 with passive emission control technology for $NO_x$ (such as pre-combustion chambers) will be considered lean burn engines. Also, existing engines where there are no manufacturer's recommendations regarding air/fuel ratio will be considered a rich burn engine if the excess oxygen content of the exhaust at full load conditions is less than or equal to 2 percent.

Site-rated HP means the maximum manufacturer's design capacity at engine site conditions.

Spark ignition engine means a type of engine in which a compressed air/fuel mixture is ignited by a timed electric spark generated by a spark plug.

Stationary reciprocating internal combustion engine (RICE) means any reciprocating internal combustion engine which uses reciprocating motion to convert heat energy into mechanical work and which is not mobile. Stationary RICE differ from mobile RICE in that a stationary RICE is not a non-road engine as defined at 40 CFR 1068.30, and is not used to propel a motor vehicle or a vehicle used solely for competition.

Stationary RICE test cell/stand means an engine test

 Attachment 2 Attachment 2

cell/stand, as defined in subpart PPPPP of this part, that tests stationary RICE.

Stoichiometric means the theoretical air-to-fuel ratio required for complete combustion.

Storage vessel with the potential for flash emissions means any storage vessel that contains a hydrocarbon liquid with a stock tank gas-to-oil ratio equal to or greater than 0.31 cubic meters per liter and an American Petroleum Institute gravity equal to or greater than 40 degrees and an actual annual average hydrocarbon liquid throughput equal to or greater than 79,500 liters per day. Flash emissions occur when dissolved hydrocarbons in the fluid evolve from solution when the fluid pressure is reduced.

Subpart means 40 CFR part 63, subpart ZZZZ.

Surface site means any combination of one or more graded pad sites, gravel pad sites, foundations, platforms, or the immediate physical location upon which equipment is physically affixed.

Two-stroke engine means a type of engine which completes the power cycle in single crankshaft revolution by combining the intake and compression operations into one stroke and the power and exhaust operations into a second stroke. This system requires auxiliary scavenging and inherently runs lean of stoichiometric.

 Attachment 2 Attachment 2

**Tables to Subpart ZZZZ of Part 63**

**Table 1a to Subpart ZZZZ of Part 63. Emission Limitations for Existing, New, and Reconstructed Spark Ignition, 4SRB Stationary RICE**

As stated in §§63.6600 and 63.6640, you must comply with the following emission limitations for existing, new and reconstructed 4SRB stationary RICE:

| For each . . . | You must meet <u>one</u> of the following emission limitations . . . |
|---|---|
| 1. 4SRB stationary RICE | a. reduce formaldehyde emissions by 76 percent or more. If you commenced construction or reconstruction between December 19, 2002 and [THE DATE THE FINAL RULE IS PUBLISHED IN THE FEDERAL REGISTER], you may reduce formaldehyde emissions by 75 percent or more until [3 YEARS AFTER THE DATE THE FINAL RULE IS PUBLISHED IN THE FEDERAL REGISTER].<br><br>OR<br><br>b. limit the concentration of formaldehyde in the stationary RICE exhaust to 350 ppbvd or less at 15 percent $O_2$. |

**Table 1b to Subpart ZZZZ of Part 63. Operating Limitations for Existing, New, and Reconstructed Spark Ignition, 4SRB Stationary RICE**

As stated in §§63.6600, 63.6630 and 63.6640, you must comply with the following operating emission limitations for existing, new and reconstructed 4SRB stationary RICE:

| For each . . . | You must meet the following operating limitation . . . |
|---|---|

| | |
|---|---|
| 1. 4SRB stationary RICE complying with the requirement to reduce formaldehyde emissions by 76 percent or more (or by 75 percent or more, if applicable) and using NSCR; or 4SRB stationary RICE complying with the requirement to limit the concentration of formaldehyde in the stationary RICE exhaust to 350 ppbvd or less at 15 percent $O_2$ and using NSCR | a. maintain your catalyst so that the pressure drop across the catalyst does not change by more than two inches of water from the pressure drop across the catalyst measured during the initial performance test;<br><br>AND<br><br>b. maintain the temperature of your stationary RICE exhaust so that the catalyst inlet temperature is greater than or equal to 750°F and less than or equal to 1250°F. |
| 2. 4SRB stationary RICE complying with the requirement to reduce formaldehyde emissions by 76 percent or more (or by 75 percent, if applicable), and not using NSCR; or 4SRB stationary RICE complying with the requirement to limit the concentration of formaldehyde in the stationary RICE exhaust to 350 ppbvd or less at 15 percent $O_2$ and not using NSCR | comply with any operating limitations approved by the Administrator. |

**Table 2a to Subpart ZZZZ of Part 63. Emission Limitations for New and Reconstructed Lean Burn and Compression Ignition Stationary RICE**

As stated in §§63.6600 and 63.6640, you must comply with the following emission limitations for new and reconstructed lean burn and new and reconstructed compression ignition stationary RICE:

| **For each . . .** | **You must meet the following emission limitation . . .** |
|---|---|

| | |
|---|---|
| 1. 2SLB stationary RICE | a. reduce CO emissions by 58 percent or more;<br><br>OR<br><br>b. limit concentration of formaldehyde in the stationary RICE exhaust to 12 ppmvd or less at 15 percent $O_2$. If you commenced construction or reconstruction between December 19, 2002 and [DATE THE FINAL RULE IS PUBLISHED IN THE FEDERAL REGISTER], you may limit concentration of formaldehyde to 17 ppmvd or less at 15 percent $O_2$ until [3 YEARS AFTER THE DATE THE FINAL RULE IS PUBLISHED IN THE FEDERAL REGISTER]. |
| 2. 4SLB stationary RICE | a. reduce CO emissions by 93 percent or more;<br><br>OR<br><br>b. limit concentration of formaldehyde in the stationary RICE exhaust to 14 ppmvd or less at 15 percent $O_2$. |
| 3. CI stationary RICE | a. reduce CO emissions by 70 percent or more;<br><br>OR<br><br>b. limit concentration of formaldehyde in the stationary RICE exhaust to 580 ppbvd or less at 15 percent $O_2$. |

 Attachment 2 Attachment 2

**Table 2b to Subpart ZZZZ of Part 63. Operating Limitations for New and Reconstructed Lean Burn and Compression Ignition Stationary RICE**

As stated in §§63.6600, 63.6630, and 63.6640, you must comply with the following operating limitations for new and reconstructed lean burn and new and reconstructed compression ignition stationary RICE:

| For each . . . | You must meet the following operating limitation . . . |
|---|---|
| 1. 2SLB and 4SLB stationary RICE and CI stationary RICE complying with the requirement to reduce CO emissions and using an oxidation catalyst; or 2SLB and 4SLB stationary RICE and CI stationary RICE complying with the requirement to limit the concentration of formaldehyde in the stationary RICE exhaust and using an oxidation catalyst | a. maintain your catalyst so that the pressure drop across the catalyst does not change by more than two inches of water from the pressure drop across the catalyst that was measured during the initial performance test;<br><br>AND<br><br>b. maintain the temperature of your stationary RICE exhaust so that the catalyst inlet temperature is greater than or equal to 450°F and less than or equal to 1350°F. |
| 2. 2SLB and 4SLB stationary RICE and CI stationary RICE complying with the requirement to reduce CO emissions and not using an oxidation catalyst; or 2SLB and 4SLB stationary RICE and CI stationary RICE complying with the requirement to limit the concentration of formaldehyde in the stationary RICE exhaust and not using an oxidation catalyst | comply with any operating limitations approved by the Administrator. |

**Table 3 to Subpart ZZZZ of Part 63. Subsequent Performance Tests**

As stated in §§63.6615 and 63.6620, you must comply with the following subsequent performance test requirements:

| For each . . . | Complying with the requirement to . . . | You must . . . |
|---|---|---|
| 1. 2SLB and 4SLB stationary RICE and CI stationary RICE | reduce CO emissions and not using a CEMS | conduct subsequent performance tests semiannually[a]. |
| 2. 4SRB stationary RICE with a brake horsepower $5,000 | reduce formaldehyde emissions | conduct subsequent performance tests semiannually[a]. |
| 3. stationary RICE (all stationary RICE subcategories and all brake horsepower ratings) | limit the concentration of formaldehyde in the stationary RICE exhaust | conduct subsequent performance tests semiannually[a]. |

a. After you have demonstrated compliance for two consecutive tests, you may reduce the frequency of subsequent performance tests to annually. If the results of any subsequent annual performance test indicate the stationary RICE is not in compliance with the CO or formaldehyde emission limitation, or you deviate from any of your operating limitations, you must resume semiannual performance tests.

**Table 4 to Subpart ZZZZ of Part 63. Requirements for Performance Tests**

As stated in §§63.6610, 63.6620, and 63.6640, you must comply with the following requirements for performance tests:

| For each . . . | Complying with the requirement to . . . | You must . . . | Using . . . | According to the following requirements . . . |
|---|---|---|---|---|

| | | | | |
|---|---|---|---|---|
| 1. 2SLB and 4SLB stationary RICE and CI stationary RICE | a. reduce CO emissions | i. measure the $O_2$ at the inlet and outlet of the control device<br><br>AND | (1) portable CO and $O_2$ analyzer | (a) using ASTM D6522-00[a]. Measurements to determine $O_2$ must be made at the same time as the measurements for CO concentra-tion. |
| | | ii. measure the CO at the inlet and the outlet of the control device | (1) portable CO and $O_2$ analyzer | (a) using ASTM D6522-00[a]. The CO concentra-tion must be at 15 percent $O_2$, dry basis. |
| 2. 4SRB stationary RICE | a. reduce formalde-hyde emissions | i. select the sampling port location and the number of traverse points<br><br>AND | (1) Method 1 or 1A of 40 CFR part 60, appendix A §63.7(d)(1)(i) | (a) sampling sites must be located at the inlet and outlet of the control device. |

 Attachment 2 Attachment 2

| | | |
|---|---|---|
| ii. measure $O_2$ at the inlet and outlet of the control device<br><br>AND | (1) Method 3 or 3A or 3B of 40 CFR part 60, appendix A | (a) measurements to determine $O_2$ concentra-tion must be made at the same time as the measurements for formaldehyde concentra-tion. |
| iii. measure moisture content at the inlet and outlet of the control device<br><br>AND | (1) Method 4 of 40 CFR part 60, appendix A, or Test Method 320 of 40 CFR part 63, appendix A, or ASTM D 6348-03 | (a) measurements to determine moisture content must be made at the same time and location as the measurements for formaldehyde concentra-tion. |

 Attachment 2 Attachment 2

| | | | | |
|---|---|---|---|---|
| | | iv. measure formalde-hyde at the inlet and the outlet of the control device | (1) Method 320 or 323 of 40 CFR part 63, appendix A; or ASTM D6348-03[b], provided in ASTM D6348-03 Annex A5 (Analyte Spiking Techniqu e), the percent R must be greater than or equal to 70 and less than or equal to 130. | (a) formaldehyde concentra-tion must be at 15 percent $O_2$, dry basis. Results of this test consist of the average of the three 1-hour or longer runs. |
| 3. stationary RICE | a. limit the concentra-tion of formalde-hyde in the stationary RICE exhaust | i. select the sampling port location and the number of traverse points<br><br>AND | (1) Method 1 or 1A of 40 CFR part 60, appendix A §63.7(d)(1)(i) | (a) if using a control device, the sampling site must be located at the outlet of the control device. |

| | | |
|---|---|---|
| ii. determine the $O_2$ concentr a-tion of the station-ary RICE exhaust at the sampling port location<br><br>AND | (1) Method 3 or 3A or 3B of 40 CFR part 60, appendix A | (a) measurements to determine $O_2$ concentra-tion must be made at the same time and location as the measurements for formaldehyde concentra-tion. |
| iii. measure moisture content of the station-ary RICE exhaust at the sampling port location<br><br>AND | (1) Method 4 of 40 CFR part 60, appendix A, or Test Method 320 of 40 CFR part 63, appendix A, or ASTM D 6348-03 | (a) measurements to determine moisture content must be made at the same time and location as the measurements for formaldehyde concentra-tion. |

 Attachment 2 Attachment 2

| | | | | |
|---|---|---|---|---|
| | | iv. measure formalde-hyde at the exhaust of the station-ary RICE | (1) Method 320 or 323 of 40 CFR part 63, appendix A; or ASTM D6348-03[b], provided in ASTM D6348-03 Annex A5 (Analyte Spiking Techniqu e), the percent R must be greater than or equal to 70 and less than or equal to 130. | (a) Formaldehyde concentratio n must be at 15 percent $O_2$, dry basis. Results of this test consist of the average of the three 1-hour or longer runs. |

[a] You may also use Methods 3A and 10 as options to ASTM-D6522-00. You may obtain a copy of ASTM-D6522-00 from at least one of the following addresses: American Society for Testing and Materials, 100 Barr Harbor Drive, West Conshohochen, PA 19428-2959, or University Microfilms International, 300 North Zeeb Road, Ann Arbor, MI 48106.
[b] You may obtain a copy of ASTM-D6348-03 from at least one of the following addresses: American Society for Testing and Materials, 100 Barr Harbor Drive, West Conshohochen, PA 19428-2959, or University Microfilms International, 300 North Zeeb Road, Ann Arbor, MI 48106.

 Attachment 2 Attachment 2

**Table 5 to Subpart ZZZZ of Part 63. Initial Compliance with Emission Limitations and Operating Limitations**

As stated in §§63.6625 and 63.6630, you must initially comply with the emission and operating limitations as required by the following:

| For each . . . | Complying with the requirement to . . . | You have demonstrated initial compliance if . . . |
|---|---|---|
| 1. 2SLB and 4SLB stationary RICE and CI stationary RICE | a. reduce CO emissions and using oxidation catalyst, and using a CPMS | i. the average reduction of emissions of CO determined from the initial performance test achieves the required CO percent reduction;<br><br>AND<br><br>ii. you have installed a CPMS to continuously monitor catalyst inlet temperature according to the requirements in §63.6625(b);<br><br>AND<br><br>iii. you have recorded the catalyst pressure drop and catalyst inlet temperature during the initial performance test. |

 Attachment 2 Attachment 2

| | | |
|---|---|---|
| 2. 2SLB and 4SLB stationary RICE and CI stationary RICE | a. reduce CO emissions and not using oxidation catalyst | i. the average reduction of emissions of CO determined from the initial performance test achieves the required CO percent reduction.<br><br>AND<br><br>ii. you have installed a CPMS to continuously monitor operating parameters approved by the Administrator (if any) according to the requirements in §63.6625(b);<br><br>AND<br><br>iii. you have recorded the approved operating parameters (if any) during the initial performance test. |
| 3. 2SLB and 4SLB stationary RICE and CI stationary RICE | a. reduce CO emissions, and using a CEMS | i. you have installed a CEMS to continuously monitor CO and either $O_2$ or $CO_2$ at both the inlet and outlet of the oxidation catalyst according to the requirements in §63.6625(a);<br><br>AND<br><br>ii. you have conducted a performance evaluation of your CEMS using PS 3 and 4A of 40 CFR part 60, appendix B;<br><br>AND<br><br>iii. the average reduction of CO calculated using §63.6620 equals or exceeds the required percent reduction. The initial test comprises the first 4-hour |

| | | |
|---|---|---|
| | | period after successful validation of the CEMS. Compliance is based on the average percent reduction achieved during the 4-hour period. |
| 4. 4SRB stationary RICE | a. reduce formaldehyde emissions and using NSCR | i. the average reduction of emissions of formaldehyde determined from the initial performance test is equal to or greater than the required formaldehyde percent reduction;<br><br>AND<br><br>ii. you have installed a CPMS to continuously monitor catalyst inlet temperature according to the requirements in §63.6625(b);<br><br>AND<br><br>iii. you have recorded the catalyst pressure drop and catalyst inlet temperature during the initial performance test. |

 Attachment 2 Attachment 2

| | | |
|---|---|---|
| 5. 4SRB stationary RICE | a. reduce formaldehyde emissions and not using NSCR | i. the average reduction of emissions of formaldehyde determined from the initial performance test is equal to or greater than the required formaldehyde percent reduction.<br><br>AND<br><br>ii. you have installed a CPMS to continuously monitor operating parameters approved by the Administrator (if any) according to the requirements in §63.6625(b);<br><br>AND<br><br>iii. you have recorded the approved operating parameters (if any) during the initial performance test. |
| 6. stationary RICE | a. limit the concentration of formaldehyde in the stationary RICE exhaust and using oxidation catalyst or NSCR | i. the average formaldehyde concentration, corrected to 15 percent $O_2$, dry basis, from the three test runs is less than or equal to the formaldehyde emission limitation.<br><br>AND<br><br>ii. you have installed a CPMS to continuously monitor catalyst inlet temperature according to the requirements in §63.6625(b);<br><br>AND<br><br>iii. you have recorded the catalyst pressure drop and catalyst inlet temperature during the initial |

 Attachment 2 Attachment 2

| | | |
|---|---|---|
| | | performance test. |
| 7. stationary RICE | a. limit the concentration of formaldehyde in the stationary RICE exhaust and not using oxidation catalyst or NSCR | i. the average formaldehyde concentration, corrected to 15 percent $O_2$, dry basis, from the three test runs is less than or equal to the formaldehyde emission limitation.<br><br>AND<br><br>ii. you have installed a CPMS to continuously monitor operating parameters approved by the Administrator (if any) according to the requirements in §63.6625(b);<br><br>AND<br><br>iii. you have recorded the approved operating parameters (if any) during the initial performance test. |

**Table 6 to Subpart ZZZZ of Part 63. Continuous Compliance with Emission Limitations and Operating Limitations**

As stated in §63.6640, you must continuously comply with the emissions and operating limitations as required by the following:

| For each . . . | Complying with the requirement to . . . | You must demonstrate continuous compliance by . . . |
|---|---|---|
| 1. 2SLB and 4SLB stationary RICE and CI stationary RICE | a. reduce CO emissions and using an oxidation catalyst, and using a CPMS | i. conducting semiannual performance tests for CO to demonstrate that the required CO percent reduction is achieved[a]; |

| | | |
|---|---|---|
| | | AND<br><br>ii. collecting the catalyst inlet temperature data according to §63.6625(b);<br><br>AND<br><br>iii. reducing these data to 4-hour rolling averages;<br><br>AND<br><br>iv. maintaining the 4-hour rolling averages within the operating limitations for the catalyst inlet temperature established during the initial performance test;<br><br>AND<br><br>v. measuring the pressure drop across the catalyst once per month and demonstrating that the pressure drop across the catalyst is within the operating limitation established during the performance test. |
| 2. 2SLB and 4SLB stationary RICE and CI stationary RICE | a. reduce CO emissions and not using an oxidation catalyst, and using a CPMS | i. conducting semiannual performance tests for CO to demonstrate that the required CO percent reduction is achieved[a];<br><br>AND<br><br>ii. collecting the approved operating parameter (if any) data according to §63.6625(b);<br><br>AND |

| | | |
|---|---|---|
| | | iii. reducing these data to 4-hour rolling averages;<br><br>AND<br><br>iv. maintaining the 4-hour rolling averages within the operating limitations for the operating parameters established during the performance test. |
| 3. 2SLB and 4SLB stationary RICE and CI stationary RICE | a. reduce CO emissions and using a CEMS | i. collecting the monitoring data according to §63.6625(a), reducing the measurements to 1-hour averages, calculating the percent reduction of CO emissions according to §63.6620;<br><br>AND<br><br>ii. demonstrating that the catalyst achieves the required percent reduction of CO emissions over the 4-hour averaging period;<br><br>AND<br><br>iii. conducting an annual RATA of your CEMS using PS 3 and 4A of 40 CFR part 60, appendix B, as well as daily and periodic data quality checks in accordance with 40 CFR part 60, appendix F, procedure 1. |
| 4. 4SRB stationary RICE | a. reduce formaldehyde emissions and using NSCR | i. collecting the catalyst inlet temperature data according to §63.6625(b);<br><br>AND<br><br>ii. reducing these data to |

| | | |
|---|---|---|
| | | 4-hour rolling averages;<br><br>AND<br><br>iii. maintaining the 4-hour rolling averages within the operating limitations for the catalyst inlet temperature established during the performance test;<br><br>AND<br><br>iv. measuring the pressure drop across the catalyst once per month and demonstrating that the pressure drop across the catalyst is within the operating limitation established during the performance test. |
| 5. 4SRB stationary RICE | a. reduce formaldehyde emissions and not using NSCR | i. collecting the approved operating parameter (if any) data according to §63.6625(b);<br><br>AND<br><br>ii. reducing these data to 4-hour rolling averages;<br><br>AND<br><br>iii. maintaining the 4-hour rolling averages within the operating limitations for the operating parameters established during the performance test. |
| 6. 4SRB stationary RICE with a brake horsepower | reduce formaldehyde emissions | conducting semiannual performance tests for formaldehyde to demonstrate that the required formaldehyde percent |

| | | |
|---|---|---|
| $5,000 | | reduction is achieved[a]. |
| 7. stationary RICE | limit the concentration of formaldehyde in the stationary RICE exhaust and using oxidation catalyst or NSCR | i. conducting semiannual performance tests for formaldehyde to demonstrate that your emissions remain at or below the formaldehyde concentration limit[a].<br><br>AND<br><br>ii. collecting the catalyst inlet temperature data according to §63.6625(b);<br><br>AND<br><br>iii. reducing these data to 4-hour rolling averages;<br><br>AND<br><br>iv. maintaining the 4-hour rolling averages within the operating limitations for the catalyst inlet temperature established during the initial performance test;<br><br>AND<br><br>v. measuring the pressure drop across the catalyst once per month and demonstrating that the pressure drop across the catalyst is within the operating limitation established during the performance test. |
| 8. stationary RICE | limit the concentration of formaldehyde in the | i. conducting semiannual performance tests for formaldehyde to demonstrate that your emissions remain at or below the |

 Attachment 2 Attachment 2

| | | |
|---|---|---|
| | stationary RICE exhaust and not using oxidation catalyst or NSCR | formaldehyde concentration limit[a].<br><br>AND<br><br>ii. collecting the approved operating parameter (if any) data according to §63.6625(b);<br><br>AND<br><br>ii. reducing these data to 4-hour rolling averages;<br><br>AND<br><br>iii. maintaining the 4-hour rolling averages within the operating limitations for the operating parameters established during the performance test. |

[a]After you have demonstrated compliance for two consecutive tests, you may reduce the frequency of subsequent performance tests to annually. If the results of any subsequent annual performance test indicate the stationary RICE is not in compliance with the CO or formaldehyde emission limitation, or you deviate from any of your operating limitations, you must resume semiannual performance tests.

**Table 7 to Subpart ZZZZ of Part 63. Requirements for Reports**

As stated in §63.6650, you must comply with the following requirements for reports:

| You must submit a(n) | The report must contain ... | You must submit the report ... |
|---|---|---|
| 1. compliance report | a. if there are no deviations from any emission limitations or operating limitations that apply to you, a statement that there were no deviations | i. semiannually according to the requirements in §63.6650(b). |

| | |
|---|---|
| from the emission limitations or operating limitations during the reporting period. If there were no periods during which the CMS, including CEMS and CPMS, was out-of-control, as specified in §63.8(c)(7), a statement that there were not periods during which the CMS was out-of-control during the reporting period. | |
| OR | |
| b. if you had a deviation from any emission limitation or operating limitation during the reporting period, the information in §63.6650(d). If there were periods during which the CMS, including CEMS and CPMS, was out-of-control, as specified in §63.8(c)(7), the information in §63.6650(e). | i. semiannually according to the requirements in §63.6650(b). |
| OR | |
| c. if you had a startup, shutdown or malfunction during the reporting period, the information in §63.10(d)(5)(i). | i. semiannually according to the requirements in §63.6650(b). |

 Attachment 2 Attachment 2

| | | |
|---|---|---|
| 2. an immediate startup, shutdown, and malfunction report if actions addressing the startup, shutdown, or malfunction were inconsistent with your startup, shutdown, or malfunction plan during the reporting period | a. actions taken for the event.<br><br>AND | i. by fax or telephone within 2 working days after starting actions inconsistent with the plan. |
| | b. the information in §63.10(d)(5)(ii). | i. by letter within 7 working days after the end of the event unless you have made alternative arrangements with the permitting authorities. (§63.10(d)(5)(ii)) |
| 3. Report | a. the fuel flow rate of each fuel and the heating values that were used in your calculations, and you must demonstrate that the percentage of heat input provided by landfill gas or digester gas, is equivalent to 10 percent or more of the gross heat input on an annual basis.<br><br>AND | annually, according to the requirements in §63.6650. |

 Attachment 2 Attachment 2

b. the operating limits provided in your federally enforceable permit, and any deviations from these limits.

AND

c. any problems or errors suspected with the meters

**Table 8 to Subpart ZZZZ of Part 63. Applicability of General Provisions to Subpart ZZZZ**

As stated in §63.6665, you must comply with the following applicable general provisions:

| General Provisions Citation | Subject of Citation | Applies to Subpart | Explanation |
|---|---|---|---|
| §63.1 | General applicability of the General Provisions | Yes | |
| §63.2 | Definitions | Yes | Additional terms defined in §63.6675. |
| §63.3 | Units and abbreviations | Yes | |
| §63.4 | Prohibited activities and circumvention | Yes | |
| §63.5 | Construction and reconstruction | Yes | |
| §63.6(a) | Applicability | Yes | |
| §63.6(b)(1)-(4) | Compliance dates for new and reconstructed sources | Yes | |
| §63.6(b)(5) | Notification | Yes | |

| | | |
|---|---|---|
| §63.6(b)(6) | [Reserved] | |
| §63.6(b)(7) | Compliance dates for new and reconstructed area sources that become major sources | Yes |
| §63.6(c)(1)-(2) | Compliance dates for existing sources | Yes |
| §63.6(c)(3)-(4) | [Reserved] | |
| §63.6(c)(5) | Compliance dates for existing area sources that become major sources | Yes |
| §63.6(d) | [Reserved] | |
| §63.6(e)(1) | Operation and maintenance | Yes |
| §63.6(e)(2) | [Reserved] | |
| §63.6(e)(3) | Startup, shutdown, and malfunction plan | Yes |
| §63.6(f)(1) | Applicability of standards except during startup shutdown 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 alternate standard | Yes |

| | | | |
|---|---|---|---|
| §63.6(h) | Opacity and visible emission standards | No | Subpart ZZZZ does not contain opacity or visible emission standards. |
| §63.6(i) | Compliance extension procedures and criteria | Yes | |
| §63.6(j) | Presidential compliance exemption | Yes | |
| §63.7(a)(1)-(2) | Performance test dates | Yes | Subpart ZZZZ contains performance test dates at §63.6610. |
| §63.7(a)(3) | CAA 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 ZZZZ specifies test methods at §63.6620. |
| §63.7(e)(3) | Test run duration | Yes | |

 Attachment 2 Attachment 2

| | | | |
|---|---|---|---|
| §63.7(e)(4) | Administrator may require other testing under section 114 of the CAA | Yes | |
| §63.7(f) | Alternative test method provisions | Yes | |
| §63.7(g) | Performance test data analysis, recordkeeping, and reporting | Yes | |
| §63.7(h) | Waiver of tests | Yes | |
| §63.8(a)(1) | Applicability of monitoring requirements | Yes | Subpart ZZZZ contains specific requirements for monitoring at §63.6625. |
| §63.8(a)(2) | Performance specifications | Yes | |
| §63.8(a)(3) | [Reserved] | | |
| §63.8(a)(4) | Monitoring for control devices | No | |
| §63.8(b)(1) | Monitoring | Yes | |
| §63.8(b)(2)-(3) | Multiple effluents and multiple 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) | SSM not in Startup Shutdown Malfunction Plan | Yes | |

| | | | |
|---|---|---|---|
| §63.8(c)(1)(iii) | Compliance with operation and maintenance requirements | Yes | |
| §63.8(c)(2)-(3) | Monitoring system installation | Yes | |
| §63.8(c)(4) | Continuous monitoring system (CMS) requirements | Yes | Except that subpart ZZZZ does not require Continuous Opacity Monitoring System (COMS). |
| §63.8(c)(5) | COMS minimum procedures | No | Subpart ZZZZ does not require COMS. |
| §63.8(c)(6)-(8) | CMS requirements | Yes | Except that subpart ZZZZ does not require COMS. |
| §63.8(d) | CMS quality control | Yes | |
| §63.8(e) | CMS performance evaluation | Yes | Except for §63.8(e)(5)(ii), which applies to COMS. |
| §63.8(f)(1)-(5) | Alternative monitoring method | Yes | |
| §63.8(f)(6) | Alternative to relative accuracy test | Yes | |

 Attachment 2 Attachment 2

| | | | |
|---|---|---|---|
| §63.8(g) | Data reduction | Yes | Except that provisions for COMS are not applicable. Averaging periods for demonstrating compliance are specified at §§63.6635 and 63.6640. |
| §63.9(a) | Applicability and State 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 emission (VE)/opacity test | No | Subpart ZZZZ 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 ZZZZ does not contain opacity or VE standards. |

 Attachment 2 Attachment 2

| | | | |
|---|---|---|---|
| §63.9(g)(3) | Notification that criterion for alternative to RATA is exceeded | Yes | If alternative is in use. |
| §63.9(h)(1)-(6) | Notification of compliance status | Yes | Except that notifications for sources using a CEMS are due 30 days after completion of performance evaluations. §63.9(h)(4) is reserved. |
| §63.9(i) | Adjustment of submittal deadlines | Yes | |
| §63.9(j) | Change in previous information | Yes | |
| §63.10(a) | Administrative provisions for record keeping/reporting | Yes | |
| §63.10(b)(1) | Record retention | Yes | |
| §63.10(b)(2)(i)-(v) | Records related to SSM | Yes | |
| §63.10(b)(2)(vi)-(xi) | Records | Yes | |
| §63.10(b)(2)(xii) | Record when under waiver | Yes | |
| §63.10(b)(2)(xiii) | Records when using alternative to RATA | Yes | For CO standard if using RATA alternative. |
| §63.10(b)(2)(xiv) | Records of supporting documentation | Yes | |
| §63.10(b)(3) | Records of applicability determination | Yes | |

| | | | |
|---|---|---|---|
| §63.10(c) | Additional records for sources using CEMS | Yes | Except that §63.10(c)(2)-(4) and (9) are reserved. |
| §63.10(d)(1) | General reporting requirements | Yes | |
| §63.10(d)(2) | Report of performance test results | Yes | |
| §63.10(d)(3) | Reporting opacity or VE observations | No | Subpart ZZZZ does not contain opacity or VE standards. |
| §63.10(d)(4) | Progress reports | Yes | |
| §63.10(d)(5) | Startup, shutdown, and malfunction reports | Yes | |
| §63.10(e)(1) and (2)(i) | Additional CMS reports | Yes | |
| §63.10(e)(2)(ii) | COMS-related report | No | Subpart ZZZZ does not require COMS. |
| §63.10(e)(3) | Excess emission and parameter exceedances reports | Yes | Except that §63.10(e)(3)(i)(C) is reserved. |
| §63.10(e)(4) | Reporting COMS data | No | Subpart ZZZZ does not require COMS. |
| §63.10(f) | Waiver for recordkeeping/ reporting | Yes | |
| §63.11 | Flares | No | |
| §63.12 | State authority and delegations | Yes | |
| §63.13 | Addresses | Yes | |

 Attachment 2 Attachment 2

| | | |
|---|---|---|
| §63.14 | Incorporation by reference | Yes |
| §63.15 | Availability of information | Yes |


Attachment 2
Attachment 2