

**Air Individual Permit  
State Permit  
11500038-101**

**Permittee:** Northern Natural Gas Co - Hinckley  
**Facility name:** Northern Natural Gas Co - Hinckley  
21892 Lone Pine Rd  
Hinckley, MN 55037  
Pine County

**Expiration date:** Non-expiring permit

\* All Title I Conditions do not expire

**State Permit:** January 13, 2021

**Permit characteristics:** State; Nonmajor for Part 70/ True minor for NSR; True Minor for NSR

The emission units, control equipment and emission stacks at the stationary source authorized in this permit are as described in the submittals listed in the Permit Applications Table.

This permit authorizes the Permittee to construct the stationary source at the address listed above unless otherwise noted in the permit. The Permittee must comply with all the conditions of the permit. Any changes or modifications to the stationary source must be performed in compliance with Minn. R. 7007.1150 to 7007.1500. Terms used in the permit are as defined in the state air pollution control rules unless the term is explicitly defined in the permit.

Unless otherwise indicated, all the Minnesota rules cited as the origin of the permit terms are incorporated into the SIP under 40 CFR § 52.1220 and as such are enforceable by U.S. Environmental Protection Agency (EPA) Administrator or citizens under the Clean Air Act.

*Signature:* 

*This document has been electronically signed.*

*for* Steven S. Pak, P.E., Manager  
Air Quality Permits Section  
Industrial Division

*for the Minnesota Pollution Control Agency*

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**Permit issued:** January 13, 2021  
**Permit expires:** Non-expiring permit

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**1. Permit applications table**

Permit applications:

<b>Title description</b>	<b>Application receipt date</b>	<b>Action number</b>
First Time State Permit	08/06/2020	11500038-101

## 2. Where to send submittals

Send submittals that are required to be submitted to the EPA regional office to:

Chief Air Enforcement  
Air and Radiation Branch  
EPA Region V  
77 West Jackson Boulevard  
Chicago, Illinois 60604

Each submittal must be postmarked or received by the date specified in the applicable Table. Those submittals required by Minn. R. 7007.0100 to 7007.1850 must be certified by a responsible official, defined in Minn. R. 7007.0100, subp. 21. Other submittals shall be certified as appropriate if certification is required by an applicable rule or permit condition.

Send submittals that are required by the Acid Rain Program to:

U.S. Environmental Protection Agency  
Clean Air Markets Division  
1200 Pennsylvania Avenue NW (6204N)  
Washington, D.C. 20460

Send any application for a permit or permit amendment to:

Fiscal Services – 6<sup>th</sup> Floor  
Minnesota Pollution Control Agency  
520 Lafayette Road North  
St. Paul, Minnesota 55155-4194

Also, where required by an applicable rule or permit condition, send to the Permit Document Coordinator notices of:

- a. Accumulated insignificant activities
- b. Installation of control equipment
- c. Replacement of an emissions unit, and
- d. Changes that contravene a permit term

Unless another person is identified in the applicable Table, send all other submittals to:

AQ Compliance Tracking Coordinator  
Industrial Division  
Minnesota Pollution Control Agency  
520 Lafayette Road North  
St. Paul, Minnesota 55155-4194

**Or** Email a signed and scanned PDF copy to:  
[submitstacktest.pca@state.mn.us](mailto:submitstacktest.pca@state.mn.us)  
(for submittals related to stack testing)  
[AQRoutineReport.PCA@state.mn.us](mailto:AQRoutineReport.PCA@state.mn.us)  
(for other compliance submittals)  
(See complete email instructions in “Routine Air Report Instructions Letter” at  
<http://www.pca.state.mn.us/nwqh472>.)

### 3. Facility description

The Northern Natural Gas Co - Hinckley (Facility) is located at 21892 Lone Pine Road in Hinckley, Pine County, Minnesota.

Northern Natural Gas Company - Hinckley is a natural gas compressor station located in Hinckley, Minnesota. Compressor stations compress natural gas to a specified pressure along natural gas pipelines allowing the gas to continue moving through the pipeline to an intended recipient. The main sources of air pollution are a natural gas-fired turbine, natural gas-fired, four-stroke, rich burn, spark ignition emergency engine, and a process heater. The facility also includes fugitive sources comprising of flanges, compressor seals, and valves. Nitrogen oxides (NOx) and carbon monoxide (CO) are the primary pollutants of concern.

This is a first time State permit for a new facility that will include one natural gas-fired turbine (EQUI 1), a natural gas-fired, four-stroke, rich burn, spark ignition emergency engine (EQUI 2), and a process heater (insignificant activity) with their associated stacks (STRU 1 and STRU 2). This permit also adds the following fugitive sources to the permit: flanges (FUGI 1), compressor seals (FUGI 2), and valves (FUGI 3). There is also a compressor building (STRU 4) and an auxiliary building (STRU 5). The turbine (EQUI 1) is a Solar Brand combustor equipped with built-in SoLoNOx technology (lean-burn, pre-mix combustion) which reduces NOx and CO formation.

**4. Summary of subject items**

SI ID: Description	Relationship type	Related SI ID: Description
TFAC 1:		
EQUI 1: Natural Gas-Fired Turbine	sends to	STRU 1: Turbine Exhaust
EQUI 2: Emergency Generator	sends to	STRU 2: Emergency Generator
FUGI 1: Flanges		
FUGI 2: Compressor Seals		

SI ID: Description	Relationship type	Related SI ID: Description
FUGI 3: Valves		
STRU 1: Turbine Exhaust		
STRU 2: Emergency Generator		
STRU 4: Compressor Building		
STRU 5: Auxiliary Building		

5. Limits and other requirements

Requirement number	Requirement and citation
<b>TFAC 1</b>	
5.1.1	<p>Permit Appendices: This permit contains appendices as listed in the permit Table of Contents. The Permittee shall comply with all requirements contained in the following Appendices:</p> <ul style="list-style-type: none"> <li>-Appendix A. Insignificant Activities and General Applicable Requirements;</li> <li>-Appendix B. 40 CFR Part 60, Subpart A - General Provisions;</li> <li>-Appendix C. 40 CFR Part 60, Subpart KKKK - Standards of Performance for Stationary Combustion Turbines;</li> <li>-Appendix D. 40 CFR Part 60, Subpart JJJJ - Standards of Performance for Stationary Spark Ignition Internal Combustion Engines. [Minn. R. 7007.0800, subp. 2(A) &amp; (B)]</li> </ul>
5.1.2	<p>The Permittee must comply with Minn. Stat. 116.385. The Permittee may not use trichloroethylene at its permitted facility after June 1, 2022, including in any manufacturing, processing, or cleaning processes, except as described in Minn. Stat. 116.385, subd. 2(b) and 4. This is a state-only requirement and is not enforceable by the U.S. Environmental Protection Agency (EPA) Administrator and citizens under the Clean Air Act. [Minn. Stat. 116.385]</p>
5.1.3	<p>PERMIT SHIELD: Subject to the limitations in Minn. R. 7007.1800, compliance with the conditions of this permit shall be deemed compliance with the specific provision of the applicable requirement identified in the permit as the basis of each condition. Subject to the limitations of Minn. R. 7007.1800 and 7017.0100, subp. 2, notwithstanding the conditions of this permit specifying compliance practices for applicable requirements, any person (including the Permittee) may also use other credible evidence to establish compliance or noncompliance with applicable requirements.</p> <p>This permit shall not alter or affect the liability of the Permittee for any violation of applicable requirements prior to or at the time of permit issuance. [Minn. R. 7007.1800(A)(2)]</p>
5.1.4	<p>Circumvention: Do not install or use a device or means that conceals or dilutes emissions, which would otherwise violate a federal or state air pollution control rule, without reducing the total amount of pollutant emitted. [Minn. R. 7011.0020]</p>
5.1.5	<p>Air Pollution Control Equipment: Operate all pollution control equipment whenever the corresponding process equipment and emission units are operated. [Minn. R. 7007.0800, subp. 16(J), Minn. R. 7007.0800, subp. 2(A) &amp; (B)]</p>
5.1.6	<p>Operation and Maintenance Plan: Retain at the stationary source an operation and maintenance plan for all air pollution control equipment. At a minimum, the O &amp; M plan shall identify all air pollution control equipment and control practices and shall include a preventative maintenance program for the equipment and practices, a description of (the minimum but not necessarily the only) corrective actions to be taken to restore the equipment and practices to proper operation to meet applicable permit conditions, a description of the employee training program for proper operation and maintenance of the control equipment and practices, and the records kept to demonstrate plan implementation. [Minn. R. 7007.0800, subp. 14, Minn. R. 7007.0800, subp. 16(J)]</p>
5.1.7	<p>Operation Changes: In any shutdown, breakdown, or deviation the Permittee shall immediately take all practical steps to modify operations to reduce the emission of any regulated air pollutant. The Commissioner may require feasible and practical modifications in the operation to reduce emissions of air pollutants. No emissions units that have an unreasonable shutdown or breakdown frequency of process or control equipment shall be permitted to operate. [Minn. R. 7019.1000, subp. 4]</p>
5.1.8	<p>Fugitive Emissions: Do not cause or permit the handling, use, transporting, or storage of any material in a manner which may allow avoidable amounts of particulate matter to become airborne. Comply with all other requirements listed in Minn. R. 7011.0150. [Minn. R. 7011.0150]</p>

Requirement number	Requirement and citation
5.1.9	Noise: The Permittee shall comply with the noise standards set forth in Minn. R. 7030.0010 to 7030.0080 at all times during the operation of any emission units. This is a state only requirement and is not enforceable by the EPA Administrator or citizens under the Clean Air Act. [Minn. R. 7030.0010-7030.0080]
5.1.10	Inspections: The Permittee shall comply with the inspection procedures and requirements as found in Minn. R. 7007.0800, subp. 9(A). [Minn. R. 7007.0800, subp. 9(A)]
5.1.11	The Permittee shall comply with the General Conditions listed in Minn. R. 7007.0800, subp. 16. [Minn. R. 7007.0800, subp. 16]
5.1.12	Performance Testing: Conduct all performance tests in accordance with Minn. R. ch. 7017 unless otherwise noted in this permit. [Minn. R. ch. 7017]
5.1.13	<p>Performance Test Notifications and Submittals:</p> <p>Performance Test Notification and Plan: due 30 days before each Performance Test                      Performance Test Pre-test Meeting: due seven days before each Performance Test                      Performance Test Report: due 45 days after each Performance Test</p> <p>The Notification, Test Plan, and Test Report must be submitted in a format specified by the commissioner. [Minn. R. 7017.2017, Minn. R. 7017.2030, subps. 1-4, Minn. R. 7017.2035, subps. 1-2]</p>
5.1.14	Limits set as a result of a performance test (conducted before or after permit issuance) apply until superseded as stated in the MPCA's Notice of Compliance letter granting preliminary approval. Preliminary approval is based on formal review of a subsequent performance test on the same unit as specified by Minn. R. 7017.2025, subp. 3. The limit is final upon issuance of a permit amendment incorporating the change. [Minn. R. 7017.2025, subp. 3]
5.1.15	<p>Monitoring Equipment Calibration - The Permittee shall either:</p> <ol style="list-style-type: none"> <li>1. Calibrate or replace required monitoring equipment every 12 months; or</li> <li>2. Calibrate at the frequency stated in the manufacturer's specifications.</li> </ol> <p>For each monitor, the Permittee shall maintain a record of all calibrations, including the date conducted, and any corrective action that resulted. The Permittee shall include the calibration frequencies, procedures, and manufacturer's specifications (if applicable) in the Operations and Maintenance Plan. Any requirements applying to continuous emission monitors are listed separately in this permit. [Minn. R. 7007.0800, subp. 4(D)]</p>
5.1.16	Operation of Monitoring Equipment: Unless noted elsewhere in this permit, monitoring a process or control equipment connected to that process is not necessary during periods when the process is shutdown, or during checks of the monitoring systems, such as calibration checks and zero and span adjustments. If monitoring records are required, they should reflect any such periods of process shutdown or checks of the monitoring system. [Minn. R. 7007.0800, subp. 4(D)]
5.1.17	Recordkeeping: Retain all records at the stationary source, unless otherwise specified within this permit, for five (5) years from the date of monitoring, sample, measurement, or report. Records which must be retained at this location include all calibration and maintenance records, all original recordings for continuous monitoring instrumentation, and copies of all reports required by the permit. Records must conform to the requirements listed in Minn. R. 7007.0800, subp. 5(A). [Minn. R. 7007.0800, subp. 5(C)]
5.1.18	Recordkeeping: Maintain records describing any insignificant modifications (as required by Minn. R. 7007.1250, subp. 3) or changes contravening permit terms (as required by Minn. R. 7007.1350, subp. 2), including records of the emissions resulting from those changes. [Minn. R. 7007.0800, subp. 5(B)]
5.1.19	If the Permittee determines that no permit amendment or notification is required prior to making a

Requirement number	Requirement and citation
	change, the Permittee must retain records of all calculations required under Minn. R. 7007.1200. For non-expiring permits, these records shall be kept for a period of five years from the date that the change was made. The records shall be kept at the stationary source for the current calendar year of operation and may be kept at the stationary source or office of the stationary source for all other years. The records may be maintained in either electronic or paper format. [Minn. R. 7007.1200, subp. 4]
5.1.20	<p>Shutdown Notifications: Notify the Commissioner at least 24 hours in advance of a planned shutdown of any control equipment or process equipment if the shutdown would cause any increase in the emissions of any regulated air pollutant. If the owner or operator does not have advance knowledge of the shutdown, notification shall be made to the Commissioner as soon as possible after the shutdown. However, notification is not required in the circumstances outlined in items A, B, and C of Minn. R. 7019.1000, subp. 3.</p> <p>At the time of notification, the owner or operator shall inform the Commissioner of the cause of the shutdown and the estimated duration. The owner or operator shall notify the Commissioner when the shutdown is over. [Minn. R. 7019.1000, subp. 3]</p>
5.1.21	<p>Breakdown Notifications: Notify the Commissioner within 24 hours of a breakdown of more than one hour duration of any control equipment or process equipment if the breakdown causes any increase in the emissions of any regulated air pollutant. The 24-hour time period starts when the breakdown was discovered or reasonably should have been discovered by the owner or operator. However, notification is not required in the circumstances outlined in items A, B, and C of Minn. R. 7019.1000, subp. 2.</p> <p>At the time of notification or as soon as possible thereafter, the owner or operator shall inform the Commissioner of the cause of the breakdown and the estimated duration. The owner or operator shall notify the Commissioner when the breakdown is over. [Minn. R. 7019.1000, subp. 2]</p>
5.1.22	Notification of Deviations Endangering Human Health or the Environment: As soon as possible after discovery, notify the Commissioner or the state duty officer, either orally or by facsimile, of any deviation from permit conditions which could endanger human health or the environment. [Minn. R. 7019.1000, subp. 1]
5.1.23	<p>Notification of Deviations Endangering Human Health or the Environment Report: Within two working days of discovery, notify the Commissioner in writing of any deviation from permit conditions which could endanger human health or the environment. Include the following information in this written description:</p> <ol style="list-style-type: none"><li>1. the cause of the deviation;</li><li>2. the exact dates of the period of the deviation, if the deviation has been corrected;</li><li>3. whether or not the deviation has been corrected;</li><li>4. the anticipated time by which the deviation is expected to be corrected, if not yet corrected; and</li><li>5. steps taken or planned to reduce, eliminate, and prevent reoccurrence of the deviation. [Minn. R. 7019.1000, subp. 1]</li></ol>
5.1.24	<p>Application for Permit Amendment: If a permit amendment is needed, submit an application in accordance with the requirements of Minn. R. 7007.1150 through Minn. R. 7007.1500. Submittal dates vary, depending on the type of amendment needed.</p> <p>Upon adoption of a new or amended federal applicable requirement, and if there are three or more years remaining in the permit term, the Permittee shall file an application for an amendment within nine months of promulgation of the applicable requirement, pursuant to Minn. R. 7007.0400, subp. 3. [Minn. R. 7007.0400, subp. 3, Minn. R. 7007.1150 - 7007.1500]</p>
5.1.25	Extension Requests: The Permittee may apply for an Administrative Amendment to extend a deadline in a permit by no more than 120 days, provided the proposed deadline extension meets the

Requirement number	Requirement and citation
	requirements of Minn. R. 7007.1400, subp. 1(H). Performance testing deadlines from the General Provisions of 40 CFR pt. 60 and pt. 63 are examples of deadlines for which the MPCA does not have authority to grant extensions and therefore do not meet the requirements of Minn. R. 7007.1400, subp. 1(H). [Minn. R. 7007.1400, subp. 1(H)]
5.1.26	Within 15 days of a request from the Commissioner, the Permittee must provide a complete summary of all performance tests required at the facility including the subject item, pollutant, most recent test date (if applicable), and the date of the next test in an approved format. [Minn. R. 7007.0800, subp. 16(L)]
5.1.27	Emission Inventory Report: due on or before April 1 of each calendar year following permit issuance. Submit in a format specified by the Commissioner. [Minn. R. 7019.3000-7019.3100]
5.1.28	Emission Fees: due 30 days after receipt of an MPCA bill. [Minn. R. 7002.0005-7002.0085]
<b>EQUI 1</b>	<b>Natural Gas-Fired Turbine</b>
5.2.1	The Permittee is authorized to construct and operate EQUI 1 meeting the following design requirements: 11,400 hp capacity, natural gas-fired turbine.  The authorization to start construction of this equipment expires 18 months after permit issuance of Air Emissions Permit No. 11500038-101. The units shall meet all applicable permit requirements. [Minn. R. 7007.0800, subp. 2(A)]
5.2.2	Opacity <= 20 percent opacity once operating temperatures have been attained. [Minn. R. 7011.2300, subp. 1]
5.2.3	Sulfur Dioxide <= 0.0015 pounds per million Btu heat input The potential to emit from the unit is 0.0014 lb/MMBtu due to equipment design and allowable fuels. [Minn. R. 7011.2300, subp. 2(B)]
5.2.4	The Permittee shall limit emissions of Sulfur Dioxide <= 110 nanograms per joule (ng/J) (0.90 pounds per megawatt-hour (lb/MWh)) gross output. [40 CFR 60.4330(a)(1), Minn. R. 7011.2375]
5.2.5	The Permittee shall limit emissions of Nitrogen Oxides <= 25 parts per million at 15 percent oxygen or 150 ng/J of useful output (1.2 lb/MWh) when turbine is operating at or above 75 percent of peak load and when operating at 0 deg F or above. [40 CFR 60.4320(a), 40 CFR pt. 60, subp. KKKK (Table 1), Minn. R. 7011.2375]
5.2.6	Fuel type: Natural gas only by design. [Minn. R. 7005.0100, subp. 35a]
5.2.7	The Permittee shall keep records of fuel type and usage on a monthly basis. [Minn. R. 7007.0800, subp. 5]
5.2.8	The Permittee must comply with all applicable requirements of 40 CFR pt. 60, subp. A as follows:  40 CFR 60.1; 40 CFR 60.2; 40 CFR 60.3; 40 CFR 60.4; 40 CFR 60.5; 40 CFR 60.6; 40 CFR 60.7; 40 CFR 60.8; 40 CFR 60.9; 40 CFR 60.11; 40 CFR 60.12; 40 CFR 60.13; 40 CFR 60.14; 40 CFR 60.15; 40 CFR 60.17;

Requirement number	Requirement and citation
	<p>40 CFR 60.18; and            40 CFR 60.19.</p> <p>A copy of 40 CFR pt. 60, subp. A is included in Appendix B. If the standard changes or upon adoption of a new or amended federal applicable requirement, and if there are more than 3 years remaining in the permit term, the Permittee shall file an application for an amendment within nine months of promulgation of the applicable requirement, pursuant to Minn. R. 7007.0400, subp. 3. [40 CFR pt. 60, subp. A, 40 CFR pt. 60, subp. KKKK, Minn. R. 7007.0400, subp. 3, Minn. R. 7007.1150-7007.1500, Minn. R. 7011.0050, Minn. R. 7017.1010 &amp; 7017.2025, Minn. R. 7019.0100]</p>
5.2.9	<p>The Permittee must comply with all applicable requirements of 40 CFR pt. 60, subp. KKKK as follows:</p> <p>40 CFR 60.4300;            40 CFR 60.4305;            40 CFR 60.4315;            40 CFR 60.4320;            40 CFR 60.4330(a)(1);            40 CFR 60.4333(a);            40 CFR 60.4340(a);            40 CFR 60.4360;            40 CFR 60.4370(c)(1);            40 CFR 60.4375;            40 CFR 60.4385;            40 CFR 60.4395;            40 CFR 60.4400(a);            40 CFR 60.4400(b)(4);            40 CFR 60.4400(b)(6);            40 CFR 60.4415(a)(1)(ii);            40 CFR 60.4420; and            40 CFR pt. 60, subp. KKKK Table 1.</p> <p>A copy of 40 CFR pt. 60, subp. KKKK is included in Appendix C. If the standard changes or upon adoption of a new or amended federal applicable requirement, and if there are more than 3 years remaining in the permit term, the Permittee shall file an application for an amendment within nine months of promulgation of the applicable requirement, pursuant to Minn. R. 7007.0400, subp. 3. [40 CFR pt. 60, subp. KKKK, Minn. R. 7007.0400, subp. 3, Minn. R. 7011.2375]</p>
5.2.10	<p>Turbine Component Replacement Recordkeeping:            The Permittee shall record the date and nature of each component replacement no later than 5 business days after completion of each replacement. For each replaced component, the Permittee shall maintain a record of the date the component was constructed or the date of the most recent overhaul, as applicable. The Permittee shall also record the total cost of the component replacement compared to the cost of an entirely new stationary gas turbine (as defined at 40 CFR Section 60.4420). This record of the component replacement cost compared to the cost of a new stationary gas turbine shall be made at least 30 days before a NOx test is conducted on the gas turbine (as a result of the component replacement), but no later than 180 days after each component replacement. [Minn. R. 7007.0800, subp. 2, Minn. R. 7007.0800, subps. 4-5]</p>
<b>EQUI 2</b>	<b>Emergency Generator</b>
5.3.1	<p>The Permittee is authorized to construct and operate EQUI 2 meeting the following design requirements: 770 hp, natural gas-fired, rich burn, four-stroke, spark ignition, emergency engine certified to meet the emission standards in 40 CFR pt. 60, subp JJJJ(Table 1).</p>

Requirement number	Requirement and citation
	The authorization to start construction of this equipment expires 18 months after permit issuance of Air Emissions Permit No. 11500038-101. The units shall meet all applicable permit requirements. [Minn. R. 7007.0800, subp. 2(A)]
5.3.2	The Permittee shall limit Nitrogen Oxides <= 2.0 grams per horsepower-hour. [40 CFR 60.4233(e), 40 CFR pt. 60, subp. JJJ(Table 1), Minn. R. 7011.2310]
5.3.3	The Permittee shall limit Carbon Monoxide <= 4.0 grams per horsepower-hour. [40 CFR 60.4233(e), 40 CFR pt. 60, subp. JJJ(Table 1), Minn. R. 7011.2310]
5.3.4	The Permittee shall limit Volatile Organic Compounds <= 1.0 grams per horsepower-hour. [40 CFR 60.4233(e), 40 CFR pt. 60, subp. JJJ(Table 1), Minn. R. 7011.2310]
5.3.5	Sulfur Dioxide <= 0.0015 pounds per million Btu heat input. The potential to emit from the unit is 0.0015 lb/MMBtu due to equipment design and allowable fuels. [Minn. R. 7011.2300, subp. 2(B)]
5.3.6	Opacity <= 20 percent opacity once operating temperatures have been attained. [Minn. R. 7011.2300, subp. 1]
5.3.7	Hours of Operation: The Permittee shall maintain documentation on site that the unit is an emergency generator by design that qualifies under the U.S. EPA memorandum entitled "Calculating Potential to Emit (PTE) for Emergency Generators" dated September 6, 1995, limiting operation to 500 hours per year. [Minn. R. 7007.0800, subps. 4-5]
5.3.8	Fuel type: Natural gas only by design. [Minn. R. 7005.0100, subp. 35a]
5.3.9	The Permittee shall keep records of fuel type and usage on a monthly basis. [Minn. R. 7007.0800, subp. 5]
5.3.10	EQUI 2 is a new affected source as defined under 40 CFR pt. 63, subp. ZZZZ, and the facility is an area source as defined at 40 CFR Section 63.2, and EQUI 2 is a spark ignition RICE. The Permittee shall meet the requirements of 40 CFR pt. 63, subp. ZZZZ by meeting the requirements of 40 CFR pt. 60, subp. JJJ. No further requirements of 40 CFR pt. 63, subp. ZZZZ apply to EQUI 2. [40 CFR 63.6590(c), Minn. R. 7011.8150]
5.3.11	<p>The Permittee must comply with all applicable requirements of 40 CFR pt. 60, subp. A as follows:</p> <ul style="list-style-type: none"> <li>40 CFR 60.1;</li> <li>40 CFR 60.2;</li> <li>40 CFR 60.3;</li> <li>40 CFR 60.4;</li> <li>40 CFR 60.5;</li> <li>40 CFR 60.6;</li> <li>40 CFR 60.7;</li> <li>40 CFR 60.8;</li> <li>40 CFR 60.9;</li> <li>40 CFR 60.10;</li> <li>40 CFR 60.11, requirements as specified in subpart JJJ;</li> <li>40 CFR 60.12;</li> <li>40 CFR 60.14;</li> <li>40 CFR 60.15;</li> <li>40 CFR 60.16;</li> <li>40 CFR 60.17; and</li> <li>40 CFR 60.19.</li> </ul> <p>A copy of 40 CFR pt. 60, subp. A is included in Appendix B. If the standard changes or upon adoption of a new or amended federal applicable requirement, and if there are more than 3 years remaining in the permit term, the Permittee shall file an application for an amendment within nine months of promulgation of the applicable requirement, pursuant to Minn. R. 7007.0400, subp. 3. [40 CFR pt. 60,</p>

Requirement number	Requirement and citation
	subp. A, 40 CFR pt. 60, subp. JJJJ, Minn. R. 7007.0400, subp. 3, Minn. R. 7007.1150-7007.1500, Minn. R. 7011.0050, Minn. R. 7017.1010 & 7017.2025, Minn. R. 7019.0100]
5.3.12	<p>The Permittee must comply with all applicable requirements of 40 CFR pt. 60, subp. JJJJ as follows:</p> <p>40 CFR 60.4230(a)(4)(iv);                      40 CFR 60.4230(a)(6);                      40 CFR 60.4233(e), as it pertains to stationary SI ICE meeting the criteria in the first sentence of this item;                      40 CFR 60.4234;                      40 CFR 60.4237(a);                      40 CFR 60.4243(b)(1);                      40 CFR 60.4243(d);                      40 CFR 60.4243(g);                      40 CFR 60.4245(a)(1);                      40 CFR 60.4245(a)(2);                      40 CFR 60.4245(a)(3);                      40 CFR 60.4245(e);                      40 CFR 60.4246;                      40 CFR 60.4248;                      40 CFR pt. 60, subp JJJJ Table 1.and                      40 CFR pt. 60, subp JJJJ Table 3.</p> <p>A copy of 40 CFR pt. 60, subp. JJJJ is included in Appendix D. If the standard changes or upon adoption of a new or amended federal applicable requirement, and if there are more than 3 years remaining in the permit term, the Permittee shall file an application for an amendment within nine months of promulgation of the applicable requirement, pursuant to Minn. R. 7007.0400, subp. 3. [40 CFR pt. 60, subp. JJJJ, 40 CFR pt. 63, subp. ZZZZ, Minn. R. 7007.0400, subp. 3, Minn. R. 7011.2310]</p>
<b>FUGI 1</b>	<b>Flanges</b>
5.4.1	The Permittee is authorized to construct and operate FUGI 1. The authorization to start construction of this equipment expires 18 months after permit issuance of Air Emissions Permit No. 11500038-101. The units shall meet all applicable permit requirements. [Minn. R. 7007.0800, subp. 2(A)]
<b>FUGI 2</b>	<b>Compressor Seals</b>
5.5.1	The Permittee is authorized to construct and operate FUGI 2. The authorization to start construction of this equipment expires 18 months after permit issuance of Air Emissions Permit No. 11500038-101. The units shall meet all applicable permit requirements. [Minn. R. 7007.0800, subp. 2(A)]
<b>FUGI 3</b>	<b>Valves</b>
5.6.1	The Permittee is authorized to construct and operate FUGI 3. The authorization to start construction of this equipment expires 18 months after permit issuance of Air Emissions Permit No. 11500038-101. The units shall meet all applicable permit requirements. [Minn. R. 7007.0800, subp. 2(A)]

## 6. Submittal/action requirements

This section lists most of the submittals required by this permit. Please note that some submittal requirements may appear in the Limits and Other Requirements section, or, if applicable, within a Compliance Schedule section.

Requirement number	Requirement and citation
<b>TFAC 1</b>	
6.1.1	The Permittee must submit a semiannual deviations report : Due semiannually, by the 30th of January and July. The first semiannual report submitted by the Permittee must cover the calendar half-year in which the permit is issued. The first report of each calendar year covers January 1 - June 30. The second report of each calendar year covers July 1 - December 31. Submit this on form DRF-2 (Deviation Reporting Form). If no deviations have occurred, submit the signed report certifying that there were no deviations. [Minn. R. 7007.0800, subp. 6(B)(2)]
6.1.2	The Permittee must submit a compliance certification : Due annually, by the 31st of January (for the previous calendar year). Submit this on form CR-04 (Annual Compliance Certification Report). This report covers all deviations experienced during the calendar year. If no deviations have occurred, submit the signed report certifying that there were no deviations. [Minn. R. 7007.0800, subp. 6(D)]
<b>EQUI 1</b>	<b>Natural Gas-Fired Turbine</b>
6.2.1	The Permittee shall submit a notification of the date construction began: Due 30 calendar days after Date of Construction Start (or reconstruction). Submit the name and number of the Subject Item and the date construction began.  The notification shall be submitted electronically on Form CS-02. [40 CFR 60.7(a)(1), Minn. R. 7007.0800, subp. 16(L), Minn. R. 7019.0100, subp. 1]
6.2.2	The Permittee shall submit a notification of the actual date of initial startup: Due 15 calendar days after Initial Startup Date. Submit the name and number of the Subject Item and the date of startup. Startup is as defined in Minn. R. 7005.0100, subp. 42a.  The notification shall be submitted electronically on Form CS-02. [40 CFR 60.7(a)(3), Minn. R. 7007.0800, subp. 16(L), Minn. R. 7019.0100, subp. 1]
6.2.3	Nitrogen Oxides: The Permittee shall conduct an initial performance test due 180 calendar days after Initial Startup Date and at a minimum every 12 months thereafter to measure emissions. If the Nitrogen Oxide emission result from the performance test is less than or equal to 75 percent of the Nitrogen Oxide emission limit for the turbine, you may reduce the frequency of subsequent performance tests to once every 2 years (no more than 26 calendar months following the previous performance test). If the results of any subsequent performance test exceed 75 percent of the Nitrogen Oxide emission limit for the turbine, you must resume annual performance tests.  The performance test shall be conducted at normal operating conditions using EPA Reference Methods 7E, or other method approved by MPCA in the performance test plan approval. [40 CFR 60.4340(a), 40 CFR 60.8(a), Minn. R. 7011.2375, Minn. R. 7017.2020, subp. 1]
6.2.4	Sulfur Dioxide: The Permittee shall conduct an initial performance test due 180 calendar days after Initial Startup Date and at a minimum every 14 months thereafter to measure emissions.  The performance test shall be conducted at normal operating conditions using EPA Reference Methods 6C, or other method approved by MPCA in the performance test plan approval. [40 CFR 60.4415(a)(1)(ii), 40 CFR 60.8(a), Minn. R. 7011.2375, Minn. R. 7017.2020, subp. 1]

<b>Requirement number</b>	<b>Requirement and citation</b>
6.2.5	<p>The Permittee shall submit notification of the date replacement began: Due 60 calendar days before Date of Replacement Start (or as soon as practicable). Submit the information specified in 40 CFR Section 60.15(d)(1) through (7).</p> <p>The notification shall be submitted electronically on Form CS-02. [40 CFR 60.15(d), Minn. R. 7011.0050]</p>
<b>EQUI 2</b>	<b>Emergency Generator</b>
6.3.1	<p>The Permittee shall submit a notification of the date construction began: Due 30 calendar days after Date of Construction Start (or reconstruction). Submit the name and number of the Subject Item and the date construction began.</p> <p>The notification shall be submitted electronically on Form CS-02. [40 CFR 60.4245(c), 40 CFR 60.7(a)(1), Minn. R. 7007.0800, subp. 16(L), Minn. R. 7019.0100, subp. 1]</p>
6.3.2	<p>The Permittee shall submit a notification of the actual date of initial startup: Due 15 calendar days after Initial Startup Date. Submit the name and number of the Subject Item and the date of startup. Startup is as defined in Minn. R. 7005.0100, subp. 42a.</p> <p>The notification shall be submitted electronically on Form CS-02. [40 CFR 60.7(a)(3), Minn. R. 7007.0800, subp. 16(L), Minn. R. 7019.0100, subp. 1]</p>
<b>FUGI 1</b>	<b>Flanges</b>
6.4.1	<p>The Permittee shall submit a notification of the date construction began: Due 30 calendar days after Date of Construction Start (or reconstruction). Submit the name and number of the Subject Item and the date construction began.</p> <p>The notification shall be submitted electronically on Form CS-02. [Minn. R. 7007.0800, subp. 16(L)]</p>
6.4.2	<p>The Permittee shall submit a notification of the actual date of initial startup: Due 15 calendar days after Initial Startup Date. Submit the name and number of the Subject Item and the date of startup. Startup is as defined in Minn. R. 7005.0100, subp. 42a.</p> <p>The notification shall be submitted electronically on Form CS-02. [Minn. R. 7007.0800, subp. 16(L)]</p>
<b>FUGI 2</b>	<b>Compressor Seals</b>
6.5.1	<p>The Permittee shall submit a notification of the date construction began: Due 30 calendar days after Date of Construction Start (or reconstruction). Submit the name and number of the Subject Item and the date construction began.</p> <p>The notification shall be submitted electronically on Form CS-02. [Minn. R. 7007.0800, subp. 16(L)]</p>
6.5.2	<p>The Permittee shall submit a notification of the actual date of initial startup: Due 15 calendar days after Initial Startup Date. Submit the name and number of the Subject Item and the date of startup. Startup is as defined in Minn. R. 7005.0100, subp. 42a.</p> <p>The notification shall be submitted electronically on Form CS-02. [Minn. R. 7007.0800, subp. 16(L)]</p>
<b>FUGI 3</b>	<b>Valves</b>
6.6.1	<p>The Permittee shall submit a notification of the date construction began: Due 30 calendar days after Date of Construction Start (or reconstruction). Submit the name and number of the Subject Item and the date construction began.</p> <p>The notification shall be submitted electronically on Form CS-02. [Minn. R. 7007.0800, subp. 16(L)]</p>
6.6.2	<p>The Permittee shall submit a notification of the actual date of initial startup: Due 15 calendar days</p>

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<b>Requirement number</b>	<b>Requirement and citation</b>
	after Initial Startup Date. Submit the name and number of the Subject Item and the date of startup. Startup is as defined in Minn. R. 7005.0100, subp. 42a.  The notification shall be submitted electronically on Form CS-02. [Minn. R. 7007.0800, subp. 16(L)]

## 7. Appendices

### Appendix A. Insignificant activities and general applicable requirements

The table below lists the insignificant activities that are currently at the Facility and their associated general applicable requirements.

<b>Minn. R.</b>	<b>Rule description of the activity</b>	<b>General applicable requirement</b>
Minn. R. 7007.1300, subp. 3(B)(2)	Indirect heating equipment with a heat input capacity less than 420,000 Btu/hour, etc. The Facility operates one process heater with heat input capacity of 280,000 Btu/hr.	PM <= 0.4 lb/MMBtu Opacity <= 20% with exceptions (Minn. R. 7011.0515)

## Appendix B. 40 CFR Part 60, Subpart A—General Provisions

### §60.1 Applicability.

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

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

(c) In addition to complying with the provisions of this part, the owner or operator of an affected facility may be required to obtain an operating permit issued to stationary sources by an authorized State air pollution control agency or by the Administrator of the U.S. Environmental Protection Agency (EPA) pursuant to Title V of the Clean Air Act (Act) as amended November 15, 1990 (42 U.S.C. 7661). For more information about obtaining an operating permit see part 70 of this chapter.

(d) *Site-specific standard for Merck & Co., Inc.'s Stonewall Plant in Elkton, Virginia.*

(1) This paragraph applies only to the pharmaceutical manufacturing facility, commonly referred to as the Stonewall Plant, located at Route 340 South, in Elkton, Virginia ("site").

(2) Except for compliance with 40 CFR 60.49b(u), the site shall have the option of either complying directly with the requirements of this part, or reducing the site-wide emissions caps in accordance with the procedures set forth in a permit issued pursuant to 40 CFR 52.2454. If the site chooses the option of reducing the site-wide emissions caps in accordance with the procedures set forth in such permit, the requirements of such permit shall apply in lieu of the otherwise applicable requirements of this part.

(3) Notwithstanding the provisions of paragraph (d)(2) of this section, for any provisions of this part except for Subpart Kb, the owner/operator of the site shall comply with the applicable provisions of this part if the Administrator determines that compliance with the provisions of this part is necessary for achieving the objectives of the regulation and the Administrator notifies the site in accordance with the provisions of the permit issued pursuant to 40 CFR 52.2454.

### §60.2 Definitions.

The terms used in this part are defined in the Act or in this section as follows:

*Act* means the Clean Air Act (42 U.S.C. 7401 *et seq.*)

*Administrator* means the Administrator of the Environmental Protection Agency or his authorized representative.

*Affected facility* means, with reference to a stationary source, any apparatus to which a standard is applicable.

*Alternative method* means any method of sampling and analyzing for an air pollutant which is not a reference or equivalent method but which has been demonstrated to the Administrator's satisfaction to, in specific cases, produce results adequate for his determination of compliance.

*Approved permit program* means a State permit program approved by the Administrator as meeting the requirements of part 70 of this chapter or a Federal permit program established in this chapter pursuant to Title V of the Act (42 U.S.C. 7661).

*Capital expenditure* means an expenditure for a physical or operational change to an existing facility which exceeds the product of the applicable “annual asset guideline repair allowance percentage” specified in the latest edition of Internal Revenue Service (IRS) Publication 534 and the existing facility's basis, as defined by section 1012 of the Internal Revenue Code. However, the total expenditure for a physical or operational change to an existing facility must not be reduced by any “excluded additions” as defined in IRS Publication 534, as would be done for tax purposes.

*Clean coal technology demonstration project* means a project using funds appropriated under the heading ‘Department of Energy-Clean Coal Technology’, up to a total amount of \$2,500,000,000 for commercial demonstrations of clean coal technology, or similar projects funded through appropriations for the Environmental Protection Agency.

*Commenced* means, with respect to the definition of *new source* in section 111(a)(2) of the Act, that an owner or operator has undertaken a continuous program of construction or modification or that an owner or operator has entered into a contractual obligation to undertake and complete, within a reasonable time, a continuous program of construction or modification.

*Construction* means fabrication, erection, or installation of an affected facility.

*Continuous monitoring system* means the total equipment, required under the emission monitoring sections in applicable subparts, used to sample and condition (if applicable), to analyze, and to provide a permanent record of emissions or process parameters.

*Electric utility steam generating unit* means any steam electric generating unit that is constructed for the purpose of supplying more than one-third of its potential electric output capacity and more than 25 MW electrical output to any utility power distribution system for sale. Any steam supplied to a steam distribution system for the purpose of providing steam to a steam-electric generator that would produce electrical energy for sale is also considered in determining the electrical energy output capacity of the affected facility.

*Equivalent method* means any method of sampling and analyzing for an air pollutant which has been demonstrated to the Administrator's satisfaction to have a consistent and quantitatively known relationship to the reference method, under specified conditions.

*Excess Emissions and Monitoring Systems Performance Report* is a report that must be submitted periodically by a source in order to provide data on its compliance with stated emission limits and operating parameters, and on the performance of its monitoring systems.

*Existing facility* means, with reference to a stationary source, any apparatus of the type for which a standard is promulgated in this part, and the construction or modification of which was commenced before the date of proposal of that standard; or any apparatus which could be altered in such a way as to be of that type.

*Force majeure* means, for purposes of §60.8, an event that will be or has been caused by circumstances beyond the control of the affected facility, its contractors, or any entity controlled by the affected facility that prevents the owner or operator from complying with the regulatory requirement to conduct performance tests within the specified timeframe despite the affected facility's best efforts to fulfill the obligation. Examples of such events are acts of nature, acts of war or terrorism, or equipment failure or safety hazard beyond the control of the affected facility.

*Isokinetic sampling* means sampling in which the linear velocity of the gas entering the sampling nozzle is equal to that of the undisturbed gas stream at the sample point.

*Issuance* of a part 70 permit will occur, if the State is the permitting authority, in accordance with the requirements of part 70 of this chapter and the applicable, approved State permit program. When the EPA is the permitting authority, issuance of a Title V permit occurs immediately after the EPA takes final action on the final permit.

*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.

*Modification* means any physical change in, or change in the method of operation of, an existing facility which increases the amount of any air pollutant (to which a standard applies) emitted into the atmosphere by that facility or which results in the emission of any air pollutant (to which a standard applies) into the atmosphere not previously emitted.

*Monitoring device* means the total equipment, required under the monitoring of operations sections in applicable subparts, used to measure and record (if applicable) process parameters.

*Nitrogen oxides* means all oxides of nitrogen except nitrous oxide, as measured by test methods set forth in this part.

*One-hour period* means any 60-minute period commencing on the hour.

*Opacity* means the degree to which emissions reduce the transmission of light and obscure the view of an object in the background.

*Owner or operator* means any person who owns, leases, operates, controls, or supervises an affected facility or a stationary source of which an affected facility is a part.

*Part 70 permit* means any permit issued, renewed, or revised pursuant to part 70 of this chapter.

*Particulate matter* means any finely divided solid or liquid material, other than uncombined water, as measured by the reference methods specified under each applicable subpart, or an equivalent or alternative method.

*Permit program* means a comprehensive State operating permit system established pursuant to title V of the Act (42 U.S.C. 7661) and regulations codified in part 70 of this chapter and applicable State regulations, or a comprehensive Federal operating permit system established pursuant to title V of the Act and regulations codified in this chapter.

*Permitting authority* means:

- (1) The State air pollution control agency, local agency, other State agency, or other agency authorized by the Administrator to carry out a permit program under part 70 of this chapter; or
- (2) The Administrator, in the case of EPA-implemented permit programs under title V of the Act (42 U.S.C. 7661).

*Proportional sampling* means sampling at a rate that produces a constant ratio of sampling rate to stack gas flow rate.

*Reactivation of a very clean coal-fired electric utility steam generating unit* means any physical change or change in the method of operation associated with the commencement of commercial operations by a coal-fired utility unit after a period of discontinued operation where the unit:

- (1) Has not been in operation for the two-year period prior to the enactment of the Clean Air Act Amendments of 1990, and the emissions from such unit continue to be carried in the permitting authority's emissions inventory at the time of enactment;
- (2) Was equipped prior to shut-down with a continuous system of emissions control that achieves a removal efficiency for sulfur dioxide of no less than 85 percent and a removal efficiency for particulates of no less than 98 percent;
- (3) Is equipped with low-NO<sub>x</sub> burners prior to the time of commencement of operations following reactivation; and
- (4) Is otherwise in compliance with the requirements of the Clean Air Act.

*Reference method* means any method of sampling and analyzing for an air pollutant as specified in the applicable subpart.

*Repowering* means replacement of an existing coal-fired boiler with one of the following clean coal technologies: atmospheric or pressurized fluidized bed combustion, integrated gasification combined cycle, magnetohydrodynamics, direct and indirect coal-fired turbines, integrated gasification fuel cells, or as determined by the Administrator, in consultation with the Secretary of Energy, a derivative of one or more of these technologies, and any other technology capable of controlling multiple combustion emissions simultaneously with improved boiler or generation efficiency and with significantly greater waste reduction relative to the performance of technology in widespread commercial use as of November 15, 1990. Repowering shall also include any oil and/or gas-fired unit which has been awarded clean coal technology demonstration funding as of January 1, 1991, by the Department of Energy.

*Run* means the net period of time during which an emission sample is collected. Unless otherwise specified, a run may be either intermittent or continuous within the limits of good engineering practice.

*Shutdown* means the cessation of operation of an affected facility for any purpose.

*Six-minute period* means any one of the 10 equal parts of a one-hour period.

*Standard* means a standard of performance proposed or promulgated under this part.

*Standard conditions* means a temperature of 293 K (68F) and a pressure of 101.3 kilopascals (29.92 in Hg).

*Startup* means the setting in operation of an affected facility for any purpose.

*State* means all non-Federal authorities, including local agencies, interstate associations, and State-wide programs, that have delegated authority to implement: (1) The provisions of this part; and/or (2) the permit program established under part 70 of this chapter. The term State shall have its conventional meaning where clear from the context.

*Stationary source* means any building, structure, facility, or installation which emits or may emit any air pollutant.

*Title V permit* means any permit issued, renewed, or revised pursuant to Federal or State regulations established to implement title V of the Act (42 U.S.C. 7661). A title V permit issued by a State permitting authority is called a part 70 permit in this part.

*Volatile Organic Compound* means any organic compound which participates in atmospheric photochemical reactions; or which is measured by a reference method, an equivalent method, an alternative method, or which is determined by procedures specified under any subpart.

### **§60.3 Units and abbreviations.**

Used in this part are abbreviations and symbols of units of measure. These are defined as follows:

(a) System International (SI) units of measure:

A—ampere

g—gram

Hz—hertz

J—joule

K—degree Kelvin

kg—kilogram

m—meter

m<sup>3</sup>—cubic meter

mg—milligram— $10^{-3}$  gram

mm—millimeter— $10^{-3}$  meter

Mg—megagram— $10^6$  gram

mol—mole

N—newton

ng—nanogram— $10^{-9}$  gram

nm—nanometer— $10^{-9}$  meter

Pa—pascal

s—second

V—volt

W—watt

$\Omega$ —ohm

$\mu\text{g}$ —microgram— $10^{-6}$  gram

(b) Other units of measure:

Btu—British thermal unit

$^{\circ}\text{C}$ —degree Celsius (centigrade)

cal—calorie

cfm—cubic feet per minute

cu ft—cubic feet

dcf—dry cubic feet

dcm—dry cubic meter

dscf—dry cubic feet at standard conditions

dscm—dry cubic meter at standard conditions

eq—equivalent

$^{\circ}\text{F}$ —degree Fahrenheit

ft—feet

gal—gallon

gr—grain

g-eq—gram equivalent

hr—hour

in—inch

k—1,000  
l—liter  
lpm—liter per minute  
lb—pound  
meq—milliequivalent  
min—minute  
ml—milliliter  
mol. wt.—molecular weight  
ppb—parts per billion  
ppm—parts per million  
psia—pounds per square inch absolute  
psig—pounds per square inch gage  
°R—degree Rankine  
scf—cubic feet at standard conditions  
scfh—cubic feet per hour at standard conditions  
scm—cubic meter at standard conditions  
sec—second  
sq ft—square feet  
std—at standard conditions

(c) Chemical nomenclature:

CdS—cadmium sulfide  
CO—carbon monoxide  
CO<sub>2</sub>—carbon dioxide  
HCl—hydrochloric acid  
Hg—mercury  
H<sub>2</sub>O—water  
H<sub>2</sub>S—hydrogen sulfide  
H<sub>2</sub>SO<sub>4</sub>—sulfuric acid  
N<sub>2</sub>—nitrogen  
NO—nitric oxide  
NO<sub>2</sub>—nitrogen dioxide  
NO<sub>x</sub>—nitrogen oxides  
O<sub>2</sub>—oxygen

SO<sub>2</sub>—sulfur dioxide

SO<sub>3</sub>—sulfur trioxide

SO<sub>x</sub>—sulfur oxides

(d) Miscellaneous:

A.S.T.M.—American Society for Testing and Materials

**§60.4 Address.**

(a) All requests, reports, applications, submittals, and other communications to the Administrator pursuant to this part shall be submitted in duplicate to the appropriate Regional Office of the U.S. Environmental Protection Agency to the attention of the Director of the Division indicated in the following list of EPA Regional Offices.

Region I (Connecticut, Maine, Massachusetts, New Hampshire, Rhode Island, Vermont), Director, Office of Ecosystem Protection, U.S. Environmental Protection Agency, 5 Post Office Square—Suite 100, Boston, MA 02109-3912.

Region II (New Jersey, New York, Puerto Rico, Virgin Islands), Director, Air and Waste Management Division, U.S. Environmental Protection Agency, Federal Office Building, 26 Federal Plaza (Foley Square), New York, NY 10278.

Region III (Delaware, District of Columbia, Maryland, Pennsylvania, Virginia, West Virginia), Director, Air Protection Division, Mail Code 3AP00, 1650 Arch Street, Philadelphia, PA 19103-2029.

Region IV (Alabama, Florida, Georgia, Kentucky, Mississippi, North Carolina, South Carolina, Tennessee), Director, Air, Pesticides and Toxics Management Division, U.S. Environmental Protection Agency, 61 Forsyth St. SW., Suite 9T43, Atlanta, Georgia 30303-8960.

Region V (Illinois, Indiana, Michigan, Minnesota, Ohio, Wisconsin), Director, Air and Radiation Division, U.S. Environmental Protection Agency, 77 West Jackson Boulevard, Chicago, IL 60604-3590.

Region VI (Arkansas, Louisiana, New Mexico, Oklahoma, Texas); Director; Air, Pesticides, and Toxics Division; U.S. Environmental Protection Agency, 1445 Ross Avenue, Dallas, TX 75202.

Region VII (Iowa, Kansas, Missouri, Nebraska), Director, Air and Waste Management Division, 11201 Renner Boulevard, Lenexa, Kansas 66219.

Region VIII (Colorado, Montana, North Dakota, South Dakota, Utah, Wyoming) Director, Air and Toxics Technical Enforcement Program, Office of Enforcement, Compliance and Environmental Justice, Mail Code 8ENF-AT, 1595 Wynkoop Street, Denver, CO 80202-1129.

Region IX (Arizona, California, Hawaii and Nevada; the territories of American Samoa and Guam; the Commonwealth of the Northern Mariana Islands; the territories of Baker Island, Howland Island, Jarvis Island, Johnston Atoll, Kingman Reef, Midway Atoll, Palmyra Atoll, and Wake Islands; and certain U.S. Government activities in the freely associated states of the Republic of the Marshall Islands, the Federated States of Micronesia, and the Republic of Palau), Director, Air Division, U.S. Environmental Protection Agency, 75 Hawthorne Street, San Francisco, CA 94105.

Region X (Alaska, Oregon, Idaho, Washington), Director, Air and Waste Management Division, U.S. Environmental Protection Agency, 1200 Sixth Avenue, Seattle, WA 98101.

(b) Section 111(c) directs the Administrator to delegate to each State, when appropriate, the authority to implement and enforce standards of performance for new stationary sources located in such State. All information required to be submitted to EPA under paragraph (a) of this section, must also be submitted to the appropriate State Agency of any State to which this authority has been delegated (provided, that each specific delegation may

except sources from a certain Federal or State reporting requirement). The appropriate mailing address for those States whose delegation request has been approved is as follows:

(1) [Reserved]

(2) State of Alabama: Alabama Department of Environmental Management, P.O. Box 301463, Montgomery, Alabama 36130-1463.

(3) State of Alaska, Department of Environmental Conservation, Pouch O, Juneau, AK 99811.

(4) Arizona:

Arizona Department of Environmental Quality, 1110 West Washington Street, Phoenix, AZ 85007.

Maricopa County Air Quality Department, 1001 North Central Avenue, Suite 900, Phoenix, AZ 85004.

Pima County Department of Environmental Quality, 33 North Stone Avenue, Suite 700, Tucson, AZ 85701.

Pinal County Air Quality Control District, 31 North Pinal Street, Building F, Florence, AZ 85132.

NOTE: For tables listing the delegation status of agencies in Region IX, see paragraph (d) of this section.

(5) State of Arkansas: Chief, Division of Air Pollution Control, Arkansas Department of Pollution Control and Ecology, 8001 National Drive, P.O. Box 9583, Little Rock, AR 72209.

(6) California:

Amador County Air Pollution Control District, 12200-B Airport Road, Jackson, CA 95642.

Antelope Valley Air Quality Management District, 43301 Division Street, Suite 206, Lancaster, CA 93535.

Bay Area Air Quality Management District, 939 Ellis Street, San Francisco, CA 94109.

Butte County Air Quality Management District, 2525 Dominic Drive, Suite J, Chico, CA 95928.

Calaveras County Air Pollution Control District, 891 Mountain Ranch Road, San Andreas, CA 95249.

Colusa County Air Pollution Control District, 100 Sunrise Blvd., Suite A-3, Colusa, CA 95932-3246.

El Dorado County Air Quality Management District, 2850 Fairlane Court, Bldg. C, Placerville, CA 95667-4100.

Eastern Kern Air Pollution Control District, 2700 "M" Street, Suite 302, Bakersfield, CA 93301-2370.

Feather River Air Quality Management District, 1007 Live Oak Blvd., Suite B-3, Yuba City, CA 95991.

Glenn County Air Pollution Control District, 720 N. Colusa Street, P.O. Box 351, Willows, CA 95988-0351.

Great Basin Unified Air Pollution Control District, 157 Short Street, Suite 6, Bishop, CA 93514-3537.

Imperial County Air Pollution Control District, 150 South Ninth Street, El Centro, CA 92243-2801.

Lake County Air Quality Management District, 885 Lakeport Blvd., Lakeport, CA 95453-5405.

Lassen County Air Pollution Control District, 707 Nevada Street, Suite 1, Susanville, CA 96130.

Mariposa County Air Pollution Control District, P.O. Box 5, Mariposa, CA 95338.

Mendocino County Air Quality Management District, 306 E. Gobbi Street, Ukiah, CA 95482-5511.

Modoc County Air Pollution Control District, 619 North Main Street, Alturas, CA 96101.

Mojave Desert Air Quality Management District, 14306 Park Avenue, Victorville, CA 92392-2310.

Monterey Bay Unified Air Pollution Control District, 24580 Silver Cloud Court, Monterey, CA 93940.

North Coast Unified Air Quality Management District, 2300 Myrtle Avenue, Eureka, CA 95501-3327.

Northern Sierra Air Quality Management District, 200 Litton Drive, Suite 320, P.O. Box 2509, Grass Valley, CA 95945-2509.

Northern Sonoma County Air Pollution Control District, 150 Matheson Street, Healdsburg, CA 95448-4908.

Placer County Air Pollution Control District, 3091 County Center Drive, Suite 240, Auburn, CA 95603.

Sacramento Metropolitan Air Quality Management District, 777 12th Street, Third Floor, Sacramento, CA 95814-1908.

San Diego County Air Pollution Control District, 10124 Old Grove Road, San Diego, CA 92131-1649.

San Joaquin Valley Air Pollution Control District, 1990 E. Gettysburg, Fresno, CA 93726.

San Luis Obispo County Air Pollution Control District, 3433 Roberto Court, San Luis Obispo, CA 93401-7126.

Santa Barbara County Air Pollution Control District, 260 North San Antonio Road, Suite A, Santa Barbara, CA 93110-1315.

Shasta County Air Quality Management District, 1855 Placer Street, Suite 101, Redding, CA 96001-1759.

Siskiyou County Air Pollution Control District, 525 So. Foothill Drive, Yreka, CA 96097-3036.

South Coast Air Quality Management District, 21865 Copley Drive, Diamond Bar, CA 91765-4182.

Tehama County Air Pollution Control District, P.O. Box 8069 (1750 Walnut Street), Red Bluff, CA 96080-0038.

Tuolumne County Air Pollution Control District, 22365 Airport, Columbia, CA 95310.

Ventura County Air Pollution Control District, 669 County Square Drive, 2nd Floor, Ventura, CA 93003-5417.

Yolo-Solano Air Quality Management District, 1947 Galileo Court, Suite 103, Davis, CA 95616-4882.

NOTE: For tables listing the delegation status of agencies in Region IX, see paragraph (d) of this section.

(7) State of Colorado, Department of Public Health and Environment, 4300 Cherry Creek Drive South, Denver, CO 80222-1530.

NOTE: For a table listing Region VIII's NSPS delegation status, see paragraph (c) of this section.

(8) State of Connecticut, Bureau of Air Management, Department of Environmental Protection, State Office Building, 165 Capitol Avenue, Hartford, CT 06106.

(9) State of Delaware, Department of Natural Resources & Environmental Control, 89 Kings Highway, P.O. Box 1401, Dover, Delaware 19903.

(10) District of Columbia, Department of Public Health, Air Quality Division, 51 N Street, NE., Washington, DC 20002.

(11) State of Florida: Florida Department of Environmental Protection, Division of Air Resources Management, 2600 Blair Stone Road, MS 5500, Tallahassee, Florida 32399-2400.

(12) State of Georgia: Georgia Department of Natural Resources, Environmental Protection Division, Air Protection Branch, 4244 International Parkway, Suite 120, Atlanta, Georgia 30354.

(13) Hawaii:

Clean Air Branch, Hawaii Department of Health, 919 Ala Moana Blvd., Suite 203, Honolulu, HI 96814.

NOTE: For tables listing the delegation status of agencies in Region IX, see paragraph (d) of this section.

(14) State of Idaho, Department of Health and Welfare, Statehouse, Boise, ID 83701.

(15) State of Illinois: Illinois Environmental Protection Agency, 1021 North Grand Avenue East, Springfield, Illinois 62794.

(16) State of Indiana: Indiana Department of Environmental Management, Office of Air Quality, 100 North Senate Avenue, Indianapolis, Indiana 46204.

(17) State of Iowa: Iowa Department of Natural Resources, Environmental Protection Division, Air Quality Bureau, 7900 Hickman Road, Suite 1, Urbandale, IA 50322.

(18) State of Kansas: Kansas Department of Health and Environment, Bureau of Air and Radiation, 1000 S.W. Jackson, Suite 310, Topeka, KS 66612-1366.

(19) Commonwealth of Kentucky: Kentucky Department for Environmental Protection, Division for Air Quality, 300 Sower Boulevard, 2nd Floor, Frankfort, Kentucky 40601 or local agency, Louisville Metro Air Pollution Control District, 701 W. Ormsby Ave., Suite 303, Louisville, Kentucky 40203.

(20) State of Louisiana: Louisiana Department of Environmental Quality, P.O. Box 4301, Baton Rouge, Louisiana 70821-4301.

NOTE: For a list of delegated standards for Louisiana (excluding Indian country), see paragraph (e)(2) of this section.

(21) State of Maine, Bureau of Air Quality Control, Department of Environmental Protection, State House, Station No. 17, Augusta, ME 04333.

(22) State of Maryland, Department of the Environment, 1800 Washington Boulevard, Suite 705, Baltimore, Maryland 21230.

(23) Commonwealth of Massachusetts, Division of Air Quality Control, Department of Environmental Protection, One Winter Street, 7th floor, Boston, MA 02108.

(24) State of Michigan: Michigan Department of Natural Resources and Environment, Air Quality Division, P.O. Box 30028, Lansing, Michigan 48909.

(25) State of Minnesota: Minnesota Pollution Control Agency, Division of Air Quality, 520 Lafayette Road North, St. Paul, Minnesota 55155.

(26) State of Mississippi: Hand Deliver or Courier: Mississippi Department of Environmental Quality, Office of Pollution Control, Air Division, 515 East Amite Street, Jackson, Mississippi 39201, Mailing Address: Mississippi Department of Environmental Quality, Office of Pollution Control, Air Division, P.O. Box 2261, Jackson, Mississippi 39225.

(27) State of Missouri: Missouri Department of Natural Resources, Division of Environmental Quality, P.O. Box 176, Jefferson City, MO 65102.

(28) State of Montana, Department of Environmental Quality, 1520 E. 6th Ave., PO Box 200901, Helena, MT 59620-0901.

NOTE: For a table listing Region VIII's NSPS delegation status, see paragraph (c) of this section.

(29) State of Nebraska, Nebraska Department of Environmental Control, P.O. Box 94877, State House Station, Lincoln, NE 68509.

Lincoln-Lancaster County Health Department, Division of Environmental Health, 2200 St. Marys Avenue, Lincoln, NE 68502

(30) Nevada:

Nevada Division of Environmental Protection, 901 South Stewart Street, Suite 4001, Carson City, NV 89701-5249.

Clark County Department of Air Quality and Environmental Management, 500 S. Grand Central Parkway, 1st Floor, P.O. Box 555210, Las Vegas, NV 89155-5210.

Washoe County Health District, Air Quality Management Division, 1001 E. 9th Street, Building A, Suite 115A, Reno, NV 89520.

NOTE: For tables listing the delegation status of agencies in Region IX, see paragraph (d) of this section.

(31) State of New Hampshire, Air Resources Division, Department of Environmental Services, 64 North Main Street, Caller Box 2033, Concord, NH 03302-2033.

(32) State of New Jersey: New Jersey Department of Environmental Protection, Division of Environmental Quality, Enforcement Element, John Fitch Plaza, CN-027, Trenton, NJ 08625.

(1) The following table lists the specific source and pollutant categories that have been delegated to the states in Region II. The (X) symbol is used to indicate each category that has been delegated.

	Subpart	State			
		New Jersey	New York	Puerto Rico	Virgin Islands
D	Fossil-Fuel Fired Steam Generators for Which Construction Commenced After August 17, 1971 (Steam Generators and Lignite Fired Steam Generators)	X	X	X	X
Da	Electric Utility Steam Generating Units for Which Construction Commenced After September 18, 1978	X		X	
Db	Industrial-Commercial-Institutional Steam Generating Units	X	X	X	X
E	Incinerators	X	X	X	X
F	Portland Cement Plants	X	X	X	X
G	Nitric Acid Plants	X	X	X	X
H	Sulfuric Acid Plants	X	X	X	X
I	Asphalt Concrete Plants	X	X	X	X
J	Petroleum Refineries—(All Categories)	X	X	X	X

	Subpart	State			
		New Jersey	New York	Puerto Rico	Virgin Islands
K	Storage Vessels for Petroleum Liquids Constructed After June 11, 1973, and prior to May 19, 1978	X	X	X	X
Ka	Storage Vessels for Petroleum Liquids Constructed After May 18, 1978	X	X	X	
L	Secondary Lead Smelters	X	X	X	X
M	Secondary Brass and Bronze Ingot Production Plants	X	X	X	X
N	Iron and Steel Plants	X	X	X	X
O	Sewage Treatment Plants	X	X	X	X
P	Primary Copper Smelters	X	X	X	X
Q	Primary Zinc Smelters	X	X	X	X
R	Primary Lead Smelters	X	X	X	X
S	Primary Aluminum Reduction Plants	X	X	X	X
T	Phosphate Fertilizer Industry: Wet Process Phosphoric Acid Plants	X	X	X	X
U	Phosphate Fertilizer Industry: Superphosphoric Acid Plants	X	X	X	X
V	Phosphate Fertilizer Industry: Diammonium Phosphate Plants	X	X	X	X
W	Phosphate Fertilizer Industry: Triple Superphosphate Plants	X	X	X	X
X	Phosphate Fertilizer Industry: Granular Triple Superphosphate	X	X	X	X
Y	Coal Preparation Plants	X	X	X	X
Z	Ferroally Production Facilities	X	X	X	X
AA	Steel Plants: Electric Arc Furnaces	X	X	X	X
AAa	Electric Arc Furnaces and Argon-Oxygen Decarburization Vessels in Steel Plants	X	X	X	
BB	Kraft Pulp Mills	X	X	X	
CC	Glass Manufacturing Plants	X	X	X	
DD	Grain Elevators	X	X	X	
EE	Surface Coating of Metal Furniture	X	X	X	
GG	Stationary Gas Turbines	X	X	X	
HH	Lime Plants	X	X	X	

	Subpart	State			
		New Jersey	New York	Puerto Rico	Virgin Islands
KK	Lead Acid Battery Manufacturing Plants	X	X		
LL	Metallic Mineral Processing Plants	X	X	X	
MM	Automobile and Light-Duty Truck Surface Coating Operations	X	X		
NN	Phosphate Rock Plants	X	X		
PP	Ammonium Sulfate Manufacturing Plants	X	X		
QQ	Graphic Art Industry Publication Rotogravure Printing	X	X	X	X
RR	Pressure Sensitive Tape and Label Surface Coating Operations	X	X	X	
SS	Industrial Surface Coating: Large Appliances	X	X	X	
TT	Metal Coil Surface Coating	X	X	X	
UU	Asphalt Processing and Asphalt Roofing Manufacture	X	X	X	
VV	Equipment Leaks of Volatile Organic Compounds in Synthetic Organic Chemical Manufacturing Industry	X		X	
WW	Beverage Can Surface Coating Industry	X	X	X	
XX	Bulk Gasoline Terminals	X	X	X	
FFF	Flexible Vinyl and Urethane Coating and Printing	X	X	X	
GGG	Equipment Leaks of VOC in Petroleum Refineries	X		X	
HHH	Synthetic Fiber Production Facilities	X		X	
JJJ	Petroleum Dry Cleaners	X	X	X	
KKK	Equipment Leaks of VOC from Onshore Natural Gas Processing Plants				
LLL	Onshore Natural Gas Processing Plants; SO <sub>2</sub> Emissions		X		
OOO	Nonmetallic Mineral Processing Plants		X	X	
PPP	Wool Fiberglass Insulation Manufacturing Plants		X	X	

(33) State of New Mexico: New Mexico Environment Department, P.O. Box 5469, Santa Fe, New Mexico 87502-5469. Note: For a list of delegated standards for New Mexico (excluding Bernalillo County and Indian country), see paragraph (e)(1) of this section.

(i) Albuquerque-Bernalillo County Air Quality Control Board, c/o Environmental Health Department, P.O. Box 1293, Albuquerque, New Mexico 87103.

(ii) [Reserved]

(34) New York: New York State Department of Environmental Conservation, 50 Wolf Road Albany, New York 12233, attention: Division of Air Resources.

(35) State of North Carolina: North Carolina Department of Environmental Quality, Division of Air Quality, 1641 Mail Service Center, Raleigh, North Carolina 27699-1641 or local agencies, Forsyth County Office of Environmental Assistance and Protection, 201 North Chestnut Street, Winston-Salem, North Carolina 27101-4120; Mecklenburg County Land Use and Environmental Services Agency, Air Quality, 2145 Suttle Avenue, Charlotte, North Carolina 28208; Western North Carolina Regional Air Quality Agency, 125 S. Lexington Ave., Suite 101, Asheville, North Carolina 28801-3661.

(36) State of North Dakota, Division of Air Quality, North Dakota Department of Health, P.O. Box 5520, Bismarck, ND 58506-5520.

NOTE: For a table listing Region VIII's NSPS delegation status, see paragraph (c) of this section.

(37) State of Ohio:

(i) Medina, Summit and Portage Counties; Director, Akron Regional Air Quality Management District, 146 South High Street, Room 904, Akron, OH 44308.

(ii) Stark County; Director, Canton City Health Department, Air Pollution Control Division, 420 Market Avenue North, Canton, Ohio 44702-1544.

(iii) Butler, Clermont, Hamilton, and Warren Counties; Director, Hamilton County Department of Environmental Services, 250 William Howard Taft Road, Cincinnati, Ohio 45219-2660.

(iv) Cuyahoga County; Commissioner, Cleveland Department of Public Health, Division of Air Quality, 75 Erievue Plaza 2nd Floor, Cleveland, Ohio 44114.

(v) Clark, Darke, Greene, Miami, Montgomery, and Preble Counties; Director, Regional Air Pollution Control Agency, 117 South Main Street, Dayton, Ohio 45422-1280.

(vi) Lucas County and the City of Rossford (in Wood County); Director, City of Toledo, Division of Environmental Services, 348 South Erie Street, Toledo, OH 43604.

(vii) Adams, Brown, Lawrence, and Scioto Counties; Portsmouth Local Air Agency, 605 Washington Street, Third Floor, Portsmouth, OH 45662.

(viii) Allen, Ashland, Auglaize, Crawford, Defiance, Erie, Fulton, Hancock, Hardin, Henry, Huron, Marion, Mercer, Ottawa, Paulding, Putnam, Richland, Sandusky, Seneca, Van Wert Williams, Wood (Except City of Rossford), and Wyandot Counties; Ohio Environmental Protection Agency, Northwest District Office, Air Pollution Control, 347 North Dunbridge Road, Bowling Green, Ohio 43402.

(ix) Ashtabula, Carroll, Columbiana, Holmes, Lorain, and Wayne Counties; Ohio Environmental Protection Agency, Northeast District Office, Air Pollution Unit, 2110 East Aurora Road, Twinsburg, OH 44087.

(x) Athens, Belmont, Coshocton, Gallia, Guemsey, Harrison, Hocking, Jackson, Jefferson, Meigs, Monroe, Morgan, Muskingum, Noble, Perry, Pike, Ross, Tuscarawas, Vinton, and Washington Counties; Ohio Environmental Protection Agency, Southeast District Office, Air Pollution Unit, 2195 Front Street, Logan, OH 43138.

(xi) Champaign, Clinton, Highland, Logan, and Shelby Counties; Ohio Environmental Protection Agency, Southwest District Office, Air Pollution Unit, 401 East Fifth Street, Dayton, Ohio 45402-2911.

(xii) Delaware, Fairfield, Fayette, Franklin, Knox, Licking, Madison, Morrow, Pickaway, and Union Counties; Ohio Environmental Protection Agency, Central District Office, Air Pollution control, 50 West Town Street, Suite 700, Columbus, Ohio 43215.

(xiii) Geauga and Lake Counties; Lake County General Health District, Air Pollution Control, 33 Mill Street, Painesville, OH 44077.

(xiv) Mahoning and Trumbull Counties; Mahoning-Trumbull Air Pollution Control Agency, 345 Oak Hill Avenue, Suite 200, Youngstown, OH 44502.

(38) State of Oklahoma, Oklahoma State Department of Health, Air Quality Service, P.O. Box 53551, Oklahoma City, OK 73152.

(i) Oklahoma City and County: Director, Oklahoma City-County Health Department, 921 Northeast 23rd Street, Oklahoma City, OK 73105.

(ii) Tulsa County: Tulsa City-County Health Department, 4616 East Fifteenth Street, Tulsa, OK 74112.

(39) State of Oregon. (i) Oregon Department of Environmental Quality (ODEQ), 811 SW Sixth Avenue, Portland, OR 97204-1390, <http://www.deq.state.or.us>.

(ii) Lane Regional Air Pollution Authority (LRAPA), 1010 Main Street, Springfield, Oregon 97477, <http://www.lrapa.org>.

(40)(i) City of Philadelphia, Department of Public Health, Air Management Services, 321 University Avenue, Philadelphia, Pennsylvania 19104.

(ii) Commonwealth of Pennsylvania, Department of Environmental Protection, Bureau of Air Quality Control, P.O. Box 8468, 400 Market Street, Harrisburg, Pennsylvania 17105.

(iii) Allegheny County Health Department, Bureau of Environmental Quality, Division of Air Quality, 301 39th Street, Pittsburgh, Pennsylvania 15201.

(41) State of Rhode Island, Division of Air and Hazardous Materials, Department of Environmental Management, 291 Promenade Street, Providence, RI 02908.

(42) State of South Carolina: South Carolina Department of Health and Environmental Control, 2600 Bull Street, Columbia, South Carolina 29201.

(43) State of South Dakota, Air Quality Program, Department of Environment and Natural Resources, Joe Foss Building, 523 East Capitol, Pierre, SD 57501-3181.

NOTE: For a table listing Region VIII's NSPS delegation status, see paragraph (c) of this section.

(44) State of Tennessee: Tennessee Department of Environment and Conservation, Division of Air Pollution Control, William R. Snodgrass Tennessee Tower, 312 Rosa L. Parks Avenue, 15th Floor, Nashville, Tennessee 37243, or local agencies, Knox County Air Quality Management—Department of Public Health, 140 Dameron Avenue, Knoxville, Tennessee 37917; Metro Public Health Department, Pollution Control Division, 2500 Charlotte Ave., Nashville, Tennessee 37209; Chattanooga-Hamilton County Air Pollution Control Bureau, 6125 Preservation Drive, Chattanooga, Tennessee 37416; Shelby County Health Department, Pollution Control Section, 814 Jefferson Avenue, Memphis, Tennessee 38105.

(45) State of Texas, Texas Air Control Board, 6330 Highway 290 East, Austin, TX 78723.

(46) State of Utah, Division of Air Quality, Department of Environmental Quality, P.O. Box 144820, Salt Lake City, UT 84114-4820.

NOTE: For a table listing Region VIII's NSPS delegation status, see paragraph (c) of this section.









Subpart <sup>1</sup>	Washington							
	Ecology <sup>2</sup>	BCAA <sup>3</sup>	NWAPA <sup>4</sup>	ORCAA <sup>5</sup>	PSCAA <sup>6</sup>	SCAPCA <sup>7</sup>	SWCAA <sup>8</sup>	YRCAA <sup>9</sup>
HHH Synthetic Fiber Production Facilities	X	X	X	X	X	X	X	X
III VOC Emissions from Synthetic Organic Chemical Manufacturing Industry Air Oxidation Unit Processes	X	X	X	X	X	X	X	X
JJJ Petroleum Dry Cleaners	X	X	X	X	X	X	X	X
KKK Equipment Leaks of VOC from Onshore Natural Gas Processing Plants	X	X	X	X	X	X	X	X
LLL Onshore Natural Gas Processing: SO <sub>2</sub> Emissions	X	X	X	X	X	X	X	X
NNN VOC Emissions from Synthetic Organic Chemical Manufacturing Industry Distillation Operations	X	X	X	X	X	X	X	X
OOO Nonmetallic Mineral Processing Plants			X		X		X	
PPP Wool Fiberglass Insulation Manufacturing Plants	X	X	X	X	X	X	X	X
QQQ VOC Emissions from Petroleum Refinery Wastewater Systems	X	X	X	X	X	X	X	X
RRR VOCs from Synthetic Organic Chemical Manufacturing Industry Reactor Processes	X	X	X	X	X	X	X	X
SSS Magnetic Tape Coating Facilities	X	X	X	X	X	X	X	X
TTT Industrial Surface Coating: Surface Coating of Plastic Parts for Business Machines	X	X	X	X	X	X	X	X
UUU Calciners and Dryers in Mineral Industries	X	X	X	X	X	X	X	X
VVV Polymeric Coating of Supporting Substrates Facilities	X	X	X	X	X	X	X	X
WWW Municipal Solid Waste Landfills	X	X	X	X	X	X	X	X
AAAA Small Municipal Waste Combustion Units for which Construction is Commenced after August 30, 1999 or for which Modification or Reconstruction is Commenced after June 6, 2001	X	X		X	X	X		X
BBBB Small Municipal Waste Combustion Units Constructed on or before August 30, 1999 (Emission Guidelines and Compliance Times)								
CCCC Commercial and Industrial Solid Waste Incineration Units for which Construction is Commenced after November, 30, 1999 or for which Modification or Reconstruction is Commenced on or after June 1, 2001	X	X		X	X	X		X

Subpart <sup>1</sup>	Washington							
	Ecology <sup>2</sup>	BCAA <sup>3</sup>	NWAPA <sup>4</sup>	ORCAA <sup>5</sup>	PSCAA <sup>6</sup>	SCAPCA <sup>7</sup>	SWCAA <sup>8</sup>	YRCAA <sup>9</sup>
DDDD Commercial and Industrial Solid Waste Incineration Units that Commenced Construction on or before November 30, 1999 (Emission Guidelines and Compliance Times)								

<sup>1</sup>Any authority within any subpart of this part that is not delegable, is not delegated. Please refer to Attachment B to the delegation letters for a listing of the NSPS authorities excluded from delegation.

<sup>2</sup>Washington State Department of Ecology, for 40 CFR 60.17(h)(1), (h)(2), (h)(3) and 40 CFR part 60, subpart AAAA, as in effect on June 6, 2001; for 40 CFR part 60, subpart CCCC, as in effect on June 1, 2001; and for all other NSPS delegated, as in effect February 20, 2001.

<sup>3</sup>Benton Clean Air Authority, for 40 CFR 60.17(h)(1), (h)(2), (h)(3) and 40 CFR part 60, subpart AAAA, as in effect on June 6, 2001; for 40 CFR part 60, subpart CCCC, as in effect on June 1, 2001; and for all other NSPS delegated, as in effect February 20, 2001.

<sup>4</sup>Northwest Air Pollution Authority, for all NSPS delegated, as in effect on July 1, 2000.

<sup>5</sup>Olympic Regional Clean Air Authority, for 40 CFR 60.17(h)(1), (h)(2), (h)(3) and 40 CFR part 60, subpart AAAA, as in effect on June 6, 2001; for 40 CFR part 60, subpart CCCC, as in effect on June 1, 2001; and for all other NSPS delegated, as in effect February 20, 2001.

<sup>6</sup>Puget Sound Clean Air Authority, for all NSPS delegated, as in effect on July 1, 2002.

<sup>7</sup>Spokane County Air Pollution Control Authority, for 40 CFR 60.17(h)(1), (h)(2), (h)(3) and 40 CFR part 60, subpart AAAA, as in effect on June 6, 2001; for 40 CFR part 60, subpart CCCC, as in effect on June 1, 2001; and for all other NSPS delegated, as in effect February 20, 2001.

<sup>8</sup>Southwest Clean Air Agency, for all NSPS delegated, as in effect on July 1, 2000.

<sup>9</sup>Yakima Regional Clean Air Authority, for 40 CFR 60.17(h)(1), (h)(2), (h)(3) and 40 CFR part 60, subpart AAAA, as in effect on June 6, 2001; for 40 CFR part 60, subpart CCCC, as in effect on June 1, 2001; and for all other NSPS delegated, as in effect February 20, 2001.

<sup>10</sup>Subpart S of this part is not delegated to local agencies in Washington because the Washington State Department of Ecology retains sole authority to regulate Primary Aluminum Plants, pursuant to Washington Administrative Code 173-415-010.

<sup>11</sup>Subpart BB of this part is not delegated to local agencies in Washington because the Washington State Department of Ecology retains sole authority to regulate Kraft and Sulfite Pulping Mills, pursuant to Washington State Administrative Code 173-405-012 and 173-410-012.

(50) State of West Virginia, Department of Environmental Protection, Division of Air Quality, 601 57th Street, SE., Charleston, West Virginia 25304.

(51) State of Wisconsin: Wisconsin Department of Natural Resources, 101 South Webster St., P.O. Box 7921, Madison, Wisconsin 53707-7921.

(52) State of Wyoming, Department of Environmental Quality, Air Quality Division, Herschler Building, 122 West 25th Street, Cheyenne, WY 82002.

NOTE: For a table listing Region VIII's NSPS delegation status, see paragraph (c) of this section.

(53) Territory of Guam: Guam Environmental Protection Agency, P.O. Box 22439 GMF, Barrigada, Guam 96921.

NOTE: For tables listing the delegation status of agencies in Region IX, see paragraph (d) of this section.

(54) Commonwealth of Puerto Rico: Commonwealth of Puerto Rico Environmental Quality Board, P.O. Box 11488, Santurce, PR 00910, Attention: Air Quality Area Director (see table under §60.4(b)(FF)(1)).

(55) U.S. Virgin Islands: U.S. Virgin Islands Department of Conservation and Cultural Affairs, P.O. Box 578, Charlotte Amalie, St. Thomas, VI 00801.

(56) American Samoa: American Samoa Environmental Protection Agency, P.O. Box PPA, Pago Pago, American Samoa 96799.

NOTE: For tables listing the delegation status of agencies in Region IX, see paragraph (d) of this section.

(57) Commonwealth of the Northern Mariana Islands: CNMI Division of Environmental Quality, P.O. Box 501304, Saipan, MP 96950.

NOTE: For tables listing the delegation status of agencies in Region IX, see paragraph (d) of this section.

(c) The delegation status table for New Source Performance Standards for Region VIII can be found online at <http://www2.epa.gov/region8/air-program>.

(d) The following tables list the specific part 60 standards that have been delegated unchanged to the air pollution control agencies in Region IX. The (X) symbol is used to indicate each standard that has been delegated. The following provisions of this subpart are not delegated: §§60.4(b), 60.8(b), 60.9, 60.11(b), 60.11(e), 60.13(a), 60.13(d)(2), 60.13(g), 60.13(i).

(1) *Arizona*. The following table identifies delegations for Arizona:

Delegation Status for New Source Performance Standards for Arizona

	Subpart	Air pollution control agency			
		Arizona DEQ	Maricopa County	Pima County	Pinal County
A	General Provisions	X	X	X	X
D	Fossil-Fuel Fired Steam Generators Constructed After August 17, 1971	X	X	X	X
Da	Electric Utility Steam Generating Units Constructed After September 18, 1978	X	X	X	X
Db	Industrial-Commercial-Institutional Steam Generating Units	X	X	X	X
Dc	Small Industrial-Commercial-Institutional Steam Generating Units	X	X	X	X
E	Incinerators	X	X	X	X
Ea	Municipal Waste Combustors Constructed After December 20, 1989 and On or Before September 20, 1994	X	X	X	X
Eb	Large Municipal Waste Combustors Constructed After September 20, 1994	X	X	X	
Ec	Hospital/Medical/Infectious Waste Incinerators for Which Construction is Commenced After June 20, 1996	X	X	X	
F	Portland Cement Plants	X	X	X	X
G	Nitric Acid Plants	X	X	X	X
Ga	Nitric Acid Plants For Which Construction, Reconstruction or Modification Commenced After October 14, 2011		X	X	

	Subpart	Air pollution control agency			
		Arizona DEQ	Maricopa County	Pima County	Pinal County
H	Sulfuric Acid Plant	X	X	X	X
I	Hot Mix Asphalt Facilities	X	X	X	X
J	Petroleum Refineries	X	X	X	X
Ja	Petroleum Refineries for Which Construction, Reconstruction, or Modification Commenced After May 14, 2007		X	X	
K	Storage Vessels for Petroleum Liquids for Which Construction, Reconstruction, or Modification Commenced After June 11, 1973, and Prior to May 19, 1978	X	X	X	X
Ka	Storage Vessels for Petroleum Liquids for Which Construction, Reconstruction, or Modification Commenced After May 18, 1978, and Prior to July 23, 1984	X	X	X	X
Kb	Volatile Organic Liquid Storage Vessels (Including Petroleum Liquid Storage Vessels) for Which Construction, Reconstruction, or Modification Commenced After July 23, 1984	X	X	X	X
L	Secondary Lead Smelters	X	X	X	X
M	Secondary Brass and Bronze Production Plants	X	X	X	X
N	Primary Emissions from Basic Oxygen Process Furnaces for Which Construction is Commenced After June 11, 1973	X	X	X	X
Na	Secondary Emissions from Basic Oxygen Process Steelmaking Facilities for Which Construction is Commenced After January 20, 1983	X	X	X	X
O	Sewage Treatment Plants	X	X	X	X
P	Primary Copper Smelters	X	X	X	X
Q	Primary Zinc Smelters	X	X	X	X
R	Primary Lead Smelters	X	X	X	X
S	Primary Aluminum Reduction Plants	X	X	X	X
T	Phosphate Fertilizer Industry: Wet Process Phosphoric Acid Plants	X	X	X	X
U	Phosphate Fertilizer Industry: Superphosphoric Acid Plants	X	X	X	X
V	Phosphate Fertilizer Industry: Diammonium Phosphate Plants	X	X	X	X
W	Phosphate Fertilizer Industry: Triple Superphosphate Plants	X	X	X	X
X	Phosphate Fertilizer Industry: Granular Triple Superphosphate Storage Facilities	X	X	X	X
Y	Coal Preparation and Processing Plants	X	X	X	X

	Subpart	Air pollution control agency			
		Arizona DEQ	Maricopa County	Pima County	Pinal County
Z	Ferroalloy Production Facilities	X	X	X	X
AA	Steel Plants: Electric Arc Furnaces Constructed After October 21, 1974 and On or Before August 17, 1983	X	X	X	X
AAa	Steel Plants: Electric Arc Furnaces and Argon-Oxygen Decarburization Vessels Constructed After August 7, 1983	X	X	X	X
BB	Kraft Pulp Mills	X	X	X	X
BBa	Kraft Pulp Mill Sources for which Construction, Reconstruction or Modification Commenced after May 23, 2013		X	X	
CC	Glass Manufacturing Plants	X	X	X	X
DD	Grain Elevators	X	X	X	X
EE	Surface Coating of Metal Furniture	X	X	X	X
FF	(Reserved)				
Ga	Nitric Acid Plants for which Construction, Reconstruction or Modification Commenced after October 14, 2011		X		
GG	Stationary Gas Turbines	X	X	X	X
HH	Lime Manufacturing Plants	X	X	X	X
KK	Lead-Acid Battery Manufacturing Plants	X	X	X	X
LL	Metallic Mineral Processing Plants	X	X	X	X
MM	Automobile and Light Duty Trucks Surface Coating Operations	X	X	X	X
NN	Phosphate Rock Plants	X	X	X	X
PP	Ammonium Sulfate Manufacture	X	X	X	X
QQ	Graphic Arts Industry: Publication Rotogravure Printing	X	X	X	X
RR	Pressure Sensitive Tape and Label Surface Coating Operations	X	X	X	X
SS	Industrial Surface Coating: Large Appliances	X	X	X	X
TT	Metal Coil Surface Coating	X	X	X	X
UU	Asphalt Processing and Asphalt Roofing Manufacture	X	X	X	X
VV	Equipment Leaks of VOC in the Synthetic Organic Industry Chemicals Manufacturing	X	X	X	X

	Subpart	Air pollution control agency			
		Arizona DEQ	Maricopa County	Pima County	Pinal County
VVa	Equipment Leaks of VOC in the Synthetic Organic Industry for Which Construction, Reconstruction, or Chemicals Manufacturing Modification Commenced After November 7, 2006	X	X	X	
WW	Beverage Can Surface Coating Industry	X	X	X	X
XX	Bulk Gasoline Terminals	X	X	X	X
AAA	New Residential Wood Heaters	X	X	X	X
BBB	Rubber Tire Manufacturing Industry	X	X	X	X
CCC	(Reserved)				
DDD	Volatile Organic Compounds (VOC) Emissions from the Polymer Manufacturing Industry	X	X	X	X
EEE	(Reserved)				
FFF	Flexible Vinyl and Urethane Coating and Printing	X	X	X	X
GGG	Equipment Leaks of VOC in Petroleum Refineries	X	X	X	X
GGGa	Equipment Leaks of VOC in Petroleum Refineries for Which Construction, Reconstruction, or Modification Commenced After November 7, 2006	X	X	X	
HHH	Synthetic Fiber Production Facilities	X	X	X	X
III	Volatile Organic Compound (VOC) Emissions From the Synthetic Organic Chemical Manufacturing Industry (SOCMI) Air Oxidation Unit Processes	X	X	X	X
JJJ	Petroleum Dry Cleaners	X	X	X	X
KKK	Equipment Leaks of VOC From Onshore Natural Gas Processing Plants	X	X	X	X
LLL	Onshore Natural Gas Processing: SO <sub>2</sub> Emissions	X	X	X	X
MMM	(Reserved)				
NNN	Volatile Organic Compound (VOC) Emissions From Synthetic Organic Chemical Manufacturing Industry (SOCMI) Distillation Operations	X	X	X	X
OOO	Nonmetallic Mineral Processing Plants	X	X	X	X
PPP	Wool Fiberglass Insulation Manufacturing Plants	X	X	X	X
QQQ	VOC Emissions From Petroleum Refinery Wastewater Systems	X	X	X	X
RRR	Volatile Organic Compound Emissions from Synthetic Organic Chemical Manufacturing Industry (SOCMI) Reactor Processes	X	X		

	Subpart	Air pollution control agency			
		Arizona DEQ	Maricopa County	Pima County	Pinal County
SSS	Magnetic Tape Coating Facilities	X	X	X	X
TTT	Industrial Surface Coating: Surface Coating of Plastic Parts for Business Machines	X	X	X	X
UUU	Calciners and Dryers in Mineral Industries	X	X	X	
VVV	Polymeric Coating of Supporting Substrates Facilities	X	X	X	X
WWW	Municipal Solid Waste Landfills	X	X	X	
AAAA	Small Municipal Waste Combustion Units for Which Construction is Commenced After August 30, 1999 or for Which Modification or Reconstruction is Commenced After June 6, 2001	X	X	X	
CCCC	Commercial and Industrial Solid Waste Incineration Units for Which Construction Is Commenced After November 30, 1999 or for Which Modification or Reconstruction Is Commenced on or After June 1, 2001	X	X	X	
EEEE	Other Solid Waste Incineration Units for Which Construction is Commenced After December 9, 2004, or for Which Modification or Reconstruction is Commenced on or After June 16, 2006	X	X	X	
GGGG	(Reserved)				
HHHH	(Reserved)				
IIII	Stationary Compression Ignition Internal Combustion Engines	X	X	X	
JJJJ	Stationary Spark Ignition Internal Combustion Engines		X	X	
KKKK	Stationary Combustion Turbines	X	X	X	
LLLL	New Sewage Sludge Incineration Units			X	
MMMM	Emissions Guidelines and Compliance Times for Existing Sewage Sludge Incineration Units	X			
OOOO	Crude Oil and Natural Gas Production, Transmission, and Distribution		X	X	
QQQQ	Standards of Performance for New Residential Hydronic Heaters and Forced-Air Furnaces		X	X	
TTTT	Standards of Performance for Greenhouse Gas Emissions for Electric Generating Units		X		

(2) *California*. The following tables identify delegations for each of the local air pollution control agencies of California.

(i) Delegations for Amador County Air Pollution Control District, Antelope Valley Air Quality Management District, Bay Area Air Quality Management District, and Butte County Air Quality Management District are shown in the following table:

Delegation Status for New Source Performance Standards for Amador County APCD, Antelope Valley AQMD, Bay Area AQMD, and Butte County AQMD

	Subpart	Air pollution control agency			
		Amador County APCD	Antelope Valley AQMD	Bay Area AQMD	Butte County AQMD
A	General Provisions		X		
D	Fossil-Fuel Fired Steam Generators Constructed After August 17, 1971		X	X	
Da	Electric Utility Steam Generating Units Constructed After September 18, 1978		X	X	
Db	Industrial-Commercial-Institutional Steam Generating Units		X	X	
Dc	Small Industrial-Commercial-Institutional Steam Generating Units		X	X	
E	Incinerators		X	X	
Ea	Municipal Waste Combustors Constructed After December 20, 1989 and On or Before September 20, 1994		X	X	
Eb	Large Municipal Waste Combustors Constructed After September 20, 1994		X		
Ec	Hospital/Medical/Infectious Waste Incinerators for Which Construction is Commenced After June 20, 1996		X		
F	Portland Cement Plants		X	X	
G	Nitric Acid Plants		X	X	
Ga	Nitric Acid Plants For Which Construction, Reconstruction or Modification Commenced After October 14, 2011				
H	Sulfuric Acid Plant		X	X	
I	Hot Mix Asphalt Facilities		X	X	
J	Petroleum Refineries		X	X	
Ja	Petroleum Refineries for Which Construction, Reconstruction, or Modification Commenced After May 14, 2007		X		
K	Storage Vessels for Petroleum Liquids for Which Construction, Reconstruction, or Modification Commenced After June 11, 1973, and Prior to May 19, 1978		X	X	

	Subpart	Air pollution control agency			
		Amador County APCD	Antelope Valley AQMD	Bay Area AQMD	Butte County AQMD
Ka	Storage Vessels for Petroleum Liquids for Which Construction, Reconstruction, or Modification Commenced After May 18, 1978, and Prior to July 23, 1984		X	X	
Kb	Volatile Organic Liquid Storage Vessels (Including Petroleum Liquid Storage Vessels) for Which Construction, Reconstruction, or Modification Commenced After July 23, 1984		X	X	
L	Secondary Lead Smelters		X	X	
M	Secondary Brass and Bronze Production Plants		X	X	
N	Primary Emissions from Basic Oxygen Process Furnaces for Which Construction is Commenced After June 11, 1973		X	X	
Na	Secondary Emissions from Basic Oxygen Process Steelmaking Facilities for Which Construction is Commenced After January 20, 1983		X	X	
O	Sewage Treatment Plants		X	X	
P	Primary Copper Smelters		X	X	
Q	Primary Zinc Smelters		X	X	
R	Primary Lead Smelters		X	X	
S	Primary Aluminum Reduction Plants		X	X	
T	Phosphate Fertilizer Industry: Wet Process Phosphoric Acid Plants		X		
U	Phosphate Fertilizer Industry: Superphosphoric Acid Plants		X	X	
V	Phosphate Fertilizer Industry: Diammonium Phosphate Plants		X	X	
W	Phosphate Fertilizer Industry: Triple Superphosphate Plants		X	X	
X	Phosphate Fertilizer Industry: Granular Triple Superphosphate Storage Facilities		X	X	
Y	Coal Preparation and Processing Plants		X	X	
Z	Ferroalloy Production Facilities		X	X	
AA	Steel Plants: Electric Arc Furnaces Constructed After October 21, 1974 and On or Before August 17, 1983		X	X	
AAa	Steel Plants: Electric Arc Furnaces and Argon-Oxygen Decarburization Vessels Constructed After August 7, 1983		X	X	
BB	Kraft Pulp Mills		X	X	

	Subpart	Air pollution control agency			
		Amador County APCD	Antelope Valley AQMD	Bay Area AQMD	Butte County AQMD
CC	Glass Manufacturing Plants		X	X	
DD	Grain Elevators		X	X	
EE	Surface Coating of Metal Furniture		X	X	
FF	(Reserved)				
GG	Stationary Gas Turbines		X	X	
HH	Lime Manufacturing Plants		X	X	
KK	Lead-Acid Battery Manufacturing Plants		X	X	
LL	Metallic Mineral Processing Plants		X	X	
MM	Automobile and Light Duty Trucks Surface Coating Operations		X	X	
NN	Phosphate Rock Plants		X	X	
PP	Ammonium Sulfate Manufacture		X	X	
QQ	Graphic Arts Industry: Publication Rotogravure Printing		X	X	
RR	Pressure Sensitive Tape and Label Surface Coating Operations		X	X	
SS	Industrial Surface Coating: Large Appliances		X	X	
TT	Metal Coil Surface Coating		X	X	
UU	Asphalt Processing and Asphalt Roofing Manufacture		X	X	
VV	Equipment Leaks of VOC in the Synthetic Organic Industry Chemicals Manufacturing		X	X	
VVa	Equipment Leaks of VOC in the Synthetic Organic Industry for Which Construction, Reconstruction, or Chemicals Manufacturing Modification Commenced After November 7, 2006		X		
WW	Beverage Can Surface Coating Industry		X	X	
XX	Bulk Gasoline Terminals				
AAA	New Residential Wood Heaters		X	X	
BBB	Rubber Tire Manufacturing Industry		X	X	
CCC	(Reserved)				

	Subpart	Air pollution control agency			
		Amador County APCD	Antelope Valley AQMD	Bay Area AQMD	Butte County AQMD
DDD	Volatile Organic Compounds (VOC) Emissions from the Polymer Manufacturing Industry		X	X	
EEE	(Reserved)				
FFF	Flexible Vinyl and Urethane Coating and Printing		X	X	
GGG	Equipment Leaks of VOC in Petroleum Refineries		X	X	
GGGa	Equipment Leaks of VOC in Petroleum Refineries for Which Construction, Reconstruction, or Modification Commenced After November 7, 2006		X		
HHH	Synthetic Fiber Production Facilities		X	X	
III	Volatile Organic Compound (VOC) Emissions From the Synthetic Organic Chemical Manufacturing Industry (SOCMI) Air Oxidation Unit Processes		X		
JJJ	Petroleum Dry Cleaners		X	X	
KKK	Equipment Leaks of VOC From Onshore Natural Gas Processing Plants		X	X	
LLL	Onshore Natural Gas Processing: SO <sub>2</sub> Emissions		X		
MMM	(Reserved)				
NNN	Volatile Organic Compound (VOC) Emissions From Synthetic Organic Chemical Manufacturing Industry (SOCMI) Distillation Operations		X	X	
OOO	Nonmetallic Mineral Processing Plants		X	X	
PPP	Wool Fiberglass Insulation Manufacturing Plants		X	X	
QQQ	VOC Emissions From Petroleum Refinery Wastewater Systems		X		
RRR	Volatile Organic Compound Emissions from Synthetic Organic Chemical Manufacturing Industry (SOCMI) Reactor Processes		X		
SSS	Magnetic Tape Coating Facilities		X	X	
TTT	Industrial Surface Coating: Surface Coating of Plastic Parts for Business Machines		X	X	
UUU	Calciners and Dryers in Mineral Industries		X	X	
VVV	Polymeric Coating of Supporting Substrates Facilities		X	X	
WWW	Municipal Solid Waste Landfills		X		

	Subpart	Air pollution control agency			
		Amador County APCD	Antelope Valley AQMD	Bay Area AQMD	Butte County AQMD
AAAA	Small Municipal Waste Combustion Units for Which Construction is Commenced After August 30, 1999 or for Which Modification or Reconstruction is Commenced After June 6, 2001		X		
CCCC	Commercial and Industrial Solid Waste Incineration Units for Which Construction Is Commenced After November 30, 1999 or for Which Modification or Reconstruction Is Commenced on or After June 1, 2001		X		
EEEE	Other Solid Waste Incineration Units for Which Construction is Commenced After December 9, 2004, or for Which Modification or Reconstruction is Commenced on or After June 16, 2006		X		
GGGG	(Reserved)				
HHHH	(Reserved)				
IIII	Stationary Compression Ignition Internal Combustion Engines		X		
JJJJ	Stationary Spark Ignition Internal Combustion Engines		X		
KKKK	Stationary Combustion Turbines		X		
LLLL	New Sewage Sludge Incineration Units				
OOOO	Crude Oil and Natural Gas Production, Transmission, and Distribution				

(ii) [Reserved]

(iii) Delegations for Glenn County Air Pollution Control District, Great Basin Unified Air Pollution Control District, Imperial County Air Pollution Control District, and Kern County Air Pollution Control District are shown in the following table:

Delegation Status for New Source Performance Standards for Glenn County APCD, Great Basin Unified APCD, Imperial County APCD, and Kern County APCD

	Subpart	Air pollution control agency			
		Glenn County APCD	Great Basin Unified APCD	Imperial County APCD	Kern County APCD
A	General Provisions		X		X
D	Fossil-Fuel Fired Steam Generators Constructed After August 17, 1971		X		X

	Subpart	Air pollution control agency			
		Glenn County APCD	Great Basin Unified APCD	Imperial County APCD	Kern County APCD
Da	Electric Utility Steam Generating Units Constructed After September 18, 1978		X		X
Db	Industrial-Commercial-Institutional Steam Generating Units		X		X
Dc	Small Industrial Steam Generating Units		X		X
E	Incinerators		X		X
Ea	Municipal Waste Combustors Constructed After December 20, 1989 and On or Before September 20, 1994		X		
Eb	Municipal Waste Combustors Constructed After September 20, 1994				
Ec	Hospital/Medical/Infectious Waste Incinerators for Which Construction is Commenced After June 20, 1996				
F	Portland Cement Plants		X		X
G	Nitric Acid Plants		X		X
H	Sulfuric Acid Plants		X		
I	Hot Mix Asphalt Facilities		X		X
J	Petroleum Refineries		X		X
K	Storage Vessels for Petroleum Liquids for Which Construction, Reconstruction, or Modification Commenced After June 11, 1973, and Prior to May 19, 1978		X		X
Ka	Storage Vessels for Petroleum Liquids for Which Construction, Reconstruction, or Modification Commenced After May 18, 1978, and Prior to July 23, 1984		X		X
Kb	Volatile Organic Liquid Storage Vessels (Including Petroleum Liquid Storage Vessels) for Which Construction, Reconstruction, or Modification Commenced After July 23, 1984		X		X
L	Secondary Lead Smelters		X		X
M	Secondary Brass and Bronze Production Plants		X		X
N	Primary Emissions from Basic Oxygen Process Furnaces for Which Construction is Commenced After June 11, 1973		X		X
Na	Secondary Emissions from Basic Oxygen Process Steelmaking Facilities for		X		X

	Subpart	Air pollution control agency			
		Glenn County APCD	Great Basin Unified APCD	Imperial County APCD	Kern County APCD
	Which Construction is Commenced After January 20, 1983				
O	Sewage Treatment Plants		X		X
P	Primary Copper Smelters		X		X
Q	Primary Zinc Smelters		X		X
R	Primary Lead Smelters		X		X
S	Primary Aluminum Reduction Plants		X		X
T	Phosphate Fertilizer Industry: Wet Process Phosphoric Acid Plants		X		X
U	Phosphate Fertilizer Industry: Superphosphoric Acid Plants		X		X
V	Phosphate Fertilizer Industry: Diammonium Phosphate Plants		X		X
W	Phosphate Fertilizer Industry: Triple Superphosphate Plants		X		X
X	Phosphate Fertilizer Industry: Granular Triple Superphosphate Storage Facilities		X		X
Y	Coal Preparation Plants		X		X
Z	Ferroalloy Production Facilities		X		X
AA	Steel Plants: Electric Arc Furnaces Constructed After October 21, 1974 and On or Before August 17, 1983		X		X
AAa	Steel Plants: Electric Arc Furnaces and Argon-Oxygen Decarburization Vessels Constructed After August 7, 1983		X		X
BB	Kraft pulp Mills		X		X
CC	Glass Manufacturing Plants		X		X
DD	Grain Elevators		X		X
EE	Surface Coating of Metal Furniture		X		X
FF	(Reserved)				
GG	Stationary Gas Turbines		X		X
HH	Lime Manufacturing Plants		X		X
KK	Lead-Acid Battery Manufacturing Plants		X		X

	Subpart	Air pollution control agency			
		Glenn County APCD	Great Basin Unified APCD	Imperial County APCD	Kern County APCD
LL	Metallic Mineral Processing Plants		X		X
MM	Automobile and Light Duty Trucks Surface Coating Operations		X		X
NN	Phosphate Rock Plants		X		X
PP	Ammonium Sulfate Manufacture		X		X
QQ	Graphic Arts Industry: Publication Rotogravure Printing		X		X
RR	Pressure Sensitive Tape and Label Surface Coating Operations		X		X
SS	Industrial Surface Coating: Large Appliances		X		X
TT	Metal Coil Surface Coating		X		X
UU	Asphalt Processing and Asphalt Roofing Manufacture		X		X
VV	Equipment Leaks of VOC in the Synthetic Organic Chemicals Manufacturing Industry		X		X
WW	Beverage Can Surface Coating Industry		X		X
XX	Bulk Gasoline Terminals				
AAA	New Residential Wool Heaters		X		X
BBB	Rubber Tire Manufacturing Industry		X		X
CCC	(Reserved)				
DDD	Volatile Organic Compounds (VOC) Emissions from the Polymer Manufacturing Industry		X		X
EEE	(Reserved)				
FFF	Flexible Vinyl and Urethane Coating and Printing		X		X
GGG	Equipment Leaks of VOC in Petroleum Refineries		X		X
HHH	Synthetic Fiber Production Facilities		X		X
III	Volatile Organic Compound (VOC) Emissions From the Synthetic Organic Chemical Manufacturing Industry (SOCMI) Air Oxidation Unit Processes		X		X
JJJ	Petroleum Dry Cleaners		X		X
KKK	Equipment Leaks of VOC From Onshore Natural Gas Processing Plants		X		X

	Subpart	Air pollution control agency			
		Glenn County APCD	Great Basin Unified APCD	Imperial County APCD	Kern County APCD
LLL	Onshore Natural Gas Processing: SO2 Emissions				X
MMM	(Reserved)				
NNN	Volatile Organic Compound (VOC) Emissions From Synthetic Organic Chemical Manufacturing Industry (SOCMI) Distillation Operations		X		X
OOO	Nonmetallic Mineral Processing Plants		X		X
PPP	Wool Fiberglass Insulation Manufacturing Plants		X		X
QQQ	VOC Emissions From Petroleum Refinery Wastewater Systems		X		X
RRR	Volatile Organic Compound Emissions from Synthetic Organic Chemical Manufacturing Industry (SOCMI) Reactor Processes				X
SSS	Magnetic Tape Coating Facilities		X		X
TTT	Industrial Surface Coating: Surface Coating of Plastic Parts for Business Machines		X	X	
UUU	Calciners and Dryers in Mineral Industries		X		X
VVV	Polymeric Coating of Supporting Substrates Facilities		X		X
WWW	Municipal Solid Waste Landfills				X

(iv) Delegations for Lake County Air Quality Management District, Lassen County Air Pollution Control District, Mariposa County Air Pollution Control District, and Mendocino County Air Pollution Control District are shown in the following table:

Delegation Status for New Source Performance Standards for Lake County Air Quality Management District, Lassen County Air Pollution Control District, Mariposa County Air Pollution Control District, and Mendocino County Air Pollution Control District

	Subpart	Air pollution control agency			
		Lake County AQMD	Lassen County APCD	Mariposa County AQMD	Mendocino County AQMD
A	General Provisions	X			X
D	Fossil-Fuel Fired Steam Generators Constructed After August 17,	X			X

	Subpart	Air pollution control agency			
		Lake County AQMD	Lassen County APCD	Mariposa County AQMD	Mendocino County AQMD
	1971				
Da	Electric Utility Steam Generating Units Constructed After September 18, 1978	X			X
Db	Industrial-Commercial-Institutional Steam Generating Units	X			
Dc	Small Industrial Steam Generating Units	X			X
E	Incinerators	X			X
Ea	Municipal Waste Combustors Constructed After December 20, 1989 and On or Before September 20, 1994	X			X
Eb	Municipal Waste Combustors Constructed After September 20, 1994				
Ec	Hospital/Medical/Infectious Waste Incinerators for Which Construction is Commenced After June 20, 1996				
F	Portland Cement Plants	X			X
G	Nitric Acid Plants	X			X
H	Sulfuric Acid Plants	X			X
I	Hot Mix Asphalt Facilities	X			X
J	Petroleum Refineries	X			X
K	Storage Vessels for Petroleum Liquids for Which Construction, Reconstruction, or Modification Commenced After June 11, 1973, and Prior to May 19, 1978	X			X
Ka	Storage Vessels for Petroleum Liquids for Which Construction, Reconstruction, or Modification Commenced After May 18, 1978, and Prior to July 23, 1984	X			X
Kb	Volatile Organic Liquid Storage Vessels (Including Petroleum Liquid Storage Vessels) for Which Construction, Reconstruction, or Modification Commenced After July 23, 1984	X			X
L	Secondary Lead Smelters	X			X
M	Secondary Brass and Bronze Production Plants	X			X
N	Primary Emissions from Basic Oxygen Process Furnaces for Which Construction is Commenced After June 11, 1973	X			X

	Subpart	Air pollution control agency			
		Lake County AQMD	Lassen County APCD	Mariposa County AQMD	Mendocino County AQMD
Na	Secondary Emissions from Basic Oxygen Process Steelmaking Facilities for Which Construction is Commenced After January 20, 1983	X			X
O	Sewage Treatment Plants	X			X
P	Primary Copper Smelters	X			X
Q	Primary Zinc Smelters	X			X
R	Primary Lead Smelters	X			X
S	Primary Aluminum Reduction Plants	X			X
T	Phosphate Fertilizer Industry: Wet Process Phosphoric Acid Plants	X			X
U	Phosphate Fertilizer Industry: Superphosphoric Acid Plants	X			X
V	Phosphate Fertilizer Industry: Diammonium Phosphate Plants	X			X
W	Phosphate Fertilizer Industry: Triple Superphosphate Plants	X			X
X	Phosphate Fertilizer Industry: Granular Triple Superphosphate Storage Facilities	X			X
Y	Coal Preparation Plants	X			X
Z	Ferroalloy Production Facilities	X			X
AA	Steel Plants: Electric Arc Furnaces Constructed After October 21, 1974 and On or Before August 17, 1983	X			X
AAa	Steel Plants: Electric Arc Furnaces and Argon-Oxygen Decarburization Vessels Constructed After August 7, 1983	X			X
BB	Kraft Pulp Mills	X			X
CC	Glass Manufacturing Plants	X			X
DD	Grain Elevators	X			X
EE	Surface Coating of Metal Furniture	X			X
FF	(Reserved)				
GG	Stationary Gas Turbines	X			X
HH	Lime Manufacturing Plants	X			X

	Subpart	Air pollution control agency			
		Lake County AQMD	Lassen County APCD	Mariposa County AQMD	Mendocino County AQMD
KK	Lead-Acid Battery Manufacturing Plants	X			X
LL	Metallic Mineral Processing Plants	X			X
MM	Automobile and Light Duty Trucks Surface Coating Operations	X			X
NN	Phosphate Rock Plants	X			X
PP	Ammonium Sulfate Manufacture	X			X
QQ	Graphic Arts Industry: Publication Rotogravure Printing	X			X
RR	Pressure Sensitive Tape and Label Surface Coating Operations	X			X
SS	Industrial Surface Coating: Large Appliances	X			X
TT	Metal Coil Surface Coating	X			X
UU	Asphalt Processing and Asphalt Roofing Manufacture	X			X
VV	Equipment Leaks of VOC in the Synthetic Organic Chemicals Manufacturing Industry	X			X
WW	Beverage Can Surface Coating Industry	X			X
XX	Bulk Gasoline Terminals				
AAA	New Residential Wool Heaters	X			X
BBB	Rubber Tire Manufacturing Industry	X			X
CCC	(Reserved)				
DDD	Volatile Organic Compounds (VOC) Emissions from the Polymer Manufacturing Industry	X			X
EEE	(Reserved)				
FFF	Flexible Vinyl and Urethane Coating and Printing	X			X
GGG	Equipment Leaks of VOC in Petroleum Refineries	X			X
HHH	Synthetic Fiber Production Facilities	X			X
III	Volatile Organic Compound (VOC) Emissions From the Synthetic Organic Chemical Manufacturing Industry (SOCMI) Air Oxidation Unit Processes	X			X

	Subpart	Air pollution control agency			
		Lake County AQMD	Lassen County APCD	Mariposa County AQMD	Mendocino County AQMD
JJJ	Petroleum Dry Cleaners	X			X
KKK	Equipment Leaks of VOC From Onshore Natural Gas Processing Plants	X			X
LLL	Onshore Natural Gas Processing: SO2 Emissions	X			X
MMM	(Reserved)				
NNN	Volatile Organic Compound (VOC) Emissions From Synthetic Organic Chemical Manufacturing Industry (SOCMI) Distillation Operations	X			X
OOO	Nonmetallic Mineral Processing Plants	X			X
PPP	Wool Fiberglass Insulation Manufacturing Plants	X			X
QQQ	VOC Emissions From Petroleum Refinery Wastewater Systems	X			X
RRR	Volatile Organic Compound Emissions from Synthetic Organic Chemical Manufacturing Industry (SOCMI) Reactor Processes	X			
SSS	Magnetic Tape Coating Facilities	X			X
TTT	Industrial Surface Coating: Surface Coating of Plastic Parts for Business Machines				
UUU	Calciners and Dryers in Mineral Industries	X			X
VVV	Polymeric Coating of Supporting Substrates Facilities	X			X
WWW	Municipal Solid Waste Landfills	X			

(v) Delegations for Modoc Air Pollution Control District, Mojave Desert Air Quality Management District, Monterey Bay Unified Air Pollution Control District and North Coast Unified Air Quality Management District are shown in the following table:

Delegation Status for New Source Performance Standards for Modoc County APCD, Mojave Desert AQMD, Monterey Bay Unified APCD, and North Coast Unified AQMD

	Subpart	Air pollution control agency			
		Modoc County APCD	Mojave Desert AQMD	Monterey Bay Unified APCD	North Coast Unified AQMD

	Subpart	Air pollution control agency			
		Modoc County APCD	Mojave Desert AQMD	Monterey Bay Unified APCD	North Coast Unified AQMD
A	General Provisions	X	X	X	X
D	Fossil-Fuel Fired Steam Generators Constructed After August 17, 1971	X	X	X	X
Da	Electric Utility Steam Generating Units Constructed After September 18, 1978	X	X	X	X
Db	Industrial-Commercial-Institutional Steam Generating Units	X	X	X	X
Dc	Small Industrial-Commercial-Institutional Steam Generating Units		X	X	
E	Incinerators	X	X	X	X
Ea	Municipal Waste Combustors Constructed After December 20, 1989 and On or Before September 20, 1994		X		
Eb	Large Municipal Waste Combustors Constructed After September 20, 1994		X		
Ec	Hospital/Medical/Infectious Waste Incinerators for Which Construction is Commenced After June 20, 1996		X		
F	Portland Cement Plants	X	X	X	X
G	Nitric Acid Plants	X	X	X	X
Ga	Nitric Acid Plants For Which Construction, Reconstruction or Modification Commenced After October 14, 2011				
H	Sulfuric Acid Plant	X	X	X	X
I	Hot Mix Asphalt Facilities	X	X	X	X
J	Petroleum Refineries	X	X	X	X
Ja	Petroleum Refineries for Which Construction, Reconstruction, or Modification Commenced After May 14, 2007		X		
K	Storage Vessels for Petroleum Liquids for Which Construction, Reconstruction, or Modification Commenced After June 11, 1973, and Prior to May 19, 1978	X	X	X	X
Ka	Storage Vessels for Petroleum Liquids for Which Construction, Reconstruction, or Modification Commenced After May 18, 1978, and Prior to July 23, 1984	X	X	X	X
Kb	Volatile Organic Liquid Storage Vessels (Including Petroleum Liquid Storage Vessels) for Which Construction, Reconstruction, or	X	X	X	X

	Subpart	Air pollution control agency			
		Modoc County APCD	Mojave Desert AQMD	Monterey Bay Unified APCD	North Coast Unified AQMD
	Modification Commenced After July 23, 1984				
L	Secondary Lead Smelters	X	X	X	X
M	Secondary Brass and Bronze Production Plants	X	X	X	X
N	Primary Emissions from Basic Oxygen Process Furnaces for Which Construction is Commenced After June 11, 1973	X	X	X	X
Na	Secondary Emissions from Basic Oxygen Process Steelmaking Facilities for Which Construction is Commenced After January 20, 1983	X	X	X	X
O	Sewage Treatment Plants	X	X	X	X
P	Primary Copper Smelters	X	X	X	X
Q	Primary Zinc Smelters	X	X	X	X
R	Primary Lead Smelters	X	X	X	X
S	Primary Aluminum Reduction Plants	X	X	X	X
T	Phosphate Fertilizer Industry: Wet Process Phosphoric Acid Plants	X	X	X	X
U	Phosphate Fertilizer Industry: Superphosphoric Acid Plants	X	X	X	X
V	Phosphate Fertilizer Industry: Diammonium Phosphate Plants	X	X	X	X
W	Phosphate Fertilizer Industry: Triple Superphosphate Plants	X	X	X	X
X	Phosphate Fertilizer Industry: Granular Triple Superphosphate Storage Facilities	X	X	X	X
Y	Coal Preparation and Processing Plants	X	X	X	X
Z	Ferroalloy Production Facilities	X	X	X	X
AA	Steel Plants: Electric Arc Furnaces Constructed After October 21, 1974 and On or Before August 17, 1983	X	X	X	X
AAa	Steel Plants: Electric Arc Furnaces and Argon-Oxygen Decarburization Vessels Constructed After August 7, 1983	X	X	X	X
BB	Kraft Pulp Mills	X	X	X	X
CC	Glass Manufacturing Plants	X	X	X	X
DD	Grain Elevators	X	X	X	X

	Subpart	Air pollution control agency			
		Modoc County APCD	Mojave Desert AQMD	Monterey Bay Unified APCD	North Coast Unified AQMD
EE	Surface Coating of Metal Furniture	X	X	X	X
FF	(Reserved)				
GG	Stationary Gas Turbines	X	X	X	X
HH	Lime Manufacturing Plants	X	X	X	X
KK	Lead-Acid Battery Manufacturing Plants	X	X	X	X
LL	Metallic Mineral Processing Plants	X	X	X	X
MM	Automobile and Light Duty Trucks Surface Coating Operations	X	X	X	X
NN	Phosphate Rock Plants	X	X	X	X
PP	Ammonium Sulfate Manufacture	X	X	X	X
QQ	Graphic Arts Industry: Publication Rotogravure Printing	X	X	X	X
RR	Pressure Sensitive Tape and Label Surface Coating Operations	X	X	X	X
SS	Industrial Surface Coating: Large Appliances	X	X	X	X
TT	Metal Coil Surface Coating	X	X	X	X
UU	Asphalt Processing and Asphalt Roofing Manufacture	X	X	X	X
VV	Equipment Leaks of VOC in the Synthetic Organic Industry Chemicals Manufacturing	X	X	X	X
VVa	Equipment Leaks of VOC in the Synthetic Organic Industry for Which Construction, Reconstruction, or Chemicals Manufacturing Modification Commenced After November 7, 2006		X		
WW	Beverage Can Surface Coating Industry	X	X	X	X
XX	Bulk Gasoline Terminals				
AAA	New Residential Wood Heaters	X	X	X	X
BBB	Rubber Tire Manufacturing Industry	X	X	X	X
CCC	(Reserved)				
DDD	Volatile Organic Compounds (VOC) Emissions from the Polymer Manufacturing Industry	X	X	X	

	Subpart	Air pollution control agency			
		Modoc County APCD	Mojave Desert AQMD	Monterey Bay Unified APCD	North Coast Unified AQMD
EEE	(Reserved)				
FFF	Flexible Vinyl and Urethane Coating and Printing	X	X	X	X
GGG	Equipment Leaks of VOC in Petroleum Refineries	X	X	X	X
GGGa	Equipment Leaks of VOC in Petroleum Refineries for Which Construction, Reconstruction, or Modification Commenced After November 7, 2006		X		
HHH	Synthetic Fiber Production Facilities	X	X	X	X
III	Volatile Organic Compound (VOC) Emissions From the Synthetic Organic Chemical Manufacturing Industry (SOCMI) Air Oxidation Unit Processes		X		
JJJ	Petroleum Dry Cleaners	X	X	X	X
KKK	Equipment Leaks of VOC From Onshore Natural Gas Processing Plants	X	X	X	X
LLL	Onshore Natural Gas Processing: SO <sub>2</sub> Emissions	X	X	X	X
MMM	(Reserved)				
NNN	Volatile Organic Compound (VOC) Emissions From Synthetic Organic Chemical Manufacturing Industry (SOCMI) Distillation Operations	X	X	X	
OOO	Nonmetallic Mineral Processing Plants	X	X	X	X
PPP	Wool Fiberglass Insulation Manufacturing Plants	X	X	X	X
QQQ	VOC Emissions From Petroleum Refinery Wastewater Systems	X	X	X	X
RRR	Volatile Organic Compound Emissions from Synthetic Organic Chemical Manufacturing Industry (SOCMI) Reactor Processes		X		
SSS	Magnetic Tape Coating Facilities	X	X	X	X
TTT	Industrial Surface Coating: Surface Coating of Plastic Parts for Business Machines	X	X	X	X
UUU	Calciners and Dryers in Mineral Industries		X	X	
VVV	Polymeric Coating of Supporting Substrates Facilities		X	X	X
WWW	Municipal Solid Waste Landfills		X		
AAAA	Small Municipal Waste Combustion Units for Which Construction is Commenced After August 30, 1999 or for Which Modification or		X		

	Subpart	Air pollution control agency			
		Modoc County APCD	Mojave Desert AQMD	Monterey Bay Unified APCD	North Coast Unified AQMD
	Reconstruction is Commenced After June 6, 2001				
CCCC	Commercial and Industrial Solid Waste Incineration Units for Which Construction Is Commenced After November 30, 1999 or for Which Modification or Reconstruction Is Commenced on or After June 1, 2001		X		
EEEE	Other Solid Waste Incineration Units for Which Construction is Commenced After December 9, 2004, or for Which Modification or Reconstruction is Commenced on or After June 16, 2006		X		
GGGG	(Reserved)				
HHHH	(Reserved)				
IIII	Stationary Compression Ignition Internal Combustion Engines		X		
JJJJ	Stationary Spark Ignition Internal Combustion Engines		X		
KKKK	Stationary Combustion Turbines		X		
LLLL	New Sewage Sludge Incineration Units				
OOOO	Crude Oil and Natural Gas Production, Transmission, and Distribution				

(vi) Delegations for Northern Sierra Air Quality Management District, Northern Sonoma County Air Pollution Control District, Placer County Air Pollution Control District, and Sacramento Metropolitan Air Quality Management District are shown in the following table:

Delegation Status for New Source Performance Standards for Northern Sierra Air Quality Management District, Northern Sonoma County Air Pollution Control District, Placer County Air Pollution Control District, and Sacramento Metropolitan Air Quality Management District

	Subpart	Air pollution control agency			
		Northern Sierra AQMD	Northern Sonoma County APCD	Placer County APCD	Sacramento Metropolitan AQMD
A	General Provisions		X		X
D	Fossil-Fuel Fired Steam Generators Constructed After August 17, 1971		X		X
Da	Electric Utility Steam Generating Units Constructed After		X		X

	Subpart	Air pollution control agency			
		Northern Sierra AQMD	Northern Sonoma County APCD	Placer County APCD	Sacramento Metropolitan AQMD
	September 18, 1978				
Db	Industrial-Commercial-Institutional Steam Generating Units				X
Dc	Small Industrial Steam Generating Units				X
E	Incinerators		X		X
Ea	Municipal Waste Combustors Constructed After December 20, 1989 and On or Before September 20, 1994				X
Eb	Municipal Waste Combustors Constructed After September 20, 1994				X
Ec	Hospital/Medical/Infectious Waste Incinerators for Which Construction is Commenced After June 20, 1996				X
F	Portland Cement Plants		X		X
G	Nitric Acid Plants		X		X
H	Sulfuric Acid Plants		X		X
I	Hot Mix Asphalt Facilities		X		X
J	Petroleum Refineries		X		X
K	Storage Vessels for Petroleum Liquids for Which Construction, Reconstruction, or Modification Commenced After June 11, 1973, and Prior to May 19, 1978		X		X
Ka	Storage Vessels for Petroleum Liquids for Which Construction, Reconstruction, or Modification Commenced After May 18, 1978, and Prior to July 23, 1984		X		X
Kb	Volatile Organic Liquid Storage Vessels (Including Petroleum Liquid Storage Vessels) for Which Construction, Reconstruction, or Modification Commenced After July 23, 1984				X
L	Secondary Lead Smelters		X		X
M	Secondary Brass and Bronze Production Plants		X		X
N	Primary Emissions from Basic Oxygen Process Furnaces for Which Construction is Commenced After June 11, 1973		X		X
Na	Secondary Emissions from Basic Oxygen Process Steelmaking Facilities for Which Construction is Commenced After January				X

	Subpart	Air pollution control agency			
		Northern Sierra AQMD	Northern Sonoma County APCD	Placer County APCD	Sacramento Metropolitan AQMD
	20, 1983				
O	Sewage Treatment Plants		X		X
P	Primary Copper Smelters		X		X
Q	Primary Zinc Smelters		X		X
R	Primary Lead Smelters		X		X
S	Primary Aluminum Reduction Plants		X		X
T	Phosphate Fertilizer Industry: Wet Process Phosphoric Acid Plants		X		X
U	Phosphate Fertilizer Industry: Superphosphoric Acid Plants		X		X
V	Phosphate Fertilizer Industry: Diammonium Phosphate Plants		X		X
W	Phosphate Fertilizer Industry: Triple Superphosphate Plants		X		X
X	Phosphate Fertilizer Industry: Granular Triple Superphosphate Storage Facilities		X		X
Y	Coal Preparation Plants		X		X
Z	Ferroalloy Production Facilities		X		X
AA	Steel Plants: Electric Arc Furnaces Constructed After October 21, 1974 and On or Before August 17, 1983		X		X
AAa	Steel Plants: Electric Arc Furnaces and Argon-Oxygen Decarburization Vessels Constructed After August 7, 1983				X
BB	Kraft pulp Mills		X		X
CC	Glass Manufacturing Plants		X		X
DD	Grain Elevators		X		X
EE	Surface Coating of Metal Furniture				X
FF	(Reserved)				
GG	Stationary Gas Turbines		X		X
HH	Lime Manufacturing Plants		X		X

	Subpart	Air pollution control agency			
		Northern Sierra AQMD	Northern Sonoma County APCD	Placer County APCD	Sacramento Metropolitan AQMD
KK	Lead-Acid Battery Manufacturing Plants				X
LL	Metallic Mineral Processing Plants				X
MM	Automobile and Light Duty Trucks Surface Coating Operations		X		X
NN	Phosphate Rock Plants				X
PP	Ammonium Sulfate Manufacture		X		X
QQ	Graphic Arts Industry: Publication Rotogravure Printing				X
RR	Pressure Sensitive Tape and Label Surface Coating Operations				X
SS	Industrial Surface Coating: Large Appliances				X
TT	Metal Coil Surface Coating				X
UU	Asphalt Processing and Asphalt Roofing Manufacture				X
VV	Equipment Leaks of VOC in the Synthetic Organic Chemicals Manufacturing Industry				X
WW	Beverage Can Surface Coating Industry				X
XX	Bulk Gasoline Terminals				
AAA	New Residential Wool Heaters				X
BBB	Rubber Tire Manufacturing Industry				X
CCC	(Reserved)				
DDD	Volatile Organic Compounds (VOC) Emissions from the Polymer Manufacturing Industry				X
EEE	(Reserved)				
FFF	Flexible Vinyl and Urethane Coating and Printing				X
GGG	Equipment Leaks of VOC in Petroleum Refineries				X
HHH	Synthetic Fiber Production Facilities				X
III	Volatile Organic Compound (VOC) Emissions From the Synthetic Organic Chemical Manufacturing Industry (SOCMI) Air Oxidation Unit Processes				X

	Subpart	Air pollution control agency			
		Northern Sierra AQMD	Northern Sonoma County APCD	Placer County APCD	Sacramento Metropolitan AQMD
JJJ	Petroleum Dry Cleaners				X
KKK	Equipment Leaks of VOC From Onshore Natural Gas Processing Plants				X
LLL	Onshore Natural Gas Processing: SO2 Emissions				X
MMM	(Reserved)				
NNN	Volatile Organic Compound (VOC) Emissions From Synthetic Organic Chemical Manufacturing Industry (SOCMI) Distillation Operations				X
OOO	Nonmetallic Mineral Processing Plants				X
PPP	Wool Fiberglass Insulation Manufacturing Plants				X
QQQ	VOC Emissions From Petroleum Refinery Wastewater Systems				X
RRR	Volatile Organic Compound Emissions from Synthetic Organic Chemical Manufacturing Industry (SOCMI) Reactor Processes				X
SSS	Magnetic Tape Coating Facilities				X
TTT	Industrial Surface Coating: Surface Coating of Plastic Parts for Business Machines				X
UUU	Calciners and Dryers in Mineral Industries				X
VVV	Polymeric Coating of Supporting Substrates Facilities				X
WWW	Municipal Solid Waste Landfills				X

(vii) Delegations for San Diego County Air Pollution Control District, San Joaquin Valley Unified Air Pollution Control District, San Luis Obispo County Air Pollution Control District, and Santa Barbara County Air Pollution Control District are shown in the following table:

Delegation Status for New Source Performance Standards for San Diego County APCD, San Joaquin Valley Unified APCD, San Luis Obispo County APCD, and Santa Barbara County APCD

	Subpart	Air pollution control agency
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		San Diego County APCD	San Joaquin Valley Unified APCD	San Luis Obispo County APCD	Santa Barbara County APCD
A	General Provisions	X	X	X	X
D	Fossil-Fuel Fired Steam Generators Constructed After August 17, 1971	X	X	X	X
Da	Electric Utility Steam Generating Units Constructed After September 18, 1978	X	X	X	X
Db	Industrial-Commercial-Institutional Steam Generating Units	X	X	X	X
Dc	Small Industrial-Commercial-Institutional Steam Generating Units	X	X	X	X
E	Incinerators	X	X	X	X
Ea	Municipal Waste Combustors Constructed After December 20, 1989 and On or Before September 20, 1994	X	X	X	
Eb	Large Municipal Waste Combustors Constructed After September 20, 1994	X	X		X
Ec	Hospital/Medical/Infectious Waste Incinerators for Which Construction is Commenced After June 20, 1996	X			X
F	Portland Cement Plants	X	X	X	
G	Nitric Acid Plants	X	X	X	
Ga	Nitric Acid Plants For Which Construction, Reconstruction or Modification Commenced After October 14, 2011				
H	Sulfuric Acid Plant	X	X	X	
I	Hot Mix Asphalt Facilities	X	X	X	X
J	Petroleum Refineries	X	X	X	X
Ja	Petroleum Refineries for Which Construction, Reconstruction, or Modification Commenced After May 14, 2007				X
K	Storage Vessels for Petroleum Liquids for Which Construction, Reconstruction, or Modification Commenced After June 11, 1973, and Prior to May 19, 1978	X	X	X	X
Ka	Storage Vessels for Petroleum Liquids for Which Construction, Reconstruction, or Modification Commenced After May 18, 1978, and Prior to July 23, 1984	X	X	X	X
Kb	Volatile Organic Liquid Storage Vessels (Including Petroleum Liquid Storage Vessels) for Which Construction, Reconstruction, or	X	X	X	X

	Subpart	Air pollution control agency			
		San Diego County APCD	San Joaquin Valley Unified APCD	San Luis Obispo County APCD	Santa Barbara County APCD
	Modification Commenced After July 23, 1984				
L	Secondary Lead Smelters	X	X	X	X
M	Secondary Brass and Bronze Production Plants	X	X	X	X
N	Primary Emissions from Basic Oxygen Process Furnaces for Which Construction is Commenced After June 11, 1973	X	X	X	
Na	Secondary Emissions from Basic Oxygen Process Steelmaking Facilities for Which Construction is Commenced After January 20, 1983	X	X	X	
O	Sewage Treatment Plants	X	X	X	X
P	Primary Copper Smelters	X	X	X	
Q	Primary Zinc Smelters	X	X	X	
R	Primary Lead Smelters	X	X	X	
S	Primary Aluminum Reduction Plants	X	X	X	
T	Phosphate Fertilizer Industry: Wet Process Phosphoric Acid Plants	X	X	X	
U	Phosphate Fertilizer Industry: Superphosphoric Acid Plants	X	X	X	
V	Phosphate Fertilizer Industry: Diammonium Phosphate Plants	X	X	X	
W	Phosphate Fertilizer Industry: Triple Superphosphate Plants	X	X	X	
X	Phosphate Fertilizer Industry: Granular Triple Superphosphate Storage Facilities	X	X	X	
Y	Coal Preparation and Processing Plants	X	X	X	
Z	Ferroalloy Production Facilities	X	X	X	
AA	Steel Plants: Electric Arc Furnaces Constructed After October 21, 1974 and On or Before August 17, 1983	X	X	X	
AAa	Steel Plants: Electric Arc Furnaces and Argon-Oxygen Decarburization Vessels Constructed After August 7, 1983	X	X	X	
BB	Kraft Pulp Mills	X	X	X	
CC	Glass Manufacturing Plants	X	X	X	X

	Subpart	Air pollution control agency			
		San Diego County APCD	San Joaquin Valley Unified APCD	San Luis Obispo County APCD	Santa Barbara County APCD
DD	Grain Elevators	X	X	X	X
EE	Surface Coating of Metal Furniture	X	X	X	
FF	(Reserved)				
GG	Stationary Gas Turbines	X	X	X	X
HH	Lime Manufacturing Plants	X	X	X	
KK	Lead-Acid Battery Manufacturing Plants	X	X	X	
LL	Metallic Mineral Processing Plants	X	X	X	
MM	Automobile and Light Duty Trucks Surface Coating Operations	X	X	X	
NN	Phosphate Rock Plants	X	X	X	
PP	Ammonium Sulfate Manufacture	X	X	X	
QQ	Graphic Arts Industry: Publication Rotogravure Printing	X	X	X	
RR	Pressure Sensitive Tape and Label Surface Coating Operations	X	X	X	
SS	Industrial Surface Coating: Large Appliances	X	X	X	
TT	Metal Coil Surface Coating	X	X	X	
UU	Asphalt Processing and Asphalt Roofing Manufacture	X	X	X	
VV	Equipment Leaks of VOC in the Synthetic Organic Industry Chemicals Manufacturing	X	X	X	
VVa	Equipment Leaks of VOC in the Synthetic Organic Industry for Which Construction, Reconstruction, or Chemicals Manufacturing Modification Commenced After November 7, 2006				X
WW	Beverage Can Surface Coating Industry	X	X	X	
XX	Bulk Gasoline Terminals				
AAA	New Residential Wood Heaters	X	X	X	X
BBB	Rubber Tire Manufacturing Industry	X	X	X	
CCC	(Reserved)				

	Subpart	Air pollution control agency			
		San Diego County APCD	San Joaquin Valley Unified APCD	San Luis Obispo County APCD	Santa Barbara County APCD
DDD	Volatile Organic Compounds (VOC) Emissions from the Polymer Manufacturing Industry	X	X		
EEE	(Reserved)				
FFF	Flexible Vinyl and Urethane Coating and Printing	X	X	X	
GGG	Equipment Leaks of VOC in Petroleum Refineries	X	X	X	
GGGa	Equipment Leaks of VOC in Petroleum Refineries for Which Construction, Reconstruction, or Modification Commenced After November 7, 2006				X
HHH	Synthetic Fiber Production Facilities	X	X	X	
III	Volatile Organic Compound (VOC) Emissions From the Synthetic Organic Chemical Manufacturing Industry (SOCMI) Air Oxidation Unit Processes	X	X		
JJJ	Petroleum Dry Cleaners	X	X	X	
KKK	Equipment Leaks of VOC From Onshore Natural Gas Processing Plants	X	X	X	
LLL	Onshore Natural Gas Processing: SO <sub>2</sub> Emissions	X	X	X	
MMM	(Reserved)				
NNN	Volatile Organic Compound (VOC) Emissions From Synthetic Organic Chemical Manufacturing Industry (SOCMI) Distillation Operations	X	X		
OOO	Nonmetallic Mineral Processing Plants	X	X	X	X
PPP	Wool Fiberglass Insulation Manufacturing Plants	X	X	X	
QQQ	VOC Emissions From Petroleum Refinery Wastewater Systems	X	X	X	
RRR	Volatile Organic Compound Emissions from Synthetic Organic Chemical Manufacturing Industry (SOCMI) Reactor Processes	X	X	X	
SSS	Magnetic Tape Coating Facilities	X	X	X	
TTT	Industrial Surface Coating: Surface Coating of Plastic Parts for Business Machines	X	X	X	
UUU	Calciners and Dryers in Mineral Industries	X	X	X	X

	Subpart	Air pollution control agency			
		San Diego County APCD	San Joaquin Valley Unified APCD	San Luis Obispo County APCD	Santa Barbara County APCD
VVV	Polymeric Coating of Supporting Substrates Facilities	X	X	X	X
WWW	Municipal Solid Waste Landfills	X	X	X	X
AAAA	Small Municipal Waste Combustion Units for Which Construction is Commenced After August 30, 1999 or for Which Modification or Reconstruction is Commenced After June 6, 2001	X			X
CCCC	Commercial and Industrial Solid Waste Incineration Units for Which Construction Is Commenced After November 30, 1999 or for Which Modification or Reconstruction Is Commenced on or After June 1, 2001	X			X
EEEE	Other Solid Waste Incineration Units for Which Construction is Commenced After December 9, 2004, or for Which Modification or Reconstruction is Commenced on or After June 16, 2006	X			X
GGGG	(Reserved)				
HHHH	(Reserved)				
IIII	Stationary Compression Ignition Internal Combustion Engines				X
JJJJ	Stationary Spark Ignition Internal Combustion Engines				X
KKKK	Stationary Combustion Turbines	X			X
LLLL	New Sewage Sludge Incineration Units				
OOOO	Crude Oil and Natural Gas Production, Transmission, and Distribution				

(viii) Delegations for Shasta County Air Quality Management District, Siskiyou County Air Pollution Control District, South Coast Air Quality Management District, and Tehama County Air Pollution Control District are shown in the following table:

Delegation Status for New Source Performance Standards for Shasta County AQMD, Siskiyou County APCD, South Coast AQMD, and Tehama County APCD

	Subpart	Air pollution control agency			
		Shasta County AQMD	Siskiyou County APCD	South Coast AQMD	Tehama County APCD

	Subpart	Air pollution control agency			
		Shasta County AQMD	Siskiyou County APCD	South Coast AQMD	Tehama County APCD
A	General Provisions	X	X	X	
D	Fossil-Fuel Fired Steam Generators Constructed After August 17, 1971	X		X	
Da	Electric Utility Steam Generating Units Constructed After September 18, 1978			X	
Db	Industrial-Commercial-Institutional Steam Generating Units			X	
Dc	Small Industrial-Commercial-Institutional Steam Generating Units			X	
E	Incinerators	X		X	
Ea	Municipal Waste Combustors Constructed After December 20, 1989 and On or Before September 20, 1994			X	
Eb	Large Municipal Waste Combustors Constructed After September 20, 1994			X	
Ec	Hospital/Medical/Infectious Waste Incinerators for Which Construction is Commenced After June 20, 1996			X	
F	Portland Cement Plants	X		X	
G	Nitric Acid Plants	X		X	
Ga	Nitric Acid Plants For Which Construction, Reconstruction or Modification Commenced After October 14, 2011				
H	Sulfuric Acid Plant	X		X	
I	Hot Mix Asphalt Facilities	X		X	
J	Petroleum Refineries	X		X	
Ja	Petroleum Refineries for Which Construction, Reconstruction, or Modification Commenced After May 14, 2007			X	
K	Storage Vessels for Petroleum Liquids for Which Construction, Reconstruction, or Modification Commenced After June 11, 1973, and Prior to May 19, 1978	X		X	
Ka	Storage Vessels for Petroleum Liquids for Which Construction, Reconstruction, or Modification Commenced After May 18, 1978, and Prior to July 23, 1984			X	
Kb	Volatile Organic Liquid Storage Vessels (Including Petroleum Liquid Storage Vessels) for Which Construction, Reconstruction, or Modification Commenced After July 23, 1984			X	

	Subpart	Air pollution control agency			
		Shasta County AQMD	Siskiyou County APCD	South Coast AQMD	Tehama County APCD
L	Secondary Lead Smelters	X		X	
M	Secondary Brass and Bronze Production Plants	X		X	
N	Primary Emissions from Basic Oxygen Process Furnaces for Which Construction is Commenced After June 11, 1973	X		X	
Na	Secondary Emissions from Basic Oxygen Process Steelmaking Facilities for Which Construction is Commenced After January 20, 1983			X	
O	Sewage Treatment Plants	X		X	
P	Primary Copper Smelters	X		X	
Q	Primary Zinc Smelters	X		X	
R	Primary Lead Smelters	X		X	
S	Primary Aluminum Reduction Plants	X		X	
T	Phosphate Fertilizer Industry: Wet Process Phosphoric Acid Plants	X		X	
U	Phosphate Fertilizer Industry: Superphosphoric Acid Plants	X		X	
V	Phosphate Fertilizer Industry: Diammonium Phosphate Plants	X		X	
W	Phosphate Fertilizer Industry: Triple Superphosphate Plants	X		X	
X	Phosphate Fertilizer Industry: Granular Triple Superphosphate Storage Facilities	X		X	
Y	Coal Preparation and Processing Plants	X		X	
Z	Ferroalloy Production Facilities	X		X	
AA	Steel Plants: Electric Arc Furnaces Constructed After October 21, 1974 and On or Before August 17, 1983	X		X	
AAa	Steel Plants: Electric Arc Furnaces and Argon-Oxygen Decarburization Vessels Constructed After August 7, 1983			X	
BB	Kraft Pulp Mills	X		X	
CC	Glass Manufacturing Plants			X	
DD	Grain Elevators	X		X	
EE	Surface Coating of Metal Furniture			X	

	Subpart	Air pollution control agency			
		Shasta County AQMD	Siskiyou County APCD	South Coast AQMD	Tehama County APCD
FF	(Reserved)				
GG	Stationary Gas Turbines			X	
HH	Lime Manufacturing Plants	X		X	
KK	Lead-Acid Battery Manufacturing Plants			X	
LL	Metallic Mineral Processing Plants			X	
MM	Automobile and Light Duty Trucks Surface Coating Operations			X	
NN	Phosphate Rock Plants			X	
PP	Ammonium Sulfate Manufacture			X	
QQ	Graphic Arts Industry: Publication Rotogravure Printing			X	
RR	Pressure Sensitive Tape and Label Surface Coating Operations			X	
SS	Industrial Surface Coating: Large Appliances			X	
TT	Metal Coil Surface Coating			X	
UU	Asphalt Processing and Asphalt Roofing Manufacture			X	
VV	Equipment Leaks of VOC in the Synthetic Organic Industry Chemicals Manufacturing			X	
VVa	Equipment Leaks of VOC in the Synthetic Organic Industry for Which Construction, Reconstruction, or Chemicals Manufacturing Modification Commenced After November 7, 2006			X	
WW	Beverage Can Surface Coating Industry			X	
XX	Bulk Gasoline Terminals				
AAA	New Residential Wood Heaters		X	X	
BBB	Rubber Tire Manufacturing Industry		X	X	
CCC	(Reserved)				
DDD	Volatile Organic Compounds (VOC) Emissions from the Polymer Manufacturing Industry			X	
EEE	(Reserved)				

	Subpart	Air pollution control agency			
		Shasta County AQMD	Siskiyou County APCD	South Coast AQMD	Tehama County APCD
FFF	Flexible Vinyl and Urethane Coating and Printing			X	
GGG	Equipment Leaks of VOC in Petroleum Refineries			X	
GGGa	Equipment Leaks of VOC in Petroleum Refineries for Which Construction, Reconstruction, or Modification Commenced After November 7, 2006			X	
HHH	Synthetic Fiber Production Facilities			X	
III	Volatile Organic Compound (VOC) Emissions From the Synthetic Organic Chemical Manufacturing Industry (SOCMI) Air Oxidation Unit Processes			X	
JJJ	Petroleum Dry Cleaners			X	
KKK	Equipment Leaks of VOC From Onshore Natural Gas Processing Plants			X	
LLL	Onshore Natural Gas Processing: SO <sub>2</sub> Emissions			X	
MMM	(Reserved)				
NNN	Volatile Organic Compound (VOC) Emissions From Synthetic Organic Chemical Manufacturing Industry (SOCMI) Distillation Operations			X	
OOO	Nonmetallic Mineral Processing Plants			X	
PPP	Wool Fiberglass Insulation Manufacturing Plants			X	
QQQ	VOC Emissions From Petroleum Refinery Wastewater Systems		X	X	
RRR	Volatile Organic Compound Emissions from Synthetic Organic Chemical Manufacturing Industry (SOCMI) Reactor Processes			X	
SSS	Magnetic Tape Coating Facilities		X	X	
TTT	Industrial Surface Coating: Surface Coating of Plastic Parts for Business Machines		X	X	
UUU	Calciners and Dryers in Mineral Industries			X	
VVV	Polymeric Coating of Supporting Substrates Facilities			X	
WWW	Municipal Solid Waste Landfills			X	
AAAA	Small Municipal Waste Combustion Units for Which Construction is Commenced After August 30, 1999 or for Which Modification or Reconstruction is Commenced After June 6, 2001	X	X	X	
CCCC	Commercial and Industrial Solid Waste Incineration Units for Which			X	

	Subpart	Air pollution control agency			
		Shasta County AQMD	Siskiyou County APCD	South Coast AQMD	Tehama County APCD
	Construction Is Commenced After November 30, 1999 or for Which Modification or Reconstruction Is Commenced on or After June 1, 2001				
EEEE	Other Solid Waste Incineration Units for Which Construction is Commenced After December 9, 2004, or for Which Modification or Reconstruction is Commenced on or After June 16, 2006			X	
G G G G	(Reserved)				
H H H H	(Reserved)				
I I I I	Stationary Compression Ignition Internal Combustion Engines			X	
J J J J	Stationary Spark Ignition Internal Combustion Engines			X	
K K K K	Stationary Combustion Turbines			X	
L L L L	New Sewage Sludge Incineration Units				
O O O O	Crude Oil and Natural Gas Production, Transmission, and Distribution				

(ix) Delegations for Tuolumne County Air Pollution Control District, Ventura County Air Pollution Control District, and Yolo-Solano Air Quality Management District are shown in the following table:

Delegation Status for New Source Performance Standards for Tuolumne County Air Pollution Control District, Ventura County Air Pollution Control District, and Yolo-Solano Air Quality Management District

	Subpart	Air Pollution Control Agency		
		Tuolumne County APCD	Ventura County APCD	Yolo-Solano AQMD
A	General Provisions	X	X	
D	Fossil-Fuel Fired Steam Generators Constructed After August 17, 1971	X	X	
Da	Electric Utility Steam Generating Units Constructed After September 18, 1978	X		
Db	Industrial-Commercial-Institutional Steam Generating Units	X	X	
Dc	Small Industrial Steam Generating Units	X		
E	Incinerators	X		

	Subpart	Air Pollution Control Agency		
		Tuolumne County APCD	Ventura County APCD	Yolo-Solano AQMD
Ea	Municipal Waste Combustors Constructed After December 20, 1989 and On or Before September 20, 1994	X		
Eb	Municipal Waste Combustors Constructed After September 20, 1994	X		
Ec	Hospital/Medical/Infectious Waste Incinerators for Which Construction is Commenced After June 20, 1996	X		
F	Portland Cement Plants	X		
G	Nitric Acid Plants	X		
H	Sulfuric Acid Plants	X		
I	Hot Mix Asphalt Facilities	X	X	
J	Petroleum Refineries	X	X	
Ja	Petroleum Refineries for Which Construction, Reconstruction, or Modification Commenced After May 14, 2007			
K	Storage Vessels for Petroleum Liquids for Which Construction, Reconstruction, or Modification Commenced After June 11, 1973, and Prior to May 19, 1978	X	X	
Ka	Storage Vessels for Petroleum Liquids for Which Construction, Reconstruction, or Modification Commenced After May 18, 1978, and Prior to July 23, 1984	X		
Kb	Volatile Organic Liquid Storage Vessels (Including Petroleum Liquid Storage Vessels) for Which Construction, Reconstruction, or Modification Commenced After July 23, 1984	X		
L	Secondary Lead Smelters	X		
M	Secondary Brass and Bronze Production Plants	X		
N	Primary Emissions from Basic Oxygen Process Furnaces for Which Construction is Commenced After June 11, 1973	X		
Na	Secondary Emissions from Basic Oxygen Process Steelmaking Facilities for Which Construction is Commenced After January 20, 1983	X		
O	Sewage Treatment Plants	X		
P	Primary Copper Smelters	X		
Q	Primary Zinc Smelters	X		

	Subpart	Air Pollution Control Agency		
		Tuolumne County APCD	Ventura County APCD	Yolo-Solano AQMD
R	Primary Lead Smelters	X		
S	Primary Aluminum Reduction Plants	X		
T	Phosphate Fertilizer Industry: Wet Process Phosphoric Acid Plants	X		
U	Phosphate Fertilizer Industry: Superphosphoric Acid Plants	X		
V	Phosphate Fertilizer Industry: Diammonium Phosphate Plants	X		
W	Phosphate Fertilizer Industry: Triple Superphosphate Plants	X		
X	Phosphate Fertilizer Industry: Granular Triple Superphosphate Storage Facilities	X		
Y	Coal Preparation Plants	X		
Z	Ferroalloy Production Facilities	X		
AA	Steel Plants: Electric Arc Furnaces Constructed After October 21, 1974 and On or Before August 17, 1983	X	X	
AAa	Steel Plants: Electric Arc Furnaces and Argon-Oxygen Decarburization Vessels Constructed After August 7, 1983	X		
BB	Kraft pulp Mills	X		
CC	Glass Manufacturing Plants	X		
DD	Grain Elevators	X		
EE	Surface Coating of Metal Furniture	X		
FF	(Reserved)			
GG	Stationary Gas Turbines	X		
HH	Lime Manufacturing Plants	X		
KK	Lead-Acid Battery Manufacturing Plants	X		
LL	Metallic Mineral Processing Plants	X		
MM	Automobile and Light Duty Trucks Surface Coating Operations	X		
NN	Phosphate Rock Plants	X		
PP	Ammonium Sulfate Manufacture	X		

	Subpart	Air Pollution Control Agency		
		Tuolumne County APCD	Ventura County APCD	Yolo-Solano AQMD
QQ	Graphic Arts Industry: Publication Rotogravure Printing	X		
RR	Pressure Sensitive Tape and Label Surface Coating Operations	X		
SS	Industrial Surface Coating: Large Appliances	X		
TT	Metal Coil Surface Coating	X		
UU	Asphalt Processing and Asphalt Roofing Manufacture	X		
VV	Equipment Leaks of VOC in the Synthetic Organic Chemicals Manufacturing Industry	X		
VVa	Equipment Leaks of VOC in the Synthetic Organic Chemicals Manufacturing Industry for Which Construction, Reconstruction, or Modification Commenced After November 7, 2006			
WW	Beverage Can Surface Coating Industry	X		
XX	Bulk Gasoline Terminals			
AAA	New Residential Wood Heaters	X		
BBB	Rubber Tire Manufacturing Industry	X		
CCC	(Reserved)			
DDD	Volatile Organic Compounds (VOC) Emissions from the Polymer Manufacturing Industry	X		
EEE	(Reserved)			
FFF	Flexible Vinyl and Urethane Coating and Printing	X		
GGG	Equipment Leaks of VOC in Petroleum Refineries	X		
GGGa	Equipment Leaks of VOC in Petroleum Refineries for Which Construction, Reconstruction, or Modification Commenced After November 7, 2006			
HHH	Synthetic Fiber Production Facilities	X		
III	Volatile Organic Compound (VOC) Emissions From the Synthetic Organic Chemical Manufacturing Industry (SOCMI) Air Oxidation Unit Processes	X		
JJJ	Petroleum Dry Cleaners	X		
KKK	Equipment Leaks of VOC From Onshore Natural Gas Processing Plants	X		
LLL	Onshore Natural Gas Processing: SO2 Emissions	X		

	Subpart	Air Pollution Control Agency		
		Tuolumne County APCD	Ventura County APCD	Yolo-Solano AQMD
MMM	(Reserved)			
NNN	Volatile Organic Compound (VOC) Emissions From Synthetic Organic Chemical Manufacturing Industry (SOCMI) Distillation Operations	X		
OOO	Nonmetallic Mineral Processing Plants	X	X	
PPP	Wool Fiberglass Insulation Manufacturing Plants	X		
QQQ	VOC Emissions From Petroleum Refinery Wastewater Systems	X		
RRR	Volatile Organic Compound Emissions from Synthetic Organic Chemical Manufacturing Industry (SOCMI) Reactor Processes	X		
SSS	Magnetic Tape Coating Facilities	X		
TTT	Industrial Surface Coating: Surface Coating of Plastic Parts for Business Machines	X		
UUU	Calciners and Dryers in Mineral Industries	X		
VVV	Polymeric Coating of Supporting Substrates Facilities	X		
WWW	Municipal Solid Waste Landfills	X	X	
AAAA	Small Municipal Waste Combustion Units for Which Construction is Commenced After August 30, 1999 or for Which Modification or Reconstruction is Commenced After June 6, 2001	X		
CCCC	Commercial and Industrial Solid Waste Incineration Units for Which Construction Is Commenced After November 30, 1999 or for Which Modification or Reconstruction Is Commenced on or After June 1, 2001	X		
EEEE	Other Solid Waste Incineration Units for Which Construction is Commenced After December 9, 2004, or for Which Modification or Reconstruction is Commenced on or After June 16, 2006			
GGGG	(Reserved)			
IIII	Stationary Compression Ignition Internal Combustion Engines			
JJJJ	Stationary Spark Ignition Internal Combustion Engines			
KKKK	Stationary Combustion Turbines			

(3) *Hawaii*. The following table identifies delegations for Hawaii:

Delegation Status for New Source Performance Standards for Hawaii:

	Subpart	Hawaii
A	General Provisions	X
D	Fossil-Fuel Fired Steam Generators Constructed After August 17, 1971	X
Da	Electric Utility Steam Generating Units Constructed After September 18, 1978	X
Db	Industrial-Commercial-Institutional Steam Generating Units	X
Dc	Small Industrial Steam Generating Units	X
E	Incinerators	X
Ea	Municipal Waste Combustors Constructed After December 20, 1989 and On or Before September 20, 1994	X
Eb	Municipal Waste Combustors Constructed After September 20, 1994	X
Ec	Hospital/Medical/Infectious Waste Incinerators for Which Construction is Commenced After June 20, 1996	X
F	Portland Cement Plants	X
G	Nitric Acid Plants	
H	Sulfuric Acid Plants	
I	Hot Mix Asphalt Facilities	X
J	Petroleum Refineries	X
Ja	Petroleum Refineries for Which Construction, Reconstruction, or Modification Commenced After May 14, 2007	
K	Storage Vessels for Petroleum Liquids for Which Construction, Reconstruction, or Modification Commenced After June 11, 1973, and Prior to May 19, 1978	X
Ka	Storage Vessels for Petroleum Liquids for Which Construction, Reconstruction, or Modification Commenced After May 18, 1978, and Prior to July 23, 1984	X
Kb	Volatile Organic Liquid Storage Vessels (Including Petroleum Liquid Storage Vessels) for Which Construction, Reconstruction, or Modification Commenced After July 23, 1984	X
L	Secondary Lead Smelters	
M	Secondary Brass and Bronze Production Plants	
N	Primary Emissions from Basic Oxygen Process Furnaces for Which Construction is Commenced After June 11, 1973	
Na	Secondary Emissions from Basic Oxygen Process Steelmaking Facilities for Which Construction is Commenced After January 20, 1983	
O	Sewage Treatment Plants	X
P	Primary Copper Smelters	

	<b>Subpart</b>	<b>Hawaii</b>
Q	Primary Zinc Smelters	
R	Primary Lead Smelters	
S	Primary Aluminum Reduction Plants	
T	Phosphate Fertilizer Industry: Wet Process Phosphoric Acid Plants	
U	Phosphate Fertilizer Industry: Superphosphoric Acid Plants	
V	Phosphate Fertilizer Industry: Diammonium Phosphate Plants	
W	Phosphate Fertilizer Industry: Triple Superphosphate Plants	
X	Phosphate Fertilizer Industry: Granular Triple Superphosphate Storage Facilities	
Y	Coal Preparation Plants	X
Z	Ferroalloy Production Facilities	
AA	Steel Plants: Electric Arc Furnaces Constructed After October 21, 1974 and On or Before August 17, 1983	X
AAa	Steel Plants: Electric Arc Furnaces and Argon-Oxygen Decarburization Vessels Constructed After August 7, 1983	X
BB	Kraft pulp Mills	
CC	Glass Manufacturing Plants	
DD	Grain Elevators	
EE	Surface Coating of Metal Furniture	
FF	(Reserved)	
GG	Stationary Gas Turbines	X
HH	Lime Manufacturing Plants	
KK	Lead-Acid Battery Manufacturing Plants	
LL	Metallic Mineral Processing Plants	
MM	Automobile and Light Duty Trucks Surface Coating Operations	
NN	Phosphate Rock Plants	
PP	Ammonium Sulfate Manufacture	
QQ	Graphic Arts Industry: Publication Rotogravure Printing	
RR	Pressure Sensitive Tape and Label Surface Coating Operations	
SS	Industrial Surface Coating: Large Appliances	

	Subpart	Hawaii
TT	Metal Coil Surface Coating	
UU	Asphalt Processing and Asphalt Roofing Manufacture	
VV	Equipment Leaks of VOC in the Synthetic Organic Chemicals Manufacturing Industry	X
VVa	Equipment Leaks of VOC in the Synthetic Organic Chemicals Manufacturing Industry for Which Construction, Reconstruction, or Modification Commenced After November 7, 2006	
WW	Beverage Can Surface Coating Industry	X
XX	Bulk Gasoline Terminals	X
AAA	New Residential Wool Heaters	
BBB	Rubber Tire Manufacturing Industry	
CCC	(Reserved)	
DDD	Volatile Organic Compounds (VOC) Emissions from the Polymer Manufacturing Industry	
EEE	(Reserved)	
FFF	Flexible Vinyl and Urethane Coating and Printing	
GGG	Equipment Leaks of VOC in Petroleum Refineries	X
GGGa	Equipment Leaks of VOC in Petroleum Refineries for Which Construction, Reconstruction, or Modification Commenced After November 7, 2006	
HHH	Synthetic Fiber Production Facilities	
III	Volatile Organic Compound (VOC) Emissions From the Synthetic Organic Chemical Manufacturing Industry (SOCMI) Air Oxidation Unit Processes	
JJJ	Petroleum Dry Cleaners	X
KKK	Equipment Leaks of VOC From Onshore Natural Gas Processing Plants	
LLL	Onshore Natural Gas Processing: SO2 Emissions	
MMM	(Reserved)	
NNN	Volatile Organic Compound (VOC) Emissions From Synthetic Organic Chemical Manufacturing Industry (SOCMI) Distillation Operations	X
OOO	Nonmetallic Mineral Processing Plants	X
PPP	Wool Fiberglass Insulation Manufacturing Plants	
QQQ	VOC Emissions From Petroleum Refinery Wastewater	X

	Subpart	Hawaii
RRR	Volatile Organic Compound Emissions from Synthetic Organic Chemical Manufacturing Industry (SOCMI) Reactor Processes	
SSS	Magnetic Tape Coating Facilities	
TTT	Industrial Surface Coating: Surface Coating of Plastic Parts for Business Machines	
UUU	Calciners and Dryers in Mineral Industries	X
VVV	Polymeric Coating of Supporting Substrates Facilities	X
WWW	Municipal Solid Waste Landfills	X
AAAA	Small Municipal Waste Combustion Units for Which Construction is Commenced After August 30, 1999 or for Which Modification or Reconstruction is Commenced After June 6, 2001	X
CCCC	Commercial and Industrial Solid Waste Incineration Units for Which Construction Is Commenced After November 30, 1999 or for Which Modification or Reconstruction Is Commenced on or After June 1, 2001	X
EEEE	Other Solid Waste Incineration Units for Which Construction is Commenced After December 9, 2004, or for Which Modification or Reconstruction is Commenced on or After June 16, 2006	
GGGG	(Reserved)	
IIII	Stationary Compression Ignition Internal Combustion Engines	
JJJJ	Stationary Spark Ignition Internal Combustion Engines	
KKKK	Stationary Combustion Turbines	

(4) Nevada. The following table identifies delegations for Nevada:

Delegation Status for New Source Performance Standards for Nevada

	Subpart	Air pollution control agency		
		Nevada DEP	Clark County	Washoe County
A	General Provisions	X	X	X
D	Fossil-Fuel Fired Steam Generators Constructed After August 17, 1971	X	X	X
Da	Electric Utility Steam Generating Units Constructed After September 18, 1978	X	X	
Db	Industrial-Commercial-Institutional Steam Generating Units	X	X	
Dc	Small Industrial-Commercial-Institutional Steam Generating Units	X	X	

	Subpart	Air pollution control agency		
		Nevada DEP	Clark County	Washoe County
E	Incinerators	X	X	X
Ea	Municipal Waste Combustors Constructed After December 20, 1989 and On or Before September 20, 1994	X	X	
Eb	Large Municipal Waste Combustors Constructed After September 20, 1994	X	X	
Ec	Hospital/Medical/Infectious Waste Incinerators for Which Construction is Commenced After June 20, 1996	X	X	
F	Portland Cement Plants	X	X	X
G	Nitric Acid Plants	X	X	
Ga	Nitric Acid Plants For Which Construction, Reconstruction or Modification Commenced After October 14, 2011	X		
H	Sulfuric Acid Plant	X	X	
I	Hot Mix Asphalt Facilities	X	X	X
J	Petroleum Refineries	X	X	
Ja	Petroleum Refineries for Which Construction, Reconstruction, or Modification Commenced After May 14, 2007	X		
K	Storage Vessels for Petroleum Liquids for Which Construction, Reconstruction, or Modification Commenced After June 11, 1973, and Prior to May 19, 1978	X	X	X
Ka	Storage Vessels for Petroleum Liquids for Which Construction, Reconstruction, or Modification Commenced After May 18, 1978, and Prior to July 23, 1984	X	X	X
Kb	Volatile Organic Liquid Storage Vessels (Including Petroleum Liquid Storage Vessels) for Which Construction, Reconstruction, or Modification Commenced After July 23, 1984	X	X	
L	Secondary Lead Smelters	X	X	X
M	Secondary Brass and Bronze Production Plants	X	X	
N	Primary Emissions from Basic Oxygen Process Furnaces for Which Construction is Commenced After June 11, 1973	X	X	
Na	Secondary Emissions from Basic Oxygen Process Steelmaking Facilities for Which Construction is Commenced After January 20, 1983	X	X	
O	Sewage Treatment Plants	X	X	X

	Subpart	Air pollution control agency		
		Nevada DEP	Clark County	Washoe County
P	Primary Copper Smelters	X	X	X
Q	Primary Zinc Smelters	X	X	X
R	Primary Lead Smelters	X	X	X
S	Primary Aluminum Reduction Plants	X	X	
T	Phosphate Fertilizer Industry: Wet Process Phosphoric Acid Plants	X	X	
U	Phosphate Fertilizer Industry: Superphosphoric Acid Plants	X	X	
V	Phosphate Fertilizer Industry: Diammonium Phosphate Plants	X	X	
W	Phosphate Fertilizer Industry: Triple Superphosphate Plants	X	X	
X	Phosphate Fertilizer Industry: Granular Triple Superphosphate Storage Facilities	X	X	
Y	Coal Preparation and Processing Plants	X	X	X
Z	Ferroalloy Production Facilities	X	X	
AA	Steel Plants: Electric Arc Furnaces Constructed After October 21, 1974 and On or Before August 17, 1983	X	X	
AAa	Steel Plants: Electric Arc Furnaces and Argon-Oxygen Decarburization Vessels Constructed After August 7, 1983	X	X	
BB	Kraft Pulp Mills	X	X	
CC	Glass Manufacturing Plants	X	X	
DD	Grain Elevators	X	X	X
EE	Surface Coating of Metal Furniture	X	X	X
FF	(Reserved)			
GG	Stationary Gas Turbines	X	X	X
HH	Lime Manufacturing Plants	X	X	X
KK	Lead-Acid Battery Manufacturing Plants	X	X	X
LL	Metallic Mineral Processing Plants	X	X	X
MM	Automobile and Light Duty Trucks Surface Coating Operations	X	X	X

	Subpart	Air pollution control agency		
		Nevada DEP	Clark County	Washoe County
NN	Phosphate Rock Plants	X	X	X
PP	Ammonium Sulfate Manufacture	X	X	
QQ	Graphic Arts Industry: Publication Rotogravure Printing	X	X	X
RR	Pressure Sensitive Tape and Label Surface Coating Operations	X	X	
SS	Industrial Surface Coating: Large Appliances	X	X	X
TT	Metal Coil Surface Coating	X	X	X
UU	Asphalt Processing and Asphalt Roofing Manufacture	X	X	X
VV	Equipment Leaks of VOC in the Synthetic Organic Industry Chemicals Manufacturing	X	X	X
VVa	Equipment Leaks of VOC in the Synthetic Organic Industry for Which Construction, Reconstruction, or Chemicals Manufacturing Modification Commenced After November 7, 2006	X	X	
WW	Beverage Can Surface Coating Industry	X	X	
XX	Bulk Gasoline Terminals	X	X	
AAA	New Residential Wood Heaters		X	
BBB	Rubber Tire Manufacturing Industry	X	X	
CCC	(Reserved)			
DDD	Volatile Organic Compounds (VOC) Emissions from the Polymer Manufacturing Industry	X	X	
EEE	(Reserved)			
FFF	Flexible Vinyl and Urethane Coating and Printing	X	X	
GGG	Equipment Leaks of VOC in Petroleum Refineries	X	X	
GGGa	Equipment Leaks of VOC in Petroleum Refineries for Which Construction, Reconstruction, or Modification Commenced After November 7, 2006	X	X	
HHH	Synthetic Fiber Production Facilities	X	X	
III	Volatile Organic Compound (VOC) Emissions From the Synthetic Organic Chemical Manufacturing Industry (SOCMI) Air Oxidation Unit Processes	X	X	
JJJ	Petroleum Dry Cleaners	X	X	X
KKK	Equipment Leaks of VOC From Onshore Natural Gas Processing Plants	X	X	

	Subpart	Air pollution control agency		
		Nevada DEP	Clark County	Washoe County
LLL	Onshore Natural Gas Processing: SO <sub>2</sub> Emissions	X	X	
MMM	(Reserved)			
NNN	Volatile Organic Compound (VOC) Emissions From Synthetic Organic Chemical Manufacturing Industry (SOCMI) Distillation Operations	X	X	
OOO	Nonmetallic Mineral Processing Plants	X	X	
PPP	Wool Fiberglass Insulation Manufacturing Plants	X	X	
QQQ	VOC Emissions From Petroleum Refinery Wastewater Systems	X	X	
RRR	Volatile Organic Compound Emissions from Synthetic Organic Chemical Manufacturing Industry (SOCMI) Reactor Processes	X	X	
SSS	Magnetic Tape Coating Facilities	X	X	
TTT	Industrial Surface Coating: Surface Coating of Plastic Parts for Business Machines	X	X	X
UUU	Calciners and Dryers in Mineral Industries	X	X	X
VVV	Polymeric Coating of Supporting Substrates Facilities	X	X	X
WWW	Municipal Solid Waste Landfills	X	X	X
AAAA	Small Municipal Waste Combustion Units for Which Construction is Commenced After August 30, 1999 or for Which Modification or Reconstruction is Commenced After June 6, 2001	X	X	X
CCCC	Commercial and Industrial Solid Waste Incineration Units for Which Construction Is Commenced After November 30, 1999 or for Which Modification or Reconstruction Is Commenced on or After June 1, 2001	X	X	X
EEEE	Other Solid Waste Incineration Units for Which Construction is Commenced After December 9, 2004, or for Which Modification or Reconstruction is Commenced on or After June 16, 2006	X	X	X
GGGG	(Reserved)			
HHHH	(Reserved)			
IIII	Stationary Compression Ignition Internal Combustion Engines	X	X	X
JJJJ	Stationary Spark Ignition Internal Combustion Engines	X	X	X
KKKK	Stationary Combustion Turbines	X	X	X
LLLL	New Sewage Sludge Incineration Units		X	

	Subpart	Air pollution control agency		
		Nevada DEP	Clark County	Washoe County
0000	Crude Oil and Natural Gas Production, Transmission, and Distribution	X		

(5) *Guam*. The following table identifies delegations as of June 15, 2001:

Delegation Status for New Source Performance Standards for Guam

	Subpart	Guam
A	General Provisions	X
D	Fossil-Fuel Fired Steam Generators Constructed After August 17, 1971	X
Da	Electric Utility Steam Generating Units Constructed After September 18, 1978	
Db	Industrial-Commercial-Institutional Steam Generating Units	
Dc	Small Industrial Steam Generating Units	
E	Incinerators	
Ea	Municipal Waste Combustors Constructed After December 20, 1989 and On or Before September 20, 1994	
Eb	Municipal Waste Combustors Constructed After September 20, 1994	
Ec	Hospital/Medical/Infectious Waste Incinerators for Which Construction is Commenced After June 20, 1996	
F	Portland Cement Plants	X
G	Nitric Acid Plants	
H	Sulfuric Acid Plants	
I	Hot Mix Asphalt Facilities	X
J	Petroleum Refineries	X
K	Storage Vessels for Petroleum Liquids for Which Construction, Reconstruction, or Modification Commenced After June 11, 1973, and Prior to May 19, 1978	X

(e) The following lists the specific part 60 standards that have been delegated unchanged to the air pollution control agencies in Region 6.

(1) *New Mexico*. The New Mexico Environment Department has been delegated all part 60 standards promulgated by EPA, except subpart AAA—Standards of Performance for New Residential Wood Heaters; and

subpart HHHH—Emission Guidelines and Compliance Times for Coal-Fired Electric Steam Generating Units, as amended in the FEDERAL REGISTER through September 23, 2013.

(2) *Louisiana*. The Louisiana Department of Environmental Quality has been delegated all part 60 standards promulgated by EPA, except subpart AAA—Standards of Performance for New Residential Wood Heaters, as amended in the FEDERAL REGISTER through July 1, 2013.

Delegation Status for Part 60 Standards—State of Louisiana  
 [Excluding Indian Country]

Subpart	Source category	LDEQ <sup>1</sup>
A	General Provisions	Yes
Ce	Emission Guidelines and Compliance Times for Hospital/Medical/Infectious Waste Incinerators	Yes
D	Fossil Fueled Steam Generators (>250 MM BTU/hr)	Yes
Da	Electric Utility Steam Generating Units (>250 MM BTU/hr)	Yes
Db	Industrial-Commercial-Institutional Steam Generating Units (100 to 250 MM BTU/hr)	Yes
Dc	Industrial-Commercial-Institutional Small Steam Generating Units (10 to 100 MM BTU/hr)	Yes
E	Incinerators (>50 tons per day)	Yes
Ea	Municipal Waste Combustors	Yes
Eb	Large Municipal Waste Combustors	Yes
Ec	Hospital/Medical/Infectious Waste Incinerators	Yes
F	Portland Cement Plants	Yes
G	Nitric Acid Plants	Yes
Ga	Nitric Acid Plants (after October 14, 2011)	Yes
H	Sulfuric Acid Plants	Yes
I	Hot Mix Asphalt Facilities	Yes
J	Petroleum Refineries	Yes
Ja	Petroleum Refineries (After May 14, 2007)	Yes
K	Storage Vessels for Petroleum Liquids (After 6/11/73 & Before 5/19/78)	Yes
Ka	Storage Vessels for Petroleum Liquids (After 6/11/73 & Before 5/19/78)	Yes
Kb	Volatile Organic Liquid Storage Vessels (Including Petroleum Liquid Stg/Vessels) After 7/23/84	Yes
L	Secondary Lead Smelters Yes	Yes

Subpart	Source category	LDEQ <sup>1</sup>
M	Secondary Brass and Bronze Production Plants	Yes
N	Primary Emissions from Basic Oxygen Process Furnaces (Construction Commenced After June 11, 1973)	Yes
Na	Secondary Emissions from Basic Oxygen Process Steelmaking Facilities Construction is Commenced After January 20, 1983	Yes
O	Sewage Treatment Plants	Yes
P	Primary Copper Smelters	Yes
Q	Primary Zinc Smelters	Yes
R	Primary Lead Smelters	Yes
S	Primary Aluminum Reduction Plants	Yes
T	Phosphate Fertilizer Industry: Wet Process Phosphoric Plants	Yes
U	Phosphate Fertilizer Industry: Superphosphoric Acid Plants	Yes
V	Phosphate Fertilizer Industry: Diammonium Phosphate Plants	Yes
W	Phosphate Fertilizer Industry: Triple Superphosphate Plants	Yes
X	Phosphate Fertilizer Industry: Granular Triple Superphosphate Storage Facilities	Yes
Y	Coal Preparation Plants	Yes
Z	Ferroalloy Production Facilities	Yes
AA	Steel Plants: Electric Arc Furnaces After 10/21/74 & On or Before 8/17/83	Yes
AAa	Steel Plants: Electric Arc Furnaces & Argon-Oxygen Decarburization Vessels After 8/07/83	Yes
BB	Kraft Pulp Mills	Yes
CC	Glass Manufacturing Plants	Yes
DD	Grain Elevators	Yes
EE	Surface Coating of Metal Furniture	Yes
GG	Stationary Gas Turbines	Yes
HH	Lime Manufacturing Plants	Yes
KK	Lead-Acid Battery Manufacturing Plants	Yes
LL	Metallic Mineral Processing Plants	Yes
MM	Automobile & Light Duty Truck Surface Coating Operations	Yes

Subpart	Source category	LDEQ <sup>1</sup>
NN	Phosphate Manufacturing Plants	Yes
PP	Ammonium Sulfate Manufacture	Yes
QQ	Graphic Arts Industry: Publication Rotogravure Printing	Yes
RR	Pressure Sensitive Tape and Label Surface Coating Operations	Yes
SS	Industrial Surface Coating: Large Appliances	Yes
TT	Metal Coil Surface Coating	Yes
UU	Asphalt Processing and Asphalt Roofing Manufacture	Yes
VV	VOC Equipment Leaks in the SOCOMI Industry	Yes
VVa	VOC Equipment Leaks in the SOCOMI Industry (After November 7, 2006)	Yes
XX	Bulk Gasoline Terminals	Yes
AAA	New Residential Wood Heaters	No
BBB	Rubber Tire Manufacturing Industry	Yes
DDD	Volatile Organic Compound (VOC) Emissions from the Polymer Manufacturing Industry	Yes
FFF	Flexible Vinyl and Urethane Coating and Printing	Yes
GGG	VOC Equipment Leaks in Petroleum Refineries	Yes
HHH	Synthetic Fiber Production	Yes
III	VOC Emissions from the SOCOMI Air Oxidation Unit Processes	Yes
JJJ	Petroleum Dry Cleaners	Yes
KKK	VOC Equipment Leaks From Onshore Natural Gas Processing Plants	Yes
LLL	Onshore Natural Gas Processing: SO <sub>2</sub> Emissions	Yes
NNN	VOC Emissions from SOCOMI Distillation Operations	Yes
OOO	Nonmetallic Mineral Processing Plants	Yes
PPP	Wool Fiberglass Insulation Manufacturing Plants	Yes
QQQ	VOC Emissions From Petroleum Refinery Wastewater Systems	Yes
RRR	VOC Emissions from SOCOMI Reactor Processes	Yes
SSS	Magnetic Tape Coating Operations	Yes
TTT	Industrial Surface Coating: Plastic Parts for Business Machines	Yes

Subpart	Source category	LDEQ <sup>1</sup>
UUU	Calciners and Dryers in Mineral Industries	Yes
VVV	Polymeric Coating of Supporting Substrates Facilities	Yes
WWW	Municipal Solid Waste Landfills	Yes
AAAA	Small Municipal Waste Combustion Units (Construction is Commenced After 8/30/99 or Modification/Reconstruction is Commenced After 6/06/2001)	Yes
CCCC	Commercial & Industrial Solid Waste Incineration Units (Construction is Commenced After 11/30/1999 or Modification/Reconstruction is Commenced on or After 6/01/2001)	Yes
DDDD	Emission Guidelines & Compliance Times for Commercial & Industrial Solid Waste Incineration Units (Commenced Construction On or Before 11/30/1999)	Yes
EEEE	Other Solid Waste Incineration Units (Constructed after 12/09/2004 or Modification/Reconstruction is commenced on or after 06/16/2004)	Yes
IIII	Stationary Compression Ignition Internal Combustion Engines	Yes
JJJJ	Stationary Spark Ignition Internal Combustion Engines	Yes
KKKK	Stationary Combustion Turbines (Construction Commenced After 02/18/2005)	Yes
LLLL	New Sewage Sludge Incineration Units	Yes
MMMM	Emission Guidelines and Compliance Times for Existing Sewage Sludge Incineration Units	Yes
OOOO	Crude Oil and Natural Gas Production, Transmission and Distribution	Yes

<sup>1</sup>The Louisiana Department of Environmental Quality (LDEQ) has been delegated all Part 60 standards promulgated by EPA, except subpart AAA—Standards of Performance for New Residential Wood Heaters—as amended in the FEDERAL REGISTER through July 1, 2013.

(3) *Albuquerque-Bernalillo County Air Quality Control Board*. The Albuquerque-Bernalillo County Air Quality Control Board has been delegated all part 60 standards promulgated by EPA, except subpart AAA—Standards of Performance for New Residential Wood Heaters, as amended in the FEDERAL REGISTER through September 13, 2013.

**§60.5 Determination of construction or modification.**

- (a) When requested to do so by an owner or operator, the Administrator will make a determination of whether action taken or intended to be taken by such owner or operator constitutes construction (including reconstruction) or modification or the commencement thereof within the meaning of this part.
- (b) The Administrator will respond to any request for a determination under paragraph (a) of this section within 30 days of receipt of such request.

**§60.6 Review of plans.**

- (a) When requested to do so by an owner or operator, the Administrator will review plans for construction or modification for the purpose of providing technical advice to the owner or operator.
- (b)(1) A separate request shall be submitted for each construction or modification project.

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

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

#### **§60.7 Notification and record keeping.**

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

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

(2) [Reserved]

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

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

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

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

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

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

(c) Each owner or operator required to install a continuous monitoring device shall submit excess emissions and monitoring systems performance report (excess emissions are defined in applicable subparts) and-or summary report form (see paragraph (d) of this section) to the Administrator semiannually, except when: more frequent

reporting is specifically required by an applicable subpart; or the Administrator, on a case-by-case basis, determines that more frequent reporting is necessary to accurately assess the compliance status of the source. All reports shall be postmarked by the 30th day following the end of each six-month period. Written reports of excess emissions shall include the following information:

- (1) The magnitude of excess emissions computed in accordance with §60.13(h), any conversion factor(s) used, and the date and time of commencement and completion of each time period of excess emissions. The process operating time during the reporting period.
  - (2) Specific identification of each period of excess emissions that occurs during startups, shutdowns, and malfunctions of the affected facility. The nature and cause of any malfunction (if known), the corrective action taken or preventative measures adopted.
  - (3) The date and time identifying each period during which the continuous monitoring system was inoperative except for zero and span checks and the nature of the system repairs or adjustments.
  - (4) When no excess emissions have occurred or the continuous monitoring system(s) have not been inoperative, repaired, or adjusted, such information shall be stated in the report.
- (d) The summary report form shall contain the information and be in the format shown in figure 1 unless otherwise specified by the Administrator. One summary report form shall be submitted for each pollutant monitored at each affected facility.
- (1) If the total duration of excess emissions for the reporting period is less than 1 percent of the total operating time for the reporting period and CMS downtime for the reporting period is less than 5 percent of the total operating time for the reporting period, only the summary report form shall be submitted and the excess emission report described in §60.7(c) need not be submitted unless requested by the Administrator.
  - (2) If the total duration of excess emissions for the reporting period is 1 percent or greater of the total operating time for the reporting period or the total CMS downtime for the reporting period is 5 percent or greater of the total operating time for the reporting period, the summary report form and the excess emission report described in §60.7(c) shall both be submitted.

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

Pollutant (Circle One—SO<sub>2</sub>/NO<sub>x</sub>/TRS/H<sub>2</sub>S/CO/Opacity)

Reporting period dates: From \_\_\_\_\_ to \_\_\_\_\_

Company:

Emission Limitation

Address:

Monitor Manufacturer and Model No.

Date of Latest CMS Certification or Audit

Process Unit(s) Description:

Total source operating time in reporting period<sup>1</sup>

Emission data summary <sup>1</sup>	CMS performance summary <sup>1</sup>
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Emission data summary <sup>1</sup>		CMS performance summary <sup>1</sup>	
1. Duration of excess emissions in reporting period due to:		1. CMS downtime in reporting period due to:	
a. Startup/shutdown		a. Monitor equipment malfunctions	
b. Control equipment problems		b. Non-Monitor equipment malfunctions	
c. Process problems		c. Quality assurance calibration	
d. Other known causes		d. Other known causes	
e. Unknown causes		e. Unknown causes	
2. Total duration of excess emission		2. Total CMS Downtime	
3. Total duration of excess emissions × (100) [Total source operating time]		3. [Total CMS Downtime] × (100) [Total source operating time]	
	% <sup>2</sup>		% <sup>2</sup>

<sup>1</sup>For opacity, record all times in minutes. For gases, record all times in hours.

<sup>2</sup>For the reporting period: If the total duration of excess emissions is 1 percent or greater of the total operating time or the total CMS downtime is 5 percent or greater of the total operating time, both the summary report form and the excess emission report described in §60.7(c) shall be submitted.

On a separate page, describe any changes since last quarter in CMS, process or controls. I certify that the information contained in this report is true, accurate, and complete.

Name

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Signature

---

Title

---

Date

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

- (i) For 1 full year (e.g., 4 quarterly or 12 monthly reporting periods) the affected facility's excess emissions and monitoring systems reports submitted to comply with a standard under this part continually demonstrate that the facility is in compliance with the applicable standard;
- (ii) The owner or operator continues to comply with all recordkeeping and monitoring requirements specified in this subpart and the applicable standard; and
- (iii) The Administrator does not object to a reduced frequency of reporting for the affected facility, as provided in paragraph (e)(2) of this section.

(2) The frequency of reporting of excess emissions and monitoring systems performance (and summary) reports may be reduced only after the owner or operator notifies the Administrator in writing of his or her intention to make such a change and the Administrator does not object to the intended change. In deciding whether to

approve a reduced frequency of reporting, the Administrator may review information concerning the source's entire previous performance history during the required recordkeeping period prior to the intended change, including performance test results, monitoring data, and evaluations of an owner or operator's conformance with operation and maintenance requirements. Such information may be used by the Administrator to make a judgment about the source's potential for noncompliance in the future. If the Administrator disapproves the owner or operator's request to reduce the frequency of reporting, the Administrator will notify the owner or operator in writing within 45 days after receiving notice of the owner or operator's intention. The notification from the Administrator to the owner or operator will specify the grounds on which the disapproval is based. In the absence of a notice of disapproval within 45 days, approval is automatically granted.

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

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

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

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

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

(g) If notification substantially similar to that in paragraph (a) of this section is required by any other State or local agency, sending the Administrator a copy of that notification will satisfy the requirements of paragraph (a) of this section.

(h) Individual subparts of this part may include specific provisions which clarify or make inapplicable the provisions set forth in this section.

**§60.8 Performance tests.**

(a) Except as specified in paragraphs (a)(1),(a)(2), (a)(3), and (a)(4) of this section, within 60 days after achieving the maximum production rate at which the affected facility will be operated, but not later than 180 days after initial startup of such facility, or at such other times specified by this part, and at such other times as may be required by the Administrator under section 114 of the Act, the owner or operator of such facility shall conduct performance test(s) and furnish the Administrator a written report of the results of such performance test(s).

(1) If a force majeure is about to occur, occurs, or has occurred for which the affected owner or operator intends to assert a claim of force majeure, the owner or operator shall notify the Administrator, in writing as soon as practicable following the date the owner or operator first knew, or through due diligence should have known that the event may cause or caused a delay in testing beyond the regulatory deadline, but the notification must occur before the performance test deadline unless the initial force majeure or a subsequent force majeure event delays the notice, and in such cases, the notification shall occur as soon as practicable.

(2) The owner or operator shall provide to the Administrator a written description of the force majeure event and a rationale for attributing the delay in testing beyond the regulatory deadline to the force majeure; describe the measures taken or to be taken to minimize the delay; and identify a date by which the owner or operator proposes to conduct the performance test. The performance test shall be conducted as soon as practicable after the force majeure occurs.

(3) The decision as to whether or not to grant an extension to the performance test deadline is solely within the discretion of the Administrator. The Administrator will notify the owner or operator in writing of approval or disapproval of the request for an extension as soon as practicable.

(4) Until an extension of the performance test deadline has been approved by the Administrator under paragraphs (a)(1), (2), and (3) of this section, the owner or operator of the affected facility remains strictly subject to the requirements of this part.

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

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

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

original test date, either by providing at least 7 days prior notice of the rescheduled date of the performance test, or by arranging a rescheduled date with the Administrator (or delegated State or local agency) by mutual agreement.

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

(1) Sampling ports adequate for test methods applicable to such facility. This includes (i) constructing the air pollution control system such that volumetric flow rates and pollutant emission rates can be accurately determined by applicable test methods and procedures and (ii) providing a stack or duct free of cyclonic flow during performance tests, as demonstrated by applicable test methods and procedures.

(2) Safe sampling platform(s).

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

(4) Utilities for sampling and testing equipment.

(f) Unless otherwise specified in the applicable subpart, each performance test shall consist of three separate runs using the applicable test method.

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

(2) Contents of report (electronic or paper submitted copy). Unless otherwise specified in a relevant standard or test method, or as otherwise approved by the Administrator in writing, the report for a performance test shall include the elements identified in paragraphs (f)(2)(i) through (vi) of this section.

(i) General identification information for the facility including a mailing address, the physical address, the owner or operator or responsible official (where applicable) and his/her email address, and the appropriate Federal Registry System (FRS) number for the facility.

(ii) Purpose of the test including the applicable regulation(s) requiring the test, the pollutant(s) and other parameters being measured, the applicable emission standard and any process parameter component, and a brief process description.

(iii) Description of the emission unit tested including fuel burned, control devices, and vent characteristics; the appropriate source classification code (SCC); the permitted maximum process rate (where applicable); and the sampling location.

(iv) Description of sampling and analysis procedures used and any modifications to standard procedures, quality assurance procedures and results, record of process operating conditions that demonstrate the applicable test conditions are met, and values for any operating parameters for which limits were being set during the test.

(v) Where a test method requires you record or report, the following shall be included: Record of preparation of standards, record of calibrations, raw data sheets for field sampling, raw data sheets for field and laboratory analyses, chain-of-custody documentation, and example calculations for reported results.

(vi) Identification of the company conducting the performance test including the primary office address, telephone number, and the contact for this test program including his/her email address.

(g) The performance testing shall include a test method performance audit (PA) during the performance test. The PAs consist of blind audit samples supplied by an accredited audit sample provider and analyzed during the performance test in order to provide a measure of test data bias. Gaseous audit samples are designed to audit the performance of the sampling system as well as the analytical system and must be collected by the sampling system during the compliance test just as the compliance samples are collected. If a liquid or solid audit sample is designed to audit the sampling system, it must also be collected by the sampling system during the compliance test. If multiple sampling systems or sampling trains are used during the compliance test for any of the test methods, the tester is only required to use one of the sampling systems per method to collect the audit sample. The audit sample must be analyzed by the same analyst using the same analytical reagents and analytical system and at the same time as the compliance samples. Retests are required when there is a failure to produce acceptable results for an audit sample. However, if the audit results do not affect the compliance or noncompliance status of the affected facility, the compliance authority may waive the reanalysis requirement, further audits, or retests and accept the results of the compliance test. Acceptance of the test results shall constitute a waiver of the reanalysis requirement, further audits, or retests. The compliance authority may also use the audit sample failure and the compliance test results as evidence to determine the compliance or noncompliance status of the affected facility. A blind audit sample is a sample whose value is known only to the sample provider and is not revealed to the tested facility until after they report the measured value of the audit sample. For pollutants that exist in the gas phase at ambient temperature, the audit sample shall consist of an appropriate concentration of the pollutant in air or nitrogen that can be introduced into the sampling system of the test method at or near the same entry point as a sample from the emission source. If no gas phase audit samples are available, an acceptable alternative is a sample of the pollutant in the same matrix that would be produced when the sample is recovered from the sampling system as required by the test method. For samples that exist only in a liquid or solid form at ambient temperature, the audit sample shall consist of an appropriate concentration of the pollutant in the same matrix that would be produced when the sample is recovered from the sampling system as required by the test method. An accredited audit sample provider (AASP) is an organization that has been accredited to prepare audit samples by an independent, third party accrediting body.

(1) The source owner, operator, or representative of the tested facility shall obtain an audit sample, if commercially available, from an AASP for each test method used for regulatory compliance purposes. No audit samples are required for the following test methods: Methods 3A and 3C of appendix A-3 of part 60, Methods 6C, 7E, 9, and 10 of appendix A-4 of part 60, Methods 18 and 19 of appendix A-6 of part 60, Methods 20, 22, and 25A of appendix A-7 of part 60, Methods 30A and 30B of appendix A-8 of part 60, and Methods 303, 318, 320, and 321 of appendix A of part 63 of this chapter. If multiple sources at a single facility are tested during a compliance test event, only one audit sample is required for each method used during a compliance test. The compliance authority responsible for the compliance test may waive the requirement to include an audit sample if they believe that an audit sample is not necessary. "Commercially available" means that two or more independent AASPs have blind audit samples available for purchase. If the source owner, operator, or representative cannot find an audit sample for a specific method, the owner, operator, or representative shall consult the EPA Web site at the following URL, [www.epa.gov/ttn/emc](http://www.epa.gov/ttn/emc), to confirm whether there is a source that can supply an audit sample for that method. If the EPA Web site does not list an available audit sample at least 60 days prior to the beginning of the compliance test, the source owner, operator, or representative shall not be required to include an audit sample as part of the quality assurance program for the compliance test. When ordering an audit sample, the source owner, operator, or representative shall give the sample provider an estimate for the concentration of each pollutant that is emitted by the source or the estimated concentration of each pollutant based on the permitted level and the name, address, and phone number of the compliance authority. The source owner, operator, or representative shall report the results for the audit sample along with

a summary of the emission test results for the audited pollutant to the compliance authority and shall report the results of the audit sample to the AASP. The source owner, operator, or representative shall make both reports at the same time and in the same manner or shall report to the compliance authority first and then report to the AASP. If the method being audited is a method that allows the samples to be analyzed in the field and the tester plans to analyze the samples in the field, the tester may analyze the audit samples prior to collecting the emission samples provided a representative of the compliance authority is present at the testing site. The tester may request and the compliance authority may grant a waiver to the requirement that a representative of the compliance authority must be present at the testing site during the field analysis of an audit sample. The source owner, operator, or representative may report the results of the audit sample to the compliance authority and report the results of the audit sample to the AASP prior to collecting any emission samples. The test protocol and final test report shall document whether an audit sample was ordered and utilized and the pass/fail results as applicable.

(2) An AASP shall have and shall prepare, analyze, and report the true value of audit samples in accordance with a written technical criteria document that describes how audit samples will be prepared and distributed in a manner that will ensure the integrity of the audit sample program. An acceptable technical criteria document shall contain standard operating procedures for all of the following operations:

- (i) Preparing the sample;
- (ii) Confirming the true concentration of the sample;
- (iii) Defining the acceptance limits for the results from a well qualified tester. This procedure must use well established statistical methods to analyze historical results from well qualified testers. The acceptance limits shall be set so that there is 95 percent confidence that 90 percent of well qualified labs will produce future results that are within the acceptance limit range.
- (iv) Providing the opportunity for the compliance authority to comment on the selected concentration level for an audit sample;
- (v) Distributing the sample to the user in a manner that guarantees that the true value of the sample is unknown to the user;
- (vi) Recording the measured concentration reported by the user and determining if the measured value is within acceptable limits;
- (vii) The AASP shall report the results from each audit sample in a timely manner to the compliance authority and then to the source owner, operator, or representative. The AASP shall make both reports at the same time and in the same manner or shall report to the compliance authority first and then report to the source owner, operator, or representative. The results shall include the name of the facility tested, the date on which the compliance test was conducted, the name of the company performing the sample collection, the name of the company that analyzed the compliance samples including the audit sample, the measured result for the audit sample, and whether the testing company passed or failed the audit. The AASP shall report the true value of the audit sample to the compliance authority. The AASP may report the true value to the source owner, operator, or representative if the AASP's operating plan ensures that no laboratory will receive the same audit sample twice.
- (viii) Evaluating the acceptance limits of samples at least once every two years to determine in cooperation with the voluntary consensus standard body if they should be changed;
- (ix) Maintaining a database, accessible to the compliance authorities, of results from the audit that shall include the name of the facility tested, the date on which the compliance test was conducted, the name of the company performing the sample collection, the name of the company that analyzed the

compliance samples including the audit sample, the measured result for the audit sample, the true value of the audit sample, the acceptance range for the measured value, and whether the testing company passed or failed the audit.

(3) The accrediting body shall have a written technical criteria document that describes how it will ensure that the AASP is operating in accordance with the AASP technical criteria document that describes how audit samples are to be prepared and distributed. This document shall contain standard operating procedures for all of the following operations:

- (i) Checking audit samples to confirm their true value as reported by the AASP;
- (ii) Performing technical systems audits of the AASP's facilities and operating procedures at least once every two years;
- (iii) Providing standards for use by the voluntary consensus standard body to approve the accrediting body that will accredit the audit sample providers.

(4) The technical criteria documents for the accredited sample providers and the accrediting body shall be developed through a public process guided by a voluntary consensus standards body (VCSB). The VCSB shall operate in accordance with the procedures and requirements in the Office of Management and Budget Circular A-119. A copy of Circular A-119 is available upon request by writing the Office of Information and Regulatory Affairs, Office of Management and Budget, 725 17th Street, NW., Washington, DC 20503, by calling (202) 395-6880 or downloading online at [http://standards.gov/standards\\_gov/a119.cfm](http://standards.gov/standards_gov/a119.cfm). The VCSB shall approve all accrediting bodies. The Administrator will review all technical criteria documents. If the technical criteria documents do not meet the minimum technical requirements in paragraphs (g)(2) through (4) of this section, the technical criteria documents are not acceptable and the proposed audit sample program is not capable of producing audit samples of sufficient quality to be used in a compliance test. All acceptable technical criteria documents shall be posted on the EPA Web site at the following URL, <http://www.epa.gov/ttn/emc>.

(h) Unless otherwise specified in the applicable subpart, each test location must be verified to be free of cyclonic flow and evaluated for the existence of emission gas stratification and the required number of sampling traverse points. If other procedures are not specified in the applicable subpart to the regulations, use the appropriate procedures in Method 1 to check for cyclonic flow and Method 7E to evaluate emission gas stratification and selection of sampling points.

(i) Whenever the use of multiple calibration gases is required by a test method, performance specification, or quality assurance procedure in a part 60 standard or appendix, Method 205 of 40 CFR part 51, appendix M of this chapter, "Verification of Gas Dilution Systems for Field Instrument Calibrations," may be used.

#### **§60.9 Availability of information.**

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

#### **§60.10 State authority.**

The provisions of this part shall not be construed in any manner to preclude any State or political subdivision thereof from:

- (a) Adopting and enforcing any emission standard or limitation applicable to an affected facility, provided that such emission standard or limitation is not less stringent than the standard applicable to such facility.
- (b) Requiring the owner or operator of an affected facility to obtain permits, licenses, or approvals prior to initiating construction, modification, or operation of such facility.

**§60.11 Compliance with standards and maintenance requirements.**

- (a) Compliance with standards in this part, other than opacity standards, shall be determined in accordance with performance tests established by §60.8, unless otherwise specified in the applicable standard.
- (b) Compliance with opacity standards in this part shall be determined by conducting observations in accordance with Method 9 in appendix A of this part, any alternative method that is approved by the Administrator, or as provided in paragraph (e)(5) of this section. For purposes of determining initial compliance, the minimum total time of observations shall be 3 hours (30 6-minute averages) for the performance test or other set of observations (meaning those fugitive-type emission sources subject only to an opacity standard).
- (c) The opacity standards set forth in this part shall apply at all times except during periods of startup, shutdown, malfunction, and as otherwise provided in the applicable standard.
- (d) At all times, including periods of startup, shutdown, and malfunction, owners and operators shall, to the extent practicable, maintain and operate any affected facility including associated air pollution control equipment in a manner consistent with good air pollution control practice for minimizing emissions. Determination of whether acceptable operating and maintenance procedures are being used will be based on information available to the Administrator which may include, but is not limited to, monitoring results, opacity observations, review of operating and maintenance procedures, and inspection of the source.
- (e)(1) For the purpose of demonstrating initial compliance, opacity observations shall be conducted concurrently with the initial performance test required in §60.8 unless one of the following conditions apply. If no performance test under §60.8 is required, then opacity observations shall be conducted within 60 days after achieving the maximum production rate at which the affected facility will be operated but no later than 180 days after initial startup of the facility. If visibility or other conditions prevent the opacity observations from being conducted concurrently with the initial performance test required under §60.8, the source owner or operator shall reschedule the opacity observations as soon after the initial performance test as possible, but not later than 30 days thereafter, and shall advise the Administrator of the rescheduled date. In these cases, the 30-day prior notification to the Administrator required in §60.7(a)(6) shall be waived. The rescheduled opacity observations shall be conducted (to the extent possible) under the same operating conditions that existed during the initial performance test conducted under §60.8. The visible emissions observer shall determine whether visibility or other conditions prevent the opacity observations from being made concurrently with the initial performance test in accordance with procedures contained in Method 9 of appendix B of this part. Opacity readings of portions of plumes which contain condensed, uncombined water vapor shall not be used for purposes of determining compliance with opacity standards. The owner or operator of an affected facility shall make available, upon request by the Administrator, such records as may be necessary to determine the conditions under which the visual observations were made and shall provide evidence indicating proof of current visible observer emission certification. Except as provided in paragraph (e)(5) of this section, the results of continuous monitoring by transmissometer which indicate that the opacity at the time visual observations were made was not in excess of the standard are probative but not conclusive evidence of the actual opacity of an emission, provided that the source shall meet the burden of proving that the instrument used meets (at the time of the alleged violation) Performance Specification 1 in appendix B of this part, has been properly maintained and (at the time of the alleged violation) that the resulting data have not been altered in any way.
- (2) Except as provided in paragraph (e)(3) of this section, the owner or operator of an affected facility to which an opacity standard in this part applies shall conduct opacity observations in accordance with paragraph (b) of this section, shall record the opacity of emissions, and shall report to the Administrator the opacity results along with the results of the initial performance test required under §60.8. The inability of an owner or operator to secure a visible emissions observer shall not be considered a reason for not conducting the opacity observations concurrent with the initial performance test.

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

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

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

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

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

(8) The Administrator will establish an opacity standard for the affected facility meeting the above requirements at a level at which the source will be able, as indicated by the performance and opacity tests, to meet the

opacity standard at all times during which the source is meeting the mass or concentration emission standard. The Administrator will promulgate the new opacity standard in the FEDERAL REGISTER.

(f) Special provisions set forth under an applicable subpart shall supersede any conflicting provisions in paragraphs (a) through (e) of this section.

(g) For the purpose of submitting compliance certifications or establishing whether or not a person has violated or is in violation of any standard in this part, nothing in this part shall preclude the use, including the exclusive use, of any credible evidence or information, relevant to whether a source would have been in compliance with applicable requirements if the appropriate performance or compliance test or procedure had been performed.

#### **§60.12 Circumvention.**

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

#### **§60.13 Monitoring requirements.**

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

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

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

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

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

(d)(1) Owners and operators of a CEMS installed in accordance with the provisions of this part, must check the zero (or low level value between 0 and 20 percent of span value) and span (50 to 100 percent of span value) calibration drifts at least once each operating day in accordance with a written procedure. The zero and span must, at a minimum, be adjusted whenever either the 24-hour zero drift or the 24-hour span drift exceeds two times the limit

of the applicable performance specification in appendix B of this part. The system must allow the amount of the excess zero and span drift to be recorded and quantified whenever specified. Owners and operators of a COMS installed in accordance with the provisions of this part must check the zero and upscale (span) calibration drifts at least once daily. For a particular COMS, the acceptable range of zero and upscale calibration materials is defined in the applicable version of PS-1 in appendix B of this part. For a COMS, the optical surfaces, exposed to the effluent gases, must be cleaned before performing the zero and upscale drift adjustments, except for systems using automatic zero adjustments. The optical surfaces must be cleaned when the cumulative automatic zero compensation exceeds 4 percent opacity.

(2) Unless otherwise approved by the Administrator, the following procedures must be followed for a COMS. Minimum procedures must include an automated method for producing a simulated zero opacity condition and an upscale opacity condition using a certified neutral density filter or other related technique to produce a known obstruction of the light beam. Such procedures must provide a system check of all active analyzer internal optics with power or curvature, all active electronic circuitry including the light source and photodetector assembly, and electronic or electro-mechanical systems and hardware and or software used during normal measurement operation.

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

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

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

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

(g) When the effluents from a single affected facility or two or more affected facilities subject to the same emission standards are combined before being released to the atmosphere, the owner or operator may install applicable continuous monitoring systems on each effluent or on the combined effluent. When the affected facilities are not subject to the same emission standards, separate continuous monitoring systems shall be installed on each effluent. When the effluent from one affected facility is released to the atmosphere through more than one point, the owner or operator shall install an applicable continuous monitoring system on each separate effluent unless the installation of fewer systems is approved by the Administrator. When more than one continuous monitoring system is used to measure the emissions from one affected facility (e.g., multiple breechings, multiple outlets), the owner or operator shall report the results as required from each continuous monitoring system.

(h)(1) Owners or operators of all continuous monitoring systems for measurement of opacity shall reduce all data to 6-minute averages and for continuous monitoring systems other than opacity to 1-hour averages for time periods as defined in §60.2. Six-minute opacity averages shall be calculated from 36 or more data points equally spaced over each 6-minute period.

(2) For continuous monitoring systems other than opacity, 1-hour averages shall be computed as follows, except that the provisions pertaining to the validation of partial operating hours are only applicable for affected facilities that are required by the applicable subpart to include partial hours in the emission calculations:

- (i) Except as provided under paragraph (h)(2)(iii) of this section, for a full operating hour (any clock hour with 60 minutes of unit operation), at least four valid data points are required to calculate the hourly average, *i.e.*, one data point in each of the 15-minute quadrants of the hour.
- (ii) Except as provided under paragraph (h)(2)(iii) of this section, for a partial operating hour (any clock hour with less than 60 minutes of unit operation), at least one valid data point in each 15-minute quadrant of the hour in which the unit operates is required to calculate the hourly average.
- (iii) For any operating hour in which required maintenance or quality-assurance activities are performed:
  - (A) If the unit operates in two or more quadrants of the hour, a minimum of two valid data points, separated by at least 15 minutes, is required to calculate the hourly average; or
  - (B) If the unit operates in only one quadrant of the hour, at least one valid data point is required to calculate the hourly average.
- (iv) If a daily calibration error check is failed during any operating hour, all data for that hour shall be invalidated, unless a subsequent calibration error test is passed in the same hour and the requirements of paragraph (h)(2)(iii) of this section are met, based solely on valid data recorded after the successful calibration.
- (v) For each full or partial operating hour, all valid data points shall be used to calculate the hourly average.
- (vi) Except as provided under paragraph (h)(2)(vii) of this section, data recorded during periods of continuous monitoring system breakdown, repair, calibration checks, and zero and span adjustments shall not be included in the data averages computed under this paragraph.
- (vii) Owners and operators complying with the requirements of §60.7(f)(1) or (2) must include any data recorded during periods of monitor breakdown or malfunction in the data averages.
- (viii) When specified in an applicable subpart, hourly averages for certain partial operating hours shall not be computed or included in the emission averages (e.g., hours with < 30 minutes of unit operation under §60.47b(d)).
- (ix) Either arithmetic or integrated averaging of all data may be used to calculate the hourly averages. The data may be recorded in reduced or nonreduced form (e.g., ppm pollutant and percent O<sub>2</sub> or ng/J of pollutant).

(3) All excess emissions shall be converted into units of the standard using the applicable conversion procedures specified in the applicable subpart. After conversion into units of the standard, the data may be rounded to the same number of significant digits used in the applicable subpart to specify the emission limit.

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

- (1) Alternative monitoring requirements when installation of a continuous monitoring system or monitoring device specified by this part would not provide accurate measurements due to liquid water or other interferences caused by substances in the effluent gases.
- (2) Alternative monitoring requirements when the affected facility is infrequently operated.
- (3) Alternative monitoring requirements to accommodate continuous monitoring systems that require additional measurements to correct for stack moisture conditions.

- (4) Alternative locations for installing continuous monitoring systems or monitoring devices when the owner or operator can demonstrate that installation at alternate locations will enable accurate and representative measurements.
  - (5) Alternative methods of converting pollutant concentration measurements to units of the standards.
  - (6) Alternative procedures for performing daily checks of zero and span drift that do not involve use of span gases or test cells.
  - (7) Alternatives to the A.S.T.M. test methods or sampling procedures specified by any subpart.
  - (8) Alternative continuous monitoring systems that do not meet the design or performance requirements in Performance Specification 1, appendix B, but adequately demonstrate a definite and consistent relationship between its measurements and the measurements of opacity by a system complying with the requirements in Performance Specification 1. The Administrator may require that such demonstration be performed for each affected facility.
  - (9) Alternative monitoring requirements when the effluent from a single affected facility or the combined effluent from two or more affected facilities is released to the atmosphere through more than one point.
- (j) An alternative to the relative accuracy (RA) test specified in Performance Specification 2 of appendix B may be requested as follows:
- (1) An alternative to the reference method tests for determining RA is available for sources with emission rates demonstrated to be less than 50 percent of the applicable standard. A source owner or operator may petition the Administrator to waive the RA test in Section 8.4 of Performance Specification 2 and substitute the procedures in Section 16.0 if the results of a performance test conducted according to the requirements in §60.8 of this subpart or other tests performed following the criteria in §60.8 demonstrate that the emission rate of the pollutant of interest in the units of the applicable standard is less than 50 percent of the applicable standard. For sources subject to standards expressed as control efficiency levels, a source owner or operator may petition the Administrator to waive the RA test and substitute the procedures in Section 16.0 of Performance Specification 2 if the control device exhaust emission rate is less than 50 percent of the level needed to meet the control efficiency requirement. The alternative procedures do not apply if the continuous emission monitoring system is used to determine compliance continuously with the applicable standard. The petition to waive the RA test shall include a detailed description of the procedures to be applied. Included shall be location and procedure for conducting the alternative, the concentration or response levels of the alternative RA materials, and the other equipment checks included in the alternative procedure. The Administrator will review the petition for completeness and applicability. The determination to grant a waiver will depend on the intended use of the CEMS data (e.g., data collection purposes other than NSPS) and may require specifications more stringent than in Performance Specification 2 (e.g., the applicable emission limit is more stringent than NSPS).
  - (2) The waiver of a CEMS RA test will be reviewed and may be rescinded at such time, following successful completion of the alternative RA procedure, that the CEMS data indicate that the source emissions are approaching the level. The criterion for reviewing the waiver is the collection of CEMS data showing that emissions have exceeded 70 percent of the applicable standard for seven, consecutive, averaging periods as specified by the applicable regulation(s). For sources subject to standards expressed as control efficiency levels, the criterion for reviewing the waiver is the collection of CEMS data showing that exhaust emissions have exceeded 70 percent of the level needed to meet the control efficiency requirement for seven, consecutive, averaging periods as specified by the applicable regulation(s) [e.g., §§60.45(g) (2) and (3), 60.73(e), and 60.84(e)]. It is the responsibility of the source operator to maintain records and determine the level of emissions relative to the criterion on the waiver of RA testing. If this criterion is exceeded, the owner or operator must notify the Administrator within 10 days of such occurrence and include a description of the nature and cause of

the increasing emissions. The Administrator will review the notification and may rescind the waiver and require the owner or operator to conduct a RA test of the CEMS as specified in Section 8.4 of Performance Specification 2.

**§60.14 Modification.**

(a) Except as provided under paragraphs (e) and (f) of this section, any physical or operational change to an existing facility which results in an increase in the emission rate to the atmosphere of any pollutant to which a standard applies shall be considered a modification within the meaning of section 111 of the Act. Upon modification, an existing facility shall become an affected facility for each pollutant to which a standard applies and for which there is an increase in the emission rate to the atmosphere.

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

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

(2) Material balances, continuous monitor data, or manual emission tests in cases where utilization of emission factors as referenced in paragraph (b)(1) of this section does not demonstrate to the Administrator's satisfaction whether the emission level resulting from the physical or operational change will either clearly increase or clearly not increase, or where an owner or operator demonstrates to the Administrator's satisfaction that there are reasonable grounds to dispute the result obtained by the Administrator utilizing emission factors as referenced in paragraph (b)(1) of this section. When the emission rate is based on results from manual emission tests or continuous monitoring systems, the procedures specified in appendix C of this part shall be used to determine whether an increase in emission rate has occurred. Tests shall be conducted under such conditions as the Administrator shall specify to the owner or operator based on representative performance of the facility. At least three valid test runs must be conducted before and at least three after the physical or operational change. All operating parameters which may affect emissions must be held constant to the maximum feasible degree for all test runs.

(c) The addition of an affected facility to a stationary source as an expansion to that source or as a replacement for an existing facility shall not by itself bring within the applicability of this part any other facility within that source.

(d) [Reserved]

(e) The following shall not, by themselves, be considered modifications under this part:

(1) Maintenance, repair, and replacement which the Administrator determines to be routine for a source category, subject to the provisions of paragraph (c) of this section and §60.15.

(2) An increase in production rate of an existing facility, if that increase can be accomplished without a capital expenditure on that facility.

(3) An increase in the hours of operation.

(4) Use of an alternative fuel or raw material if, prior to the date any standard under this part becomes applicable to that source type, as provided by §60.1, the existing facility was designed to accommodate that alternative use. A facility shall be considered to be designed to accommodate an alternative fuel or raw material if that use could be accomplished under the facility's construction specifications as amended prior to the change. Conversion to coal required for energy considerations, as specified in section 111(a)(8) of the Act, shall not be considered a modification.

(5) The addition or use of any system or device whose primary function is the reduction of air pollutants, except when an emission control system is removed or is replaced by a system which the Administrator determines to be less environmentally beneficial.

(6) The relocation or change in ownership of an existing facility.

(f) Special provisions set forth under an applicable subpart of this part shall supersede any conflicting provisions of this section.

(g) Within 180 days of the completion of any physical or operational change subject to the control measures specified in paragraph (a) of this section, compliance with all applicable standards must be achieved.

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

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

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

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

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

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

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

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

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

#### **§60.15 Reconstruction.**

(a) An existing facility, upon reconstruction, becomes an affected facility, irrespective of any change in emission rate.

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

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

(2) It is technologically and economically feasible to meet the applicable standards set forth in this part.

(c) "Fixed capital cost" means the capital needed to provide all the depreciable components.

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

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

(2) The location of the existing facility.

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

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

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

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

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

(e) The Administrator will determine, within 30 days of the receipt of the notice required by paragraph (d) of this section and any additional information he may reasonably require, whether the proposed replacement constitutes reconstruction.

(f) The Administrator's determination under paragraph (e) shall be based on:

(1) The fixed capital cost of the replacements in comparison to the fixed capital cost that would be required to construct a comparable entirely new facility;

(2) The estimated life of the facility after the replacements compared to the life of a comparable entirely new facility;

(3) The extent to which the components being replaced cause or contribute to the emissions from the facility; and

(4) Any economic or technical limitations on compliance with applicable standards of performance which are inherent in the proposed replacements.

(g) Individual subparts of this part may include specific provisions which refine and delimit the concept of reconstruction set forth in this section.

**§60.16 Priority list.**

Prioritized Major Source Categories

<b>Priority Number<sup>1</sup></b>	<b>Source Category</b>
1.	Synthetic Organic Chemical Manufacturing Industry (SOCMI) and Volatile Organic Liquid Storage Vessels and Handling Equipment

<i>Priority Number<sup>1</sup></i>	<i>Source Category</i>
	(a) SOCM I unit processes
	(b) Volatile organic liquid (VOL) storage vessels and handling equipment
	(c) SOCM I fugitive sources
	(d) SOCM I secondary sources
2.	Industrial Surface Coating: Cans
3.	Petroleum Refineries: Fugitive Sources
4.	Industrial Surface Coating: Paper
5.	Dry Cleaning
	(a) Perchloroethylene
	(b) Petroleum solvent
6.	Graphic Arts
7.	Polymers and Resins: Acrylic Resins
8.	Mineral Wool (Deleted)
9.	Stationary Internal Combustion Engines
10.	Industrial Surface Coating: Fabric
11.	Industrial-Commercial-Institutional Steam Generating Units.
12.	Incineration: Non-Municipal (Deleted)
13.	Non-Metallic Mineral Processing
14.	Metallic Mineral Processing
15.	Secondary Copper (Deleted)
16.	Phosphate Rock Preparation
17.	Foundries: Steel and Gray Iron
18.	Polymers and Resins: Polyethylene
19.	Charcoal Production
20.	Synthetic Rubber
	(a) Tire manufacture

<i>Priority Number</i> <sup>1</sup>	<i>Source Category</i>
	(b) SBR production
21.	Vegetable Oil
22.	Industrial Surface Coating: Metal Coil
23.	Petroleum Transportation and Marketing
24.	By-Product Coke Ovens
25.	Synthetic Fibers
26.	Plywood Manufacture
27.	Industrial Surface Coating: Automobiles
28.	Industrial Surface Coating: Large Appliances
29.	Crude Oil and Natural Gas Production
30.	Secondary Aluminum
31.	Potash (Deleted)
32.	Lightweight Aggregate Industry: Clay, Shale, and Slate <sup>2</sup>
33.	Glass
34.	Gypsum
35.	Sodium Carbonate
36.	Secondary Zinc (Deleted)
37.	Polymers and Resins: Phenolic
38.	Polymers and Resins: Urea-Melamine
39.	Ammonia (Deleted)
40.	Polymers and Resins: Polystyrene
41.	Polymers and Resins: ABS-SAN Resins
42.	Fiberglass
43.	Polymers and Resins: Polypropylene
44.	Textile Processing
45.	Asphalt Processing and Asphalt Roofing Manufacture

<i>Priority Number<sup>1</sup></i>	<i>Source Category</i>
46.	Brick and Related Clay Products
47.	Ceramic Clay Manufacturing (Deleted)
48.	Ammonium Nitrate Fertilizer
49.	Castable Refractories (Deleted)
50.	Borax and Boric Acid (Deleted)
51.	Polymers and Resins: Polyester Resins
52.	Ammonium Sulfate
53.	Starch
54.	Perlite
55.	Phosphoric Acid: Thermal Process (Deleted)
56.	Uranium Refining
57.	Animal Feed Defluorination (Deleted)
58.	Urea (for fertilizer and polymers)
59.	Detergent (Deleted)
<i>Other Source Categories</i>	
	Lead acid battery manufacture <sup>3</sup>
	Organic solvent cleaning <sup>3</sup>
	Industrial surface coating: metal furniture <sup>3</sup>
	Stationary gas turbines <sup>4</sup>
	Municipal solid waste landfills <sup>4</sup>

<sup>1</sup>Low numbers have highest priority, e.g., No. 1 is high priority, No. 59 is low priority.

<sup>2</sup>Formerly titled "Sintering: Clay and Fly Ash".

<sup>3</sup>Minor source category, but included on list since an NSPS is being developed for that source category.

<sup>4</sup>Not prioritized, since an NSPS for this major source category has already been promulgated.

**§60.17 Incorporations by reference.**

(a) Certain material is incorporated by reference into this part with the approval of the Director of the Federal Register under 5 U.S.C. 552(a) and 1 CFR part 51. To enforce any edition other than that specified in this section, the EPA must publish notice of change in the FEDERAL REGISTER and the material must be available to the public. All approved material is available for inspection at the EPA Docket Center, Public Reading Room, EPA WJC West, Room 3334, 1301 Constitution Ave. NW., Washington, DC, telephone number 202-566-1744, and is available from the sources listed below. It is also available for inspection at the National Archives and Records Administration (NARA). For information on the availability of this material at NARA, call (202) 741-6030 or go to [http://www.archives.gov/federal\\_register/code\\_of\\_federal\\_regulations/ibr\\_locations.html](http://www.archives.gov/federal_register/code_of_federal_regulations/ibr_locations.html).

(b) American Gas Association, available through ILL Infodisk, 610 Winters Avenue, Paramus, New Jersey 07652:

(1) American Gas Association Report No. 3: Orifice Metering for Natural Gas and Other Related Hydrocarbon Fluids, Part 1: General Equations and Uncertainty Guidelines (1990), IBR approved for §60.107a(d).

(2) American Gas Association Report No. 3: Orifice Metering for Natural Gas and Other Related Hydrocarbon Fluids, Part 2: Specification and Installation Requirements (2000), IBR approved for §60.107a(d).

(3) American Gas Association Report No. 11: Measurement of Natural Gas by Coriolis Meter (2003), IBR approved for §60.107a(d).

(4) American Gas Association Transmission Measurement Committee Report No. 7: Measurement of Gas by Turbine Meters (Revised February 2006), IBR approved for §60.107a(d).

(c) American Hospital Association (AHA) Service, Inc., Post Office Box 92683, Chicago, Illinois 60675-2683. You may inspect a copy at the EPA's Air and Radiation Docket and Information Center (Docket A-91-61, Item IV-J-124), Room M-1500, 1200 Pennsylvania Ave. NW., Washington, DC 20460.

(1) An Ounce of Prevention: Waste Reduction Strategies for Health Care Facilities. American Society for Health Care Environmental Services of the American Hospital Association. Chicago, Illinois. 1993. AHA Catalog No. 057007. ISBN 0-87258-673-5. IBR approved for §§60.35e and 60.55c.

(2) [Reserved]

(d) The following material is available for purchase from the American National Standards Institute (ANSI), 25 W. 43rd Street, 4th Floor, New York, NY 10036, Telephone (212) 642-4980, and is also available at the following Web site: <http://www.ansi.org>.

(1) ANSI No. C12.20-2010 American National Standard for Electricity Meters—0.2 and 0.5 Accuracy Classes (Approved August 31, 2010), IBR approved for §60.5535(d).

(2) [Reserved]

(e) American Petroleum Institute (API), 1220 L Street NW., Washington, DC 20005.

(1) API Publication 2517, Evaporation Loss from External Floating Roof Tanks, Second Edition, February 1980, IBR approved for §§60.111(i), 60.111a(f), and 60.116b(e).

(2) API Manual of Petroleum Measurement Standards, Chapter 22—Testing Protocol, Section 2—Differential Pressure Flow Measurement Devices, First Edition, August 2005, IBR approved for §60.107a(d).

(f) American Public Health Association, 1015 18th Street NW., Washington, DC 20036.

(1) "Standard Methods for the Examination of Water and Wastewater," 16th edition, 1985. Method 303F: "Determination of Mercury by the Cold Vapor Technique." Incorporated by reference for appendix A-8 to part 60, Method 29, §§9.2.3, 10.3, and 11.1.3.

(2) 2540 G. Total, Fixed, and Volatile Solids in Solid and Semisolid Samples, in Standard Methods for the Examination of Water and Wastewater, 20th Edition, 1998, IBR approved for §60.154(b).

(g) The following material is available for purchase from the American Society of Mechanical Engineers (ASME), Two Park Avenue, New York, NY 10016-5990, Telephone (800) 843-2763, and is also available at the following Web site: <http://www.asme.org>.

(1) ASME Interim Supplement 19.5 on Instruments and Apparatus: Application, Part II of Fluid Meters, 6th Edition (1971), IBR approved for §§60.58a(h), 60.58b(i), 60.1320(a), and 60.1810(a).

(2) ASME MFC-3M-2004, Measurement of Fluid Flow in Pipes Using Orifice, Nozzle, and Venturi, IBR approved for §60.107a(d).

(3) ASME/ANSI MFC-4M-1986 (Reaffirmed 2008), Measurement of Gas Flow by Turbine Meters, IBR approved for §60.107a(d).

(4) ASME/ANSI MFC-5M-1985 (Reaffirmed 2006), Measurement of Liquid Flow in Closed Conduits Using Transit-Time Ultrasonic Flowmeters, IBR approved for §60.107a(d).

(5) ASME MFC-6M-1998 (Reaffirmed 2005), Measurement of Fluid Flow in Pipes Using Vortex Flowmeters, IBR approved for §60.107a(d).

(6) ASME/ANSI MFC-7M-1987 (Reaffirmed 2006), Measurement of Gas Flow by Means of Critical Flow Venturi Nozzles, IBR approved for §60.107a(d).

(7) ASME/ANSI MFC-9M-1988 (Reaffirmed 2006), Measurement of Liquid Flow in Closed Conduits by Weighing Method, IBR approved for §60.107a(d).

(8) ASME MFC-11M-2006, Measurement of Fluid Flow by Means of Coriolis Mass Flowmeters, IBR approved for §60.107a(d).

(9) ASME MFC-14M-2003, Measurement of Fluid Flow Using Small Bore Precision Orifice Meters, IBR approved for §60.107a(d).

(10) ASME MFC-16-2007, Measurement of Liquid Flow in Closed Conduits with Electromagnetic Flowmeters, IBR approved for §60.107a(d).

(11) ASME MFC-18M-2001, Measurement of Fluid Flow Using Variable Area Meters, IBR approved for §60.107a(d).

(12) ASME MFC-22-2007, Measurement of Liquid by Turbine Flowmeters, IBR approved for §60.107a(d).

(13) ASME PTC 4.1-1964 (Reaffirmed 1991), Power Test Codes: Test Code for Steam Generating Units (with 1968 and 1969 Addenda), IBR approved for §§60.46b, 60.58a(h), 60.58b(i), 60.1320(a), and 60.1810(a).

(14) ASME/ANSI PTC 19.10-1981, Flue and Exhaust Gas Analyses [Part 10, Instruments and Apparatus], (Issued August 31, 1981), IBR approved for §§60.56c(b), 60.63(f), 60.106(e), 60.104a(d), (h), (i), and (j), 60.105a(b), (d), (f), and (g), 60.106a(a), 60.107a(a), (c), and (d), tables 1 and 3 to subpart EEEE, tables 2 and 4 to subpart FFFF, table 2 to subpart JJJJ, §§60.285a(f), 60.4415(a), 60.2145(s) and (t), 60.2710(s) and (t), 60.2730(q), 60.4900(b),

60.5220(b), tables 1 and 2 to subpart LLLL, tables 2 and 3 to subpart MMMM, §§60.5406(c), 60.5406a(c), 60.5407a(g), 60.5413(b), 60.5413a(b), and 60.5413a(d).

(15) ASME PTC 22-2014, Gas Turbines: Performance Test Codes, (Issued December 31, 2014), IBR approved for §60.5580.

(16) ASME PTC 46-1996, Performance Test Code on Overall Plant Performance, (Issued October 15, 1997), IBR approved for §60.5580.

(17) ASME QRO-1-1994, Standard for the Qualification and Certification of Resource Recovery Facility Operators, IBR approved for §§60.54b(a) and (b), 60.56a, 60.1185(a) and (c), and 60.1675(a) and (c).

(h) The following material is available for purchase from ASTM International, 100 Barr Harbor Drive, P.O. Box CB700, West Conshohocken, Pennsylvania 19428-2959, (800) 262-1373, <http://www.astm.org>.

(1) ASTM A99-76, Standard Specification for Ferromanganese, IBR approved for §60.261.

(2) ASTM A99-82 (Reapproved 1987), Standard Specification for Ferromanganese, IBR approved for §60.261.

(3) ASTM A100-69, Standard Specification for Ferrosilicon, IBR approved for §60.261.

(4) ASTM A100-74, Standard Specification for Ferrosilicon, IBR approved for §60.261.

(5) ASTM A100-93, Standard Specification for Ferrosilicon, IBR approved for §60.261.

(6) ASTM A101-73, Standard Specification for Ferrochromium, IBR approved for §60.261.

(7) ASTM A101-93, Standard Specification for Ferrochromium, IBR approved for §60.261.

(8) ASTM A482-76, Standard Specification for Ferrochromesilicon, IBR approved for §60.261.

(9) ASTM A482-93, Standard Specification for Ferrochromesilicon, IBR approved for §60.261.

(10) ASTM A483-64, Standard Specification for Silicomanganese, IBR approved for §60.261.

(11) ASTM A483-74 (Reapproved 1988), Standard Specification for Silicomanganese, IBR approved for §60.261.

(12) ASTM A495-76, Standard Specification for Calcium-Silicon and Calcium Manganese-Silicon, IBR approved for §60.261.

(13) ASTM A495-94, Standard Specification for Calcium-Silicon and Calcium Manganese-Silicon, IBR approved for §60.261.

(14) ASTM D86-78, Distillation of Petroleum Products, IBR approved for §§60.562-2(d), 60.593(d), 60.593a(d), 60.633(h).

(15) ASTM D86-82, Distillation of Petroleum Products, IBR approved for §§60.562-2(d), 60.593(d), 60.593a(d), 60.633(h).

(16) ASTM D86-90, Distillation of Petroleum Products, IBR approved for §§60.562-2(d), 60.593(d), 60.593a(d), 60.633(h).

(17) ASTM D86-93, Distillation of Petroleum Products, IBR approved for §§60.562-2(d), 60.593(d), 60.593a(d), 60.633(h).

(18) ASTM D86-95, Distillation of Petroleum Products, IBR approved for §§60.562-2(d), 60.593(d), 60.593a(d), 60.633(h).

- (19) ASTM D86-96, Distillation of Petroleum Products, (Approved April 10, 1996), IBR approved for §§60.562-2(d), 60.593(d), 60.593a(d), 60.633(h), 60.5401(f), 60.5401a(f).
- (20) ASTM D129-64, Standard Test Method for Sulfur in Petroleum Products (General Bomb Method), IBR approved for §§60.106(j) and appendix A-7 to part 60: Method 19, Section 12.5.2.2.3.
- (21) ASTM D129-78, Standard Test Method for Sulfur in Petroleum Products (General Bomb Method), IBR approved for §§60.106(j) and appendix A-7 to part 60: Method 19, Section 12.5.2.2.3.
- (22) ASTM D129-95, Standard Test Method for Sulfur in Petroleum Products (General Bomb Method), IBR approved for §§60.106(j) and appendix A-7 to part 60: Method 19, Section 12.5.2.2.3.
- (23) ASTM D129-00, Standard Test Method for Sulfur in Petroleum Products (General Bomb Method), IBR approved for §60.335(b).
- (24) ASTM D129-00 (Reapproved 2005), Standard Test Method for Sulfur in Petroleum Products (General Bomb Method), IBR approved for §60.4415(a).
- (25) ASTM D240-76, Standard Test Method for Heat of Combustion of Liquid Hydrocarbon Fuels by Bomb Calorimeter, IBR approved for §§60.46(c), 60.296(b), and appendix A-7 to part 60: Method 19, Section 12.5.2.2.3.
- (26) ASTM D240-92, Standard Test Method for Heat of Combustion of Liquid Hydrocarbon Fuels by Bomb Calorimeter, IBR approved for §§60.46(c), 60.296(b), and appendix A-7: Method 19, Section 12.5.2.2.3.
- (27) ASTM D240-02 (Reapproved 2007), Standard Test Method for Heat of Combustion of Liquid Hydrocarbon Fuels by Bomb Calorimeter, (Approved May 1, 2007), IBR approved for §60.107a(d).
- (28) ASTM D270-65, Standard Method of Sampling Petroleum and Petroleum Products, IBR approved for appendix A-7 to part 60: Method 19, Section 12.5.2.2.1.
- (29) ASTM D270-75, Standard Method of Sampling Petroleum and Petroleum Products, IBR approved for appendix A-7 to part 60: Method 19, Section 12.5.2.2.1.
- (30) ASTM D323-82, Test Method for Vapor Pressure of Petroleum Products (Reid Method), IBR approved for §§60.111(l), 60.111a(g), 60.111b, and 60.116b(f).
- (31) ASTM D323-94, Test Method for Vapor Pressure of Petroleum Products (Reid Method), IBR approved for §§60.111(l), 60.111a(g), 60.111b, and 60.116b(f).
- (32) ASTM D388-77, Standard Specification for Classification of Coals by Rank, IBR approved for §§60.41, 60.45(f), 60.41Da, 60.41b, 60.41c, and 60.251.
- (33) ASTM D388-90, Standard Specification for Classification of Coals by Rank, IBR approved for §§60.41, 60.45(f), 60.41Da, 60.41b, 60.41c, and 60.251.
- (34) ASTM D388-91, Standard Specification for Classification of Coals by Rank, IBR approved for §§60.41, 60.45(f), 60.41Da, 60.41b, 60.41c, and 60.251.
- (35) ASTM D388-95, Standard Specification for Classification of Coals by Rank, IBR approved for §§60.41, 60.45(f), 60.41Da, 60.41b, 60.41c, and 60.251.
- (36) ASTM D388-98a, Standard Specification for Classification of Coals by Rank, IBR approved for §§60.41, 60.45(f), 60.41Da, 60.41b, 60.41c, and 60.251.

- (37) ASTM D388-99 (Reapproved 2004)<sup>e1</sup> Standard Classification of Coals by Rank, IBR approved for §§60.41, 60.45(f), 60.41Da, 60.41b, 60.41c, 60.251, and 60.5580.
- (38) ASTM D396-78, Standard Specification for Fuel Oils, IBR approved for §§60.41b, 60.41c, 60.111(b), and 60.111a(b).
- (39) ASTM D396-89, Standard Specification for Fuel Oils, IBR approved for §§60.41b, 60.41c, 60.111(b), and 60.111a(b).
- (40) ASTM D396-90, Standard Specification for Fuel Oils, IBR approved for §§60.41b, 60.41c, 60.111(b), and 60.111a(b).
- (41) ASTM D396-92, Standard Specification for Fuel Oils, IBR approved for §§60.41b, 60.41c, 60.111(b), and 60.111a(b).
- (42) ASTM D396-98, Standard Specification for Fuel Oils, IBR approved for §§60.41b, 60.41c, 60.111(b), 60.111a(b), and 60.5580.
- (43) ASTM D975-78, Standard Specification for Diesel Fuel Oils, IBR approved for §§60.111(b) and 60.111a(b).
- (44) ASTM D975-96, Standard Specification for Diesel Fuel Oils, IBR approved for §§60.111(b) and 60.111a(b).
- (45) ASTM D975-98a, Standard Specification for Diesel Fuel Oils, IBR approved for §§60.111(b) and 60.111a(b).
- (46) ASTM D975-08a, Standard Specification for Diesel Fuel Oils, IBR approved for §§60.41b 60.41c, and 60.5580.
- (47) ASTM D1072-80, Standard Test Method for Total Sulfur in Fuel Gases, IBR approved for §60.335(b).
- (48) ASTM D1072-90 (Reapproved 1994), Standard Test Method for Total Sulfur in Fuel Gases, IBR approved for §60.335(b).
- (49) ASTM D1072-90 (Reapproved 1999), Standard Test Method for Total Sulfur in Fuel Gases, IBR approved for §60.4415(a).
- (50) ASTM D1137-53, Standard Method for Analysis of Natural Gases and Related Types of Gaseous Mixtures by the Mass Spectrometer, IBR approved for §60.45(f).
- (51) ASTM D1137-75, Standard Method for Analysis of Natural Gases and Related Types of Gaseous Mixtures by the Mass Spectrometer, IBR approved for §60.45(f).
- (52) ASTM D1193-77, Standard Specification for Reagent Water, IBR approved for appendix A-3 to part 60: Method 5, Section 7.1.3; Method 5E, Section 7.2.1; Method 5F, Section 7.2.1; appendix A-4 to part 60: Method 6, Section 7.1.1; Method 7, Section 7.1.1; Method 7C, Section 7.1.1; Method 7D, Section 7.1.1; Method 10A, Section 7.1.1; appendix A-5 to part 60: Method 11, Section 7.1.3; Method 12, Section 7.1.3; Method 13A, Section 7.1.2; appendix A-8 to part 60: Method 26, Section 7.1.2; Method 26A, Section 7.1.2; and Method 29, Section 7.2.2.
- (53) ASTM D1193-91, Standard Specification for Reagent Water, IBR approved for appendix A-3 to part 60: Method 5, Section 7.1.3; Method 5E, Section 7.2.1; Method 5F, Section 7.2.1; appendix A-4 to part 60: Method 6, Section 7.1.1; Method 7, Section 7.1.1; Method 7C, Section 7.1.1; Method 7D, Section 7.1.1; Method 10A, Section 7.1.1; appendix A-5 to part 60: Method 11, Section 7.1.3; Method 12, Section 7.1.3; Method 13A, Section 7.1.2; appendix A-8 to part 60: Method 26, Section 7.1.2; Method 26A, Section 7.1.2; and Method 29, Section 7.2.2.

- (54) ASTM D1266-87, Standard Test Method for Sulfur in Petroleum Products (Lamp Method), IBR approved for §§60.106(j) and 60.335(b).
- (55) ASTM D1266-91, Standard Test Method for Sulfur in Petroleum Products (Lamp Method), IBR approved for §§60.106(j) and 60.335(b).
- (56) ASTM D1266-98, Standard Test Method for Sulfur in Petroleum Products (Lamp Method), IBR approved for §§60.106(j) and 60.335(b).
- (57) ASTM D1266-98 (Reapproved 2003)<sup>ε</sup>,1 Standard Test Method for Sulfur in Petroleum Products (Lamp Method), IBR approved for §60.4415(a).
- (58) ASTM D1475-60 (Reapproved 1980), Standard Test Method for Density of Paint, Varnish Lacquer, and Related Products, IBR approved for §60.435(d), appendix A-8 to part 60: Method 24, Section 6.1; and Method 24A, Sections 6.5 and 7.1.
- (59) ASTM D1475-90, Standard Test Method for Density of Paint, Varnish Lacquer, and Related Products, IBR approved for §60.435(d), appendix A-8 to part 60: Method 24, Section 6.1; and Method 24A, §§6.5 and 7.1.
- (60) ASTM D1552-83, Standard Test Method for Sulfur in Petroleum Products (High-Temperature Method), IBR approved for §§60.106(j), 60.335(b), and appendix A-7 to part 60: Method 19, Section 12.5.2.2.3.
- (61) ASTM D1552-95, Standard Test Method for Sulfur in Petroleum Products (High-Temperature Method), IBR approved for §§60.106(j), 60.335(b), and appendix A-7 to part 60: Method 19, Section 12.5.2.2.3.
- (62) ASTM D1552-01, Standard Test Method for Sulfur in Petroleum Products (High-Temperature Method), IBR approved for §§60.106(j), 60.335(b), and appendix A-7 to part 60: Method 19, Section 12.5.2.2.3.
- (63) ASTM D1552-03, Standard Test Method for Sulfur in Petroleum Products (High-Temperature Method), IBR approved for §60.4415(a).
- (64) ASTM D1826-77, Standard Test Method for Calorific Value of Gases in Natural Gas Range by Continuous Recording Calorimeter, IBR approved for §§60.45(f), 60.46(c), 60.296(b), and appendix A-7 to part 60: Method 19, Section 12.3.2.4.
- (65) ASTM D1826-94, Standard Test Method for Calorific Value of Gases in Natural Gas Range by Continuous Recording Calorimeter, IBR approved for §§60.45(f), 60.46(c), 60.296(b), and appendix A-7 to part 60: Method 19, Section 12.3.2.4.
- (66) ASTM D1826-94 (Reapproved 2003), Standard Test Method for Calorific (Heating) Value of Gases in Natural Gas Range by Continuous Recording Calorimeter, (Approved May 10, 2003), IBR approved for §60.107a(d).
- (67) ASTM D1835-87, Standard Specification for Liquefied Petroleum (LP) Gases, IBR approved for §§60.41Da, 60.41b, and 60.41c.
- (68) ASTM D1835-91, Standard Specification for Liquefied Petroleum (LP) Gases, IBR approved for §§60.41Da, 60.41b, and 60.41c.
- (69) ASTM D1835-97, Standard Specification for Liquefied Petroleum (LP) Gases, IBR approved for §§60.41Da, 60.41b, and 60.41c.
- (70) ASTM D1835-03a, Standard Specification for Liquefied Petroleum (LP) Gases, IBR approved for §§60.41Da, 60.41b, and 60.41c.

- (71) ASTM D1945-64, Standard Method for Analysis of Natural Gas by Gas Chromatography, IBR approved for §60.45(f).
- (72) ASTM D1945-76, Standard Method for Analysis of Natural Gas by Gas Chromatography, IBR approved for §60.45(f).
- (73) ASTM D1945-91, Standard Method for Analysis of Natural Gas by Gas Chromatography, IBR approved for §60.45(f).
- (74) ASTM D1945-96, Standard Method for Analysis of Natural Gas by Gas Chromatography, IBR approved for §60.45(f).
- (75) ASTM D1945-03 (Reapproved 2010), Standard Method for Analysis of Natural Gas by Gas Chromatography, (Approved January 1, 2010), IBR approved for §§60.107a(d), 60.5413(d), 60.5413a(d).
- (76) ASTM D1946-77, Standard Method for Analysis of Reformed Gas by Gas Chromatography, IBR approved for §§60.18(f), 60.45(f), 60.564(f), 60.614(e), 60.664(e), and 60.704(d).
- (77) ASTM D1946-90 (Reapproved 1994), Standard Method for Analysis of Reformed Gas by Gas Chromatography, IBR approved for §§60.18(f), 60.45(f), 60.564(f), 60.614(e), 60.664(e), and 60.704(d).
- (78) ASTM D1946-90 (Reapproved 2006), Standard Method for Analysis of Reformed Gas by Gas Chromatography, (Approved June 1, 2006), IBR approved for §60.107a(d).
- (79) ASTM D2013-72, Standard Method of Preparing Coal Samples for Analysis, IBR approved for appendix A-7 to part 60: Method 19, Section 12.5.2.1.3.
- (80) ASTM D2013-86, Standard Method of Preparing Coal Samples for Analysis, IBR approved for appendix A-7 to part 60: Method 19, Section 12.5.2.1.3.
- (81) ASTM D2015-77 (Reapproved 1978), Standard Test Method for Gross Calorific Value of Solid Fuel by the Adiabatic Bomb Calorimeter, IBR approved for §§60.45(f), 60.46(c), and appendix A-7 to part 60: Method 19, Section 12.5.2.1.3.
- (82) ASTM D2015-96, Standard Test Method for Gross Calorific Value of Solid Fuel by the Adiabatic Bomb Calorimeter, IBR approved for §§60.45(f), 60.46(c), and appendix A-7 to part 60: Method 19, Section 12.5.2.1.3.
- (83) ASTM D2016-74, Standard Test Methods for Moisture Content of Wood, IBR approved for appendix A-8 to part 60: Method 28, Section 16.1.1.
- (84) ASTM D2016-83, Standard Test Methods for Moisture Content of Wood, IBR approved for appendix A-8 to part 60: Method 28, Section 16.1.1.
- (85) ASTM D2234-76, Standard Methods for Collection of a Gross Sample of Coal, IBR approved for appendix A-7 to part 60: Method 19, Section 12.5.2.1.1.
- (86) ASTM D2234-96, Standard Methods for Collection of a Gross Sample of Coal, IBR approved for appendix A-7 to part 60: Method 19, Section 12.5.2.1.1.
- (87) ASTM D2234-97b, Standard Methods for Collection of a Gross Sample of Coal, IBR approved for appendix A-7 to part 60: Method 19, Section 12.5.2.1.1.
- (88) ASTM D2234-98, Standard Methods for Collection of a Gross Sample of Coal, IBR approved for appendix A-7 to part 60: Method 19, Section 12.5.2.1.1.

- (89) ASTM D2369-81, Standard Test Method for Volatile Content of Coatings, IBR approved for appendix A-8 to part 60: Method 24, Section 6.2.
- (90) ASTM D2369-87, Standard Test Method for Volatile Content of Coatings, IBR approved for appendix A-8 to part 60: Method 24, Section 6.2.
- (91) ASTM D2369-90, Standard Test Method for Volatile Content of Coatings, IBR approved for appendix A-8 to part 60: Method 24, Section 6.2.
- (92) ASTM D2369-92, Standard Test Method for Volatile Content of Coatings, IBR approved for appendix A-8 to part 60: Method 24, Section 6.2.
- (93) ASTM D2369-93, Standard Test Method for Volatile Content of Coatings, IBR approved for appendix A-8 to part 60: Method 24, Section 6.2.
- (94) ASTM D2369-95, Standard Test Method for Volatile Content of Coatings, IBR approved for appendix A-8 to part 60: Method 24, Section 6.2.
- (95) ASTM D2382-76, Heat of Combustion of Hydrocarbon Fuels by Bomb Calorimeter (High-Precision Method), IBR approved for §§60.18(f), 60.485(g), 60.485a(g), 60.564(f), 60.614(e), 60.664(e), and 60.704(d).
- (96) ASTM D2382-88, Heat of Combustion of Hydrocarbon Fuels by Bomb Calorimeter (High-Precision Method), IBR approved for §§60.18(f), 60.485(g), 60.485a(g), 60.564(f), 60.614(e), 60.664(e), and 60.704(d).
- (97) ASTM D2504-67, Noncondensable Gases in C3 and Lighter Hydrocarbon Products by Gas Chromatography, IBR approved for §§60.485(g) and 60.485a(g).
- (98) ASTM D2504-77, Noncondensable Gases in C3 and Lighter Hydrocarbon Products by Gas Chromatography, IBR approved for §§60.485(g) and 60.485a(g).
- (99) ASTM D2504-88 (Reapproved 1993), Noncondensable Gases in C3 and Lighter Hydrocarbon Products by Gas Chromatography, IBR approved for §§60.485(g) and 60.485a(g).
- (100) ASTM D2584-68(Reapproved 1985), Standard Test Method for Ignition Loss of Cured Reinforced Resins, IBR approved for §60.685(c).
- (101) ASTM D2584-94, Standard Test Method for Ignition Loss of Cured Reinforced Resins, IBR approved for §60.685(c).
- (102) ASTM D2597-94 (Reapproved 1999), Standard Test Method for Analysis of Demethanized Hydrocarbon Liquid Mixtures Containing Nitrogen and Carbon Dioxide by Gas Chromatography, IBR approved for §60.335(b).
- (103) ASTM D2622-87, Standard Test Method for Sulfur in Petroleum Products by Wavelength Dispersive X-Ray Fluorescence Spectrometry, IBR approved for §§60.106(j) and 60.335(b).
- (104) ASTM D2622-94, Standard Test Method for Sulfur in Petroleum Products by Wavelength Dispersive X-Ray Fluorescence Spectrometry, IBR approved for §§60.106(j) and 60.335(b).
- (105) ASTM D2622-98, Standard Test Method for Sulfur in Petroleum Products by Wavelength Dispersive X-Ray Fluorescence Spectrometry, IBR approved for §§60.106(j) and 60.335(b).
- (106) ASTM D2622-05, Standard Test Method for Sulfur in Petroleum Products by Wavelength Dispersive X-Ray Fluorescence Spectrometry, IBR approved for §60.4415(a).

- (107) ASTM D2879-83 Test Method for Vapor Pressure-Temperature Relationship and Initial Decomposition Temperature of Liquids by Isoteniscope, IBR approved for §§60.111b(f)(3), 60.116b(e), 60.116b(f), 60.485(e), and 60.485a(e).
- (108) ASTM D2879-96, Test Method for Vapor Pressure-Temperature Relationship and Initial Decomposition Temperature of Liquids by Isoteniscope, IBR approved for §§60.111b(f)(3), 60.116b(e), 60.116b(f), 60.485(e), and 60.485a(e).
- (109) ASTM D2879-97, Test Method for Vapor Pressure-Temperature Relationship and Initial Decomposition Temperature of Liquids by Isoteniscope, IBR approved for §§60.111b(f)(3), 60.116b(e), 60.116b(f), 60.485(e), and 60.485a(e).
- (110) ASTM D2880-78, Standard Specification for Gas Turbine Fuel Oils, IBR approved for §§60.111(b), 60.111a(b), and 60.335(d).
- (111) ASTM D2880-96, Standard Specification for Gas Turbine Fuel Oils, IBR approved for §§60.111(b), 60.111a(b), and 60.335(d).
- (112) ASTM D2908-74, Standard Practice for Measuring Volatile Organic Matter in Water by Aqueous-Injection Gas Chromatography, IBR approved for §60.564(j).
- (113) ASTM D2908-91, Standard Practice for Measuring Volatile Organic Matter in Water by Aqueous-Injection Gas Chromatography, IBR approved for §60.564(j).
- (114) ASTM D2986-71, Standard Method for Evaluation of Air, Assay Media by the Monodisperse DOP (Diocetyl Phthalate) Smoke Test, IBR approved for appendix A-3 to part 60: Method 5, Section 7.1.1; appendix A-5 to part 60: Method 12, Section 7.1.1; and Method 13A, Section 7.1.1.2.
- (115) ASTM D2986-78, Standard Method for Evaluation of Air, Assay Media by the Monodisperse DOP (Diocetyl Phthalate) Smoke Test, IBR approved for appendix A-3 to part 60: Method 5, Section 7.1.1; appendix A-5 to part 60: Method 12, Section 7.1.1; and Method 13A, Section 7.1.1.2.
- (116) ASTM D2986-95a, Standard Method for Evaluation of Air, Assay Media by the Monodisperse DOP (Diocetyl Phthalate) Smoke Test, IBR approved for appendix A-3 to part 60: Method 5, Section 7.1.1; appendix A-5 to part 60: Method 12, Section 7.1.1; and Method 13A, Section 7.1.1.2.
- (117) ASTM D3173-73, Standard Test Method for Moisture in the Analysis Sample of Coal and Coke, IBR approved for appendix A-7 to part 60: Method 19, Section 12.5.2.1.3.
- (118) ASTM D3173-87, Standard Test Method for Moisture in the Analysis Sample of Coal and Coke, IBR approved for appendix A-7 to part 60: Method 19, Section 12.5.2.1.3.
- (119) ASTM D3176-74, Standard Method for Ultimate Analysis of Coal and Coke, IBR approved for §60.45(f)(5)(i) and appendix A-7 to part 60: Method 19, Section 12.3.2.3.
- (120) ASTM D3176-89, Standard Method for Ultimate Analysis of Coal and Coke, IBR approved for §60.45(f)(5)(i) and appendix A-7 to part 60: Method 19, Section 12.3.2.3.
- (121) ASTM D3177-75, Standard Test Method for Total Sulfur in the Analysis Sample of Coal and Coke, IBR approved for appendix A-7 to part 60: Method 19, Section 12.5.2.1.3.
- (122) ASTM D3177-89, Standard Test Method for Total Sulfur in the Analysis Sample of Coal and Coke, IBR approved for appendix A-7 to part 60: Method 19, Section 12.5.2.1.3.

- (123) ASTM D3178-73 (Reapproved 1979), Standard Test Methods for Carbon and Hydrogen in the Analysis Sample of Coal and Coke, IBR approved for §60.45(f).
- (124) ASTM D3178-89, Standard Test Methods for Carbon and Hydrogen in the Analysis Sample of Coal and Coke, IBR approved for §60.45(f).
- (125) ASTM D3246-81, Standard Test Method for Sulfur in Petroleum Gas by Oxidative Microcoulometry, IBR approved for §60.335(b).
- (126) ASTM D3246-92, Standard Test Method for Sulfur in Petroleum Gas by Oxidative Microcoulometry, IBR approved for §60.335(b).
- (127) ASTM D3246-96, Standard Test Method for Sulfur in Petroleum Gas by Oxidative Microcoulometry, IBR approved for §60.335(b).
- (128) ASTM D3246-05, Standard Test Method for Sulfur in Petroleum Gas by Oxidative Microcoulometry, IBR approved for §60.4415(a)(1).
- (129) ASTM D3270-73T, Standard Test Methods for Analysis for Fluoride Content of the Atmosphere and Plant Tissues (Semiautomated Method), IBR approved for appendix A-5 to part 60: Method 13A, Section 16.1.
- (130) ASTM D3270-80, Standard Test Methods for Analysis for Fluoride Content of the Atmosphere and Plant Tissues (Semiautomated Method), IBR approved for appendix A-5 to part 60: Method 13A, Section 16.1.
- (131) ASTM D3270-91, Standard Test Methods for Analysis for Fluoride Content of the Atmosphere and Plant Tissues (Semiautomated Method), IBR approved for appendix A-5 to part 60: Method 13A, Section 16.1.
- (132) ASTM D3270-95, Standard Test Methods for Analysis for Fluoride Content of the Atmosphere and Plant Tissues (Semiautomated Method), IBR approved for appendix A-5 to part 60: Method 13A, Section 16.1.
- (133) ASTM D3286-85, Standard Test Method for Gross Calorific Value of Coal and Coke by the Isoperibol Bomb Calorimeter, IBR approved for appendix A-7 to part 60: Method 19, Section 12.5.2.1.3.
- (134) ASTM D3286-96, Standard Test Method for Gross Calorific Value of Coal and Coke by the Isoperibol Bomb Calorimeter, IBR approved for appendix A-7 to part 60: Method 19, Section 12.5.2.1.3.
- (135) ASTM D3370-76, Standard Practices for Sampling Water, IBR approved for §60.564(j).
- (136) ASTM D3370-95a, Standard Practices for Sampling Water, IBR approved for §60.564(j).
- (137) ASTM D3588-98 (Reapproved 2003), Standard Practice for Calculating Heat Value, Compressibility Factor, and Relative Density of Gaseous Fuels, (Approved May 10, 2003), IBR approved for §§60.107a(d), 60.5413(d), and 60.5413a(d).
- (138) ASTM D3699-08, Standard Specification for Kerosine, including Appendix X1, (Approved September 1, 2008), IBR approved for §§60.41b, 60.41c, and 60.5580.
- (139) ASTM D3792-79, Standard Test Method for Water Content of Water-Reducible Paints by Direct Injection into a Gas Chromatograph, IBR approved for appendix A-7 to part 60: Method 24, Section 6.3.
- (140) ASTM D3792-91, Standard Test Method for Water Content of Water-Reducible Paints by Direct Injection into a Gas Chromatograph, IBR approved for appendix A-7 to part 60: Method 24, Section 6.3.
- (141) ASTM D4017-81, Standard Test Method for Water in Paints and Paint Materials by the Karl Fischer Titration Method, IBR approved for appendix A-7 to part 60: Method 24, Section 6.4.

- (142) ASTM D4017-90, Standard Test Method for Water in Paints and Paint Materials by the Karl Fischer Titration Method, IBR approved for appendix A-7 to part 60: Method 24, Section 6.4.
- (143) ASTM D4017-96a, Standard Test Method for Water in Paints and Paint Materials by the Karl Fischer Titration Method, IBR approved for appendix A-7 to part 60: Method 24, Section 6.4.
- (144) ASTM D4057-81, Standard Practice for Manual Sampling of Petroleum and Petroleum Products, IBR approved for appendix A-7 to part 60: Method 19, Section 12.5.2.2.3.
- (145) ASTM D4057-95, Standard Practice for Manual Sampling of Petroleum and Petroleum Products, IBR approved for appendix A-7 to part 60: Method 19, Section 12.5.2.2.3.
- (146) ASTM D4057-95 (Reapproved 2000), Standard Practice for Manual Sampling of Petroleum and Petroleum Products, IBR approved for §60.4415(a).
- (147) ASTM D4084-82, Standard Test Method for Analysis of Hydrogen Sulfide in Gaseous Fuels (Lead Acetate Reaction Rate Method), IBR approved for §60.334(h).
- (148) ASTM D4084-94, Standard Test Method for Analysis of Hydrogen Sulfide in Gaseous Fuels (Lead Acetate Reaction Rate Method), IBR approved for §60.334(h).
- (149) ASTM D4084-05, Standard Test Method for Analysis of Hydrogen Sulfide in Gaseous Fuels (Lead Acetate Reaction Rate Method), IBR approved for §§60.4360 and 60.4415(a).
- (150) ASTM D4177-95, Standard Practice for Automatic Sampling of Petroleum and Petroleum Products, IBR approved for appendix A-7 to part 60: Method 19, Section 12.5.2.2.1.
- (151) ASTM D4177-95 (Reapproved 2000), Standard Practice for Automatic Sampling of Petroleum and Petroleum Products, IBR approved for §60.4415(a).
- (152) ASTM D4239-85, Standard Test Methods for Sulfur in the Analysis Sample of Coal and Coke Using High Temperature Tube Furnace Combustion Methods, IBR approved for appendix A-7 to part 60: Method 19, Section 12.5.2.1.3.
- (153) ASTM D4239-94, Standard Test Methods for Sulfur in the Analysis Sample of Coal and Coke Using High Temperature Tube Furnace Combustion Methods, IBR approved for appendix A-7 to part 60: Method 19, Section 12.5.2.1.3.
- (154) ASTM D4239-97, Standard Test Methods for Sulfur in the Analysis Sample of Coal and Coke Using High Temperature Tube Furnace Combustion Methods, IBR approved for appendix A-7 to part 60: Method 19, Section 12.5.2.1.3.
- (155) ASTM D4294-02, Standard Test Method for Sulfur in Petroleum and Petroleum Products by Energy-Dispersive X-Ray Fluorescence Spectrometry, IBR approved for §60.335(b).
- (156) ASTM D4294-03, Standard Test Method for Sulfur in Petroleum and Petroleum Products by Energy-Dispersive X-Ray Fluorescence Spectrometry, IBR approved for §60.4415(a).
- (157) ASTM D4442-84, Standard Test Methods for Direct Moisture Content Measurement in Wood and Wood-base Materials, IBR approved for appendix A-8 to part 60: Method 28, Section 16.1.1.
- (158) ASTM D4442-92, Standard Test Methods for Direct Moisture Content Measurement in Wood and Wood-base Materials, IBR approved for appendix A-8 to part 60: Method 28, Section 16.1.1.

- (159) ASTM D4444-92, Standard Test Methods for Use and Calibration of Hand-Held Moisture Meters, IBR approved for appendix A-8 to part 60: Method 28, Section 16.1.1.
- (160) ASTM D4457-85 (Reapproved 1991), Test Method for Determination of Dichloromethane and 1,1,1-Trichloroethane in Paints and Coatings by Direct Injection into a Gas Chromatograph, IBR approved for appendix A-7 to part 60: Method 24, Section 6.5.
- (161) ASTM D4468-85 (Reapproved 2000), Standard Test Method for Total Sulfur in Gaseous Fuels by Hydrogenolysis and Rateometric Colorimetry, IBR approved for §§60.335(b) and 60.4415(a).
- (162) ASTM D4468-85 (Reapproved 2006), Standard Test Method for Total Sulfur in Gaseous Fuels by Hydrogenolysis and Rateometric Colorimetry, (Approved June 1, 2006), IBR approved for §60.107a(e).
- (163) ASTM D4629-02, Standard Test Method for Trace Nitrogen in Liquid Petroleum Hydrocarbons by Syringe/Inlet Oxidative Combustion and Chemiluminescence Detection, IBR approved for §§60.49b(e) and 60.335(b).
- (164) ASTM D4809-95, Standard Test Method for Heat of Combustion of Liquid Hydrocarbon Fuels by Bomb Calorimeter (Precision Method), IBR approved for §§60.18(f), 60.485(g), 60.485a(g), 60.564(f), 60.614(d), 60.664(e), and 60.704(d).
- (165) ASTM D4809-06, Standard Test Method for Heat of Combustion of Liquid Hydrocarbon Fuels by Bomb Calorimeter (Precision Method), (Approved December 1, 2006), IBR approved for §60.107a(d).
- (166) ASTM D4810-88 (Reapproved 1999), Standard Test Method for Hydrogen Sulfide in Natural Gas Using Length of Stain Detector Tubes, IBR approved for §§60.4360 and 60.4415(a).
- (167) ASTM D4891-89 (Reapproved 2006) Standard Test Method for Heating Value of Gases in Natural Gas Range by Stoichiometric Combustion, (Approved June 1, 2006), IBR approved for §§60.107a(d), 60.5413(d), and 60.5413a(d).
- (168) ASTM D5287-97 (Reapproved 2002), Standard Practice for Automatic Sampling of Gaseous Fuels, IBR approved for §60.4415(a).
- (169) ASTM D5403-93, Standard Test Methods for Volatile Content of Radiation Curable Materials, IBR approved for appendix A-7 to part 60: Method 24, Section 6.6.
- (170) ASTM D5453-00, Standard Test Method for Determination of Total Sulfur in Light Hydrocarbons, Motor Fuels and Oils by Ultraviolet Fluorescence, IBR approved for §60.335(b).
- (171) ASTM D5453-05, Standard Test Method for Determination of Total Sulfur in Light Hydrocarbons, Motor Fuels and Oils by Ultraviolet Fluorescence, IBR approved for §60.4415(a).
- (172) ASTM D5504-01, Standard Test Method for Determination of Sulfur Compounds in Natural Gas and Gaseous Fuels by Gas Chromatography and Chemiluminescence, IBR approved for §§60.334(h) and 60.4360.
- (173) ASTM D5504-08, Standard Test Method for Determination of Sulfur Compounds in Natural Gas and Gaseous Fuels by Gas Chromatography and Chemiluminescence, (Approved June 15, 2008), IBR approved for §§60.107a(e) and 60.5413(d).
- (174) ASTM D5762-02, Standard Test Method for Nitrogen in Petroleum and Petroleum Products by Boat-Inlet Chemiluminescence, IBR approved for §60.335(b).

- (175) ASTM D5865-98, Standard Test Method for Gross Calorific Value of Coal and Coke, IBR approved for §§60.45(f) and 60.46(c), and appendix A-7 to part 60: Method 19, Section 12.5.2.1.3.
- (176) ASTM D5865-10, Standard Test Method for Gross Calorific Value of Coal and Coke, (Approved January 1, 2010), IBR approved for §§60.45(f), 60.46(c), and appendix A-7 to part 60: Method 19, section 12.5.2.1.3.
- (177) ASTM D6216-12, Standard Practice for Opacity Monitor Manufacturers to Certify Conformance with Design and Performance Specifications, approved October 1, 2012; IBR approved for appendix B to part 60.
- (178) ASTM D6228-98, Standard Test Method for Determination of Sulfur Compounds in Natural Gas and Gaseous Fuels by Gas Chromatography and Flame Photometric Detection, IBR approved for §60.334(h).
- (179) ASTM D6228-98 (Reapproved 2003), Standard Test Method for Determination of Sulfur Compounds in Natural Gas and Gaseous Fuels by Gas Chromatography and Flame Photometric Detection, IBR approved for §§60.4360 and 60.4415.
- (180) ASTM D6348-03, Standard Test Method for Determination of Gaseous Compounds by Extractive Direct Interface Fourier Transform Infrared (FTIR) Spectroscopy, (Approved October 1, 2003), IBR approved for §60.73a(b), table 7 to subpart IIII, table 2 to subpart JJJ, and §60.4245(d).
- (181) ASTM D6366-99, Standard Test Method for Total Trace Nitrogen and Its Derivatives in Liquid Aromatic Hydrocarbons by Oxidative Combustion and Electrochemical Detection, IBR approved for §60.335(b)(9).
- (182) ASTM D6420-99 (Reapproved 2004), Standard Test Method for Determination of Gaseous Organic Compounds by Direct Interface Gas Chromatography-Mass Spectrometry, (Approved October 1, 2004), IBR approved for §60.107a(d) and table 2 to subpart JJJ.
- (183) ASTM D6522-00, Standard Test Method for Determination of Nitrogen Oxides, Carbon Monoxide, and Oxygen Concentrations in Emissions from Natural Gas-Fired Reciprocating Engines, Combustion Turbines, Boilers, and Process Heaters Using Portable Analyzers, IBR approved for §60.335(a).
- (184) ASTM D6522-00 (Reapproved 2005), Standard Test Method for Determination of Nitrogen Oxides, Carbon Monoxide, and Oxygen Concentrations in Emissions from Natural Gas-Fired Reciprocating Engines, Combustion Turbines, Boilers, and Process Heaters Using Portable Analyzers, (Approved October 1, 2005), IBR approved for table 2 to subpart JJJ, §§60.5413(b) and (d), and 60.5413a(b).
- (185) ASTM D6522-11 Standard Test Method for Determination of Nitrogen Oxides, Carbon Monoxide, and Oxygen Concentrations in Emissions from Natural Gas-Fired Reciprocating Engines, Combustion Turbines, Boilers, and Process Heaters Using Portable Analyzers (Approved December 1, 2011), IBR approved for §60.37f(a), 60.766(a).
- (186) ASTM D6667-01, Standard Test Method for Determination of Total Volatile Sulfur in Gaseous Hydrocarbons and Liquefied Petroleum Gases by Ultraviolet Fluorescence, IBR approved for §60.335(b).
- (187) ASTM D6667-04, Standard Test Method for Determination of Total Volatile Sulfur in Gaseous Hydrocarbons and Liquefied Petroleum Gases by Ultraviolet Fluorescence, IBR approved for §60.4415(a).
- (188) ASTM D6751-11b, Standard Specification for Biodiesel Fuel Blend Stock (B100) for Middle Distillate Fuels, including Appendices X1 through X3, (Approved July 15, 2011), IBR approved for §§60.41b, 60.41c, and 60.5580.
- (189) ASTM D6784-02, Standard Test Method for Elemental, Oxidized, Particle-Bound and Total Mercury in Flue Gas Generated from Coal-Fired Stationary Sources (Ontario Hydro Method), IBR approved for §60.56c(b) and appendix B to part 60: Performance Specification 12A, Section 8.6.2.

(190) ASTM D6784-02 (Reapproved 2008) Standard Test Method for Elemental, Oxidized, Particle-Bound and Total Mercury in Flue Gas Generated from Coal-Fired Stationary Sources (Ontario Hydro Method), (Approved April 1, 2008), IBR approved for §§60.2165(j) and 60.2730(j), tables 5, 6 and 8 to subpart CCCC, and tables 2, 6, 7, and 9 to subpart DDDD, §§60.4900(b), 60.5220(b), tables 1 and 2 to subpart LLLL, and tables 2 and 3 to subpart MMMM.

(191) ASTM D6911-15, Standard Guide for Packaging and Shipping Environmental Samples for Laboratory Analysis, approved January 15, 2015, IBR approved for appendix A-8: Method 30B.

(192) ASTM D7467-10, Standard Specification for Diesel Fuel Oil, Biodiesel Blend (B6 to B20), including Appendices X1 through X3, (Approved August 1, 2010), IBR approved for §§60.41b, 60.41c, and 60.5580.

(193) ASTM E168-67, General Techniques of Infrared Quantitative Analysis, IBR approved for §§60.485a(d), 60.593(b), 60.593a(b), and 60.632(f).

(194) ASTM E168-77, General Techniques of Infrared Quantitative Analysis, IBR approved for §§60.485a(d), 60.593(b), 60.593a(b), and 60.632(f).

(195) ASTM E168-92, General Techniques of Infrared Quantitative Analysis, IBR approved for §§60.485a(d), 60.593(b), 60.593a(b), 60.632(f), 60.5400, 60.5400a(f).

(196) ASTM E169-63, General Techniques of Ultraviolet Quantitative Analysis, IBR approved for §§60.485a(d), 60.593(b), 60.593a(b), and 60.632(f) .

(197) ASTM E169-77, General Techniques of Ultraviolet Quantitative Analysis, IBR approved for §§60.485a(d), 60.593(b), and 60.593a(b), 60.632(f).

(198) ASTM E169-93, General Techniques of Ultraviolet Quantitative Analysis, (Approved May 15, 1993), IBR approved for §§60.485a(d), 60.593(b), 60.593a(b), 60.632(f), 60.5400(f), and 60.5400a(f).

(199) ASTM E260-73, General Gas Chromatography Procedures, IBR approved for §§60.485a(d), 60.593(b), 60.593a(b), and 60.632(f).

(200) ASTM E260-91, General Gas Chromatography Procedures, (IBR approved for §§60.485a(d), 60.593(b), 60.593a(b), and 60.632(f).

(201) ASTM E260-96, General Gas Chromatography Procedures, (Approved April 10, 1996), IBR approved for §§60.485a(d), 60.593(b), 60.593a(b), 60.632(f), 60.5400(f), 60.5400a(f) 60.5406(b), and 60.5406a(b)(3).

(202) ASTM E617-13, Standard Specification for Laboratory Weights and Precision Mass Standards, approved May 1, 2013, IBR approved for appendix A-3: Methods 4, 5, 5H, 5I, and appendix A-8: Method 29.

(203) ASTM E871-82 (Reapproved 2013), Standard Test Method for Moisture Analysis of Particulate Wood Fuels, (Approved August 15, 2013), IBR approved for appendix A-8: method 28R.

(204) ASTM E1584-11, Standard Test Method for Assay of Nitric Acid, (Approved August 1, 2011), IBR approved for §60.73a(c).

(205) ASTM E2515-11, Standard Test Method for Determination of Particulate Matter Emissions Collected by a Dilution Tunnel, (Approved November 1, 2011), IBR approved for §60.534 and §60.5476.

(206) ASTM E2618-13 Standard Test Method for Measurement of Particulate Matter Emissions and Heating Efficiency of Outdoor Solid Fuel-Fired Hydronic Heating Appliances, (Approved September 1, 2013), IBR approved for §60.5476.

(207) ASTM E2779-10, Standard Test Method for Determining Particulate Matter Emissions from Pellet Heaters, (Approved October 1, 2010), IBR approved for §60.534.

(208) ASTM E2780-10, Standard Test Method for Determining Particulate Matter Emissions from Wood Heaters, (Approved October 1, 2010), IBR approved for appendix A: method 28R.

(209) ASTM UOP539-97, Refinery Gas Analysis by Gas Chromatography, (Copyright 1997), IBR approved for §60.107a(d).

(i) Association of Official Analytical Chemists, 1111 North 19th Street, Suite 210, Arlington, VA 22209.

(1) AOAC Method 9, Official Methods of Analysis of the Association of Official Analytical Chemists (AOAC), 11th edition, 1970, pp. 11-12, IBR approved for §§60.204(b), 60.214(b), 60.224(b), and 60.234(b).

(2) [Reserved]

(j) U.S. Environmental Protection Agency, 1200 Pennsylvania Avenue NW., Washington, DC 20460, (202) 272-0167, <http://www.epa.gov>.

(1) EPA-454/R-98-015, Office of Air Quality Planning and Standards (OAQPS) Fabric Filter Bag Leak Detection Guidance, September 1997, IBR approved for §§60.2145(r), 60.2710(r), 60.4905(b), and 60.5225(b).

(2) EPA-600/R-12/531, EPA Traceability Protocol for Assay and Certification of Gaseous Calibration Standards, May 2012, IBR approved for §§60.5413(d) and 60.5413a(d).

(k) The Gas Processors Association, 6526 East 60th Street, Tulsa, OK 74145; also available through Information Handling Services, 15 Inverness Way East, PO Box 1154, Englewood, CO 80150-1154. You may inspect a copy at the EPA's Air and Radiation Docket and Information Center, Room 3334, 1301 Constitution Ave. NW., Washington, DC 20460.

(1) Gas Processors Association Standard 2172-09, Calculation of Gross Heating Value, Relative Density, Compressibility and Theoretical Hydrocarbon Liquid Content for Natural Gas Mixtures for Custody Transfer (2009), IBR approved for §60.107a(d).

(2) Gas Processors Association Standard 2261-00, Analysis for Natural Gas and Similar Gaseous Mixtures by Gas Chromatography (2000), IBR approved for §60.107a(d).

(3) Gas Processors Association Standard 2377-86, Test for Hydrogen Sulfide and Carbon Dioxide in Natural Gas Using Length of Stain Tubes, 1986 Revision, IBR approved for §§60.105(b), 60.107a(b), 60.334(h), 60.4360, and 60.4415(a).

(l) International Organization for Standardization (ISO) available through IHS Inc., 15 Inverness Way East, Englewood, CO 80112.

(1) ISO 8178-4: 1996(E), Reciprocating Internal Combustion Engines—Exhaust Emission Measurement—part 4: Test Cycles for Different Engine Applications, IBR approved for §60.4241(b).

(2) [Reserved]

(m) International Organization for Standardization (ISO), 1, ch. de la Voie-Creuse, Case postale 56, CH-1211 Geneva 20, Switzerland, + 41 22 749 01 11, <http://www.iso.org/iso/home.htm>.

(1) ISO 2314:2009(E), Gas turbines-Acceptance tests, Third edition (December 15, 2009), IBR approved for §60.5580.

(2) ISO 8316: Measurement of Liquid Flow in Closed Conduits—Method by Collection of the Liquid in a Volumetric Tank (1987-10-01)—First Edition, IBR approved for §60.107a(d).

(n) This material is available for purchase from the National Technical Information Services (NTIS), 5285 Port Royal Road, Springfield, Virginia 22161. You may inspect a copy at the EPA's Air and Radiation Docket and Information Center (Docket A-91-61, Item IV-J-125), Room M-1500, 1200 Pennsylvania Ave. NW., Washington, DC 20460.

(1) OMB Bulletin No. 93-17: Revised Statistical Definitions for Metropolitan Areas. Office of Management and Budget, June 30, 1993. NTIS No. PB 93-192-664. IBR approved for §60.31e.

(2) [Reserved]

(o) North American Electric Reliability Corporation, 1325 G Street NW., Suite 600, Washington, DC 20005-3801, <http://www.nerc.com>.

(1) North American Electric Reliability Corporation Reliability Standard EOP-002-3, Capacity and Energy Emergencies, updated November 19, 2012, IBR approved for §§60.4211(f) and 60.4243(d). Also available online: [http://www.nerc.com/files/EOP-002-3\\_\\_\\_\\_1.pdf](http://www.nerc.com/files/EOP-002-3____1.pdf).

(2) [Reserved]

(p) The following material is available for purchase from the Technical Association of the Pulp and Paper Industry (TAPPI), 15 Technology Parkway South, Suite 115, Peachtree Corners, GA 30092, Telephone (800) 332-8686, and is also available at the following Web site: <http://www.tappi.org>.

(1) TAPPI Method T 624 cm-11, (Copyright 2011), IBR approved, for §§60.285(d) and 60.285a(d).

(2) [Reserved]

(q) Underwriter's Laboratories, Inc. (UL), 333 Pfingsten Road, Northbrook, IL 60062.

(1) UL 103, Sixth Edition revised as of September 3, 1986, Standard for Chimneys, Factory-built, Residential Type and Building Heating Appliance, IBR approved for appendix A-8 to part 60.

(2) [Reserved]

(r) Water Pollution Control Federation (WPCF), 2626 Pennsylvania Avenue NW., Washington, DC 20037.

(1) Method 209A, Total Residue Dried at 103-105 °C, in Standard Methods for the Examination of Water and Wastewater, 15th Edition, 1980, IBR approved for §60.683(b).

(2) [Reserved]

(s) West Coast Lumber Inspection Bureau, 6980 SW. Barnes Road, Portland, OR 97223.

(1) West Coast Lumber Standard Grading Rules No. 16, pages 5-21, 90 and 91, September 3, 1970, revised 1984, IBR approved for appendix A-8 to part 60.

(2) [Reserved]

(t) This material is available for purchase from the Canadian Standards Association (CSA), 5060 Spectrum Way, Suite 100, Mississauga, Ontario, Canada L4W 5N6, Telephone: 800-463-6727.

(1) CSA B415.1-10, Performance Testing of Solid-fuel-burning Heating Appliances, (March 2010), IBR approved for §60.534 and §60.5476. (The standard is also available at <http://shop.csa.ca/en/canada/fuel-burning-equipment/b4151-10/invt/27013322010>)

(2) [Reserved]

(u) This European National (EN) standards material is available for purchase at European Committee for Standardization, Management Centre, Avenue Marnix 17, B-1000 Brussels, Belgium, Telephone: + 32 2 550 08 11.

(1) DIN EN 303-5:2012E (EN 303-5), Heating boilers—Part 5: Heating boilers for solid fuels, manually and automatically stoked, nominal heat output of up to 500 kW—Terminology, requirements, testing and marking, (October 2012), IBR approved for §60.5476. (The standard is also available at [http://www.en-standard.eu/csn-en-303-5-heating-boilers-part-5-heating-boilers-for-solid-fuels-manually-and-automatically-stoked-nominal-heat-output-of-up-to-500-kw-terminology-requirements-testing-and-marking/?gclid=CJXI2P\\_\\_\\_\\_97MMCFdcccQodan8ATA](http://www.en-standard.eu/csn-en-303-5-heating-boilers-part-5-heating-boilers-for-solid-fuels-manually-and-automatically-stoked-nominal-heat-output-of-up-to-500-kw-terminology-requirements-testing-and-marking/?gclid=CJXI2P____97MMCFdcccQodan8ATA))

(2) [Reserved]

### §60.18 General control device and work practice requirements.

(a) *Introduction.*

(1) This section contains requirements for control devices used to comply with applicable subparts of 40 CFR parts 60 and 61. The requirements are placed here for administrative convenience and apply only to facilities covered by subparts referring to this section.

(2) This section also contains requirements for an alternative work practice used to identify leaking equipment. This alternative work practice is placed here for administrative convenience and is available to all subparts in 40 CFR parts 60, 61, 63, and 65 that require monitoring of equipment with a 40 CFR part 60, appendix A-7, Method 21 monitor.

(b) *Flares.* Paragraphs (c) through (f) apply to flares.

(c)(1) Flares shall be designed for and operated with no visible emissions as determined by the methods specified in paragraph (f), except for periods not to exceed a total of 5 minutes during any 2 consecutive hours.

(2) Flares shall be operated with a flame present at all times, as determined by the methods specified in paragraph (f).

(3) An owner/operator has the choice of adhering to either the heat content specifications in paragraph (c)(3)(ii) of this section and the maximum tip velocity specifications in paragraph (c)(4) of this section, or adhering to the requirements in paragraph (c)(3)(i) of this section.

(i)(A) Flares shall be used that have a diameter of 3 inches or greater, are nonassisted, have a hydrogen content of 8.0 percent (by volume), or greater, and are designed for and operated with an exit velocity less than 37.2 m/sec (122 ft/sec) and less than the velocity,  $V_{\max}$ , as determined by the following equation:

$$V_{\max} = (X_{H_2} - K_1) * K_2$$

Where:

$V_{\max}$  = Maximum permitted velocity, m/sec.

$K_1$  = Constant, 6.0 volume-percent hydrogen.

$K_2$  = Constant, 3.9(m/sec)/volume-percent hydrogen.

$X_{H_2}$  = The volume-percent of hydrogen, on a wet basis, as calculated by using the American Society for Testing and Materials (ASTM) Method D1946-77. (Incorporated by reference as specified in §60.17).

(B) The actual exit velocity of a flare shall be determined by the method specified in paragraph (f)(4) of this section.

(ii) Flares shall be used only with the net heating value of the gas being combusted being 11.2 MJ/scm (300 Btu/scf) or greater if the flare is steam-assisted or air-assisted; or with the net heating value of the gas being combusted being 7.45 MJ/scm (200 Btu/scf) or greater if the flare is nonassisted. The net heating value of the gas being combusted shall be determined by the methods specified in paragraph (f)(3) of this section.

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

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

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

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

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

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

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

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

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

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

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

where:

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

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

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

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

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

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

(5) The maximum permitted velocity,  $V_{max}$ , for flares complying with paragraph (c)(4)(iii) shall be determined by the following equation.

$$\text{Log}_{10}(V_{max}) = (H_T + 28.8)/31.7$$

$V_{max}$  = Maximum permitted velocity, M/sec

28.8 = Constant

31.7 = Constant

$H_T$  = The net heating value as determined in paragraph (f)(3).

(6) The maximum permitted velocity,  $V_{max}$ , for air-assisted flares shall be determined by the following equation.

$$V_{max} = 8.706 + 0.7084 (H_T)$$

$V_{max}$  = Maximum permitted velocity, m/sec

8.706 = Constant

0.7084 = Constant

$H_T$  = The net heating value as determined in paragraph (f)(3).

(g) *Alternative work practice for monitoring equipment for leaks.* Paragraphs (g), (h), and (i) of this section apply to all equipment for which the applicable subpart requires monitoring with a 40 CFR part 60, appendix A-7, Method 21 monitor, except for closed vent systems, equipment designated as leakless, and equipment identified in the applicable subpart as having no detectable emissions, as indicated by an instrument reading of less than 500 ppm above background. An owner or operator may use an optical gas imaging instrument instead of a 40 CFR part 60, appendix A-7, Method 21 monitor. Requirements in the existing subparts that are specific to the Method 21 instrument do not apply under this section. All other requirements in the applicable subpart that are not addressed in paragraphs (g), (h), and (i) of this section apply to this standard. For example, equipment specification requirements, and non-Method 21 instrument recordkeeping and reporting requirements in the applicable subpart continue to apply. The terms defined in paragraphs (g)(1) through (5) of this section have meanings that are specific to the alternative work practice standard in paragraphs (g), (h), and (i) of this section.

(1) *Applicable subpart* means the subpart in 40 CFR parts 60, 61, 63, or 65 that requires monitoring of equipment with a 40 CFR part 60, appendix A-7, Method 21 monitor.

(2) *Equipment* means pumps, valves, pressure relief valves, compressors, open-ended lines, flanges, connectors, and other equipment covered by the applicable subpart that require monitoring with a 40 CFR part 60, appendix A-7, Method 21 monitor.

- (3) *Imaging* means making visible emissions that may otherwise be invisible to the naked eye.
- (4) *Optical gas imaging instrument* means an instrument that makes visible emissions that may otherwise be invisible to the naked eye.
- (5) *Repair* means that equipment is adjusted, or otherwise altered, in order to eliminate a leak.
- (6) *Leak* means:
- (i) Any emissions imaged by the optical gas instrument;
  - (ii) Indications of liquids dripping;
  - (iii) Indications by a sensor that a seal or barrier fluid system has failed; or
  - (iv) Screening results using a 40 CFR part 60, appendix A-7, Method 21 monitor that exceed the leak definition in the applicable subpart to which the equipment is subject.

(h) The alternative work practice standard for monitoring equipment for leaks is available to all subparts in 40 CFR parts 60, 61, 63, and 65 that require monitoring of equipment with a 40 CFR part 60, appendix A-7, Method 21 monitor.

- (1) An owner or operator of an affected source subject to CFR parts 60, 61, 63, or 65 can choose to comply with the alternative work practice requirements in paragraph (i) of this section instead of using the 40 CFR part 60, appendix A-7, Method 21 monitor to identify leaking equipment. The owner or operator must document the equipment, process units, and facilities for which the alternative work practice will be used to identify leaks.
- (2) Any leak detected when following the leak survey procedure in paragraph (i)(3) of this section must be identified for repair as required in the applicable subpart.
- (3) If the alternative work practice is used to identify leaks, re-screening after an attempted repair of leaking equipment must be conducted using either the alternative work practice or the 40 CFR part 60, appendix A-7, Method 21 monitor at the leak definition required in the applicable subpart to which the equipment is subject.
- (4) The schedule for repair is as required in the applicable subpart.
- (5) When this alternative work practice is used for detecting leaking equipment, choose one of the monitoring frequencies listed in Table 1 to subpart A of this part in lieu of the monitoring frequency specified for regulated equipment in the applicable subpart. Reduced monitoring frequencies for good performance are not applicable when using the alternative work practice.
- (6) When this alternative work practice is used for detecting leaking equipment the following are not applicable for the equipment being monitored:
  - (i) Skip period leak detection and repair;
  - (ii) Quality improvement plans; or
  - (iii) Complying with standards for allowable percentage of valves and pumps to leak.
- (7) When the alternative work practice is used to detect leaking equipment, the regulated equipment in paragraph (h)(1)(i) of this section must also be monitored annually using a 40 CFR part 60, appendix A-7, Method 21 monitor at the leak definition required in the applicable subpart. The owner or operator may choose the specific monitoring period (for example, first quarter) to conduct the annual monitoring. Subsequent monitoring must be conducted every 12 months from the initial period. Owners or operators must keep records of the annual Method 21 screening results, as specified in paragraph (i)(4)(vii) of this section.

(i) An owner or operator of an affected source who chooses to use the alternative work practice must comply with the requirements of paragraphs (i)(1) through (i)(5) of this section.

(1) Instrument Specifications. The optical gas imaging instrument must comply with the requirements in (i)(1)(i) and (i)(1)(ii) of this section.

(i) Provide the operator with an image of the potential leak points for each piece of equipment at both the detection sensitivity level and within the distance used in the daily instrument check described in paragraph (i)(2) of this section. The detection sensitivity level depends upon the frequency at which leak monitoring is to be performed.

(ii) Provide a date and time stamp for video records of every monitoring event.

(2) Daily Instrument Check. On a daily basis, and prior to beginning any leak monitoring work, test the optical gas imaging instrument at the mass flow rate determined in paragraph (i)(2)(i) of this section in accordance with the procedure specified in paragraphs (i)(2)(ii) through (i)(2)(iv) of this section for each camera configuration used during monitoring (for example, different lenses used), unless an alternative method to demonstrate daily instrument checks has been approved in accordance with paragraph (i)(2)(v) of this section.

(i) Calculate the mass flow rate to be used in the daily instrument check by following the procedures in paragraphs (i)(2)(i)(A) and (i)(2)(i)(B) of this section.

(A) For a specified population of equipment to be imaged by the instrument, determine the piece of equipment in contact with the lowest mass fraction of chemicals that are detectable, within the distance to be used in paragraph (i)(2)(iv)(B) of this section, at or below the standard detection sensitivity level.

(B) Multiply the standard detection sensitivity level, corresponding to the selected monitoring frequency in Table 1 of subpart A of this part, by the mass fraction of detectable chemicals from the stream identified in paragraph (i)(2)(i)(A) of this section to determine the mass flow rate to be used in the daily instrument check, using the following equation.

$$E_{dic} = (E_{sds}) \sum_{i=1}^k \chi_i$$

Where:

$E_{dic}$  = Mass flow rate for the daily instrument check, grams per hour

$\chi_i$  = Mass fraction of detectable chemical(s)  $i$  seen by the optical gas imaging instrument, within the distance to be used in paragraph (i)(2)(iv)(B) of this section, at or below the standard detection sensitivity level,  $E_{sds}$ .

$E_{sds}$  = Standard detection sensitivity level from Table 1 to subpart A, grams per hour

$k$  = Total number of detectable chemicals emitted from the leaking equipment and seen by the optical gas imaging instrument.

(ii) Start the optical gas imaging instrument according to the manufacturer's instructions, ensuring that all appropriate settings conform to the manufacturer's instructions.

(iii) Use any gas chosen by the user that can be viewed by the optical gas imaging instrument and that has a purity of no less than 98 percent.

(iv) Establish a mass flow rate by using the following procedures:

(A) Provide a source of gas where it will be in the field of view of the optical gas imaging instrument.

(B) Set up the optical gas imaging instrument at a recorded distance from the outlet or leak orifice of the flow meter that will not be exceeded in the actual performance of the leak survey. Do not exceed the operating parameters of the flow meter.

(C) Open the valve on the flow meter to set a flow rate that will create a mass emission rate equal to the mass rate specified in paragraph (i)(2)(i) of this section while observing the gas flow through the optical gas imaging instrument viewfinder. When an image of the gas emission is seen through the viewfinder at the required emission rate, make a record of the reading on the flow meter.

(v) Repeat the procedures specified in paragraphs (i)(2)(ii) through (i)(2)(iv) of this section for each configuration of the optical gas imaging instrument used during the leak survey.

(vi) To use an alternative method to demonstrate daily instrument checks, apply to the Administrator for approval of the alternative under §60.13(i).

(3) Leak Survey Procedure. Operate the optical gas imaging instrument to image every regulated piece of equipment selected for this work practice in accordance with the instrument manufacturer's operating parameters. All emissions imaged by the optical gas imaging instrument are considered to be leaks and are subject to repair. All emissions visible to the naked eye are also considered to be leaks and are subject to repair.

(4) Recordkeeping. You must keep the records described in paragraphs (i)(4)(i) through (i)(4)(vii) of this section:

(i) The equipment, processes, and facilities for which the owner or operator chooses to use the alternative work practice.

(ii) The detection sensitivity level selected from Table 1 to subpart A of this part for the optical gas imaging instrument.

(iii) The analysis to determine the piece of equipment in contact with the lowest mass fraction of chemicals that are detectable, as specified in paragraph (i)(2)(i)(A) of this section.

(iv) The technical basis for the mass fraction of detectable chemicals used in the equation in paragraph (i)(2)(i)(B) of this section.

(v) The daily instrument check. Record the distance, per paragraph (i)(2)(iv)(B) of this section, and the flow meter reading, per paragraph (i)(2)(iv)(C) of this section, at which the leak was imaged. Keep a video record of the daily instrument check for each configuration of the optical gas imaging instrument used during the leak survey (for example, the daily instrument check must be conducted for each lens used). The video record must include a time and date stamp for each daily instrument check. The video record must be kept for 5 years.

(vi) Recordkeeping requirements in the applicable subpart. A video record must be used to document the leak survey results. The video record must include a time and date stamp for each monitoring event. A video record can be used to meet the recordkeeping requirements of the applicable subparts if each piece of regulated equipment selected for this work practice can be identified in the video record. The video record must be kept for 5 years.

(vii) The results of the annual Method 21 screening required in paragraph (h)(7) of this section. Records must be kept for all regulated equipment specified in paragraph (h)(1) of this section. Records must identify the equipment screened, the screening value measured by Method 21, the time and date of the screening, and calibration information required in the existing applicable subpart.

(5) Reporting. Submit the reports required in the applicable subpart. Submit the records of the annual Method 21 screening required in paragraph (h)(7) of this section to the Administrator via e-mail to *CCG-AWP@EPA.GOV*.

**§60.19 General notification and reporting requirements.**

- (a) For the purposes of this part, time periods specified in days shall be measured in calendar days, even if the word "calendar" is absent, unless otherwise specified in an applicable requirement.
- (b) For the purposes of this part, if an explicit postmark deadline is not specified in an applicable requirement for the submittal of a notification, application, report, or other written communication to the Administrator, the owner or operator shall postmark the submittal on or before the number of days specified in the applicable requirement. For example, if a notification must be submitted 15 days before a particular event is scheduled to take place, the notification shall be postmarked on or before 15 days preceding the event; likewise, if a notification must be submitted 15 days after a particular event takes place, the notification shall be delivered or postmarked on or before 15 days following the end of the event. The use of reliable non-Government mail carriers that provide indications of verifiable delivery of information required to be submitted to the Administrator, similar to the postmark provided by the U.S. Postal Service, or alternative means of delivery, including the use of electronic media, agreed to by the permitting authority, is acceptable.
- (c) Notwithstanding time periods or postmark deadlines specified in this part for the submittal of information to the Administrator by an owner or operator, or the review of such information by the Administrator, such time periods or deadlines may be changed by mutual agreement between the owner or operator and the Administrator. Procedures governing the implementation of this provision are specified in paragraph (f) of this section.
- (d) If an owner or operator of an affected facility in a State with delegated authority is required to submit periodic reports under this part to the State, and if the State has an established timeline for the submission of periodic reports that is consistent with the reporting frequency(ies) specified for such facility under this part, the owner or operator may change the dates by which periodic reports under this part shall be submitted (without changing the frequency of reporting) to be consistent with the State's schedule by mutual agreement between the owner or operator and the State. The allowance in the previous sentence applies in each State beginning 1 year after the affected facility is required to be in compliance with the applicable subpart in this part. Procedures governing the implementation of this provision are specified in paragraph (f) of this section.
- (e) If an owner or operator supervises one or more stationary sources affected by standards set under this part and standards set under part 61, part 63, or both such parts of this chapter, he/she may arrange by mutual agreement between the owner or operator and the Administrator (or the State with an approved permit program) a common schedule on which periodic reports required by each applicable standard shall be submitted throughout the year. The allowance in the previous sentence applies in each State beginning 1 year after the stationary source is required to be in compliance with the applicable subpart in this part, or 1 year after the stationary source is required to be in compliance with the applicable 40 CFR part 61 or part 63 of this chapter standard, whichever is latest. Procedures governing the implementation of this provision are specified in paragraph (f) of this section.
- (f)(1)(i) Until an adjustment of a time period or postmark deadline has been approved by the Administrator under paragraphs (f)(2) and (f)(3) of this section, the owner or operator of an affected facility remains strictly subject to the requirements of this part.
- (ii) An owner or operator shall request the adjustment provided for in paragraphs (f)(2) and (f)(3) of this section each time he or she wishes to change an applicable time period or postmark deadline specified in this part.

(2) Notwithstanding time periods or postmark deadlines specified in this part for the submittal of information to the Administrator by an owner or operator, or the review of such information by the Administrator, such time periods or deadlines may be changed by mutual agreement between the owner or operator and the

Administrator. An owner or operator who wishes to request a change in a time period or postmark deadline for a particular requirement shall request the adjustment in writing as soon as practicable before the subject activity is required to take place. The owner or operator shall include in the request whatever information he or she considers useful to convince the Administrator that an adjustment is warranted.

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

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

**Table 1 to Subpart A of Part 60—Detection Sensitivity Levels (grams per hour)**

<b>Monitoring frequency per subpart<sup>a</sup></b>	<b>Detection sensitivity level</b>
Bi-Monthly	60
Semi-Quarterly	85
Monthly	100

<sup>a</sup>When this alternative work practice is used to identify leaking equipment, the owner or operator must choose one of the monitoring frequencies listed in this table in lieu of the monitoring frequency specified in the applicable subpart. Bi-monthly means every other month. Semi-quarterly means twice per quarter. Monthly means once per month.

## Appendix C. 40 CFR Part 60, Subpart KKKK—Standards of Performance for Stationary Combustion Turbines

### §60.4300 What is the purpose of this subpart?

This subpart establishes emission standards and compliance schedules for the control of emissions from stationary combustion turbines that commenced construction, modification or reconstruction after February 18, 2005.

#### Applicability

### §60.4305 Does this subpart apply to my stationary combustion turbine?

(a) If you are the owner or operator of a stationary combustion turbine with a heat input at peak load equal to or greater than 10.7 gigajoules (10 MMBtu) per hour, based on the higher heating value of the fuel, which commenced construction, modification, or reconstruction after February 18, 2005, your turbine is subject to this subpart. Only heat input to the combustion turbine should be included when determining whether or not this subpart is applicable to your turbine. Any additional heat input to associated heat recovery steam generators (HRSG) or duct burners should not be included when determining your peak heat input. However, this subpart does apply to emissions from any associated HRSG and duct burners.

(b) Stationary combustion turbines regulated under this subpart are exempt from the requirements of subpart GG of this part. Heat recovery steam generators and duct burners regulated under this subpart are exempted from the requirements of subparts Da, Db, and Dc of this part.

### §60.4310 What types of operations are exempt from these standards of performance?

(a) Emergency combustion turbines, as defined in §60.4420(i), are exempt from the nitrogen oxides (NO<sub>x</sub>) emission limits in §60.4320.

(b) Stationary combustion turbines engaged by manufacturers in research and development of equipment for both combustion turbine emission control techniques and combustion turbine efficiency improvements are exempt from the NO<sub>x</sub> emission limits in §60.4320 on a case-by-case basis as determined by the Administrator.

(c) Stationary combustion turbines at integrated gasification combined cycle electric utility steam generating units that are subject to subpart Da of this part are exempt from this subpart.

(d) Combustion turbine test cells/stands are exempt from this subpart.

#### Emission Limits

### §60.4315 What pollutants are regulated by this subpart?

The pollutants regulated by this subpart are nitrogen oxide (NO<sub>x</sub>) and sulfur dioxide (SO<sub>2</sub>).

### §60.4320 What emission limits must I meet for nitrogen oxides (NO<sub>x</sub>)?

(a) You must meet the emission limits for NO<sub>x</sub> specified in Table 1 to this subpart.

(b) If you have two or more turbines that are connected to a single generator, each turbine must meet the emission limits for NO<sub>x</sub>.

### §60.4325 What emission limits must I meet for NO<sub>x</sub> if my turbine burns both natural gas and distillate oil (or some other combination of fuels)?

You must meet the emission limits specified in Table 1 to this subpart. If your total heat input is greater than or equal to 50 percent natural gas, you must meet the corresponding limit for a natural gas-fired turbine when you are burning that fuel. Similarly, when your total heat input is greater than 50 percent distillate oil and fuels other than natural gas, you must meet the corresponding limit for distillate oil and fu

**§60.4330 What emission limits must I meet for sulfur dioxide (SO<sub>2</sub>)?**

(a) If your turbine is located in a continental area, you must comply with either paragraph (a)(1), (a)(2), or (a)(3) of this section. If your turbine is located in Alaska, you do not have to comply with the requirements in paragraph (a) of this section until January 1, 2008.

(1) You must not cause to be discharged into the atmosphere from the subject stationary combustion turbine any gases which contain SO<sub>2</sub> in excess of 110 nanograms per Joule (ng/J) (0.90 pounds per megawatt-hour (lb/MWh)) gross output;

(2) You must not burn in the subject stationary combustion turbine any fuel which contains total potential sulfur emissions in excess of 26 ng SO<sub>2</sub>/J (0.060 lb SO<sub>2</sub>/MMBtu) heat input. If your turbine simultaneously fires multiple fuels, each fuel must meet this requirement; or

(3) For each stationary combustion turbine burning at least 50 percent biogas on a calendar month basis, as determined based on total heat input, you must not cause to be discharged into the atmosphere from the affected source any gases that contain SO<sub>2</sub> in excess of 65 ng SO<sub>2</sub>/J (0.15 lb SO<sub>2</sub>/MMBtu) heat input.

(b) If your turbine is located in a noncontinental area or a continental area that the Administrator determines does not have access to natural gas and that the removal of sulfur compounds would cause more environmental harm than benefit, you must comply with one or the other of the following conditions:

(1) You must not cause to be discharged into the atmosphere from the subject stationary combustion turbine any gases which contain SO<sub>2</sub> in excess of 780 ng/J (6.2 lb/MWh) gross output, or

(2) You must not burn in the subject stationary combustion turbine any fuel which contains total sulfur with potential sulfur emissions in excess of 180 ng SO<sub>2</sub>/J (0.42 lb SO<sub>2</sub>/MMBtu) heat input. If your turbine simultaneously fires multiple fuels, each fuel must meet this requirement.

**General Compliance Requirements**

**§60.4333 What are my general requirements for complying with this subpart?**

(a) You must operate and maintain your stationary combustion turbine, 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.

(b) When an affected unit with heat recovery utilizes a common steam header with one or more combustion turbines, the owner or operator shall either:

(1) Determine compliance with the applicable NO<sub>x</sub> emissions limits by measuring the emissions combined with the emissions from the other unit(s) utilizing the common heat recovery unit; or

(2) Develop, demonstrate, and provide information satisfactory to the Administrator on methods for apportioning the combined gross energy output from the heat recovery unit for each of the affected combustion turbines. The Administrator may approve such demonstrated substitute methods for apportioning the combined gross energy output measured at the steam turbine whenever the demonstration ensures accurate estimation of emissions related under this part.

**Monitoring**

**§60.4335 How do I demonstrate compliance for NO<sub>x</sub> if I use water or steam injection?**

(a) If you are using water or steam injection to control NO<sub>x</sub> emissions, you must install, calibrate, maintain and operate a continuous monitoring system to monitor and record the fuel consumption and the ratio of water or steam to fuel being fired in the turbine when burning a fuel that requires water or steam injection for compliance.

(b) Alternatively, you may use continuous emission monitoring, as follows:

- (1) Install, certify, maintain, and operate a continuous emission monitoring system (CEMS) consisting of a NO<sub>x</sub> monitor and a diluent gas (oxygen (O<sub>2</sub>) or carbon dioxide (CO<sub>2</sub>)) monitor, to determine the hourly NO<sub>x</sub> emission rate in parts per million (ppm) or pounds per million British thermal units (lb/MMBtu); and
- (2) For units complying with the output-based standard, install, calibrate, maintain, and operate a fuel flow meter (or flow meters) to continuously measure the heat input to the affected unit; and
- (3) For units complying with the output-based standard, install, calibrate, maintain, and operate a watt meter (or meters) to continuously measure the gross electrical output of the unit in megawatt-hours; and
- (4) For combined heat and power units complying with the output-based standard, install, calibrate, maintain, and operate meters for useful recovered energy flow rate, temperature, and pressure, to continuously measure the total thermal energy output in British thermal units per hour (Btu/h).

**§60.4340 How do I demonstrate continuous compliance for NO<sub>x</sub> if I do not use water or steam injection?**

(a) If you are not using water or steam injection to control NO<sub>x</sub> emissions, you must perform annual performance tests in accordance with §60.4400 to demonstrate continuous compliance. If the NO<sub>x</sub> emission result from the performance test is less than or equal to 75 percent of the NO<sub>x</sub> emission limit for the turbine, you may reduce the frequency of subsequent performance tests to once every 2 years (no more than 26 calendar months following the previous performance test). If the results of any subsequent performance test exceed 75 percent of the NO<sub>x</sub> emission limit for the turbine, you must resume annual performance tests.

(b) As an alternative, you may install, calibrate, maintain and operate one of the following continuous monitoring systems:

- (1) Continuous emission monitoring as described in §§60.4335(b) and 60.4345, or
- (2) Continuous parameter monitoring as follows:
  - (i) For a diffusion flame turbine without add-on selective catalytic reduction (SCR) controls, you must define parameters indicative of the unit's NO<sub>x</sub> formation characteristics, and you must monitor these parameters continuously.
  - (ii) For any lean premix stationary combustion turbine, you must continuously monitor the appropriate parameters to determine whether the unit is operating in low-NO<sub>x</sub> mode.
  - (iii) For any turbine that uses SCR to reduce NO<sub>x</sub> emissions, you must continuously monitor appropriate parameters to verify the proper operation of the emission controls.
  - (iv) For affected units that are also regulated under part 75 of this chapter, with state approval you can monitor the NO<sub>x</sub> emission rate using the methodology in appendix E to part 75 of this chapter, or the low mass emissions methodology in §75.19, the requirements of this paragraph (b) may be met by performing the parametric monitoring described in section 2.3 of part 75 appendix E or in §75.19(c)(1)(iv)(H).

**§60.4345 What are the requirements for the continuous emission monitoring system equipment, if I choose to use this option?**

If the option to use a NO<sub>x</sub> CEMS is chosen:

(a) Each NO<sub>x</sub> diluent CEMS must be installed and certified according to Performance Specification 2 (PS 2) in appendix B to this part, except the 7-day calibration drift is based on unit operating days, not calendar days. With state approval, Procedure 1 in appendix F to this part is not required. Alternatively, a NO<sub>x</sub> diluent CEMS that is

installed and certified according to appendix A of part 75 of this chapter is acceptable for use under this subpart. The relative accuracy test audit (RATA) of the CEMS shall be performed on a lb/MMBtu basis.

(b) As specified in §60.13(e)(2), during each full unit operating hour, both the NO<sub>x</sub> monitor and the diluent monitor must complete a minimum of one cycle of operation (sampling, analyzing, and data recording) for each 15-minute quadrant of the hour, to validate the hour. For partial unit operating hours, at least one valid data point must be obtained with each monitor for each quadrant of the hour in which the unit operates. For unit operating hours in which required quality assurance and maintenance activities are performed on the CEMS, a minimum of two valid data points (one in each of two quadrants) are required for each monitor to validate the NO<sub>x</sub> emission rate for the hour.

(c) Each fuel flowmeter shall be installed, calibrated, maintained, and operated according to the manufacturer's instructions. Alternatively, with state approval, fuel flowmeters that meet the installation, certification, and quality assurance requirements of appendix D to part 75 of this chapter are acceptable for use under this subpart.

(d) Each watt meter, steam flow meter, and each pressure or temperature measurement device shall be installed, calibrated, maintained, and operated according to manufacturer's instructions.

(e) The owner or operator shall develop and keep on-site a quality assurance (QA) plan for all of the continuous monitoring equipment described in paragraphs (a), (c), and (d) of this section. For the CEMS and fuel flow meters, the owner or operator may, with state approval, satisfy the requirements of this paragraph by implementing the QA program and plan described in section 1 of appendix B to part 75 of this chapter.

#### **§60.4350 How do I use data from the continuous emission monitoring equipment to identify excess emissions?**

For purposes of identifying excess emissions:

(a) All CEMS data must be reduced to hourly averages as specified in §60.13(h).

(b) For each unit operating hour in which a valid hourly average, as described in §60.4345(b), is obtained for both NO<sub>x</sub> and diluent monitors, the data acquisition and handling system must calculate and record the hourly NO<sub>x</sub> emission rate in units of ppm or lb/MMBtu, using the appropriate equation from method 19 in appendix A of this part. For any hour in which the hourly average O<sub>2</sub> concentration exceeds 19.0 percent O<sub>2</sub> (or the hourly average CO<sub>2</sub> concentration is less than 1.0 percent CO<sub>2</sub>), a diluent cap value of 19.0 percent O<sub>2</sub> or 1.0 percent CO<sub>2</sub> (as applicable) may be used in the emission calculations.

(c) Correction of measured NO<sub>x</sub> concentrations to 15 percent O<sub>2</sub> is not allowed.

(d) If you have installed and certified a NO<sub>x</sub> diluent CEMS to meet the requirements of part 75 of this chapter, states can approve that only quality assured data from the CEMS shall be used to identify excess emissions under this subpart. Periods where the missing data substitution procedures in subpart D of part 75 are applied are to be reported as monitor downtime in the excess emissions and monitoring performance report required under §60.7(c).

(e) All required fuel flow rate, steam flow rate, temperature, pressure, and megawatt data must be reduced to hourly averages.

(f) Calculate the hourly average NO<sub>x</sub> emission rates, in units of the emission standards under §60.4320, using either ppm for units complying with the concentration limit or the following equation for units complying with the output based standard:

(1) For simple-cycle operation:

$$E = \frac{(\text{NO}_x)_b * (\text{HI})_b}{P} \quad (\text{Eq. 1})$$

Where:

E = hourly NO<sub>x</sub> emission rate, in lb/MWh,

(NO<sub>x</sub>)<sub>h</sub> = hourly NO<sub>x</sub> emission rate, in lb/MMBtu,

(HI)<sub>h</sub> = hourly heat input rate to the unit, in MMBtu/h, measured using the fuel flowmeter(s), *e.g.*, calculated using Equation D-15a in appendix D to part 75 of this chapter, and

P = gross energy output of the combustion turbine in MW.

(2) For combined-cycle and combined heat and power complying with the output-based standard, use Equation 1 of this subpart, except that the gross energy output is calculated as the sum of the total electrical and mechanical energy generated by the combustion turbine, the additional electrical or mechanical energy (if any) generated by the steam turbine following the heat recovery steam generator, and 100 percent of the total useful thermal energy output that is not used to generate additional electricity or mechanical output, expressed in equivalent MW, as in the following equations:

$$P = (Pe)_t + (Pe)_c + Ps + Po \quad (\text{Eq. 2})$$

Where:

P = gross energy output of the stationary combustion turbine system in MW.

(Pe)<sub>t</sub> = electrical or mechanical energy output of the combustion turbine in MW,

(Pe)<sub>c</sub> = electrical or mechanical energy output (if any) of the steam turbine in MW, and

$$Ps = \frac{Q * H}{3.413 \times 10^6 \text{ Btu/MWh}} \quad (\text{Eq. 3})$$

Where:

Ps = useful thermal energy of the steam, measured relative to ISO conditions, not used to generate additional electric or mechanical output, in MW,

Q = measured steam flow rate in lb/h,

H = enthalpy of the steam at measured temperature and pressure relative to ISO conditions, in Btu/lb, and 3.413 × 10<sup>6</sup> = conversion from Btu/h to MW.

Po = other useful heat recovery, measured relative to ISO conditions, not used for steam generation or performance enhancement of the combustion turbine.

(3) For mechanical drive applications complying with the output-based standard, use the following equation:

$$E = \frac{(NO_x)_m}{BL * AL} \quad (\text{Eq. 4})$$

Where:

E = NO<sub>x</sub> emission rate in lb/MWh,

(NO<sub>x</sub>)<sub>m</sub> = NO<sub>x</sub> emission rate in lb/h,

BL = manufacturer's base load rating of turbine, in MW, and

AL = actual load as a percentage of the base load.

(g) For simple cycle units without heat recovery, use the calculated hourly average emission rates from paragraph (f) of this section to assess excess emissions on a 4-hour rolling average basis, as described in §60.4380(b)(1).

(h) For combined cycle and combined heat and power units with heat recovery, use the calculated hourly average emission rates from paragraph (f) of this section to assess excess emissions on a 30 unit operating day rolling average basis, as described in §60.4380(b)(1).

**§60.4355 How do I establish and document a proper parameter monitoring plan?**

(a) The steam or water to fuel ratio or other parameters that are continuously monitored as described in §§60.4335 and 60.4340 must be monitored during the performance test required under §60.8, to establish acceptable values and ranges. You may supplement the performance test data with engineering analyses, design specifications, manufacturer's recommendations and other relevant information to define the acceptable parametric ranges more precisely. You must develop and keep on-site a parameter monitoring plan which explains the procedures used to document proper operation of the NO<sub>x</sub> emission controls. The plan must:

- (1) Include the indicators to be monitored and show there is a significant relationship to emissions and proper operation of the NO<sub>x</sub> emission controls,
- (2) Pick ranges (or designated conditions) of the indicators, or describe the process by which such range (or designated condition) will be established,
- (3) Explain the process you will use to make certain that you obtain data that are representative of the emissions or parameters being monitored (such as detector location, installation specification if applicable),
- (4) Describe quality assurance and control practices that are adequate to ensure the continuing validity of the data,
- (5) Describe the frequency of monitoring and the data collection procedures which you will use (e.g., you are using a computerized data acquisition over a number of discrete data points with the average (or maximum value) being used for purposes of determining whether an exceedance has occurred), and
- (6) Submit justification for the proposed elements of the monitoring. If a proposed performance specification differs from manufacturer recommendation, you must explain the reasons for the differences. You must submit the data supporting the justification, but you may refer to generally available sources of information used to support the justification. You may rely on engineering assessments and other data, provided you demonstrate factors which assure compliance or explain why performance testing is unnecessary to establish indicator ranges. When establishing indicator ranges, you may choose to simplify the process by treating the parameters as if they were correlated. Using this assumption, testing can be divided into two cases:

(i) All indicators are significant only on one end of range (e.g., for a thermal incinerator controlling volatile organic compounds (VOC) it is only important to insure a minimum temperature, not a maximum). In this case, you may conduct your study so that each parameter is at the significant limit of its range while you conduct your emissions testing. If the emissions tests show that the source is in compliance at the significant limit of each parameter, then as long as each parameter is within its limit, you are presumed to be in compliance.

(ii) Some or all indicators are significant on both ends of the range. In this case, you may conduct your study so that each parameter that is significant at both ends of its range assumes its extreme values in all possible combinations of the extreme values (either single or double) of all of the other parameters. For example, if there were only two parameters, A and B, and A had a range of values while B had only a minimum value, the combinations would be A high with B minimum and A low with B minimum. If both A and B had a range, the combinations would be A high and B high, A low and B low, A high and B low, A low and B high. For the case of four parameters all having a range, there are 16 possible combinations.

(b) For affected units that are also subject to part 75 of this chapter and that have state approval to use the low mass emissions methodology in §75.19 or the NO<sub>x</sub> emission measurement methodology in appendix E to part 75,

you may meet the requirements of this paragraph by developing and keeping on-site (or at a central location for unmanned facilities) a QA plan, as described in §75.19(e)(5) or in section 2.3 of appendix E to part 75 of this chapter and section 1.3.6 of appendix B to part 75 of this chapter.

**§60.4360 How do I determine the total sulfur content of the turbine's combustion fuel?**

You must monitor the total sulfur content of the fuel being fired in the turbine, except as provided in §60.4365. The sulfur content of the fuel must be determined using total sulfur methods described in §60.4415. Alternatively, if the total sulfur content of the gaseous fuel during the most recent performance test was less than half the applicable limit, ASTM D4084, D4810, D5504, or D6228, or Gas Processors Association Standard 2377 (all of which are incorporated by reference, see §60.17), which measure the major sulfur compounds, may be used.

**§60.4365 How can I be exempted from monitoring the total sulfur content of the fuel?**

You may elect not to monitor the total sulfur content of the fuel combusted in the turbine, if the fuel is demonstrated not to exceed potential sulfur emissions of 26 ng SO<sub>2</sub>/J (0.060 lb SO<sub>2</sub>/MMBtu) heat input for units located in continental areas and 180 ng SO<sub>2</sub>/J (0.42 lb SO<sub>2</sub>/MMBtu) heat input for units located in noncontinental areas or a continental area that the Administrator determines does not have access to natural gas and that the removal of sulfur compounds would cause more environmental harm than benefit. You must use one of the following sources of information to make the required demonstration:

- (a) The fuel quality characteristics in a current, valid purchase contract, tariff sheet or transportation contract for the fuel, specifying that the maximum total sulfur content for oil use in continental areas is 0.05 weight percent (500 ppmw) or less and 0.4 weight percent (4,000 ppmw) or less for noncontinental areas, the total sulfur content for natural gas use in continental areas is 20 grains of sulfur or less per 100 standard cubic feet and 140 grains of sulfur or less per 100 standard cubic feet for noncontinental areas, has potential sulfur emissions of less than less than 26 ng SO<sub>2</sub>/J (0.060 lb SO<sub>2</sub>/MMBtu) heat input for continental areas and has potential sulfur emissions of less than less than 180 ng SO<sub>2</sub>/J (0.42 lb SO<sub>2</sub>/MMBtu) heat input for noncontinental areas; or
- (b) Representative fuel sampling data which show that the sulfur content of the fuel does not exceed 26 ng SO<sub>2</sub>/J (0.060 lb SO<sub>2</sub>/MMBtu) heat input for continental areas or 180 ng SO<sub>2</sub>/J (0.42 lb SO<sub>2</sub>/MMBtu) heat input for noncontinental areas. At a minimum, the amount of fuel sampling data specified in section 2.3.1.4 or 2.3.2.4 of appendix D to part 75 of this chapter is required.

**§60.4370 How often must I determine the sulfur content of the fuel?**

The frequency of determining the sulfur content of the fuel must be as follows:

- (a) *Fuel oil.* For fuel oil, use one of the total sulfur sampling options and the associated sampling frequency described in sections 2.2.3, 2.2.4.1, 2.2.4.2, and 2.2.4.3 of appendix D to part 75 of this chapter (*i.e.*, flow proportional sampling, daily sampling, sampling from the unit's storage tank after each addition of fuel to the tank, or sampling each delivery prior to combining it with fuel oil already in the intended storage tank).
- (b) *Gaseous fuel.* If you elect not to demonstrate sulfur content using options in §60.4365, and the fuel is supplied without intermediate bulk storage, the sulfur content value of the gaseous fuel must be determined and recorded once per unit operating day.
- (c) *Custom schedules.* Notwithstanding the requirements of paragraph (b) of this section, operators or fuel vendors may develop custom schedules for determination of the total sulfur content of gaseous fuels, based on the design and operation of the affected facility and the characteristics of the fuel supply. Except as provided in paragraphs (c)(1) and (c)(2) of this section, custom schedules shall be substantiated with data and shall be approved by the Administrator before they can be used to comply with the standard in §60.4330.

(1) The two custom sulfur monitoring schedules set forth in paragraphs (c)(1)(i) through (iv) and in paragraph (c)(2) of this section are acceptable, without prior Administrative approval:

(i) The owner or operator shall obtain daily total sulfur content measurements for 30 consecutive unit operating days, using the applicable methods specified in this subpart. Based on the results of the 30 daily samples, the required frequency for subsequent monitoring of the fuel's total sulfur content shall be as specified in paragraph (c)(1)(ii), (iii), or (iv) of this section, as applicable.

(ii) If none of the 30 daily measurements of the fuel's total sulfur content exceeds half the applicable standard, subsequent sulfur content monitoring may be performed at 12-month intervals. If any of the samples taken at 12-month intervals has a total sulfur content greater than half but less than the applicable limit, follow the procedures in paragraph (c)(1)(iii) of this section. If any measurement exceeds the applicable limit, follow the procedures in paragraph (c)(1)(iv) of this section.

(iii) If at least one of the 30 daily measurements of the fuel's total sulfur content is greater than half but less than the applicable limit, but none exceeds the applicable limit, then:

(A) Collect and analyze a sample every 30 days for 3 months. If any sulfur content measurement exceeds the applicable limit, follow the procedures in paragraph (c)(1)(iv) of this section. Otherwise, follow the procedures in paragraph (c)(1)(iii)(B) of this section.

(B) Begin monitoring at 6-month intervals for 12 months. If any sulfur content measurement exceeds the applicable limit, follow the procedures in paragraph (c)(1)(iv) of this section. Otherwise, follow the procedures in paragraph (c)(1)(iii)(C) of this section.

(C) Begin monitoring at 12-month intervals. If any sulfur content measurement exceeds the applicable limit, follow the procedures in paragraph (c)(1)(iv) of this section. Otherwise, continue to monitor at this frequency.

(iv) If a sulfur content measurement exceeds the applicable limit, immediately begin daily monitoring according to paragraph (c)(1)(i) of this section. Daily monitoring shall continue until 30 consecutive daily samples, each having a sulfur content no greater than the applicable limit, are obtained. At that point, the applicable procedures of paragraph (c)(1)(ii) or (iii) of this section shall be followed.

(2) The owner or operator may use the data collected from the 720-hour sulfur sampling demonstration described in section 2.3.6 of appendix D to part 75 of this chapter to determine a custom sulfur sampling schedule, as follows:

(i) If the maximum fuel sulfur content obtained from the 720 hourly samples does not exceed 20 grains/100 scf, no additional monitoring of the sulfur content of the gas is required, for the purposes of this subpart.

(ii) If the maximum fuel sulfur content obtained from any of the 720 hourly samples exceeds 20 grains/100 scf, but none of the sulfur content values (when converted to weight percent sulfur) exceeds half the applicable limit, then the minimum required sampling frequency shall be one sample at 12 month intervals.

(iii) If any sample result exceeds half the applicable limit, but none exceeds the applicable limit, follow the provisions of paragraph (c)(1)(iii) of this section.

(iv) If the sulfur content of any of the 720 hourly samples exceeds the applicable limit, follow the provisions of paragraph (c)(1)(iv) of this section.

## Reporting

### §60.4375 What reports must I submit?

(a) For each affected unit required to continuously monitor parameters or emissions, or to periodically determine the fuel sulfur content under this subpart, you must submit reports of excess emissions and monitor downtime, in accordance with §60.7(c). Excess emissions must be reported for all periods of unit operation, including start-up, shutdown, and malfunction.

(b) For each affected unit that performs annual performance tests in accordance with §60.4340(a), you must submit a written report of the results of each performance test before the close of business on the 60th day following the completion of the performance test.

#### **§60.4380 How are excess emissions and monitor downtime defined for NO<sub>x</sub>?**

For the purpose of reports required under §60.7(c), periods of excess emissions and monitor downtime that must be reported are defined as follows:

(a) For turbines using water or steam to fuel ratio monitoring:

(1) An excess emission is any unit operating hour for which the 4-hour rolling average steam or water to fuel ratio, as measured by the continuous monitoring system, falls below the acceptable steam or water to fuel ratio needed to demonstrate compliance with §60.4320, as established during the performance test required in §60.8. Any unit operating hour in which no water or steam is injected into the turbine when a fuel is being burned that requires water or steam injection for NO<sub>x</sub> control will also be considered an excess emission.

(2) A period of monitor downtime is any unit operating hour in which water or steam is injected into the turbine, but the essential parametric data needed to determine the steam or water to fuel ratio are unavailable or invalid.

(3) Each report must include the average steam or water to fuel ratio, average fuel consumption, and the combustion turbine load during each excess emission.

(b) For turbines using continuous emission monitoring, as described in §§60.4335(b) and 60.4345:

(1) An excess emissions is any unit operating period in which the 4-hour or 30-day rolling average NO<sub>x</sub> emission rate exceeds the applicable emission limit in §60.4320. For the purposes of this subpart, a "4-hour rolling average NO<sub>x</sub> emission rate" is the arithmetic average of the average NO<sub>x</sub> emission rate in ppm or ng/J (lb/MWh) measured by the continuous emission monitoring equipment for a given hour and the three unit operating hour average NO<sub>x</sub> emission rates immediately preceding that unit operating hour. Calculate the rolling average if a valid NO<sub>x</sub> emission rate is obtained for at least 3 of the 4 hours. For the purposes of this subpart, a "30-day rolling average NO<sub>x</sub> emission rate" is the arithmetic average of all hourly NO<sub>x</sub> emission data in ppm or ng/J (lb/MWh) measured by the continuous emission monitoring equipment for a given day and the twenty-nine unit operating days immediately preceding that unit operating day. A new 30-day average is calculated each unit operating day as the average of all hourly NO<sub>x</sub> emissions rates for the preceding 30 unit operating days if a valid NO<sub>x</sub> emission rate is obtained for at least 75 percent of all operating hours.

(2) A period of monitor downtime is any unit operating hour in which the data for any of the following parameters are either missing or invalid: NO<sub>x</sub> concentration, CO<sub>2</sub> or O<sub>2</sub> concentration, fuel flow rate, steam flow rate, steam temperature, steam pressure, or megawatts. The steam flow rate, steam temperature, and steam pressure are only required if you will use this information for compliance purposes.

(3) For operating periods during which multiple emissions standards apply, the applicable standard is the average of the applicable standards during each hour. For hours with multiple emissions standards, the applicable limit for that hour is determined based on the condition that corresponded to the highest emissions standard.

(c) For turbines required to monitor combustion parameters or parameters that document proper operation of the NO<sub>x</sub> emission controls:

(1) An excess emission is a 4-hour rolling unit operating hour average in which any monitored parameter does not achieve the target value or is outside the acceptable range defined in the parameter monitoring plan for the unit.

(2) A period of monitor downtime is a unit operating hour in which any of the required parametric data are either not recorded or are invalid.

#### **§60.4385 How are excess emissions and monitoring downtime defined for SO<sub>2</sub>?**

If you choose the option to monitor the sulfur content of the fuel, excess emissions and monitoring downtime are defined as follows:

(a) For samples of gaseous fuel and for oil samples obtained using daily sampling, flow proportional sampling, or sampling from the unit's storage tank, an excess emission occurs each unit operating hour included in the period beginning on the date and hour of any sample for which the sulfur content of the fuel being fired in the combustion turbine exceeds the applicable limit and ending on the date and hour that a subsequent sample is taken that demonstrates compliance with the sulfur limit.

(b) If the option to sample each delivery of fuel oil has been selected, you must immediately switch to one of the other oil sampling options (i.e., daily sampling, flow proportional sampling, or sampling from the unit's storage tank) if the sulfur content of a delivery exceeds 0.05 weight percent. You must continue to use one of the other sampling options until all of the oil from the delivery has been combusted, and you must evaluate excess emissions according to paragraph (a) of this section. When all of the fuel from the delivery has been burned, you may resume using the as-delivered sampling option.

(c) A period of monitor downtime begins when a required sample is not taken by its due date. A period of monitor downtime also begins on the date and hour of a required sample, if invalid results are obtained. The period of monitor downtime ends on the date and hour of the next valid sample.

#### **§60.4390 What are my reporting requirements if I operate an emergency combustion turbine or a research and development turbine?**

(a) If you operate an emergency combustion turbine, you are exempt from the NO<sub>x</sub> limit and must submit an initial report to the Administrator stating your case.

(b) Combustion turbines engaged by manufacturers in research and development of equipment for both combustion turbine emission control techniques and combustion turbine efficiency improvements may be exempted from the NO<sub>x</sub> limit on a case-by-case basis as determined by the Administrator. You must petition for the exemption.

#### **§60.4395 When must I submit my reports?**

All reports required under §60.7(c) must be postmarked by the 30th day following the end of each 6-month period.

### **Performance Tests**

#### **§60.4400 How do I conduct the initial and subsequent performance tests, regarding NO<sub>x</sub>?**

(a) You must conduct an initial performance test, as required in §60.8. Subsequent NO<sub>x</sub> performance tests shall be conducted on an annual basis (no more than 14 calendar months following the previous performance test).

(1) There are two general methodologies that you may use to conduct the performance tests. For each test run:

(i) Measure the NO<sub>x</sub> concentration (in parts per million (ppm)), using EPA Method 7E or EPA Method 20 in appendix A of this part. For units complying with the output based standard, concurrently measure the stack gas flow rate, using EPA Methods 1 and 2 in appendix A of this part, and measure and record the electrical and thermal output from the unit. Then, use the following equation to calculate the NO<sub>x</sub> emission rate:

$$E = \frac{1.194 \times 10^{-7} * (NO_x)_c * Q_{std}}{P} \quad (\text{Eq. 5})$$

Where:

E = NO<sub>x</sub> emission rate, in lb/MWh

1.194 × 10<sup>-7</sup> = conversion constant, in lb/dscf-ppm

(NO<sub>x</sub>)<sub>c</sub> = average NO<sub>x</sub> concentration for the run, in ppm

Q<sub>std</sub> = stack gas volumetric flow rate, in dscf/hr

P = gross electrical and mechanical energy output of the combustion turbine, in MW (for simple-cycle operation), for combined-cycle operation, the sum of all electrical and mechanical output from the combustion and steam turbines, or, for combined heat and power operation, the sum of all electrical and mechanical output from the combustion and steam turbines plus all useful recovered thermal output not used for additional electric or mechanical generation, in MW, calculated according to §60.4350(f)(2); or

(ii) Measure the NO<sub>x</sub> and diluent gas concentrations, using either EPA Methods 7E and 3A, or EPA Method 20 in appendix A of this part. Concurrently measure the heat input to the unit, using a fuel flowmeter (or flowmeters), and measure the electrical and thermal output of the unit. Use EPA Method 19 in appendix A of this part to calculate the NO<sub>x</sub> emission rate in lb/MMBtu. Then, use Equations 1 and, if necessary, 2 and 3 in §60.4350(f) to calculate the NO<sub>x</sub> emission rate in lb/MWh.

(2) Sampling traverse points for NO<sub>x</sub> and (if applicable) diluent gas are to be selected following EPA Method 20 or EPA Method 1 (non-particulate procedures), and sampled for equal time intervals. The sampling must be performed with a traversing single-hole probe, or, if feasible, with a stationary multi-hole probe that samples each of the points sequentially. Alternatively, a multi-hole probe designed and documented to sample equal volumes from each hole may be used to sample simultaneously at the required points.

(3) Notwithstanding paragraph (a)(2) of this section, you may test at fewer points than are specified in EPA Method 1 or EPA Method 20 in appendix A of this part if the following conditions are met:

(i) You may perform a stratification test for NO<sub>x</sub> and diluent pursuant to

(A) [Reserved], or

(B) The procedures specified in section 6.5.6.1(a) through (e) of appendix A of part 75 of this chapter.

(ii) Once the stratification sampling is completed, you may use the following alternative sample point selection criteria for the performance test:

(A) If each of the individual traverse point NO<sub>x</sub> concentrations is within ±10 percent of the mean concentration for all traverse points, or the individual traverse point diluent concentrations differs by no more than ±5ppm or ±0.5 percent CO<sub>2</sub> (or O<sub>2</sub>) from the mean for all traverse points, then you may use three points (located either 16.7, 50.0 and 83.3 percent of the way across the stack or duct, or, for circular stacks or ducts greater than 2.4 meters (7.8 feet) in diameter, at

0.4, 1.2, and 2.0 meters from the wall). The three points must be located along the measurement line that exhibited the highest average NO<sub>x</sub> concentration during the stratification test; or

(B) For turbines with a NO<sub>x</sub> standard greater than 15 ppm @ 15% O<sub>2</sub>, you may sample at a single point, located at least 1 meter from the stack wall or at the stack centroid if each of the individual traverse point NO<sub>x</sub> concentrations is within ±5 percent of the mean concentration for all traverse points, or the individual traverse point diluent concentrations differs by no more than ±3ppm or ±0.3 percent CO<sub>2</sub> (or O<sub>2</sub>) from the mean for all traverse points; or

(C) For turbines with a NO<sub>x</sub> standard less than or equal to 15 ppm @ 15% O<sub>2</sub>, you may sample at a single point, located at least 1 meter from the stack wall or at the stack centroid if each of the individual traverse point NO<sub>x</sub> concentrations is within ±2.5 percent of the mean concentration for all traverse points, or the individual traverse point diluent concentrations differs by no more than ±1ppm or ±0.15 percent CO<sub>2</sub> (or O<sub>2</sub>) from the mean for all traverse points.

(b) The performance test must be done at any load condition within plus or minus 25 percent of 100 percent of peak load. You may perform testing at the highest achievable load point, if at least 75 percent of peak load cannot be achieved in practice. You must conduct three separate test runs for each performance test. The minimum time per run is 20 minutes.

(1) If the stationary combustion turbine combusts both oil and gas as primary or backup fuels, separate performance testing is required for each fuel.

(2) For a combined cycle and CHP turbine systems with supplemental heat (duct burner), you must measure the total NO<sub>x</sub> emissions after the duct burner rather than directly after the turbine. The duct burner must be in operation during the performance test.

(3) If water or steam injection is used to control NO<sub>x</sub> with no additional post-combustion NO<sub>x</sub> control and you choose to monitor the steam or water to fuel ratio in accordance with §60.4335, then that monitoring system must be operated concurrently with each EPA Method 20 or EPA Method 7E run and must be used to determine the fuel consumption and the steam or water to fuel ratio necessary to comply with the applicable §60.4320 NO<sub>x</sub> emission limit.

(4) Compliance with the applicable emission limit in §60.4320 must be demonstrated at each tested load level. Compliance is achieved if the three-run arithmetic average NO<sub>x</sub> emission rate at each tested level meets the applicable emission limit in §60.4320.

(5) If you elect to install a CEMS, the performance evaluation of the CEMS may either be conducted separately or (as described in §60.4405) as part of the initial performance test of the affected unit.

(6) The ambient temperature must be greater than 0 °F during the performance test.

#### **§60.4405 How do I perform the initial performance test if I have chosen to install a NO<sub>x</sub>-diluent CEMS?**

If you elect to install and certify a NO<sub>x</sub>-diluent CEMS under §60.4345, then the initial performance test required under §60.8 may be performed in the following alternative manner:

(a) Perform a minimum of nine RATA reference method runs, with a minimum time per run of 21 minutes, at a single load level, within plus or minus 25 percent of 100 percent of peak load. The ambient temperature must be greater than 0 °F during the RATA runs.

(b) For each RATA run, concurrently measure the heat input to the unit using a fuel flow meter (or flow meters) and measure the electrical and thermal output from the unit.

(c) Use the test data both to demonstrate compliance with the applicable NO<sub>x</sub> emission limit under §60.4320 and to provide the required reference method data for the RATA of the CEMS described under §60.4335.

(d) Compliance with the applicable emission limit in §60.4320 is achieved if the arithmetic average of all of the NO<sub>x</sub> emission rates for the RATA runs, expressed in units of ppm or lb/MWh, does not exceed the emission limit.

**§60.4410 How do I establish a valid parameter range if I have chosen to continuously monitor parameters?**

If you have chosen to monitor combustion parameters or parameters indicative of proper operation of NO<sub>x</sub> emission controls in accordance with §60.4340, the appropriate parameters must be continuously monitored and recorded during each run of the initial performance test, to establish acceptable operating ranges, for purposes of the parameter monitoring plan for the affected unit, as specified in §60.4355.

**§60.4415 How do I conduct the initial and subsequent performance tests for sulfur?**

(a) You must conduct an initial performance test, as required in §60.8. Subsequent SO<sub>2</sub> performance tests shall be conducted on an annual basis (no more than 14 calendar months following the previous performance test). There are three methodologies that you may use to conduct the performance tests.

(1) If you choose to periodically determine the sulfur content of the fuel combusted in the turbine, a representative fuel sample would be collected following ASTM D5287 (incorporated by reference, see §60.17) for natural gas or ASTM D4177 (incorporated by reference, see §60.17) for oil. Alternatively, for oil, you may follow the procedures for manual pipeline sampling in section 14 of ASTM D4057 (incorporated by reference, see §60.17). The fuel analyses of this section may be performed either by you, a service contractor retained by you, the fuel vendor, or any other qualified agency. Analyze the samples for the total sulfur content of the fuel using:

(i) For liquid fuels, ASTM D129, or alternatively D1266, D1552, D2622, D4294, or D5453 (all of which are incorporated by reference, see §60.17); or

(ii) For gaseous fuels, ASTM D1072, or alternatively D3246, D4084, D4468, D4810, D6228, D6667, or Gas Processors Association Standard 2377 (all of which are incorporated by reference, see §60.17).

(2) Measure the SO<sub>2</sub> concentration (in parts per million (ppm)), using EPA Methods 6, 6C, 8, or 20 in appendix A of this part. In addition, the American Society of Mechanical Engineers (ASME) standard, ASME PTC 19-10-1981-Part 10, "Flue and Exhaust Gas Analyses," manual methods for sulfur dioxide (incorporated by reference, see §60.17) can be used instead of EPA Methods 6 or 20. For units complying with the output based standard, concurrently measure the stack gas flow rate, using EPA Methods 1 and 2 in appendix A of this part, and measure and record the electrical and thermal output from the unit. Then use the following equation to calculate the SO<sub>2</sub> emission rate:

$$E = \frac{1.664 \times 10^{-7} * (SO_2)_c * Q_{std}}{P} \quad (\text{Eq. 6})$$

Where:

E = SO<sub>2</sub> emission rate, in lb/MWh

1.664 × 10<sup>-7</sup> = conversion constant, in lb/dscf-ppm

(SO<sub>2</sub>)<sub>c</sub> = average SO<sub>2</sub> concentration for the run, in ppm

Q<sub>std</sub> = stack gas volumetric flow rate, in dscf/hr

P = gross electrical and mechanical energy output of the combustion turbine, in MW (for simple-cycle operation), for combined-cycle operation, the sum of all electrical and mechanical output from the combustion and steam turbines, or, for combined heat and power operation, the sum of all electrical

and mechanical output from the combustion and steam turbines plus all useful recovered thermal output not used for additional electric or mechanical generation, in MW, calculated according to §60.4350(f)(2); or

(3) Measure the SO<sub>2</sub> and diluent gas concentrations, using either EPA Methods 6, 6C, or 8 and 3A, or 20 in appendix A of this part. In addition, you may use the manual methods for sulfur dioxide ASME PTC 19-10-1981-Part 10 (incorporated by reference, see §60.17). Concurrently measure the heat input to the unit, using a fuel flowmeter (or flowmeters), and measure the electrical and thermal output of the unit. Use EPA Method 19 in appendix A of this part to calculate the SO<sub>2</sub> emission rate in lb/MMBtu. Then, use Equations 1 and, if necessary, 2 and 3 in §60.4350(f) to calculate the SO<sub>2</sub> emission rate in lb/MWh.

(b) [Reserved]

## Definitions

### §60.4420 What definitions apply to this subpart?

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

*Biogas* means gas produced by the anaerobic digestion or fermentation of organic matter including manure, sewage sludge, municipal solid waste, biodegradable waste, or any other biodegradable feedstock, under anaerobic conditions. Biogas is comprised primarily of methane and CO<sub>2</sub>.

*Combined cycle combustion turbine* means any stationary combustion turbine which recovers heat from the combustion turbine exhaust gases to generate steam that is only used to create additional power output in a steam turbine.

*Combined heat and power combustion turbine* means any stationary combustion turbine which recovers heat from the exhaust gases to heat water or another medium, generate steam for useful purposes other than additional electric generation, or directly uses the heat in the exhaust gases for a useful purpose.

*Combustion turbine model* means a group of combustion turbines having the same nominal air flow, combustor inlet pressure, combustor inlet temperature, firing temperature, turbine inlet temperature and turbine inlet pressure.

*Combustion turbine test cell/stand* means any apparatus used for testing uninstalled stationary or uninstalled mobile (motive) combustion turbines.

*Diffusion flame stationary combustion turbine* means any stationary combustion turbine where fuel and air are injected at the combustor and are mixed only by diffusion prior to ignition.

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

*Efficiency* means the combustion turbine manufacturer's rated heat rate at peak load in terms of heat input per unit of power output—based on the higher heating value of the fuel.

*Emergency combustion turbine* means any stationary combustion turbine which 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 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 combustion turbines.

*Excess emissions* means a specified averaging period over which either (1) the NO<sub>x</sub> emissions are higher than the applicable emission limit in §60.4320; (2) the total sulfur content of the fuel being combusted in the affected facility exceeds the limit specified in §60.4330; or (3) the recorded value of a particular monitored parameter is outside the acceptable range specified in the parameter monitoring plan for the affected unit.

*Gross useful output* means the gross useful work performed by the stationary combustion turbine system. For units using the mechanical energy directly or generating only electricity, the gross useful work performed is the gross electrical or mechanical output from the turbine/generator set. For combined heat and power units, the gross useful work performed is the gross electrical or mechanical output plus the useful thermal output (i.e., thermal energy delivered to a process).

*Heat recovery steam generating unit* means a unit where the hot exhaust gases from the combustion turbine are routed in order to extract heat from the gases and generate steam, for use in a steam turbine or other device that utilizes steam. Heat recovery steam generating units can be used with or without duct burners.

*Integrated gasification combined cycle electric utility steam generating unit* means a coal-fired electric utility steam generating unit that burns a synthetic gas derived from coal in a combined-cycle gas turbine. No solid coal is directly burned in the unit during operation.

*ISO conditions* means 288 Kelvin, 60 percent relative humidity and 101.3 kilopascals pressure.

*Lean premix stationary combustion turbine* means any stationary combustion turbine where the air and fuel are thoroughly mixed to form a lean mixture before delivery to the combustor. Mixing may occur before or in the combustion chamber. A lean premixed turbine may operate in diffusion flame mode during operating conditions such as startup and shutdown, extreme ambient temperature, or low or transient load.

*Natural gas* means a naturally occurring fluid mixture of hydrocarbons (e.g., methane, ethane, or propane) produced in geological formations beneath the Earth's surface that maintains a gaseous state at standard atmospheric temperature and pressure under ordinary conditions. Additionally, natural gas must either be composed of at least 70 percent methane by volume or have a gross calorific value between 950 and 1,100 British thermal units (Btu) per standard cubic foot. Natural gas does not include the following gaseous fuels: landfill gas, digester gas, refinery gas, sour gas, blast furnace gas, coal-derived gas, producer gas, coke oven gas, or any gaseous fuel produced in a process which might result in highly variable sulfur content or heating value.

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

*Peak load* means 100 percent of the manufacturer's design capacity of the combustion turbine at ISO conditions.

*Regenerative cycle combustion turbine* means any stationary combustion turbine which recovers heat from the combustion turbine exhaust gases to preheat the inlet combustion air to the combustion turbine.

*Simple cycle combustion turbine* means any stationary combustion turbine which does not recover heat from the combustion turbine exhaust gases to preheat the inlet combustion air to the combustion turbine, or which does not recover heat from the combustion turbine exhaust gases for purposes other than enhancing the performance of the combustion turbine itself.

*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), heat recovery system, and any ancillary components and sub-components comprising any simple cycle stationary combustion turbine, any regenerative/recuperative cycle stationary combustion turbine, any combined cycle combustion turbine, and any

combined heat and power combustion turbine based system. Stationary means that the combustion turbine is not self propelled or intended to be propelled while performing its function. It may, however, be mounted on a vehicle for portability.

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

*Unit operating hour* means a clock hour during which any fuel is combusted in the affected unit. If the unit combusts fuel for the entire clock hour, it is considered to be a full unit operating hour. If the unit combusts fuel for only part of the clock hour, it is considered to be a partial unit operating hour.

*Useful thermal output* means the thermal energy made available for use in any industrial or commercial process, or used in any heating or cooling application, i.e., total thermal energy made available for processes and applications other than electrical or mechanical generation. Thermal output for this subpart means the energy in recovered thermal output measured against the energy in the thermal output at 15 degrees Celsius and 101.325 kilopascals of pressure.

**Table 1 to Subpart KKKK of Part 60—Nitrogen Oxide Emission Limits for New Stationary Combustion Turbines**

Combustion turbine type	Combustion turbine heat input at peak load (HHV)	NO <sub>x</sub> emission standard
New turbine firing natural gas, electric generating	≤ 50 MMBtu/h	42 ppm at 15 percent O <sub>2</sub> or 290 ng/J of useful output (2.3 lb/MWh).
New turbine firing natural gas, mechanical drive	≤ 50 MMBtu/h	100 ppm at 15 percent O <sub>2</sub> or 690 ng/J of useful output (5.5 lb/MWh).
New turbine firing natural gas	> 50 MMBtu/h and ≤ 850 MMBtu/h	25 ppm at 15 percent O <sub>2</sub> or 150 ng/J of useful output (1.2 lb/MWh).
New, modified, or reconstructed turbine firing natural gas	> 850 MMBtu/h	15 ppm at 15 percent O <sub>2</sub> or 54 ng/J of useful output (0.43 lb/MWh)
New turbine firing fuels other than natural gas, electric generating	≤ 50 MMBtu/h	96 ppm at 15 percent O <sub>2</sub> or 700 ng/J of useful output (5.5 lb/MWh).
New turbine firing fuels other than natural gas, mechanical drive	≤ 50 MMBtu/h	150 ppm at 15 percent O <sub>2</sub> or 1,100 ng/J of useful output (8.7 lb/MWh).
New turbine firing fuels other than natural gas	> 50 MMBtu/h and ≤ 850 MMBtu/h	74 ppm at 15 percent O <sub>2</sub> or 460 ng/J of useful output (3.6 lb/MWh).

Combustion turbine type	Combustion turbine heat input at peak load (HHV)	NO <sub>x</sub> emission standard
New, modified, or reconstructed turbine firing fuels other than natural gas	> 850 MMBtu/h	42 ppm at 15 percent O <sub>2</sub> or 160 ng/J of useful output (1.3 lb/MWh).
Modified or reconstructed turbine	≤ 50 MMBtu/h	150 ppm at 15 percent O <sub>2</sub> or 1,100 ng/J of useful output (8.7 lb/MWh).
Modified or reconstructed turbine firing natural gas	> 50 MMBtu/h and ≤ 850 MMBtu/h	42 ppm at 15 percent O <sub>2</sub> or 250 ng/J of useful output (2.0 lb/MWh).
Modified or reconstructed turbine firing fuels other than natural gas	> 50 MMBtu/h and ≤ 850 MMBtu/h	96 ppm at 15 percent O <sub>2</sub> or 590 ng/J of useful output (4.7 lb/MWh).
Turbines located north of the Arctic Circle (latitude 66.5 degrees north), turbines operating at less than 75 percent of peak load, modified and reconstructed offshore turbines, and turbine operating at temperatures less than 0 °F	≤ 30 MW output	150 ppm at 15 percent O <sub>2</sub> or 1,100 ng/J of useful output (8.7 lb/MWh).
Turbines located north of the Arctic Circle (latitude 66.5 degrees north), turbines operating at less than 75 percent of peak load, modified and reconstructed offshore turbines, and turbine operating at temperatures less than 0 °F	> 30 MW output	96 ppm at 15 percent O <sub>2</sub> or 590 ng/J of useful output (4.7 lb/MWh).
Heat recovery units operating independent of the combustion turbine	All sizes	54 ppm at 15 percent O <sub>2</sub> or 110 ng/J of useful output (0.86 lb/MWh).

## Appendix D. 40 CFR Part 60, Subpart JJJ—Standards of Performance for Stationary Spark Ignition Internal Combustion Engines

### §60.4230 Am I subject to this subpart?

(a) The provisions of this subpart are applicable to manufacturers, owners, and operators of stationary spark ignition (SI) internal combustion engines (ICE) as specified in paragraphs (a)(1) through (6) of this section. For the purposes of this subpart, the date that construction commences is the date the engine is ordered by the owner or operator.

(1) Manufacturers of stationary SI ICE with a maximum engine power less than or equal to 19 kilowatt (KW) (25 horsepower (HP)) that are manufactured on or after July 1, 2008.

(2) Manufacturers of stationary SI ICE with a maximum engine power greater than 19 KW (25 HP) that are gasoline fueled or that are rich burn engines fueled by liquefied petroleum gas (LPG), where the date of manufacture is:

(i) On or after July 1, 2008; or

(ii) On or after January 1, 2009, for emergency engines.

(3) Manufacturers of stationary SI ICE

with a maximum engine power greater than 19 KW (25 HP) that are not gasoline fueled and are not rich burn engines fueled by LPG, where the manufacturer participates in the voluntary manufacturer certification program described in this subpart and where the date of manufacture is:

(i) On or after July 1, 2007, for engines with a maximum engine power greater than or equal to 500 HP (except lean burn engines with a maximum engine power greater than or equal to 500 HP and less than 1,350 HP);

(ii) On or after January 1, 2008, for lean burn engines with a maximum engine power greater than or equal to 500 HP and less than 1,350 HP;

(iii) On or after July 1, 2008, for engines with a maximum engine power less than 500 HP; or

(iv) On or after January 1, 2009, for emergency engines.

(4) Owners and operators of stationary SI ICE that commence construction after June 12, 2006, where the stationary SI ICE are manufactured:

(i) On or after July 1, 2007, for engines with a maximum engine power greater than or equal to 500 HP (except lean burn engines with a maximum engine power greater than or equal to 500 HP and less than 1,350 HP);

(ii) on or after January 1, 2008, for lean burn engines with a maximum engine power greater than or equal to 500 HP and less than 1,350 HP;

(iii) on or after July 1, 2008, for engines with a maximum engine power less than 500 HP; or

(iv) on or after January 1, 2009, for emergency engines with a maximum engine power greater than 19 KW (25 HP).

(5) Owners and operators of stationary SI ICE that are modified or reconstructed after June 12, 2006, and any person that modifies or reconstructs any stationary SI ICE after June 12, 2006.

(6) The provisions of §60.4236 of this subpart are applicable to all owners and operators of stationary SI ICE that commence construction after June 12, 2006.

(b) The provisions of this subpart are not applicable to stationary SI ICE being tested at an engine test cell/stand.

(c) If you are an owner or operator of an area source subject to this subpart, you are exempt from the obligation to obtain a permit under 40 CFR part 70 or 40 CFR part 71, provided you are not required to obtain a permit under 40 CFR

70.3(a) or 40 CFR 71.3(a) for a reason other than your status as an area source under this subpart. Notwithstanding the previous sentence, you must continue to comply with the provisions of this subpart as applicable.

(d) For the purposes of this subpart, stationary SI ICE using alcohol-based fuels are considered gasoline engines.

(e) Stationary SI ICE may be eligible for exemption from the requirements of this subpart as described in 40 CFR part 1068, subpart C (or the exemptions described in 40 CFR parts 90 and 1048, for engines that would need to be certified to standards in those parts), except that owners and operators, as well as manufacturers, may be eligible to request an exemption for national security.

(f) Owners and operators of facilities with internal combustion engines that are acting as temporary replacement units and that are located at a stationary source for less than 1 year and that have been properly certified as meeting the standards that would be applicable to such engine under the appropriate nonroad engine provisions, are not required to meet any other provisions under this subpart with regard to such engines.

**Emission Standards for Manufacturers**

**§60.4231 What emission standards must I meet if I am a manufacturer of stationary SI internal combustion engines or equipment containing such engines?**

(a) Stationary SI internal combustion engine manufacturers must certify their stationary SI ICE with a maximum engine power less than or equal to 19 KW (25 HP) manufactured on or after July 1, 2008 to the certification emission standards and other requirements for new nonroad SI engines in 40 CFR part 90 or 1054, as follows:

<b>If engine displacement is * * *</b>	<b>and manufacturing dates are * * *</b>	<b>the engine must meet emission standards and related requirements for nonhandheld engines under * * *</b>
(1) below 225 cc	July 1, 2008 to December 31, 2011	40 CFR part 90.
(2) below 225 cc	January 1, 2012 or later	40 CFR part 1054.
(3) at or above 225 cc	July 1, 2008 to December 31, 2010	40 CFR part 90.
(4) at or above 225 cc	January 1, 2011 or later	40 CFR part 1054.

(b) Stationary SI internal combustion engine manufacturers must certify their stationary SI ICE with a maximum engine power greater than 19 KW (25 HP) (except emergency stationary ICE with a maximum engine power greater than 25 HP and less than 130 HP) that use gasoline and that are manufactured on or after the applicable date in §60.4230(a)(2), or manufactured on or after the applicable date in §60.4230(a)(4) for emergency stationary ICE with a maximum engine power greater than or equal to 130 HP, to the certification emission standards and other requirements for new nonroad SI engines in 40 CFR part 1048. Stationary SI internal combustion engine manufacturers must certify their emergency stationary SI ICE with a maximum engine power greater than 25 HP and less than 130 HP that use gasoline and that are manufactured on or after the applicable date in §60.4230(a)(4) to the Phase 1 emission standards in 40 CFR 90.103, applicable to class II engines, and other requirements for new nonroad SI engines in 40 CFR part 90. Stationary SI internal combustion engine manufacturers may certify their stationary SI ICE with a maximum engine power less than or equal to 30 KW (40 HP) with a total displacement less than or equal to 1,000 cubic centimeters (cc) that use gasoline to the certification emission standards and other requirements for new nonroad SI engines in 40 CFR part 90 or 1054, as appropriate.

(c) Stationary SI internal combustion engine manufacturers must certify their stationary SI ICE with a maximum engine power greater than 19 KW (25 HP) (except emergency stationary ICE with a maximum engine power greater than 25 HP

and less than 130 HP) that are rich burn engines that use LPG and that are manufactured on or after the applicable date in §60.4230(a)(2), or manufactured on or after the applicable date in §60.4230(a)(4) for emergency stationary ICE with a maximum engine power greater than or equal to 130 HP, to the certification emission standards and other requirements for new nonroad SI engines in 40 CFR part 1048. Stationary SI internal combustion engine manufacturers must certify their emergency stationary SI ICE greater than 25 HP and less than 130 HP that are rich burn engines that use LPG and that are manufactured on or after the applicable date in §60.4230(a)(4) to the Phase 1 emission standards in 40 CFR 90.103, applicable to class II engines, and other requirements for new nonroad SI engines in 40 CFR part 90. Stationary SI internal combustion engine manufacturers may certify their stationary SI ICE with a maximum engine power less than or equal to 30 KW (40 HP) with a total displacement less than or equal to 1,000 cc that are rich burn engines that use LPG to the certification emission standards and other requirements for new nonroad SI engines in 40 CFR part 90 or 1054, as appropriate.

(d) Stationary SI internal combustion engine manufacturers who choose to certify their stationary SI ICE with a maximum engine power greater than 19 KW (25 HP) and less than 75 KW (100 HP) (except gasoline and rich burn engines that use LPG and emergency stationary ICE with a maximum engine power greater than 25 HP and less than 130 HP) under the voluntary manufacturer certification program described in this subpart must certify those engines to the certification emission standards for new nonroad SI engines in 40 CFR part 1048. Stationary SI internal combustion engine manufacturers who choose to certify their emergency stationary SI ICE greater than 25 HP and less than 130 HP (except gasoline and rich burn engines that use LPG), must certify those engines to the Phase 1 emission standards in 40 CFR 90.103, applicable to class II engines, for new nonroad SI engines in 40 CFR part 90. Stationary SI internal combustion engine manufacturers may certify their stationary SI ICE with a maximum engine power less than or equal to 30 KW (40 HP) with a total displacement less than or equal to 1,000 cc (except gasoline and rich burn engines that use LPG) to the certification emission standards for new nonroad SI engines in 40 CFR part 90 or 1054, as appropriate. For stationary SI ICE with a maximum engine power greater than 19 KW (25 HP) and less than 75 KW (100 HP) (except gasoline and rich burn engines that use LPG and emergency stationary ICE with a maximum engine power greater than 25 HP and less than 130 HP) manufactured prior to January 1, 2011, manufacturers may choose to certify these engines to the standards in Table 1 to this subpart applicable to engines with a maximum engine power greater than or equal to 100 HP and less than 500 HP.

(e) Stationary SI internal combustion engine manufacturers who choose to certify their stationary SI ICE with a maximum engine power greater than or equal to 75 KW (100 HP) (except gasoline and rich burn engines that use LPG) under the voluntary manufacturer certification program described in this subpart must certify those engines to the emission standards in Table 1 to this subpart. Stationary SI internal combustion engine manufacturers may certify their stationary SI ICE with a maximum engine power greater than or equal to 75 KW (100 HP) that are lean burn engines that use LPG to the certification emission standards for new nonroad SI engines in 40 CFR part 1048. For stationary SI ICE with a maximum engine power greater than or equal to 100 HP (75 KW) and less than 500 HP (373 KW) manufactured prior to January 1, 2011, and for stationary SI ICE with a maximum engine power greater than or equal to 500 HP (373 KW) manufactured prior to July 1, 2010, manufacturers may choose to certify these engines to the certification emission standards for new nonroad SI engines in 40 CFR part 1048 applicable to engines that are not severe duty engines.

(f) Manufacturers of equipment containing stationary SI internal combustion engines meeting the provisions of 40 CFR part 1054 must meet the provisions of 40 CFR part 1060, to the extent they apply to equipment manufacturers.

(g) Notwithstanding the requirements in paragraphs (a) through (c) of this section, stationary SI internal combustion engine manufacturers are not required to certify reconstructed engines; however manufacturers may elect to do so. The reconstructed engine must be certified to the emission standards specified in paragraphs (a) through (e) of this section that are applicable to the model year, maximum engine power and displacement of the reconstructed stationary SI ICE.

**§60.4232 How long must my engines meet the emission standards if I am a manufacturer of stationary SI internal combustion engines?**

Engines manufactured by stationary SI internal combustion engine manufacturers must meet the emission standards as required in §60.4231 during the certified emissions life of the engines.

#### Emission Standards for Owners and Operators

#### **§60.4233 What emission standards must I meet if I am an owner or operator of a stationary SI internal combustion engine?**

- (a) Owners and operators of stationary SI ICE with a maximum engine power less than or equal to 19 KW (25 HP) manufactured on or after July 1, 2008, must comply with the emission standards in §60.4231(a) for their stationary SI ICE.
- (b) Owners and operators of stationary SI ICE with a maximum engine power greater than 19 KW (25 HP) manufactured on or after the applicable date in §60.4230(a)(4) that use gasoline must comply with the emission standards in §60.4231(b) for their stationary SI ICE.
- (c) Owners and operators of stationary SI ICE with a maximum engine power greater than 19 KW (25 HP) manufactured on or after the applicable date in §60.4230(a)(4) that are rich burn engines that use LPG must comply with the emission standards in §60.4231(c) for their stationary SI ICE.
- (d) Owners and operators of stationary SI ICE with a maximum engine power greater than 19 KW (25 HP) and less than 75 KW (100 HP) (except gasoline and rich burn engines that use LPG) must comply with the emission standards for field testing in 40 CFR 1048.101(c) for their non-emergency stationary SI ICE and with the emission standards in Table 1 to this subpart for their emergency stationary SI ICE. Owners and operators of stationary SI ICE with a maximum engine power greater than 19 KW (25 HP) and less than 75 KW (100 HP) manufactured prior to January 1, 2011, that were certified to the standards in Table 1 to this subpart applicable to engines with a maximum engine power greater than or equal to 100 HP and less than 500 HP, may optionally choose to meet those standards.
- (e) Owners and operators of stationary SI ICE with a maximum engine power greater than or equal to 75 KW (100 HP) (except gasoline and rich burn engines that use LPG) must comply with the emission standards in Table 1 to this subpart for their stationary SI ICE. For owners and operators of stationary SI ICE with a maximum engine power greater than or equal to 100 HP (except gasoline and rich burn engines that use LPG) manufactured prior to January 1, 2011 that were certified to the certification emission standards in 40 CFR part 1048 applicable to engines that are not severe duty engines, if such stationary SI ICE was certified to a carbon monoxide (CO) standard above the standard in Table 1 to this subpart, then the owners and operators may meet the CO certification (not field testing) standard for which the engine was certified.
- (f) Owners and operators of any modified or reconstructed stationary SI ICE subject to this subpart must meet the requirements as specified in paragraphs (f)(1) through (5) of this section.
- (1) Owners and operators of stationary SI ICE with a maximum engine power less than or equal to 19 KW (25 HP), that are modified or reconstructed after June 12, 2006, must comply with emission standards in §60.4231(a) for their stationary SI ICE. Engines with a date of manufacture prior to July 1, 2008 must comply with the emission standards specified in §60.4231(a) applicable to engines manufactured on July 1, 2008.
- (2) Owners and operators of stationary SI ICE with a maximum engine power greater than 19 KW (25 HP) that are gasoline engines and are modified or reconstructed after June 12, 2006, must comply with the emission standards in §60.4231(b) for their stationary SI ICE. Engines with a date of manufacture prior to July 1, 2008 (or January 1, 2009 for emergency engines) must comply with the emission standards specified in §60.4231(b) applicable to engines manufactured on July 1, 2008 (or January 1, 2009 for emergency engines).
- (3) Owners and operators of stationary SI ICE with a maximum engine power greater than 19 KW (25 HP) that are rich burn engines that use LPG, that are modified or reconstructed after June 12, 2006, must comply with the same emission standards as those specified in §60.4231(c). Engines with a date of manufacture prior to July 1, 2008 (or January 1, 2009

for emergency engines) must comply with the emission standards specified in §60.4231(c) applicable to engines manufactured on July 1, 2008 (or January 1, 2009 for emergency engines).

(4) Owners and operators of stationary SI natural gas and lean burn LPG engines with a maximum engine power greater than 19 KW (25 HP), that are modified or reconstructed after June 12, 2006, must comply with the same emission standards as those specified in paragraph (d) or (e) of this section, except that such owners and operators of non-emergency engines and emergency engines greater than or equal to 130 HP must meet a nitrogen oxides (NO<sub>x</sub>) emission standard of 3.0 grams per HP-hour (g/HP-hr), a CO emission standard of 4.0 g/HP-hr (5.0 g/HP-hr for non-emergency engines less than 100 HP), and a volatile organic compounds (VOC) emission standard of 1.0 g/HP-hr, or a NO<sub>x</sub> emission standard of 250 ppmvd at 15 percent oxygen (O<sub>2</sub>), a CO emission standard 540 ppmvd at 15 percent O<sub>2</sub> (675 ppmvd at 15 percent O<sub>2</sub> for non-emergency engines less than 100 HP), and a VOC emission standard of 86 ppmvd at 15 percent O<sub>2</sub>, where the date of manufacture of the engine is:

- (i) Prior to July 1, 2007, for non-emergency engines with a maximum engine power greater than or equal to 500 HP (except lean burn natural gas engines and LPG engines with a maximum engine power greater than or equal to 500 HP and less than 1,350 HP);
- (ii) Prior to July 1, 2008, for non-emergency engines with a maximum engine power less than 500 HP;
- (iii) Prior to January 1, 2009, for emergency engines;
- (iv) Prior to January 1, 2008, for non-emergency lean burn natural gas engines and LPG engines with a maximum engine power greater than or equal to 500 HP and less than 1,350 HP.

(5) Owners and operators of stationary SI landfill/digester gas ICE engines with a maximum engine power greater than 19 KW (25 HP), that are modified or reconstructed after June 12, 2006, must comply with the same emission standards as those specified in paragraph (e) of this section for stationary landfill/digester gas engines. Engines with maximum engine power less than 500 HP and a date of manufacture prior to July 1, 2008 must comply with the emission standards specified in paragraph (e) of this section for stationary landfill/digester gas ICE with a maximum engine power less than 500 HP manufactured on July 1, 2008. Engines with a maximum engine power greater than or equal to 500 HP (except lean burn engines greater than or equal to 500 HP and less than 1,350 HP) and a date of manufacture prior to July 1, 2007 must comply with the emission standards specified in paragraph (e) of this section for stationary landfill/digester gas ICE with a maximum engine power greater than or equal to 500 HP (except lean burn engines greater than or equal to 500 HP and less than 1,350 HP) manufactured on July 1, 2007. Lean burn engines greater than or equal to 500 HP and less than 1,350 HP with a date of manufacture prior to January 1, 2008 must comply with the emission standards specified in paragraph (e) of this section for stationary landfill/digester gas ICE that are lean burn engines greater than or equal to 500 HP and less than 1,350 HP and manufactured on January 1, 2008.

(g) Owners and operators of stationary SI wellhead gas ICE engines may petition the Administrator for approval on a case-by-case basis to meet emission standards no less stringent than the emission standards that apply to stationary emergency SI engines greater than 25 HP and less than 130 HP due to the presence of high sulfur levels in the fuel, as specified in Table 1 to this subpart. The request must, at a minimum, demonstrate that the fuel has high sulfur levels that prevent the use of aftertreatment controls and also that the owner has reasonably made all attempts possible to obtain an engine that will meet the standards without the use of aftertreatment controls. The petition must request the most stringent standards reasonably applicable to the engine using the fuel.

(h) Owners and operators of stationary SI ICE that are required to meet standards that reference 40 CFR 1048.101 must, if testing their engines in use, meet the standards in that section applicable to field testing, except as indicated in paragraph (e) of this section.

**§60.4234 How long must I meet the emission standards if I am an owner or operator of a stationary SI internal combustion engine?**

Owners and operators of stationary SI ICE must operate and maintain stationary SI ICE that achieve the emission standards as required in §60.4233 over the entire life of the engine.

### **Other Requirements for Owners and Operators**

#### **§60.4235 What fuel requirements must I meet if I am an owner or operator of a stationary SI gasoline fired internal combustion engine subject to this subpart?**

Owners and operators of stationary SI ICE subject to this subpart that use gasoline must use gasoline that meets the per gallon sulfur limit in 40 CFR 80.195.

#### **§60.4236 What is the deadline for importing or installing stationary SI ICE produced in previous model years?**

- (a) After July 1, 2010, owners and operators may not install stationary SI ICE with a maximum engine power of less than 500 HP that do not meet the applicable requirements in §60.4233.
- (b) After July 1, 2009, owners and operators may not install stationary SI ICE with a maximum engine power of greater than or equal to 500 HP that do not meet the applicable requirements in §60.4233, except that lean burn engines with a maximum engine power greater than or equal to 500 HP and less than 1,350 HP that do not meet the applicable requirements in §60.4233 may not be installed after January 1, 2010.
- (c) For emergency stationary SI ICE with a maximum engine power of greater than 19 KW (25 HP), owners and operators may not install engines that do not meet the applicable requirements in §60.4233 after January 1, 2011.
- (d) In addition to the requirements specified in §§60.4231 and 60.4233, it is prohibited to import stationary SI ICE less than or equal to 19 KW (25 HP), stationary rich burn LPG SI ICE, and stationary gasoline SI ICE that do not meet the applicable requirements specified in paragraphs (a), (b), and (c) of this section, after the date specified in paragraph (a), (b), and (c) of this section.
- (e) The requirements of this section do not apply to owners and operators of stationary SI ICE that have been modified or reconstructed, and they do not apply to engines that were removed from one existing location and reinstalled at a new location.

#### **§60.4237 What are the monitoring requirements if I am an owner or operator of an emergency stationary SI internal combustion engine?**

- (a) Starting on July 1, 2010, if the emergency stationary SI internal combustion engine that is greater than or equal to 500 HP that was built on or after July 1, 2010, does not meet the standards applicable to non-emergency engines, the owner or operator must install a non-resettable hour meter.
- (b) Starting on January 1, 2011, if the emergency stationary SI internal combustion engine that is greater than or equal to 130 HP and less than 500 HP that was built on or after January 1, 2011, does not meet the standards applicable to non-emergency engines, the owner or operator must install a non-resettable hour meter.
- (c) If you are an owner or operator of an emergency stationary SI internal combustion engine that is less than 130 HP, was built on or after July 1, 2008, and does not meet the standards applicable to non-emergency engines, you must install a non-resettable hour meter upon startup of your emergency engine.

### **Compliance Requirements for Manufacturers**

#### **§60.4238 What are my compliance requirements if I am a manufacturer of stationary SI internal combustion engines ≤19 KW (25 HP) or a manufacturer of equipment containing such engines?**

Stationary SI internal combustion engine manufacturers who are subject to the emission standards specified in §60.4231(a) must certify their stationary SI ICE using the certification procedures required in 40 CFR part 90, subpart B, or 40 CFR part 1054, subpart C, as applicable, and must test their engines as specified in those parts. Manufacturers of

equipment containing stationary SI internal combustion engines meeting the provisions of 40 CFR part 1054 must meet the provisions of 40 CFR part 1060, subpart C, to the extent they apply to equipment manufacturers.

**§60.4239 What are my compliance requirements if I am a manufacturer of stationary SI internal combustion engines >19 KW (25 HP) that use gasoline or a manufacturer of equipment containing such engines?**

Stationary SI internal combustion engine manufacturers who are subject to the emission standards specified in §60.4231(b) must certify their stationary SI ICE using the certification procedures required in 40 CFR part 1048, subpart C, and must test their engines as specified in that part. Stationary SI internal combustion engine manufacturers who certify their stationary SI ICE with a maximum engine power less than or equal to 30 KW (40 HP) with a total displacement less than or equal to 1,000 cc to the certification emission standards and other requirements for new nonroad SI engines in 40 CFR part 90 or 40 CFR part 1054, and manufacturers of stationary SI emergency engines that are greater than 25 HP and less than 130 HP who meet the Phase 1 emission standards in 40 CFR 90.103, applicable to class II engines, must certify their stationary SI ICE using the certification procedures required in 40 CFR part 90, subpart B, or 40 CFR part 1054, subpart C, as applicable, and must test their engines as specified in those parts. Manufacturers of equipment containing stationary SI internal combustion engines meeting the provisions of 40 CFR part 1054 must meet the provisions of 40 CFR part 1060, subpart C, to the extent they apply to equipment manufacturers.

**§60.4240 What are my compliance requirements if I am a manufacturer of stationary SI internal combustion engines >19 KW (25 HP) that are rich burn engines that use LPG or a manufacturer of equipment containing such engines?**

Stationary SI internal combustion engine manufacturers who are subject to the emission standards specified in §60.4231(c) must certify their stationary SI ICE using the certification procedures required in 40 CFR part 1048, subpart C, and must test their engines as specified in that part. Stationary SI internal combustion engine manufacturers who certify their stationary SI ICE with a maximum engine power less than or equal to 30 KW (40 HP) with a total displacement less than or equal to 1,000 cc to the certification emission standards and other requirements for new nonroad SI engines in 40 CFR part 90 or 40 CFR part 1054, and manufacturers of stationary SI emergency engines that are greater than 25 HP and less than 130 HP who meet the Phase 1 emission standards in 40 CFR 90.103, applicable to class II engines, must certify their stationary SI ICE using the certification procedures required in 40 CFR part 90, subpart B, or 40 CFR part 1054, subpart C, as applicable, and must test their engines as specified in those parts. Manufacturers of equipment containing stationary SI internal combustion engines meeting the provisions of 40 CFR part 1054 must meet the provisions of 40 CFR part 1060, subpart C, to the extent they apply to equipment manufacturers.

**§60.4241 What are my compliance requirements if I am a manufacturer of stationary SI internal combustion engines participating in the voluntary certification program or a manufacturer of equipment containing such engines?**

(a) Manufacturers of stationary SI internal combustion engines with a maximum engine power greater than 19 KW (25 HP) that do not use gasoline and are not rich burn engines that use LPG can choose to certify their engines to the emission standards in §60.4231(d) or (e), as applicable, under the voluntary certification program described in this subpart. Manufacturers who certify their engines under the voluntary certification program must meet the requirements as specified in paragraphs (b) through (g) of this section. In addition, manufacturers of stationary SI internal combustion engines who choose to certify their engines under the voluntary certification program, must also meet the requirements as specified in §60.4247.

(b) Manufacturers of engines other than those certified to standards in 40 CFR part 90 or 40 CFR part 1054 must certify their stationary SI ICE using the certification procedures required in 40 CFR part 1048, subpart C, and must follow the same test procedures that apply to large SI nonroad engines under 40 CFR part 1048, but must use the D-1 cycle of International Organization of Standardization 8178-4: 1996(E) (incorporated by reference, see 40 CFR 60.17) or the test cycle requirements specified in Table 3 to 40 CFR 1048.505, except that Table 3 of 40 CFR 1048.505 applies to high load engines only. Stationary SI internal combustion engine manufacturers who certify their stationary SI ICE with a maximum engine power less than or equal to 30 KW (40 HP) with a total displacement less than or equal to 1,000 cc to the certification emission standards and other requirements for new nonroad SI engines in 40 CFR part 90 or 40 CFR part

1054, and manufacturers of emergency engines that are greater than 25 HP and less than 130 HP who meet the Phase 1 standards in 40 CFR 90.103, applicable to class II engines, must certify their stationary SI ICE using the certification procedures required in 40 CFR part 90, subpart B, or 40 CFR part 1054, subpart C, as applicable, and must test their engines as specified in those parts. Manufacturers of equipment containing stationary SI internal combustion engines meeting the provisions of 40 CFR part 1054 must meet the provisions of 40 CFR part 1060, subpart C, to the extent they apply to equipment manufacturers.

(c) Certification of stationary SI ICE to the emission standards specified in §60.4231(d) or (e), as applicable, is voluntary, but manufacturers who decide to certify are subject to all of the requirements indicated in this subpart with regard to the engines included in their certification. Manufacturers must clearly label their stationary SI engines as certified or non-certified engines.

(d) Manufacturers of natural gas fired stationary SI ICE who conduct voluntary certification of stationary SI ICE to the emission standards specified in §60.4231(d) or (e), as applicable, must certify their engines for operation using fuel that meets the definition of pipeline-quality natural gas. The fuel used for certifying stationary SI natural gas engines must meet the definition of pipeline-quality natural gas as described in §60.4248. In addition, the manufacturer must provide information to the owner and operator of the certified stationary SI engine including the specifications of the pipeline-quality natural gas to which the engine is certified and what adjustments the owner or operator must make to the engine when installed in the field to ensure compliance with the emission standards.

(e) Manufacturers of stationary SI ICE that are lean burn engines fueled by LPG who conduct voluntary certification of stationary SI ICE to the emission standards specified in §60.4231(d) or (e), as applicable, must certify their engines for operation using fuel that meets the specifications in 40 CFR 1065.720.

(f) Manufacturers may certify their engines for operation using gaseous fuels in addition to pipeline-quality natural gas; however, the manufacturer must specify the properties of that fuel and provide testing information showing that the engine will meet the emission standards specified in §60.4231(d) or (e), as applicable, when operating on that fuel. The manufacturer must also provide instructions for configuring the stationary engine to meet the emission standards on fuels that do not meet the pipeline-quality natural gas definition. The manufacturer must also provide information to the owner and operator of the certified stationary SI engine regarding the configuration that is most conducive to reduced emissions where the engine will be operated on gaseous fuels with different quality than the fuel that it was certified to.

(g) A stationary SI engine manufacturer may certify an engine family solely to the standards applicable to landfill/digester gas engines as specified in §60.4231(d) or (e), as applicable, but must certify their engines for operation using landfill/digester gas and must add a permanent label stating that the engine is for use only in landfill/digester gas applications. The label must be added according to the labeling requirements specified in 40 CFR 1048.135(b).

(h) For purposes of this subpart, when calculating emissions of volatile organic compounds, emissions of formaldehyde should not be included.

(i) For engines being certified to the voluntary certification standards in Table 1 of this subpart, the VOC measurement shall be made by following the procedures in 40 CFR 1065.260 and 1065.265 in order to determine the total NMHC emissions by using a flame-ionization detector and non-methane cutter. As an alternative to the nonmethane cutter, manufacturers may use a gas chromatograph as allowed under 40 CFR 1065.267 and may measure ethane, as well as methane, for excluding such levels from the total VOC measurement.

**§60.4242 What other requirements must I meet if I am a manufacturer of stationary SI internal combustion engines or equipment containing stationary SI internal combustion engines or a manufacturer of equipment containing such engines?**

(a) Stationary SI internal combustion engine manufacturers must meet the provisions of 40 CFR part 90, 40 CFR part 1048, or 40 CFR part 1054, as applicable, as well as 40 CFR part 1068 for engines that are certified to the emission

standards in 40 CFR part 1048 or 1054, except that engines certified pursuant to the voluntary certification procedures in §60.4241 are subject only to the provisions indicated in §60.4247 and are permitted to provide instructions to owners and operators allowing for deviations from certified configurations, if such deviations are consistent with the provisions of paragraphs §60.4241(c) through (f). Manufacturers of equipment containing stationary SI internal combustion engines meeting the provisions of 40 CFR part 1054 must meet the provisions of 40 CFR part 1060, as applicable. Labels on engines certified to 40 CFR part 1048 must refer to stationary engines, rather than or in addition to nonroad engines, as appropriate.

(b) An engine manufacturer certifying an engine family or families to standards under this subpart that are identical to standards applicable under 40 CFR part 90, 40 CFR part 1048, or 40 CFR part 1054 for that model year may certify any such family that contains both nonroad and stationary engines as a single engine family and/or may include any such family containing stationary engines in the averaging, banking and trading provisions applicable for such engines under those parts. This provision also applies to equipment or component manufacturers certifying to standards under 40 CFR part 1060.

(c) Manufacturers of engine families certified to 40 CFR part 1048 may meet the labeling requirements referred to in paragraph (a) of this section for stationary SI ICE by either adding a separate label containing the information required in paragraph (a) of this section or by adding the words “and stationary” after the word “nonroad” to the label.

(d) For all engines manufactured on or after January 1, 2011, and for all engines with a maximum engine power greater than 25 HP and less than 130 HP manufactured on or after July 1, 2008, a stationary SI engine manufacturer that certifies an engine family solely to the standards applicable to emergency engines must add a permanent label stating that the engines in that family are for emergency use only. The label must be added according to the labeling requirements specified in 40 CFR 1048.135(b).

(e) All stationary SI engines subject to mandatory certification that do not meet the requirements of this subpart must be labeled according to 40 CFR 1068.230 and must be exported under the provisions of 40 CFR 1068.230. Stationary SI engines subject to standards in 40 CFR part 90 may use the provisions in 40 CFR 90.909. Manufacturers of stationary engines with a maximum engine power greater than 25 HP that are not certified to standards and other requirements under 40 CFR part 1048 are subject to the labeling provisions of 40 CFR 1048.20 pertaining to excluded stationary engines.

(f) For manufacturers of gaseous-fueled stationary engines required to meet the warranty provisions in 40 CFR 90.1103 or 1054.120, we may establish an hour-based warranty period equal to at least the certified emissions life of the engines (in engine operating hours) if we determine that these engines are likely to operate for a number of hours greater than the applicable useful life within 24 months. We will not approve an alternate warranty under this paragraph (f) for nonroad engines. An alternate warranty period approved under this paragraph (f) will be the specified number of engine operating hours or two years, whichever comes first. The engine manufacturer shall request this alternate warranty period in its application for certification or in an earlier submission. We may approve an alternate warranty period for an engine family subject to the following conditions:

(1) The engines must be equipped with non-resettable hour meters.

(2) The engines must be designed to operate for a number of hours substantially greater than the applicable certified emissions life.

(3) The emission-related warranty for the engines may not be shorter than any published warranty offered by the manufacturer without charge for the engines. Similarly, the emission-related warranty for any component shall not be shorter than any published warranty offered by the manufacturer without charge for that component.

### **Compliance Requirements for Owners and Operators**

**§60.4243 What are my compliance requirements if I am an owner or operator of a stationary SI internal combustion engine?**

(a) If you are an owner or operator of a stationary SI internal combustion engine that is manufactured after July 1, 2008, and must comply with the emission standards specified in §60.4233(a) through (c), you must comply by purchasing an engine certified to the emission standards in §60.4231(a) through (c), as applicable, for the same engine class and maximum engine power. In addition, you must meet one of the requirements specified in (a)(1) and (2) of this section.

(1) If you operate and maintain the certified stationary SI internal combustion engine and control device according to the manufacturer's emission-related written instructions, you must keep records of conducted maintenance to demonstrate compliance, but no performance testing is required if you are an owner or operator. You must also meet the requirements as specified in 40 CFR part 1068, subparts A through D, as they apply to you. If you adjust engine settings according to and consistent with the manufacturer's instructions, your stationary SI internal combustion engine will not be considered out of compliance.

(2) If you do not operate and maintain the certified stationary SI internal combustion engine and control device according to the manufacturer's emission-related written instructions, your engine will be considered a non-certified engine, and you must demonstrate compliance according to (a)(2)(i) through (iii) of this section, as appropriate.

(i) If you are an owner or operator of a stationary SI internal combustion engine less than 100 HP, you must keep a maintenance plan and records of conducted maintenance to demonstrate compliance and must, to the extent practicable, maintain and operate the engine in a manner consistent with good air pollution control practice for minimizing emissions, but no performance testing is required if you are an owner or operator.

(ii) If you are an owner or operator of a stationary SI internal combustion engine greater than or equal to 100 HP and less than or equal to 500 HP, you must keep a maintenance plan and records of conducted maintenance and must, to the extent practicable, maintain and operate the engine in a manner consistent with good air pollution control practice for minimizing emissions. In addition, you must conduct an initial performance test within 1 year of engine startup to demonstrate compliance.

(iii) If you are an owner or operator of a stationary SI internal combustion engine greater than 500 HP, you must keep a maintenance plan and records of conducted maintenance and must, to the extent practicable, maintain and operate the engine in a manner consistent with good air pollution control practice for minimizing emissions. In addition, you must conduct an initial performance test within 1 year of engine startup and conduct subsequent performance testing every 8,760 hours or 3 years, whichever comes first, thereafter to demonstrate compliance.

(b) If you are an owner or operator of a stationary SI internal combustion engine and must comply with the emission standards specified in §60.4233(d) or (e), you must demonstrate compliance according to one of the methods specified in paragraphs (b)(1) and (2) of this section.

(1) Purchasing an engine certified according to procedures specified in this subpart, for the same model year and demonstrating compliance according to one of the methods specified in paragraph (a) of this section.

(2) Purchasing a non-certified engine and demonstrating compliance with the emission standards specified in §60.4233(d) or (e) and according to the requirements specified in §60.4244, as applicable, and according to paragraphs (b)(2)(i) and (ii) of this section.

(i) If you are an owner or operator of a stationary SI internal combustion engine greater than 25 HP and less than or equal to 500 HP, you must keep a maintenance plan and records of conducted maintenance and must, to the extent practicable, maintain and operate the engine in a manner consistent with good air pollution control practice for minimizing emissions. In addition, you must conduct an initial performance test to demonstrate compliance.

(ii) If you are an owner or operator of a stationary SI internal combustion engine greater than 500 HP, you must keep a maintenance plan and records of conducted maintenance and must, to the extent practicable, maintain and operate the

engine in a manner consistent with good air pollution control practice for minimizing emissions. In addition, you must conduct an initial performance test and conduct subsequent performance testing every 8,760 hours or 3 years, whichever comes first, thereafter to demonstrate compliance.

(c) If you are an owner or operator of a stationary SI internal combustion engine that must comply with the emission standards specified in §60.4233(f), you must demonstrate compliance according paragraph (b)(2)(i) or (ii) of this section, except that if you comply according to paragraph (b)(2)(i) of this section, you demonstrate that your non-certified engine complies with the emission standards specified in §60.4233(f).

(d) If you own or operate an emergency stationary ICE, you must operate the emergency stationary ICE according to the requirements in paragraphs (d)(1) through (3) of this section. In order for the engine to be considered an emergency stationary ICE under this subpart, any operation other than emergency operation, maintenance and testing, emergency demand response, and operation in non-emergency situations for 50 hours per year, as described in paragraphs (d)(1) through (3) of this section, is prohibited. If you do not operate the engine according to the requirements in paragraphs (d)(1) through (3) of this section, the engine will not be considered an emergency engine under this subpart and must meet all requirements for non-emergency engines.

(1) There is no time limit on the use of emergency stationary ICE in emergency situations.

(2) You may operate your emergency stationary ICE for any combination of the purposes specified in paragraphs (d)(2)(i) through (iii) of this section for a maximum of 100 hours per calendar year. Any operation for non-emergency situations as allowed by paragraph (d)(3) of this section counts as part of the 100 hours per calendar year allowed by this paragraph (d)(2).

(i) Emergency stationary ICE may be operated for maintenance checks and readiness testing, provided that the tests are recommended by federal, state or local government, the manufacturer, the vendor, the regional transmission organization or equivalent balancing authority and transmission operator, or the insurance company associated with the engine. The owner or operator may petition the Administrator for approval of additional hours to be used for maintenance checks and readiness testing, but a petition is not required if the owner or operator maintains records indicating that federal, state, or local standards require maintenance and testing of emergency ICE beyond 100 hours per calendar year.

~~(ii) Emergency stationary ICE may be operated for emergency demand response for periods in which the Reliability Coordinator under the North American Electric Reliability Corporation (NERC) Reliability Standard EOP-002-3, Capacity and Energy Emergencies (incorporated by reference, see §60.17), or other authorized entity as determined by the Reliability Coordinator, has declared an Energy Emergency Alert Level 2 as defined in the NERC Reliability Standard EOP-002-3. [vacated by May 4, 2016 court mandate]~~

~~(iii) Emergency stationary ICE may be operated for periods where there is a deviation of voltage or frequency of 5 percent or greater below standard voltage or frequency. [vacated by May 4, 2016 court mandate]~~

(3) Emergency stationary ICE may be operated for up to 50 hours per calendar year in non-emergency situations. The 50 hours of operation in non-emergency situations are counted as part of the 100 hours per calendar year for maintenance and testing and emergency demand response provided in paragraph (d)(2) of this section. Except as provided in paragraph (d)(3)(i) of this section, the 50 hours per year for non-emergency situations cannot be used for peak shaving or non-emergency demand response, or to generate income for a facility to an electric grid or otherwise supply power as part of a financial arrangement with another entity.

(i) The 50 hours per year for non-emergency situations can be used to supply power as part of a financial arrangement with another entity if all of the following conditions are met:

(A) The engine is dispatched by the local balancing authority or local transmission and distribution system operator;

(B) The dispatch is intended to mitigate local transmission and/or distribution limitations so as to avert potential voltage collapse or line overloads that could lead to the interruption of power supply in a local area or region.

(C) The dispatch follows reliability, emergency operation or similar protocols that follow specific NERC, regional, state, public utility commission or local standards or guidelines.

(D) The power is provided only to the facility itself or to support the local transmission and distribution system.

(E) The owner or operator identifies and records the entity that dispatches the engine and the specific NERC, regional, state, public utility commission or local standards or guidelines that are being followed for dispatching the engine. The local balancing authority or local transmission and distribution system operator may keep these records on behalf of the engine owner or operator.

(ii) [Reserved]

(e) Owners and operators of stationary SI natural gas fired engines may operate their engines using propane for a maximum of 100 hours per year as an alternative fuel solely during emergency operations, but must keep records of such use. If propane is used for more than 100 hours per year in an engine that is not certified to the emission standards when using propane, the owners and operators are required to conduct a performance test to demonstrate compliance with the emission standards of §60.4233.

(f) If you are an owner or operator of a stationary SI internal combustion engine that is less than or equal to 500 HP and you purchase a non-certified engine or you do not operate and maintain your certified stationary SI internal combustion engine and control device according to the manufacturer's written emission-related instructions, you are required to perform initial performance testing as indicated in this section, but you are not required to conduct subsequent performance testing unless the stationary engine is rebuilt or undergoes major repair or maintenance. A rebuilt stationary SI ICE means an engine that has been rebuilt as that term is defined in 40 CFR 94.11(a).

(g) It is expected that air-to-fuel ratio controllers will be used with the operation of three-way catalysts/non-selective catalytic reduction. The AFR controller must be maintained and operated appropriately in order to ensure proper operation of the engine and control device to minimize emissions at all times.

(h) If you are an owner/operator of an stationary SI internal combustion engine with maximum engine power greater than or equal to 500 HP that is manufactured after July 1, 2007 and before July 1, 2008, and must comply with the emission standards specified in sections 60.4233(b) or (c), you must comply by one of the methods specified in paragraphs (h)(1) through (h)(4) of this section.

(1) Purchasing an engine certified according to 40 CFR part 1048. The engine must be installed and configured according to the manufacturer's specifications.

(2) Keeping records of performance test results for each pollutant for a test conducted on a similar engine. The test must have been conducted using the same methods specified in this subpart and these methods must have been followed correctly.

(3) Keeping records of engine manufacturer data indicating compliance with the standards.

(4) Keeping records of control device vendor data indicating compliance with the standards.

(i) If you are an owner or operator of a modified or reconstructed stationary SI internal combustion engine and must comply with the emission standards specified in §60.4233(f), you must demonstrate compliance according to one of the methods specified in paragraphs (i)(1) or (2) of this section.

(1) Purchasing, or otherwise owning or operating, an engine certified to the emission standards in §60.4233(f), as applicable.

(2) Conducting a performance test to demonstrate initial compliance with the emission standards according to the requirements specified in §60.4244. The test must be conducted within 60 days after the engine commences operation after the modification or reconstruction.

### Testing Requirements for Owners and Operators

#### §60.4244 What test methods and other procedures must I use if I am an owner or operator of a stationary SI internal combustion engine?

Owners and operators of stationary SI ICE who conduct performance tests must follow the procedures in paragraphs (a) through (f) of this section.

(a) Each performance test must be conducted within 10 percent of 100 percent peak (or the highest achievable) load and according to the requirements in §60.8 and under the specific conditions that are specified by Table 2 to this subpart.

(b) You may not conduct performance tests during periods of startup, shutdown, or malfunction, as specified in §60.8(c). If your stationary SI internal combustion engine is non-operational, you do not need to startup the engine solely to conduct a performance test; however, you must conduct the performance test immediately upon startup of the engine.

(c) You must conduct three separate test runs for each performance test required in this section, as specified in §60.8(f). Each test run must be conducted within 10 percent of 100 percent peak (or the highest achievable) load and last at least 1 hour.

(d) To determine compliance with the NO<sub>x</sub> mass per unit output emission limitation, convert the concentration of NO<sub>x</sub> in the engine exhaust using Equation 1 of this section:

$$ER = \frac{C_d \times 1.912 \times 10^{-3} \times Q \times T}{HP-hr} \quad (\text{Eq. 1})$$

Where:

ER = Emission rate of NO<sub>x</sub> in g/HP-hr.

C<sub>d</sub> = Measured NO<sub>x</sub> concentration in parts per million by volume (ppmv).

1.912 × 10<sup>-3</sup> = Conversion constant for ppm NO<sub>x</sub> to grams per standard cubic meter at 20 degrees Celsius.

Q = Stack gas volumetric flow rate, in standard cubic meter per hour, dry basis.

T = Time of test run, in hours.

HP-hr = Brake work of the engine, horsepower-hour (HP-hr).

(e) To determine compliance with the CO mass per unit output emission limitation, convert the concentration of CO in the engine exhaust using Equation 2 of this section:

$$ER = \frac{C_d \times 1.164 \times 10^{-3} \times Q \times T}{HP-hr} \quad (\text{Eq. 2})$$

Where:

ER = Emission rate of CO in g/HP-hr.

C<sub>d</sub> = Measured CO concentration in ppmv.

1.164 × 10<sup>-3</sup> = Conversion constant for ppm CO to grams per standard cubic meter at 20 degrees Celsius.

Q = Stack gas volumetric flow rate, in standard cubic meters per hour, dry basis.

T = Time of test run, in hours.

HP-hr = Brake work of the engine, in HP-hr.

(f) For purposes of this subpart, when calculating emissions of VOC, emissions of formaldehyde should not be included. To determine compliance with the VOC mass per unit output emission limitation, convert the concentration of VOC in the engine exhaust using Equation 3 of this section:

$$ER = \frac{C_d \times 1.833 \times 10^{-3} \times Q \times T}{HP-hr} \quad (\text{Eq. 3})$$

Where:

ER = Emission rate of VOC in g/HP-hr.

$C_d$  = VOC concentration measured as propane in ppmv.

$1.833 \times 10^{-3}$  = Conversion constant for ppm VOC measured as propane, to grams per standard cubic meter at 20 degrees Celsius.

Q = Stack gas volumetric flow rate, in standard cubic meters per hour, dry basis.

T = Time of test run, in hours.

HP-hr = Brake work of the engine, in HP-hr.

(g) If the owner/operator chooses to measure VOC emissions using either Method 18 of 40 CFR part 60, appendix A, or Method 320 of 40 CFR part 63, appendix A, then it has the option of correcting the measured VOC emissions to account for the potential differences in measured values between these methods and Method 25A. The results from Method 18 and Method 320 can be corrected for response factor differences using Equations 4 and 5 of this section. The corrected VOC concentration can then be placed on a propane basis using Equation 6 of this section.

$$RF_i = \frac{C_{Mi}}{C_{Ai}} \quad (\text{Eq. 4})$$

Where:

$RF_i$  = Response factor of compound i when measured with EPA Method 25A.

$C_{Mi}$  = Measured concentration of compound i in ppmv as carbon.

$C_{Ai}$  = True concentration of compound i in ppmv as carbon.

$$C_{i\text{corr}} = RF_i \times C_{i\text{meas}} \quad (\text{Eq. 5})$$

Where:

$C_{i\text{corr}}$  = Concentration of compound i corrected to the value that would have been measured by EPA Method 25A, ppmv as carbon.

$C_{i\text{meas}}$  = Concentration of compound i measured by EPA Method 320, ppmv as carbon.

$$C_{Peq} = 0.6098 \times C_{i\text{corr}} \quad (\text{Eq. 6})$$

Where:

$C_{Peq}$  = Concentration of compound i in mg of propane equivalent per DSCM.

## Notification, Reports, and Records for Owners and Operators

### §60.4245 What are my notification, reporting, and recordkeeping requirements if I am an owner or operator of a stationary SI internal combustion engine?

Owners or operators of stationary SI ICE must meet the following notification, reporting and recordkeeping requirements.

(a) Owners and operators of all stationary SI ICE must keep records of the information in paragraphs (a)(1) through (4) of this section.

(1) All notifications submitted to comply with this subpart and all documentation supporting any notification.

(2) Maintenance conducted on the engine.

(3) If the stationary SI internal combustion engine is a certified engine, documentation from the manufacturer that the engine is certified to meet the emission standards and information as required in 40 CFR parts 90, 1048, 1054, and 1060, as applicable.

(4) If the stationary SI internal combustion engine is not a certified engine or is a certified engine operating in a non-certified manner and subject to §60.4243(a)(2), documentation that the engine meets the emission standards.

(b) For all stationary SI emergency ICE greater than or equal to 500 HP manufactured on or after July 1, 2010, that do not meet the standards applicable to non-emergency engines, the owner or operator of must keep records of the hours of operation of the engine that is recorded through the non-resettable hour meter. For all stationary SI emergency ICE greater than or equal to 130 HP and less than 500 HP manufactured on or after July 1, 2011 that do not meet the standards applicable to non-emergency engines, the owner or operator of must keep records of the hours of operation of the engine that is recorded through the non-resettable hour meter. For all stationary SI emergency ICE greater than 25 HP and less than 130 HP manufactured on or after July 1, 2008, that do not meet the standards applicable to non-emergency engines, the owner or operator of must keep records of the hours of operation of the engine that is recorded through the non-resettable hour meter. The owner or operator must document how many hours are spent for emergency operation, including what classified the operation as emergency and how many hours are spent for non-emergency operation.

(c) Owners and operators of stationary SI ICE greater than or equal to 500 HP that have not been certified by an engine manufacturer to meet the emission standards in §60.4231 must submit an initial notification as required in §60.7(a)(1). The notification must include the information in paragraphs (c)(1) through (5) of this section.

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

(2) The address of the affected source;

(3) Engine information including make, model, engine family, serial number, model year, maximum engine power, and engine displacement;

(4) Emission control equipment; and

(5) Fuel used.

(d) Owners and operators of stationary SI ICE that are subject to performance testing must submit a copy of each performance test as conducted in §60.4244 within 60 days after the test has been completed. Performance test reports using EPA Method 18, EPA Method 320, or ASTM D6348-03 (incorporated by reference—see 40 CFR 60.17) to measure VOC require reporting of all QA/QC data. For Method 18, report results from sections 8.4 and 11.1.1.4; for Method 320, report results from sections 8.6.2, 9.0, and 13.0; and for ASTM D6348-03 report results of all QA/QC procedures in Annexes 1-7.

(e) If you own or operate an emergency stationary SI ICE with a maximum engine power more than 100 HP that operates or is contractually obligated to be available for more than 15 hours per calendar year for the purposes specified in §60.4243(d)(2)(ii) and (iii) or that operates for the purposes specified in §60.4243(d)(3)(i), you must submit an annual report according to the requirements in paragraphs (e)(1) through (3) of this section.

(1) The report must contain the following information:

(i) Company name and address where the engine is located.

(ii) Date of the report and beginning and ending dates of the reporting period.

(iii) Engine site rating and model year.

(iv) Latitude and longitude of the engine in decimal degrees reported to the fifth decimal place.

(v) Hours operated for the purposes specified in §60.4243(d)(2)(ii) and (iii), including the date, start time, and end time for engine operation for the purposes specified in §60.4243(d)(2)(ii) and (iii).

(vi) Number of hours the engine is contractually obligated to be available for the purposes specified in §60.4243(d)(2)(ii) and (iii).

(vii) Hours spent for operation for the purposes specified in §60.4243(d)(3)(i), including the date, start time, and end time for engine operation for the purposes specified in §60.4243(d)(3)(i). The report must also identify the entity that dispatched the engine and the situation that necessitated the dispatch of the engine.

(2) The first annual report must cover the calendar year 2015 and must be submitted no later than March 31, 2016. Subsequent annual reports for each calendar year must be submitted no later than March 31 of the following calendar year.

(3) The annual report must be submitted electronically using the subpart specific reporting form in the Compliance and Emissions Data Reporting Interface (CEDRI) that is accessed through EPA's Central Data Exchange (CDX) ([www.epa.gov/cdx](http://www.epa.gov/cdx)). However, if the reporting form specific to this subpart is not available in CEDRI at the time that the report is due, the written report must be submitted to the Administrator at the appropriate address listed in §60.4.

## General Provisions

### §60.4246 What parts of the General Provisions apply to me?

Table 3 to this subpart shows which parts of the General Provisions in §§60.1 through 60.19 apply to you.

## Mobile Source Provisions

### §60.4247 What parts of the mobile source provisions apply to me if I am a manufacturer of stationary SI internal combustion engines or a manufacturer of equipment containing such engines?

(a) Manufacturers certifying to emission standards in 40 CFR part 90, including manufacturers certifying emergency engines below 130 HP, must meet the provisions of 40 CFR part 90. Manufacturers certifying to emission standards in 40 CFR part 1054 must meet the provisions of 40 CFR part 1054. Manufacturers of equipment containing stationary SI internal combustion engines meeting the provisions of 40 CFR part 1054 must meet the provisions of 40 CFR part 1060 to the extent they apply to equipment manufacturers.

(b) Manufacturers required to certify to emission standards in 40 CFR part 1048 must meet the provisions of 40 CFR part 1048. Manufacturers certifying to emission standards in 40 CFR part 1048 pursuant to the voluntary certification program must meet the requirements in Table 4 to this subpart as well as the standards in 40 CFR 1048.101.

(c) For manufacturers of stationary SI internal combustion engines participating in the voluntary certification program and certifying engines to Table 1 to this subpart, Table 4 to this subpart shows which parts of the mobile source provisions in 40 CFR parts 1048, 1065, and 1068 apply to you. Compliance with the deterioration factor provisions under

40 CFR 1048.205(n) and 1048.240 will be required for engines built new on and after January 1, 2010. Prior to January 1, 2010, manufacturers of stationary internal combustion engines participating in the voluntary certification program have the option to develop their own deterioration factors based on an engineering analysis.

## Definitions

### §60.4248 What definitions apply to this subpart?

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

*Certified emissions life* means the period during which the engine is designed to properly function in terms of reliability and fuel consumption, without being remanufactured, specified as a number of hours of operation or calendar years, whichever comes first. The values for certified emissions life for stationary SI ICE with a maximum engine power less than or equal to 19 KW (25 HP) are given in 40 CFR 90.105, 40 CFR 1054.107, and 40 CFR 1060.101, as appropriate. The values for certified emissions life for stationary SI ICE with a maximum engine power greater than 19 KW (25 HP) certified to 40 CFR part 1048 are given in 40 CFR 1048.101(g). The certified emissions life for stationary SI ICE with a maximum engine power greater than 75 KW (100 HP) certified under the voluntary manufacturer certification program of this subpart is 5,000 hours or 7 years, whichever comes first. You may request in your application for certification that we approve a shorter certified emissions life for an engine family. We may approve a shorter certified emissions life, in hours of engine operation but not in years, if we determine that these engines will rarely operate longer than the shorter certified emissions life. If engines identical to those in the engine family have already been produced and are in use, your demonstration must include documentation from such in-use engines. In other cases, your demonstration must include an engineering analysis of information equivalent to such in-use data, such as data from research engines or similar engine models that are already in production. Your demonstration must also include any overhaul interval that you recommend, any mechanical warranty that you offer for the engine or its components, and any relevant customer design specifications. Your demonstration may include any other relevant information. The certified emissions life value may not be shorter than any of the following:

- (i) 1,000 hours of operation.
- (ii) Your recommended overhaul interval.
- (iii) Your mechanical warranty for the engine.

*Certified stationary internal combustion engine* means an engine that belongs to an engine family that has a certificate of conformity that complies with the emission standards and requirements in this part, or of 40 CFR part 90, 40 CFR part 1048, or 40 CFR part 1054, as appropriate.

*Combustion turbine* means all equipment, including but not limited to the turbine, the fuel, air, lubrication and exhaust gas systems, control systems (except emissions control equipment), and any ancillary components and sub-components comprising any simple cycle combustion turbine, any regenerative/recuperative cycle combustion turbine, the combustion turbine portion of any cogeneration cycle combustion system, or the combustion turbine portion of any combined cycle steam/electric generating system.

*Compression ignition* means relating to a type of stationary internal combustion engine that is not a spark ignition engine.

*Date of manufacture* means one of the following things:

- (1) For freshly manufactured engines and modified engines, date of manufacture means the date the engine is originally produced.
- (2) For reconstructed engines, date of manufacture means the date the engine was originally produced, except as specified in paragraph (3) of this definition.

(3) Reconstructed engines are assigned a new date of manufacture if the fixed capital cost of the new and refurbished components exceeds 75 percent of the fixed capital cost of a comparable entirely new facility. An engine that is produced from a previously used engine block does not retain the date of manufacture of the engine in which the engine block was previously used if the engine is produced using all new components except for the engine block. In these cases, the date of manufacture is the date of reconstruction or the date the new engine is produced.

*Diesel fuel* means any liquid obtained from the distillation of petroleum with a boiling point of approximately 150 to 360 degrees Celsius. One commonly used form is number 2 distillate oil.

*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 carbon dioxide (CO<sub>2</sub>).

*Emergency stationary internal combustion engine* means any stationary reciprocating internal combustion engine that meets all of the criteria in paragraphs (1) through (3) of this definition. All emergency stationary ICE must comply with the requirements specified in §60.4243(d) in order to be considered emergency stationary ICE. If the engine does not comply with the requirements specified in §60.4243(d), then it is not considered to be an emergency stationary ICE under this subpart.

(1) The stationary ICE is operated to provide electrical power or mechanical work during an emergency situation. Examples include stationary ICE used to produce power for critical networks or equipment (including power supplied to portions of a facility) when electric power from the local utility (or the normal power source, if the facility runs on its own power production) is interrupted, or stationary ICE used to pump water in the case of fire or flood, etc.

(2) The stationary ICE is operated under limited circumstances for situations not included in paragraph (1) of this definition, as specified in §60.4243(d).

(3) The stationary ICE operates as part of a financial arrangement with another entity in situations not included in paragraph (1) of this definition only as allowed in §60.4243(d)(2)(ii) or (iii) and §60.4243(d)(3)(i).

*Engine manufacturer* means the manufacturer of the engine. See the definition of “manufacturer” in this section.

*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.

*Freshly manufactured engine* means an engine that has not been placed into service. An engine becomes freshly manufactured when it is originally produced.

*Gasoline* means any fuel sold in any State for use in motor vehicles and motor vehicle engines, or nonroad or stationary engines, and commonly or commercially known or sold as gasoline.

*Installed* means the engine is placed and secured at the location where it is intended to be operated.

*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<sub>2</sub>.

*Lean burn engine* means any two-stroke or four-stroke spark ignited engine that does not meet the definition of a rich burn engine.

*Liquefied petroleum gas* means any liquefied hydrocarbon gas obtained as a by-product in petroleum refining or natural gas production.

*Manufacturer* has the meaning given in section 216(1) of the Clean Air Act. In general, this term includes any person who manufactures a stationary engine for sale in the United States or otherwise introduces a new stationary engine into commerce in the United States. This includes importers who import stationary engines for resale.

*Maximum engine power* means maximum engine power as defined in 40 CFR 1048.801.

*Model year* means the calendar year in which an engine is manufactured (see “date of manufacture”), except as follows:

(1) Model year means the annual new model production period of the engine manufacturer in which an engine is manufactured (see “date of manufacture”), if the annual new model production period is different than the calendar year and includes January 1 of the calendar year for which the model year is named. It may not begin before January 2 of the previous calendar year and it must end by December 31 of the named calendar year.

(2) For an engine that is converted to a stationary engine after being placed into service as a nonroad or other non-stationary engine, model year means the calendar year or new model production period in which the engine was manufactured (see “date of manufacture”).

*Natural gas* means a naturally occurring mixture of hydrocarbon and non-hydrocarbon gases found in geologic formations beneath the Earth's surface, of which the principal constituent is methane. Natural gas may be field or pipeline quality.

*Other internal combustion engine* means any internal combustion engine, except combustion turbines, which is not a reciprocating internal combustion engine or rotary internal combustion engine.

*Pipeline-quality natural gas* means a naturally occurring fluid mixture of hydrocarbons (e.g., methane, ethane, or propane) produced in geological formations beneath the Earth's surface that maintains a gaseous state at standard atmospheric temperature and pressure under ordinary conditions, and which is provided by a supplier through a pipeline. Pipeline-quality natural gas must either be composed of at least 70 percent methane by volume or have a gross calorific value between 950 and 1,100 British thermal units per standard cubic foot.

*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 June 12, 2006, with passive emission control technology for NO<sub>x</sub> (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.

*Rotary internal combustion engine* means any internal combustion engine which uses rotary motion to convert heat energy into mechanical work.

*Spark ignition* means relating to either: a gasoline-fueled engine; or any other type of engine with a spark plug (or other sparking device) and with operating characteristics significantly similar to the theoretical Otto combustion cycle. Spark ignition engines usually use a throttle to regulate intake air flow to control power during normal operation. Dual-fuel engines in which a liquid fuel (typically diesel fuel) is used for compression ignition and gaseous fuel (typically natural gas) is used as the primary fuel at an annual average ratio of less than 2 parts diesel fuel to 100 parts total fuel on an energy equivalent basis are spark ignition engines.

*Stationary internal combustion engine* means any internal combustion engine, except combustion turbines, that converts heat energy into mechanical work and is not mobile. Stationary ICE differ from mobile ICE in that a stationary internal combustion engine is not a nonroad engine as defined at 40 CFR 1068.30 (excluding paragraph (2)(ii) of that definition), and is not used to propel a motor vehicle, aircraft, or a vehicle used solely for competition. Stationary ICE include reciprocating ICE, rotary ICE, and other ICE, except combustion turbines.

*Stationary internal combustion engine test cell/stand* means an engine test cell/stand, as defined in 40 CFR part 63, subpart P, that tests stationary ICE.

*Stoichiometric* means the theoretical air-to-fuel ratio required for complete combustion.

*Subpart* means 40 CFR part 60, subpart JJJJ.

*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.

*Volatile organic compounds* means volatile organic compounds as defined in 40 CFR 51.100(s).

*Voluntary certification program* means an optional engine certification program that manufacturers of stationary SI internal combustion engines with a maximum engine power greater than 19 KW (25 HP) that do not use gasoline and are not rich burn engines that use LPG can choose to participate in to certify their engines to the emission standards in §60.4231(d) or (e), as applicable.

**Table 1 to Subpart JJJJ of Part 60—NO<sub>x</sub>, CO, and VOC Emission Standards for Stationary Non-Emergency SI Engines ≥100 HP (Except Gasoline and Rich Burn LPG), Stationary SI Landfill/Digester Gas Engines, and Stationary Emergency Engines >25 HP**

Engine type and fuel	Maximum engine power	Manufacture date	Emission standards <sup>a</sup>					
			g/HP-hr			ppmvd at 15% O <sub>2</sub>		
			NO <sub>x</sub>	CO	VOC <sup>d</sup>	NO <sub>x</sub>	CO	VOC <sup>d</sup>
Non-Emergency SI Natural Gas <sup>b</sup> and Non-Emergency SI Lean Burn LPG <sup>b</sup>	100≤HP<500	7/1/2008	2.0	4.0	1.0	160	540	86
		1/1/2011	1.0	2.0	0.7	82	270	60
Non-Emergency SI Lean Burn Natural Gas and LPG	500≤HP<1,350	1/1/2008	2.0	4.0	1.0	160	540	86
		7/1/2010	1.0	2.0	0.7	82	270	60
Non-Emergency SI Natural Gas and Non-Emergency SI Lean Burn LPG (except lean burn 500≤HP<1,350)	HP≥500	7/1/2007	2.0	4.0	1.0	160	540	86
		7/1/2010	1.0	2.0	0.7	82	270	60
Landfill/Digester Gas (except lean burn 500≤HP<1,350)	HP<500	7/1/2008	3.0	5.0	1.0	220	610	80
		1/1/2011	2.0	5.0	1.0	150	610	80
		7/1/2007	3.0	5.0	1.0	220	610	80
		7/1/2010	2.0	5.0	1.0	150	610	80
Landfill/Digester Gas Lean Burn	500≤HP<1,350	1/1/2008	3.0	5.0	1.0	220	610	80
		7/1/2010	2.0	5.0	1.0	150	610	80
Emergency	25<HP<130	1/1/2009	<sup>c</sup> 10	387	N/A	N/A	N/A	N/A
		HP≥130	2.0	4.0	1.0	160	540	86

<sup>a</sup>Owners and operators of stationary non-certified SI engines may choose to comply with the emission standards in units of either g/HP-hr or ppmvd at 15 percent O<sub>2</sub>.

<sup>b</sup>Owners and operators of new or reconstructed non-emergency lean burn SI stationary engines with a site rating of greater than or equal to 250 brake HP located at a major source that are meeting the requirements of 40 CFR part 63, subpart ZZZZ, Table 2a do not have to comply with the CO emission standards of Table 1 of this subpart.

<sup>c</sup>The emission standards applicable to emergency engines between 25 HP and 130 HP are in terms of NO<sub>x</sub> + HC.

<sup>d</sup>For purposes of this subpart, when calculating emissions of volatile organic compounds, emissions of formaldehyde should not be included.

**Table 2 to Subpart JJJ of Part 60—Requirements for Performance Tests**

[As stated in §60.4244, you must comply with the following requirements for performance tests within 10 percent of 100 percent peak (or the highest achievable) load]

For each	Complying with the requirement to	You must	Using	According to the following requirements
1. Stationary SI internal combustion engine demonstrating compliance according to §60.4244	a. limit the concentration of NO <sub>x</sub> in the stationary SI internal combustion engine exhaust	i. Select the sampling port location and the number/location of traverse points at the exhaust of the stationary internal combustion engine;	(1) Method 1 or 1A of 40 CFR part 60, appendix A-1, if measuring flow rate	(a) Alternatively, for NO <sub>x</sub> , O <sub>2</sub> , and moisture measurement, ducts ≤6 inches in diameter may be sampled at a single point located at the duct centroid and ducts >6 and ≤12 inches in diameter may be sampled at 3 traverse points located at 16.7, 50.0, and 83.3% of the measurement line ('3-point long line'). If the duct is >12 inches in diameter <i>and</i> the sampling port location meets the two and half-diameter criterion of Section 11.1.1 of Method 1 of 40 CFR part 60, Appendix A, the duct may be sampled at '3-point long line'; otherwise, conduct the stratification testing and select sampling points according to Section 8.1.2 of Method 7E of 40 CFR part 60, Appendix A.
		ii. Determine the O <sub>2</sub> concentration of the stationary internal combustion engine exhaust at the sampling port location;	(2) Method 3, 3A, or 3B <sup>b</sup> of 40 CFR part 60, appendix A-2 or ASTM Method D6522-00 (Reapproved 2005) <sup>ad</sup>	(b) Measurements to determine O <sub>2</sub> concentration must be made at the same time as the measurements for NO <sub>x</sub> concentration.
		iii. If necessary, determine the exhaust flowrate of the stationary internal combustion engine exhaust;	(3) Method 2 or 2C of 40 CFR part 60, appendix A-1 or Method 19 of 40 CFR part 60, appendix A-7	
		iv. If necessary, measure moisture content of the stationary internal	(4) Method 4 of 40 CFR part 60, appendix A-3, Method 320 of 40 CFR part 63,	(c) Measurements to determine moisture must be made at the same time as the measurement for NO <sub>x</sub>

For each	Complying with the requirement to	You must	Using	According to the following requirements
		combustion engine exhaust at the sampling port location; and	appendix A <sup>e</sup> , or ASTM Method D6348-03 <sup>de</sup>	concentration.
		v. Measure NO <sub>x</sub> at the exhaust of the stationary internal combustion engine; if using a control device, the sampling site must be located at the outlet of the control device	(5) Method 7E of 40 CFR part 60, appendix A-4, ASTM Method D6522-00 (Reapproved 2005) <sup>ad</sup> , Method 320 of 40 CFR part 63, appendix A <sup>e</sup> , or ASTM Method D6348-03 <sup>de</sup>	(d) Results of this test consist of the average of the three 1-hour or longer runs.
	b. limit the concentration of CO in the stationary SI internal combustion engine exhaust	i. Select the sampling port location and the number/location of traverse points at the exhaust of the stationary internal combustion engine;	(1) Method 1 or 1A of 40 CFR part 60, appendix A-1, if measuring flow rate	(a) Alternatively, for CO, O <sub>2</sub> , and moisture measurement, ducts ≤6 inches in diameter may be sampled at a single point located at the duct centroid and ducts >6 and ≤12 inches in diameter may be sampled at 3 traverse points located at 16.7, 50.0, and 83.3% of the measurement line ('3-point long line'). If the duct is >12 inches in diameter <i>and</i> the sampling port location meets the two and half-diameter criterion of Section 11.1.1 of Method 1 of 40 CFR part 60, Appendix A, the duct may be sampled at '3-point long line'; otherwise, conduct the stratification testing and select sampling points according to Section 8.1.2 of Method 7E of 40 CFR part 60, Appendix A.
		ii. Determine the O <sub>2</sub> concentration of the stationary internal combustion engine exhaust at the sampling port location;	(2) Method 3, 3A, or 3B <sup>b</sup> of 40 CFR part 60, appendix A-2 or ASTM Method D6522-00 (Reapproved 2005) <sup>ad</sup>	(b) Measurements to determine O <sub>2</sub> concentration must be made at the same time as the measurements for CO concentration.
		iii. If necessary, determine the exhaust flowrate of the stationary internal combustion engine exhaust;	(3) Method 2 or 2C of 40 CFR 60, appendix A-1 or Method 19 of 40 CFR part 60, appendix A-7	
		iv. If necessary, measure moisture content of the stationary internal	(4) Method 4 of 40 CFR part 60, appendix A-3, Method 320 of 40 CFR part 63,	(c) Measurements to determine moisture must be made at the same time as the measurement for CO

For each	Complying with the requirement to	You must	Using	According to the following requirements
		combustion engine exhaust at the sampling port location; and	appendix A <sup>e</sup> , or ASTM Method D6348-03 <sup>de</sup>	concentration.
		v. Measure CO at the exhaust of the stationary internal combustion engine; if using a control device, the sampling site must be located at the outlet of the control device	(5) Method 10 of 40 CFR part 60, appendix A4, ASTM Method D6522-00 (Reapproved 2005) <sup>ade</sup> , Method 320 of 40 CFR part 63, appendix A <sup>e</sup> , or ASTM Method D6348-03 <sup>de</sup>	(d) Results of this test consist of the average of the three 1-hour or longer runs.
	c. limit the concentration of VOC in the stationary SI internal combustion engine exhaust	i. Select the sampling port location and the number/location of traverse points at the exhaust of the stationary internal combustion engine;	(1) Method 1 or 1A of 40 CFR part 60, appendix A-1, if measuring flow rate	(a) Alternatively, for VOC, O <sub>2</sub> , and moisture measurement, ducts ≤6 inches in diameter may be sampled at a single point located at the duct centroid and ducts >6 and ≤12 inches in diameter may be sampled at 3 traverse points located at 16.7, 50.0, and 83.3% of the measurement line ('3-point long line'). If the duct is >12 inches in diameter <i>and</i> the sampling port location meets the two and half-diameter criterion of Section 11.1.1 of Method 1 of 40 CFR part 60, Appendix A, the duct may be sampled at '3-point long line'; otherwise, conduct the stratification testing and select sampling points according to Section 8.1.2 of Method 7E of 40 CFR part 60, Appendix A.
		ii. Determine the O <sub>2</sub> concentration of the stationary internal combustion engine exhaust at the sampling port location;	(2) Method 3, 3A, or 3B <sup>b</sup> of 40 CFR part 60, appendix A-2 or ASTM Method D6522-00 (Reapproved 2005) <sup>ad</sup>	(b) Measurements to determine O <sub>2</sub> concentration must be made at the same time as the measurements for VOC concentration.
		iii. If necessary, determine the exhaust flowrate of the stationary internal combustion engine exhaust;	(3) Method 2 or 2C of 40 CFR 60, appendix A-1 or Method 19 of 40 CFR part 60, appendix A-7	
		iv. If necessary, measure moisture content of the stationary internal	(4) Method 4 of 40 CFR part 60, appendix A-3, Method 320 of 40 CFR part 63,	(c) Measurements to determine moisture must be made at the same time as the measurement for VOC

For each	Complying with the requirement to	You must	Using	According to the following requirements
		combustion engine exhaust at the sampling port location; and	appendix A <sup>e</sup> , or ASTM Method D6348-03 <sup>de</sup>	concentration.
		v. Measure VOC at the exhaust of the stationary internal combustion engine; if using a control device, the sampling site must be located at the outlet of the control device	(5) Methods 25A and 18 of 40 CFR part 60, appendices A-6 and A-7, Method 25A with the use of a hydrocarbon cutter as described in 40 CFR 1065.265, Method 18 of 40 CFR part 60, appendix A-6 <sup>ce</sup> , Method 320 of 40 CFR part 63, appendix A <sup>e</sup> , or ASTM Method D6348-03 <sup>de</sup>	(d) Results of this test consist of the average of the three 1-hour or longer runs.

<sup>a</sup>Also, you may petition the Administrator for approval to use alternative methods for portable analyzer.

<sup>b</sup>You may use ASME PTC 19.10-1981, Flue and Exhaust Gas Analyses, for measuring the O<sub>2</sub> content of the exhaust gas as an alternative to EPA Method 3B. AMSE PTC 19.10-1981 incorporated by reference, see 40 CFR 60.17

<sup>c</sup>You may use EPA Method 18 of 40 CFR part 60, appendix A-6, provided that you conduct an adequate pre-survey test prior to the emissions test, such as the one described in OTM 11 on EPA's Web site (<http://www.epa.gov/ttn/emc/prelim/otm11.pdf>).

<sup>d</sup>Incorporated by reference; see 40 CFR 60.17.

<sup>e</sup>You must meet the requirements in §60.4245(d).

**Table 3 to Subpart JJJJ of Part 60—Applicability of General Provisions to Subpart JJJJ**

[As stated in §60.4246, you must comply with the following applicable General Provisions]

General provisions citation	Subject of citation	Applies to subpart	Explanation
§60.1	General applicability of the General Provisions	Yes	
§60.2	Definitions	Yes	Additional terms defined in §60.4248.
§60.3	Units and abbreviations	Yes	
§60.4	Address	Yes	
§60.5	Determination of construction or modification	Yes	
§60.6	Review of plans	Yes	
§60.7	Notification and Recordkeeping	Yes	Except that §60.7 only applies as specified in §60.4245.

General provisions citation	Subject of citation	Applies to subpart	Explanation
§60.8	Performance tests	Yes	Except that §60.8 only applies to owners and operators who are subject to performance testing in subpart JJJJ.
§60.9	Availability of information	Yes	
§60.10	State Authority	Yes	
§60.11	Compliance with standards and maintenance requirements	Yes	Requirements are specified in subpart JJJJ.
§60.12	Circumvention	Yes	
§60.13	Monitoring requirements	No	
§60.14	Modification	Yes	
§60.15	Reconstruction	Yes	
§60.16	Priority list	Yes	
§60.17	Incorporations by reference	Yes	
§60.18	General control device requirements	No	
§60.19	General notification and reporting requirements	Yes	

Table 4 to Subpart JJJ of Part 60—Applicability of Mobile Source Provisions for Manufacturers Participating in the Voluntary Certification Program and Certifying Stationary SI ICE to Emission Standards in Table 1 of Subpart JJJJ

[As stated in §60.4247, you must comply with the following applicable mobile source provisions if you are a manufacturer participating in the voluntary certification program and certifying stationary SI ICE to emission standards in Table 1 of subpart JJJJ]

Mobile source provisions citation	Subject of citation	Applies to subpart	Explanation
1048 subpart A	Overview and Applicability	Yes	
1048 subpart B	Emission Standards and Related Requirements	Yes	Except for the specific sections below.
1048.101	Exhaust Emission Standards	No	
1048.105	Evaporative Emission Standards	No	
1048.110	Diagnosing Malfunctions	No	
1048.140	Certifying Blue Sky Series Engines	No	
1048.145	Interim Provisions	No	

Mobile source provisions citation	Subject of citation	Applies to subpart	Explanation
1048 subpart C	Certifying Engine Families	Yes	Except for the specific sections below.
1048.205(b)	AECD reporting	Yes	
1048.205(c)	OBD Requirements	No	
1048.205(n)	Deterioration Factors	Yes	Except as indicated in 60.4247(c).
1048.205(p)(1)	Deterioration Factor Discussion	Yes	
1048.205(p)(2)	Liquid Fuels as they require	No	
1048.240(b)(c)(d)	Deterioration Factors	Yes	
1048 subpart D	Testing Production-Line Engines	Yes	
1048 subpart E	Testing In-Use Engines	No	
1048 subpart F	Test Procedures	Yes	
1065.5(a)(4)	Raw sampling (refers reader back to the specific emissions regulation for guidance)	Yes	
1048 subpart G	Compliance Provisions	Yes	
1048 subpart H	Reserved		
1048 subpart I	Definitions and Other Reference Information	Yes	
1048 appendix I and II	Yes		
1065 (all subparts)	Engine Testing Procedures	Yes	Except for the specific section below.
1065.715	Test Fuel Specifications for Natural Gas	No	
1068 (all subparts)	General Compliance Provisions for Nonroad Programs	Yes	Except for the specific sections below.
1068.245	Hardship Provisions for Unusual Circumstances	No	
1068.250	Hardship Provisions for Small-Volume Manufacturers	No	
1068.255	Hardship Provisions for Equipment Manufacturers and Secondary Engine Manufacturers	No	

**Technical Support Document  
for  
Air Emission Permit No. 11500038-101**

This technical support document (TSD) is intended for all parties interested in the permit and to meet the requirements that have been set forth by the federal and state regulations (40 CFR § 70.7(a)(5) and Minn. R. 7007.0850, subp. 1). The purpose of this document is to provide the legal and factual justification for each applicable requirement or policy decision considered in the determination to issue the permit.

**1. General information**

**1.1 Applicant and stationary source location**

**Table 1. Applicant and source address**

<b>Applicant/Address</b>	<b>Stationary source/Address</b> (SIC Code: 4922 - Natural Gas Transmission)
Northern Natural Gas Co 1111 103rd St S Omaha, Nebraska 68124-1072	Northern Natural Gas Co - Hinckley 21892 Lone Pine Rd Hinckley, MN 55037
Contact: Kelly Henry Phone: 651-456-1712	

**1.2 Facility description**

Northern Natural Gas Company - Hinckley is a natural gas compressor station located in Hinckley, Minnesota. Compressor stations compress natural gas to a specified pressure along natural gas pipelines allowing the gas to continue moving through the pipeline to an intended recipient. The main sources of air pollution are a natural gas-fired turbine, natural gas-fired, four-stroke, rich burn, spark ignition emergency engine, and a process heater. The facility also includes fugitive sources comprising of flanges, compressor seals, and valves. Nitrogen oxides (NO<sub>x</sub>) and carbon monoxide (CO) are the primary pollutants of concern.

**1.3 Description of the activities allowed by this permit action**

This is a first time State permit for a new facility that will include one natural gas-fired turbine (EQUI 1), a natural gas-fired, four-stroke, rich burn, spark ignition emergency engine (EQUI 2), and a process heater (insignificant activity) with their associated stacks (STRU 1 and STRU 2). This permit also adds the following fugitive sources to the permit: flanges (FUGI 1), compressor seals (FUGI 2), and valves (FUGI 3). There is also a compressor building (STRU 4) and an auxiliary building (STRU 5). The turbine (EQUI 1) is a Solar Brand combustor equipped with built-in SoLoNO<sub>x</sub> technology (lean-burn, pre-mix combustion) which reduces NO<sub>x</sub> and CO formation.

The Minnesota Pollution Control Agency (MPCA) has a combined operating and construction permitting program under Minn. R. ch. 7007. Under that authority, this permit action authorizes construction.

**1.4 Facility emissions**

**Table 2. Total facility potential to emit summary**

	<b>PM</b> tpy	<b>PM<sub>10</sub></b> tpy	<b>PM<sub>2.5</sub></b> tpy	<b>SO<sub>2</sub></b> tpy	<b>NO<sub>x</sub></b> tpy	<b>CO</b> tpy	<b>CO<sub>2e</sub></b> tpy	<b>VOC</b> tpy	<b>Single HAP*</b> tpy	<b>All HAPs</b> tpy
Total facility limited potential emissions	5.01	5.01	5.01	0.50	25.9	29.4	42,541	15.3	0.27	0.39

\*Maximum Single HAP is Formaldehyde

**Table 3. Facility classification**

<b>Classification</b>	<b>Major</b>	<b>Synthetic minor/area</b>	<b>Minor/Area</b>
New Source Review			X
Part 70			X
Part 63			X

## 2. Regulatory and/or statutory basis

### 2.1 New source review (NSR)

The facility is a minor source under New Source Review regulations.

### 2.2 Part 70 permit program

The facility is a nonmajor source under the Part 70 permit program.

### 2.3 New source performance standards (NSPS)

#### 2.3.1 NSPS KKKK (Stationary Combustion Turbines)

The New Source Performance Standards for Stationary Combustion Turbines applies to EQUI 1 since the turbine commenced construction after February 18, 2005 and has a heat input at peak load equal to or greater than 10 MMBtu per hour.

#### 2.3.2 NSPS JJJJ (Stationary Spark Ignition Internal Combustion Engines)

The New Source Performance Standards for Stationary Spark Ignition Internal Combustion Engines applies to EQUI 2 since the emergency generator commenced construction after July 12, 2005, was manufactured after January 1, 2009, and a maximum engine power greater than 25 HP. EQUI 2 is a certified emergency engine and does not require performance testing as indicated in 40 CFR § 63.4243(a)(1).

### 2.4 National emission standards for hazardous air pollutants (NESHAP)

#### 2.4.1 NESHAP ZZZZ (Reciprocating Internal Combustion Engines)

The National Emission Standards for Hazardous Air Pollutants for Reciprocating Internal Combustion Engines applies to EQUI 2 because it is considered to be a new stationary RICE per 40 CFR § 63.6590(a)(2)(i). EQUI 2 meets the requirements of 40 CFR pt. 63, subp. ZZZZ by meeting the requirements of 40 CFR pt. 60, subp. JJJJ as established at 40 CFR § 63.6590(c)(1). No further requirements of 40 CFR pt. 63, subp. ZZZZ apply to EQUI 2.

### 2.5 Compliance assurance monitoring (CAM)

CAM does not apply to any emission unit at this Facility because none of the emission units use control equipment and none of the emission units has pre-control emissions that exceed 100 percent of the part 70 major source threshold for the pollutant.

### 2.6 Environmental review and air emissions risk analysis (AERA)

This permit is not subject to environmental review i.e., an Environmental Assessment Worksheet (EAW), and does not trigger any requirement to perform an Air Emissions Analysis.

## 2.7 Regulatory Overview

**Table 4. Regulatory overview of facility**

Subject item*	Applicable regulations	Rationale
EQUI 1 – Natural Gas-Fired Turbine	Minn. R. 7011.2300	Standards of Performance for Stationary Internal Combustion Engines. Fuel limited to natural gas only, by design. Sulfur content of fuel limited to 0.0015 percent by weight.
	40 CFR 60, subp. KKKK Minn. R. 7011.2375	NSPS for Stationary Combustion Turbines. Applicability criteria include: <ul style="list-style-type: none"> <li>turbine constructed after February 18, 2005;</li> <li>turbine heat input greater than 10 MMBtu/hr.</li> </ul>
EQUI 2 – Emergency Generator	Minn. R. 7011.2300	Standards of Performance for Stationary Internal Combustion Engines. Fuel limited to natural gas only, by design. Sulfur content of fuel limited to 0.0015 percent by weight.
	40 CFR 60, subp. JJJJ Minn. R. 7011.2310	NSPS for Stationary Spark Ignition Internal Combustion Engines. Applicability criteria include: <ul style="list-style-type: none"> <li>engine manufactured on or after January 1, 2009 and constructed after June 12, 2006;</li> <li>non-certified engine; and</li> <li>Emergency, natural gas engine with maximum engine power greater than or equal to 500 hp.</li> </ul>
	40 CFR 63, subp. ZZZZ Minn. R. 7011.8150	NESHAP for Stationary Reciprocating Internal Combustion Engines. EQUI 2 is a new affected source subject to 40 CFR pt. 63, subp. ZZZZ. Under 40 CFR § 63.6590(c) the engine complies with the requirements 40 CFR pt. 63, subp. ZZZZ by complying with the requirements of 40 CFR pt. 60, subp. JJJJ and no further requirements apply under 40 CFR pt. 63, subp. ZZZZ.

\*Location of the requirement in the permit (e.g., EQUI 1, STRU 2, etc.).

## 3. Technical information

### 3.1 Calculations of potential to emit (PTE)

Emission factors for EQUI 1 (turbine) are from manufacturer data (NO<sub>x</sub>, CO, VOC, and PM), Minn. R. 7011.2300 (SO<sub>2</sub>), and AP-42 Table 3.1-3 (HAPs). The turbine is equipped with SoLoNO<sub>x</sub> to minimize emissions and PACO logic emissions controls to minimize emissions when ambient temperatures are less than zero degrees Fahrenheit. The pound per hour emissions calculations use the worst case factors for temperatures below zero degrees Fahrenheit. The ton per year emissions calculations account for the annual temperature variation and use different pound per MMBtu factors for operations above and below zero degrees Fahrenheit.

Emission factors for EQUI 2 (emergency generator) are from 40 CFR pt. 60, subp. JJJJ, Table 1 (NO<sub>x</sub>, CO, and VOC) and AP-42 Table 3.2-3 (HAPs, PM, and SO<sub>2</sub>). The annual ton per year emissions are limited to 500 hours per year for emergency engines.

Emission factors for fugitive emissions are from MPCA Form EC-14, Table EC-14.1. The percent VOC from a representative gas analysis estimates the VOC content is five percent.

Attachment 1 to this TSD contains a summary of the PTE of the Facility.

### 3.2 Monitoring

In accordance with the Clean Air Act, it is the responsibility of the owner or operator of a facility to have sufficient knowledge of the facility to certify that the facility is in compliance with all applicable requirements.

In evaluating the monitoring included in the permit, the MPCA considered the following:

- the likelihood of the facility violating the applicable requirements;
- whether add-on controls are necessary to meet the emission limits;
- the variability of emissions over time;
- the type of monitoring, process, maintenance, or control equipment data already available for the emission unit;
- the technical and economic feasibility of possible periodic monitoring methods; and
- the kind of monitoring found on similar units elsewhere.

The Table below summarizes the monitoring requirements.

**Table 5. Monitoring**

Subject Item*	Requirement (basis)	What is the monitoring?	Why is this monitoring adequate?
EQUI 1 – Natural Gas-Fired Turbine	Nitrogen Oxides <= 25 parts per million at 15 percent oxygen, or 150 ng/J of useful output (1.2 lb/MWh). [40 CFR 60.4320(a), 40 CFR pt. 60, subp. KKKK (Table 1), Minn. R. 7011.2375]	Performance testing	Monitoring required by the NSPS is adequate to demonstrate compliance with the requirements because this standard was promulgated after November 15, 1990, and post-November 15, 1990, NSPS and NESHAPs contain adequate monitoring requirements.
	Sulfur Dioxide <= 110 nanograms per joule (0.90 pounds per megawatt-hour (lb/MWh)) gross output. [40 CFR 60.4330(a)(1), Minn. R. 7011.2375]		
	Opacity <= 20 percent opacity once operating temperatures have been attained. [Minn. R. 7011.2300, subp. 1]	None	The opacity requirement applies when the engine is warmed up. The use of very low sulfur fuel ensures compliance with the opacity limit.
	Sulfur Dioxide <= 0.0015 pounds per million Btu heat input. [Minn. R. 7011.2300, subp. 2(B)]	Recordkeeping: Monthly fuel records	This unit uses natural gas only by design. Permit conditions limit sulfur content of fuel. The potential to emit from the unit is 0.0015 lb/MMBtu due to equipment design and allowable fuel.
EQUI 2 – Emergency Generator	Opacity <= 20 percent opacity once operating temperatures have been attained. [Minn. R. 7011.2300, subp. 1]	None	The opacity requirement applies when the engine is warmed up. The use of very low sulfur fuel ensures compliance with the opacity limit.
	Sulfur Dioxide <= 0.0015 pounds per million Btu heat input. [Minn. R. 7011.2300, subp. 2(B)]	Recordkeeping: Monthly fuel records	This unit uses natural gas only by design. Permit conditions limit sulfur content of fuel. The potential to emit from the unit is 0.0015 lb/MMBtu due to equipment design and allowable fuel.

Subject Item*	Requirement (basis)	What is the monitoring?	Why is this monitoring adequate?
	<p>Nitrogen Oxides &lt;= 2.0 grams per horsepower-hour. [40 CFR pt. 60, subp. JJJ, Minn. R. 7007.0400, subp. 3, Minn. R. 7011.2310, 40 CFR pt. 63, subp. ZZZZ]</p> <p>Volatile Organic Compounds &lt;= 1.0 grams per horsepower-hour. [40 CFR 60.4233(e), 40 CFR pt. 60, subp. JJJ(Table 1), Minn. R. 7011.2310, 40 CFR pt. 63, subp. ZZZZ]</p> <p>Carbon Monoxide &lt;= 4.0 grams per horsepower-hour. [40 CFR 60.4233(e), 40 CFR pt. 60, subp. JJJ(Table 1), Minn. R. 7011.2310, 40 CFR pt. 63, subp. ZZZZ]</p>	Recordkeeping: fuel type and usage on monthly basis	Monitoring required by the NSPS is adequate to demonstrate compliance with the requirements because this standard was promulgated after November 15, 1990, and post-November 15, 1990, NSPS and NESHAPs contain adequate monitoring requirements. Compliance with NESHAP subp. ZZZZ is shown by complying with the requirements of NSPS subp. JJJ.

\*Location of the requirement in the permit (e.g., EQUI 1, STRU 2, etc.).

### 3.3 Insignificant activities

Northern Natural Gas Co - Hinckley has one operation which is classified as an insignificant activity under the MPCA's permitting rules. This operation is listed in Appendix A to the permit.

**Table 6. Insignificant activities**

Insignificant activity	General applicable emission limit	Discussion
Indirect heating equipment with a heat input capacity less than 420,000 Btu/hour, etc.	PM <= 0.4 lb/MMBtu Opacity <= 20% with exceptions (Minn. R. 7011.0515)	The Facility has one process heater with heat input capacity of 280,000 Btu/hr. For this unit, based on the fuels used and EPA published emissions factors, it is highly unlikely that it could violate the applicable requirements.

### 3.4 Permit organization

Historically the MPCA's standard practice is to incorporate federal requirements into the permit as individual permit requirements. In this permit, federal requirements from NESHAPs and NSPS limits and submittal/actions are included individually in the permit. For the remaining portions of the rule, a requirement in Section 5 of the permit lists the citations of all of the applicable parts of the standard along with a reference to the permit appendix where the full text of the standard is included. 40 CFR pt. 60, subps. A, KKKK, and JJJ are included in Appendices B, C, and D, respectively.

### 3.5 Environmental Justice Additional Engagement

The Minnesota Pollution Control Agency's (MPCA) mission is to protect and improve our environment and enhance human health. The agency is committed to ensuring that pollution does not have a disproportionate impact on any people group—the principle of environmental justice. The MPCA defines environmental justice as the fair treatment and meaningful involvement of all people regardless of race, color, national origin, or income with respect to the development, implementation, and enforcement of environmental laws, regulations, and policies. The impacts of pollution vary across Minnesota, and historical

inequities have exposed some populations (such as: people of color, low-income households, and people with underlying health issues) to greater health impacts from pollution.

Permits are an important tool used to protect the environment and people in Minnesota. The permitting process is a critical opportunity to identify activities and pollutants that pose the greatest risk to neighborhoods of environmental concern, to evaluate potential pollution reduction efforts, and to allow for community involvement in an accessible and meaningful manner. Additional community outreach allows the MPCA and the facilities to understand and address community concerns and establish or enhance relationships with the surrounding community members.

The Facility is located in an area where a significant number of residents reported income less than 185% of the federal poverty level (the EPA's income threshold for EJ areas). As a part of this permit action, there was an effort to involve the community in a meaningful way. The MPCA performed additional outreach by contacting the City of Hinckley and Pine County officials.

### **3.6 Comments received**

Public Notice Period: 12/9/2020 – 1/9/2021

EPA Review Period: 12/9/2020 – 1/9/2021

No comments were received from the public during the public notice period. Because this is a state permit, the EPA review period ended with the public comment period on January 8, 2021. No comments were received from the EPA during their review period.

## **4. Permit fee assessment**

This permit action is the issuance of an individual state permit based on an application received August 6, 2020. This action is not considered a reissuance of an individual state or Part 70 operating permit; therefore, the application fees apply under Minn. R. 7002.0019. Attachment 3 to this TSD contains the MPCA's assessment of Application and Additional Points used to determine the permit application fee for this permit action as required by Minn. R. 7002.0019. Additional points apply toward review of 40 CFR pt. 60, subps. KKKK and JJJJ, and 40 CFR pt. 63, subp. ZZZZ.

## **5. Conclusion**

Based on the information provided by Northern Natural Gas Co - Hinckley the MPCA has reasonable assurance that the proposed operation of the emission facility, as described in the Air Emission Permit No. 11500038-101 and this TSD, will not cause or contribute to a violation of applicable federal regulations and Minnesota Rules.

Staff members on permit team: Hannah Braatz (permit engineer)  
Marshall Cole (peer reviewer)  
Beckie Olson (data coordinator)  
Andy Place (performance testing)  
Steve Palzkill (compliance and enforcement)  
Laurie O'Brien (administrative support)

Tempo Activities: State Permit (IND20200001)

Attachments: 1. PTE summary calculation spreadsheets  
2. Subject item inventory and facility requirements  
3. Points Calculator

**Attachment 1 – PTE Summary Calculation Spreadsheets**

1a) AQ Facility ID No.:

1b) Agency Interest ID No.:

2) Facility Name: Northern Natural Gas Company - Hinckley

You may use and submit this spreadsheet in place of Form GI-07. Follow the instructions for Form GI-07 to complete this spreadsheet. This spreadsheet can be copied into a tab for your emissions spreadsheet and must be submitted on a CD with your application. If you need to provide emissions information for more emissions units, add more sets of columns (3a through 3f) to the right as needed in the Emissions by Source table. If you need to provide information for more pollutants, add rows as needed.

Emissions by Source Table

Emissions by Source Table

EU001					EU002					EU003							
3a) Delta ID No.:					3a) Delta ID No.:					3a) Delta ID No.:							
3b) Tempo SI ID No.:					3b) Tempo SI ID No.:					3b) Tempo SI ID No.:							
EQUI 1					EQUI 2					FUGI 3							
3c) Pollutant Name	3d) CAS #	3e) Potential			3f) Actual tpy	3c) Pollutant Name	3d) CAS #	3e) Potential			3f) Actual tpy	3c) Pollutant Name	3d) CAS #	3e) Potential			3f) Actual tpy
		Lbs per Hr	Unc tpy	Limited tpy				Lbs per Hr	Unc tpy	Limited tpy				Lbs per Hr	Unc tpy	Limited tpy	
NOx		14.29	25.08	25.08		NOx		3.40	14.87	0.85		NOx					
VOC		5.92	13.75	13.75		VOC		1.70	7.44	0.42		VOC		0.18	0.78	0.78	
CO		20.71	27.72	27.72		CO		6.79	29.74	1.70		CO					
PM		1.27	4.98	4.98		PM		0.13	0.55	0.03		PM					
PM <sub>10</sub>		1.27	4.98	4.98		PM <sub>10</sub>		0.13	0.55	0.03		PM <sub>10</sub>					
PM <sub>2.5</sub>		1.27	4.98	4.98		PM <sub>2.5</sub>		0.13	0.55	0.03		PM <sub>2.5</sub>					
SO2		0.13	0.50	0.50		SO2		0.0097	0.042	0.0024		SO2					
1,3-Butadiene		3.65E-05	1.43E-04	1.43E-04		1,3-Butadiene		4.28E-03	1.87E-02	1.07E-03							
Acetaldehyde		3.39E-03	1.33E-02	1.33E-02		Acetaldehyde		1.80E-02	7.89E-02	7.89E-02							
Acrolein		5.43E-04	2.12E-03	2.12E-03		Acrolein		1.70E-02	7.44E-02	4.24E-03							
Benzene		1.02E-03	3.98E-03	3.98E-03		Benzene		1.02E-02	4.47E-02	2.55E-03							
Carbon Tetrachloride		--	--	--		Carbon Tetrachloride		1.14E-04	5.00E-04	2.86E-05							
Chlorobenzene		--	--	--		Chlorobenzene		8.33E-05	3.65E-04	2.08E-05							
Chloroform		--	--	--		Chloroform		8.84E-05	3.87E-04	2.21E-05							
Ethylbenzene		2.71E-03	1.06E-02	1.06E-02		Ethylbenzene		1.60E-04	7.01E-04	4.00E-05							
Ethylene Dibromide		--	--	--		Ethylene Dibromide		1.38E-04	6.02E-04	3.44E-05							
Formaldehyde		6.02E-02	2.36E-01	2.36E-01		Formaldehyde		1.32E-01	5.80E-01	3.31E-02							
Methanol		--	--	--		Methanol		1.98E-02	8.65E-02	4.94E-03							
Methylene Chloride		--	--	--		Methylene Chloride		2.66E-04	1.16E-03	6.65E-05							
Naphthalene		1.10E-04	4.32E-04	4.32E-04		Naphthalene		6.27E-04	2.75E-03	1.57E-04							
POM		1.87E-04	7.30E-04	7.30E-04		POM		9.10E-04	3.99E-03	2.28E-04							
Propylene Oxide		2.46E-03	9.63E-03	9.63E-03		Propylene Oxide		--	--	--							
Styrene		--	--	--		Styrene		7.68E-05	3.36E-04	1.92E-05							
Toluene		1.10E-02	4.32E-02	4.32E-02		Toluene		3.60E-03	1.58E-02	9.01E-04							
Vinyl Chloride		--	--	--		Vinyl Chloride		4.64E-05	2.03E-04	1.16E-05							
Xylene		5.43E-03	2.12E-02	2.12E-02		Xylene		1.26E-03	5.51E-03	3.15E-04							
Total HAP		8.71E-02	3.41E-01	3.41E-01		Total HAP		2.05E-01	8.96E-01	5.12E-02							
CO <sub>2</sub>		9917.50	42309.12	42309.12		CO <sub>2</sub>		755.17	3307.64	188.79							
Methane		0.19	0.80	0.80		Methane		0.01	0.06	0.00							
N <sub>2</sub> O		0.02	0.08	0.08		N <sub>2</sub> O		0.00	0.01	0.00							
CO <sub>2</sub> e		9927.74	42352.82	42352.82		CO <sub>2</sub> e		755.95	3311.05	188.99							
1,1,2,2-Tetrachloroethane		--	--	--		1,1,2,2-Tetrachloroethane		9.68E-03	7.15E-04	4.08E-05							
1,1,2-Trichloroethane		--	--	--		1,1,2-Trichloroethane		9.88E-05	4.33E-04	2.47E-05							
1,3-Dichloropropane		--	--	--		1,3-Dichloropropane		8.20E-05	3.59E-04	2.05E-05							

Application is being submitted on a compact disc (CD), and the editable calculation spreadsheet(s) are included on the CD.

Application is being submitted on paper, and editable calculation spreadsheet(s) are included on an enclosed CD.

1a) AQ Facility ID No.: \_\_\_\_\_

1b) Agency Interest ID No.: \_\_\_\_\_

2) Facility Name: Northern Natural Gas Company - Hinckley

Emissions by Source Table

3a) Delta ID No.: FS003					3a) Delta ID No.: FS002						
3b) Tempo SI ID No.: FUGI 2					3b) Tempo SI ID No.: FUGI 1						
3c) Pollutant Name	3d) CAS #	3e) Potential			3f) Actual tpy	3c) Pollutant Name	3d) CAS #	3e) Potential			3f) Actual tpy
		Lbs per Hr	Unc tpy	Limited tpy				Lbs per Hr	Unc tpy	Limited tpy	
NOx					NOx						
VOC		0.07	0.31	0.31	VOC		0.003	0.014	0.014		
CO					CO						
PM					PM						
PM <sub>10</sub>					PM <sub>10</sub>						
PM <sub>2.5</sub>					PM <sub>2.5</sub>						
SO2					SO2						

Emissions Summary Table

4a) Pollutant Name	Potential (lb/hr)		4b) Potential (tons/year)	
	Hourly	Unrestricted	Unrestricted	Limited
NOx	17.69	39.95	25.93	
VOC	7.87	22.28	15.27	
CO	27.50	57.46	29.41	
PM	1.40	5.53	5.01	
PM <sub>10</sub>	1.40	5.53	5.01	
PM <sub>2.5</sub>	1.40	5.53	5.01	
SO2	0.14	0.54	0.50	
1,3-Butadiene	4.32E-03	1.89E-02	1.21E-03	
Acetaldehyde	2.14E-02	9.22E-02	9.22E-02	
Acrolein	1.75E-02	7.65E-02	6.37E-03	
Benzene	1.12E-02	4.87E-02	6.53E-03	
Carbon Tetrachloride	1.14E-04	5.00E-04	2.86E-05	
Chlorobenzene	8.33E-05	3.65E-04	2.08E-05	
Chloroform	8.84E-05	3.87E-04	2.21E-05	
Ethylbenzene	2.87E-03	1.13E-02	1.07E-02	
Ethylene Dibromide	1.38E-04	6.02E-04	3.44E-05	
Formaldehyde	1.93E-01	8.15E-01	2.69E-01	
Methanol	1.98E-02	8.65E-02	4.94E-03	
Methylene Chloride	2.66E-04	1.16E-03	6.65E-05	
Naphthalene	7.37E-04	3.18E-03	5.88E-04	
POM	1.10E-03	4.72E-03	9.58E-04	
Propylene Oxide	2.46E-03	9.63E-03	9.63E-03	
Styrene	7.68E-05	3.36E-04	1.92E-05	
Toluene	1.46E-02	5.89E-02	4.41E-02	
Vinyl Chloride	4.64E-05	2.03E-04	1.16E-05	
Xylene	6.68E-03	2.68E-02	2.16E-02	
Total HAP	0.29	1.24	0.39	
CO <sub>2</sub>	10,672.67	45,616.76	42,497.92	
Methane	0.20	0.86	0.80	
N <sub>2</sub> O	0.02	0.09	0.08	
CO <sub>2e</sub>	10,683.69	45,663.87	42,541.81	
1,1,2,2-Tetrachloroethane	9.68E-03	7.15E-04	4.08E-05	
1,1,2-Trichloroethane	9.88E-05	4.33E-04	2.47E-05	
1,3-Dichloropropane	8.20E-05	3.59E-04	2.05E-05	

**FACILITY-WIDE POTENTIAL EMISSIONS SUMMARY  
HINCKLEY COMPRESSOR STATION  
NORTHERN NATURAL GAS COMPANY**

Emissions Source	Emission Unit ID	Criteria Pollutants														
		NO <sub>x</sub>			VOC			CO			PM/PM <sub>10</sub> /PM <sub>2.5</sub>			Lead		
		(lb/hr)	(tpy)	Limited (tpy)	(lb/hr)	(tpy)	Limited (tpy)	(lb/hr)	(tpy)	Limited (tpy)	(lb/hr)	(tpy)	Limited (tpy)	(lb/hr)	(tpy)	Limited (tpy)
Solar Taurus 70-10802S Turbine	EQUI 1	14.29	25.08	25.08	5.92	13.75	13.75	20.71	27.72	27.72	1.27	4.98	4.98	--	--	--
Cummins GTA28E Emergency Generator	EQUI 2	3.40	14.87	0.85	1.70	7.44	0.42	6.79	29.74	1.70	0.13	0.55	0.031	--	--	--
Fugitive VOC Emissions - Valves	FUGI 3	--	--	--	0.18	0.78	0.78	--	--	--	--	--	--	--	--	--
Fugitive VOC Emissions - Compressor Seal	FUGI 2	--	--	--	0.07	0.31	0.31	--	--	--	--	--	--	--	--	--
Fugitive VOC Emissions - Flanges	FUGI 1	--	--	--	0.003	0.01	0.01	--	--	--	--	--	--	--	--	--
<b>Total Facility Emissions</b>		<b>17.69</b>	<b>39.95</b>	<b>25.93</b>	<b>7.87</b>	<b>22.28</b>	<b>15.27</b>	<b>27.50</b>	<b>57.46</b>	<b>29.41</b>	<b>1.40</b>	<b>5.53</b>	<b>5.01</b>	<b>0.00E+00</b>	<b>0.00E+00</b>	<b>0.00E+00</b>

Emissions Source	Emission Unit ID	Hazardous Air Pollutants														
		1,3-Butadiene			Acetaldehyde			Acrolein			Arsenic			Benzene		
		(lb/hr)	(tpy)	Limited (tpy)	(lb/hr)	(tpy)	Limited (tpy)	(lb/hr)	(tpy)	Limited (tpy)	(lb/hr)	(tpy)	Limited (tpy)	(lb/hr)	(tpy)	Limited (tpy)
Solar Taurus 70-10802S Turbine	EQUI 1	3.65E-05	1.43E-04	1.43E-04	3.39E-03	1.33E-02	1.33E-02	5.43E-04	2.12E-03	2.12E-03	--	--	--	1.02E-03	3.98E-03	3.98E-03
Cummins GTA28E Emergency Generator	EQUI 2	4.28E-03	1.87E-02	1.07E-03	1.80E-02	7.89E-02	4.50E-03	1.70E-02	7.44E-02	4.24E-03	--	--	--	1.02E-02	4.47E-02	2.55E-03
Fugitive VOC Emissions - Valves	FUGI 3	--	--	--	--	--	--	--	--	--	--	--	--	--	--	--
Fugitive VOC Emissions - Compressor Seal	FUGI 2	--	--	--	--	--	--	--	--	--	--	--	--	--	--	--
Fugitive VOC Emissions - Flanges	FUGI 1	--	--	--	--	--	--	--	--	--	--	--	--	--	--	--
<b>Total Facility Emissions</b>		<b>4.32E-03</b>	<b>1.89E-02</b>	<b>1.21E-03</b>	<b>2.14E-02</b>	<b>9.22E-02</b>	<b>1.78E-02</b>	<b>1.75E-02</b>	<b>7.65E-02</b>	<b>6.37E-03</b>	<b>0.00E+00</b>	<b>0.00E+00</b>	<b>0.00E+00</b>	<b>1.12E-02</b>	<b>4.87E-02</b>	<b>6.53E-03</b>

**FACILITY-WIDE POTENTIAL EMISSIONS SUMMARY  
HINCKLEY COMPRESSOR STATION  
NORTHERN NATURAL GAS COMPANY**

Emissions Source	Emission Unit ID	SO <sub>2</sub>			GHG CO <sub>2</sub> e			HAPs					
		(lb/hr)	(tpy)	Limited (tpy)	(lb/hr)	Limited (tpy)		Single- HAP			Total HAP		
						(tpy)	(tpy)	(lb/hr)	(tpy)	Limited (tpy)	(lb/hr)	(tpy)	Limited (tpy)
Solar Taurus 70-10802S Turbine	EQUI 1	0.13	0.50	0.50	9,928	42,353	42,353	--	--	--	8.71E-02	3.41E-01	3.41E-01
Cummins GTA28E Emergency Generator	EQUI 2	0.010	0.042	0.0024	756	3,311	189	--	--	--	2.05E-01	8.96E-01	5.12E-02
Fugitive VOC Emissions - Valves	FUGI 3	--	--	--	--	--	--	--	--	--	--	--	--
Fugitive VOC Emissions - Compressor Seal	FUGI 2	--	--	--	--	--	--	--	--	--	--	--	--
Fugitive VOC Emissions - Flanges	FUGI 1	--	--	--	--	--	--	--	--	--	--	--	--
<b>Total Facility Emissions</b>		<b>0.14</b>	<b>0.54</b>	<b>0.50</b>	<b>10684</b>	<b>45664</b>	<b>42542</b>	<b>0.19</b>	<b>0.82</b>	<b>0.27</b>	<b>0.29</b>	<b>1.24</b>	<b>0.39</b>

Emissions Source	Emission Unit ID	Hazardous Air Pollutants											
		Beryllium			Biphenyl			Cadmium			Carbon Tetrachloride		
		(lb/hr)	(tpy)	Limited (tpy)	(lb/hr)	(tpy)	Limited (tpy)	(lb/hr)	(tpy)	Limited (tpy)	(lb/hr)	(tpy)	Limited (tpy)
Solar Taurus 70-10802S Turbine	EQUI 1	--	--	--	--	--	--	--	--	--	--	--	--
Cummins GTA28E Emergency Generator	EQUI 2	--	--	--	--	--	--	--	--	--	1.14E-04	5.00E-04	2.86E-05
Fugitive VOC Emissions - Valves	FUGI 3	--	--	--	--	--	--	--	--	--	--	--	--
Fugitive VOC Emissions - Compressor Seal	FUGI 2	--	--	--	--	--	--	--	--	--	--	--	--
Fugitive VOC Emissions - Flanges	FUGI 1	--	--	--	--	--	--	--	--	--	--	--	--
<b>Total Facility Emissions</b>		<b>#####</b>	<b>0.00E+00</b>	<b>0.00E+00</b>	<b>0.00E+00</b>	<b>0.00E+00</b>	<b>0.00E+00</b>	<b>0.00E+00</b>	<b>0.00E+00</b>	<b>0.00E+00</b>	<b>1.14E-04</b>	<b>5.00E-04</b>	<b>2.86E-05</b>

**FACILITY-WIDE POTENTIAL EMISSIONS SUMMARY  
HINCKLEY COMPRESSOR STATION  
NORTHERN NATURAL GAS COMPANY**

Emissions Source	Emission Unit ID	Hazardous Air Pollutants														
		Chlorobenzene			Chloroform			Chromium			Cobalt			Dichlorobenzene		
		(lb/hr)	(tpy)	Limited (tpy)	(lb/hr)	(tpy)	Limited (tpy)	(lb/hr)	(tpy)	Limited (tpy)	(lb/hr)	(tpy)	Limited (tpy)	(lb/hr)	(tpy)	Limited (tpy)
Solar Taurus 70-10802S Turbine	EQUI 1	--	--	--	--	--	--	--	--	--	--	--	--	--	--	--
Cummins GTA28E Emergency Generator	EQUI 2	8.33E-05	3.65E-04	2.08E-05	8.84E-05	3.87E-04	2.21E-05	--	--	--	--	--	--	--	--	--
Fugitive VOC Emissions - Valves	FUGI 3	--	--	--	--	--	--	--	--	--	--	--	--	--	--	--
Fugitive VOC Emissions - Compressor Seal	FUGI 2	--	--	--	--	--	--	--	--	--	--	--	--	--	--	--
Fugitive VOC Emissions - Flanges	FUGI 1	--	--	--	--	--	--	--	--	--	--	--	--	--	--	--
<b>Total Facility Emissions</b>		<b>8.33E-05</b>	<b>3.65E-04</b>	<b>2.08E-05</b>	<b>8.84E-05</b>	<b>3.87E-04</b>	<b>2.21E-05</b>	<b>0.00E+00</b>	<b>0.00E+00</b>	<b>0.00E+00</b>	<b>0.00E+00</b>	<b>0.00E+00</b>	<b>0.00E+00</b>	<b>0.00E+00</b>	<b>0.00E+00</b>	<b>0.00E+00</b>

Emissions Source	Emission Unit ID	Hazardous Air Pollutants														
		n-Hexane			Manganese			Mercury			Methanol			Methylene Chloride		
		(lb/hr)	(tpy)	Limited (tpy)	(lb/hr)	(tpy)	Limited (tpy)	(lb/hr)	(tpy)	Limited (tpy)	(lb/hr)	(tpy)	Limited (tpy)	(lb/hr)	(tpy)	Limited (tpy)
Solar Taurus 70-10802S Turbine	EQUI 1	--	--	--	--	--	--	--	--	--	--	--	--	--	--	--
Cummins GTA28E Emergency Generator	EQUI 2	--	--	--	--	--	--	--	--	--	1.98E-02	8.65E-02	4.94E-03	2.66E-04	1.16E-03	6.65E-05
Fugitive VOC Emissions - Valves	FUGI 3	--	--	--	--	--	--	--	--	--	--	--	--	--	--	--
Fugitive VOC Emissions - Compressor Seal	FUGI 2	--	--	--	--	--	--	--	--	--	--	--	--	--	--	--
Fugitive VOC Emissions - Flanges	FUGI 1	--	--	--	--	--	--	--	--	--	--	--	--	--	--	--
<b>Total Facility Emissions</b>		<b>0.00</b>	<b>0.00</b>	<b>0.00</b>	<b>0.00E+00</b>	<b>0.00E+00</b>	<b>0.00E+00</b>	<b>0.00E+00</b>	<b>0.00E+00</b>	<b>0.00E+00</b>	<b>1.98E-02</b>	<b>8.65E-02</b>	<b>4.94E-03</b>	<b>2.66E-04</b>	<b>1.16E-03</b>	<b>6.65E-05</b>

**FACILITY-WIDE POTENTIAL EMISSIONS SUMMARY  
HINCKLEY COMPRESSOR STATION  
NORTHERN NATURAL GAS COMPANY**

Emissions Source	Emission Unit ID	Hazardous Air Pollutants											
		Ethylbenzene			Ethylene Dibromide			Formaldehyde			Hexane		
		(lb/hr)	(tpy)	Limited (tpy)	(lb/hr)	(tpy)	Limited (tpy)	(lb/hr)	(tpy)	Limited (tpy)	(lb/hr)	(tpy)	Limited (tpy)
Solar Taurus 70-10802S Turbine	EQUI 1	2.71E-03	1.06E-02	1.06E-02	--	--	--	6.02E-02	0.24	2.36E-01	--	--	--
Cummins GTA28E Emergency Generator	EQUI 2	1.60E-04	7.01E-04	4.00E-05	1.38E-04	6.02E-04	3.44E-05	1.32E-01	0.58	3.31E-02	--	--	--
Fugitive VOC Emissions - Valves	FUGI 3	--	--	--	--	--	--	--	--	--	--	--	--
Fugitive VOC Emissions - Compressor Seal	FUGI 2	--	--	--	--	--	--	--	--	--	--	--	--
Fugitive VOC Emissions - Flanges	FUGI 1	--	--	--	--	--	--	--	--	--	--	--	--
<b>Total Facility Emissions</b>		<b>2.87E-03</b>	<b>1.13E-02</b>	<b>1.07E-02</b>	<b>1.38E-04</b>	<b>6.02E-04</b>	<b>3.44E-05</b>	<b>1.93E-01</b>	<b>8.15E-01</b>	<b>2.69E-01</b>	<b>0.00E+00</b>	<b>0.00E+00</b>	<b>0.00E+00</b>

Emissions Source	Emission Unit ID	Hazardous Air Pollutants											
		Naphthalene			Nickel			Lead			POM		
		(lb/hr)	(tpy)	Limited (tpy)	(lb/hr)	(tpy)	Limited (tpy)	(lb/hr)	(tpy)	Limited (tpy)	(lb/hr)	(tpy)	Limited (tpy)
Solar Taurus 70-10802S Turbine	EQUI 1	1.10E-04	4.32E-04	4.32E-04	--	--	--	--	--	--	1.87E-04	7.30E-04	7.30E-04
Cummins GTA28E Emergency Generator	EQUI 2	6.27E-04	2.75E-03	1.57E-04	--	--	--	--	--	--	9.10E-04	3.99E-03	2.28E-04
Fugitive VOC Emissions - Valves	FUGI 3	--	--	--	--	--	--	--	--	--	--	--	--
Fugitive VOC Emissions - Compressor Seal	FUGI 2	--	--	--	--	--	--	--	--	--	--	--	--
Fugitive VOC Emissions - Flanges	FUGI 1	--	--	--	--	--	--	--	--	--	--	--	--
<b>Total Facility Emissions</b>		<b>7.37E-04</b>	<b>3.18E-03</b>	<b>5.88E-04</b>	<b>0.00E+00</b>	<b>0.00E+00</b>	<b>0.00E+00</b>	<b>0.00E+00</b>	<b>0.00E+00</b>	<b>0.00E+00</b>	<b>1.10E-03</b>	<b>4.72E-03</b>	<b>9.58E-04</b>

**FACILITY-WIDE POTENTIAL EMISSIONS SUMMARY  
HINCKLEY COMPRESSOR STATION  
NORTHERN NATURAL GAS COMPANY**

Emissions Source	Emission Unit ID	Hazardous Air Pollutants														
		Propylene Oxide			Selenium			Styrene			Toluene			Vinyl Chloride		
		(lb/hr)	(tpy)	Limited (tpy)	(lb/hr)	(tpy)	Limited (tpy)	(lb/hr)	(tpy)	Limited (tpy)	(lb/hr)	(tpy)	Limited (tpy)	(lb/hr)	(tpy)	Limited (tpy)
Solar Taurus 70-10802S Turbine	EQUI 1	2.46E-03	9.63E-03	9.63E-03	--	--	--	--	--	--	1.10E-02	4.32E-02	4.32E-02	--	--	--
Cummins GTA28E Emergency Generator	EQUI 2	--	--	--	--	--	--	7.68E-05	3.36E-04	1.92E-05	3.60E-03	1.58E-02	9.01E-04	4.64E-05	2.03E-04	1.16E-05
Fugitive VOC Emissions - Valves	FUGI 3	--	--	--	--	--	--	--	--	--	--	--	--	--	--	--
Fugitive VOC Emissions - Compressor Seal	FUGI 2	--	--	--	--	--	--	--	--	--	--	--	--	--	--	--
Fugitive VOC Emissions - Flanges	FUGI 1	--	--	--	--	--	--	--	--	--	--	--	--	--	--	--
<b>Total Facility Emissions</b>		<b>2.46E-03</b>	<b>9.63E-03</b>	<b>9.63E-03</b>	<b>0.00E+00</b>	<b>0.00E+00</b>	<b>0.00E+00</b>	<b>7.68E-05</b>	<b>3.36E-04</b>	<b>1.92E-05</b>	<b>1.46E-02</b>	<b>5.89E-02</b>	<b>4.41E-02</b>	<b>4.64E-05</b>	<b>2.03E-04</b>	<b>1.16E-05</b>

**FACILITY-WIDE POTENTIAL EMISSIONS SUMMARY  
HINCKLEY COMPRESSOR STATION  
NORTHERN NATURAL GAS COMPANY**

Emissions Source	Emission Unit ID	Hazardous Air Pollutants			Hazardous Air Pollutants			Hazardous Air Pollutants			Hazardous Air Pollutants		
		Xylene			1,1,2,2-Tetrachloroethane			1,1,2-Trichloroethane			1,3-Dichloropropane		
		(lb/hr)	(tpy)	Limited (tpy)	(lb/hr)	(tpy)	Limited (tpy)	(lb/hr)	(tpy)	Limited (tpy)	(lb/hr)	(tpy)	Limited (tpy)
Solar Taurus 70-10802S Turbine	EQUI 1	5.43E-03	2.12E-02	2.12E-02	--	--	--	--	--	--	--	--	--
Cummins GTA28E Emergency Generator	EQUI 2	1.26E-03	5.51E-03	3.15E-04	9.68E-03	7.15E-04	4.08E-05	9.88E-05	4.33E-04	2.47E-05	8.20E-05	3.59E-04	2.05E-05
Fugitive VOC Emissions - Valves	FUGI 3	--	--	--	--	--	--	--	--	--	--	--	--
Fugitive VOC Emissions - Compressor Seal	FUGI 2	--	--	--	--	--	--	--	--	--	--	--	--
Fugitive VOC Emissions - Flanges	FUGI 1	--	--	--	--	--	--	--	--	--	--	--	--
<b>Total Facility Emissions</b>		<b>6.68E-03</b>	<b>2.68E-02</b>	<b>2.16E-02</b>	<b>9.68E-03</b>	<b>7.15E-04</b>	<b>4.08E-05</b>	<b>9.88E-05</b>	<b>4.33E-04</b>	<b>2.47E-05</b>	<b>8.20E-05</b>	<b>3.59E-04</b>	<b>2.05E-05</b>

**EQUI 1, STRU 1**  
**POTENTIAL EMISSIONS SUMMARY**  
**SOLAR TAURUS 70-10802S TURBINE (EU 001)**  
**HINCKLEY COMPRESSOR STATION**  
**NORTHERN NATURAL GAS COMPANY**

	BTU/scf	scfm exhaust	Hp	MMBtu/hr	hr/yr
Above 0° F	954.2	1,442	11,315	83	8,040
Below 0° F	954.2	1,481	11,377	85	720

Pollutant	Emission Factors <sup>1,2,3</sup>		Potential Emission Rate <sup>4,5</sup>		Limited PTE
	(grams/Hp-hr)	(lb/MMBtu)	(lb/hr)	(tpy)	(tpy)
NO <sub>x</sub>	0.57	0.06	14.29	25.08	--
VOC	0.24	0.03	5.92	13.75	13.7
CO	0.83	0.06	20.71	27.72	--
PM/PM <sub>10</sub> /PM <sub>2.5</sub> <sup>6</sup>	--	0.015	1.27	4.98	4.98
SO <sub>2</sub>	--	0.0015	0.13	0.50	0.5
1-3-BUTADIENE	--	4.3E-07	3.65E-05	1.43E-04	1.43E-04
ACETALDEHYDE	--	4.0E-05	3.39E-03	1.33E-02	1.33E-02
ACROLEIN	--	6.4E-06	5.43E-04	2.12E-03	2.12E-03
BENZENE	--	1.2E-05	1.02E-03	3.98E-03	3.98E-03
ETHYLBENZENE	--	3.2E-05	2.71E-03	1.06E-02	1.06E-02
FORMALDEHYDE	--	7.1E-04	6.02E-02	2.36E-01	2.36E-01
NAPHTHALENE	--	1.3E-06	1.10E-04	4.32E-04	4.32E-04
POM	--	2.2E-06	1.87E-04	7.30E-04	7.30E-04
PROPYLENE OXIDE	--	2.9E-05	2.46E-03	9.63E-03	9.63E-03
TOLUENE	--	1.3E-04	1.10E-02	4.32E-02	4.32E-02
XYLENE	--	6.4E-05	5.43E-03	2.12E-02	2.12E-02
SINGLE HAP	--	--	6.02E-02	2.36E-01	2.36E-01
TOTAL HAP	--	--	8.71E-02	3.41E-01	3.41E-01

Pollutant	Emission Factor		GWP	GHG Emissions		Limited PTE
	(kg/MMBtu)	(lb/MMBtu)		(lb/hr)	(tpy)	(tpy)
CO <sub>2</sub> <sup>1</sup>	53.06	116.98	1	9,917	42,309	42,309
Methane <sup>2</sup>	0.001	0.0022	25	0.19	0.80	0.80
N <sub>2</sub> O <sup>2</sup>	0.0001	0.00022	298	0.02	0.08	0.08
CO <sub>2</sub> e				9,928	42,353	42,353

Notes:

1. Emission factor based on 40 CFR 98, Subpart C, Table C-1.
2. Emission factor based on 40 CFR 98, Subpart C, Table C-2.

Notes:

1. Emission factors for NO<sub>x</sub>, CO, and VOC obtained from manufacturer data
  - 1a. Emission factors in gr/HP-hr are for emissions when temperatures are less than 0° F, these emission factors are worst case and are used to calculate hourly emissions
  - 1b. Annual average temperatures are above 0° F, therefore annual emissions are calculated using emissions factors for when temperatures are above 0° F.
2. Emission factors for SO<sub>2</sub> based on Minn. R. 7011.2300.
3. Emission factors for HAPs based on AP-42 factors (AP-42 Section 3.1 - Stationary Gas Turbines, Table 3.1-3).
4. Potential emissions based on worst case emission factors, maximum horsepower or maximum MMBtu/hr rating
5. The turbine is equipped with SoLoNO<sub>x</sub> to minimize emissions, and PACO logic emissions controls minimize emissions when ambient temperatures are less than 0 degrees F.
6. Emission factor for PM based on manufacturer recommendations. PM = PM<sub>10</sub> = PM<sub>2.5</sub> is assumed

**EQUI 2, STRU 2**  
**POTENTIAL EMISSIONS SUMMARY**  
**CUMMINS GTA28E EMERGENCY GENERATOR (EU 002)**  
**HINCKLEY COMPRESSOR STATION**  
**NORTHERN NATURAL GAS COMPANY**

Capacity

770 Hp

8,384 Btu/hp-hr

Pollutant	Emission Factors		Potential Emission Rate <sup>3</sup>		Limited Emission Rate <sup>3</sup>	
	(g/hp-hr) <sup>1</sup>	(lb/MMBtu) <sup>2</sup>	(lb/hr)	(tpy)	(lb/hr)	(tpy)
NO <sub>x</sub>	2.00	--	3.40	14.87	3.40	0.85
VOC	1.00	--	1.70	7.44	1.70	0.42
CO	4.00	--	6.79	29.74	6.79	1.70
PM/PM <sub>10</sub> /PM <sub>2.5</sub> <sup>4</sup>	--	0.01941	0.13	0.55	0.13	0.031
SO <sub>2</sub>	--	0.0015	0.0097	0.042	0.0097	0.0024
1,1,2,2-Tetrachloroethane	--	2.53E-05	1.63E-04	7.15E-04	1.63E-04	4.08E-05
1,1,2-Trichloroethane	--	1.53E-05	9.88E-05	4.33E-04	9.88E-05	2.47E-05
1,3-Butadiene	--	6.63E-04	4.28E-03	1.87E-02	4.28E-03	1.07E-03
1,3-Dichloropropane	--	1.27E-05	8.20E-05	3.59E-04	8.20E-05	2.05E-05
ACETALDEHYDE	--	2.79E-03	1.80E-02	7.89E-02	1.80E-02	4.50E-03
ACROLEIN	--	2.63E-03	1.70E-02	7.44E-02	1.70E-02	4.24E-03
BENZENE	--	1.58E-03	1.02E-02	4.47E-02	1.02E-02	2.55E-03
CARBON TETRACHLORIDE	--	1.77E-05	1.14E-04	5.00E-04	1.14E-04	2.86E-05
CHLOROBENZENE	--	1.29E-05	8.33E-05	3.65E-04	8.33E-05	2.08E-05
CHLOROFORM	--	1.37E-05	8.84E-05	3.87E-04	8.84E-05	2.21E-05
ETHYLBENZENE	--	2.48E-05	1.60E-04	7.01E-04	1.60E-04	4.00E-05
ETHYLENE DIBROMIDE	--	2.13E-05	1.38E-04	6.02E-04	1.38E-04	3.44E-05
FORMALDEHYDE	--	2.05E-02	1.32E-01	5.80E-01	1.32E-01	3.31E-02
METHANOL	--	3.06E-03	1.98E-02	8.65E-02	1.98E-02	4.94E-03
METHYLENE CHLORIDE	--	4.12E-05	2.66E-04	1.16E-03	2.66E-04	6.65E-05
NAPHTHALENE	--	9.71E-05	6.27E-04	2.75E-03	6.27E-04	1.57E-04
PAH	--	1.41E-04	9.10E-04	3.99E-03	9.10E-04	2.28E-04
STYRENE	--	1.19E-05	7.68E-05	3.36E-04	7.68E-05	1.92E-05
TOLUENE	--	5.58E-04	3.60E-03	1.58E-02	3.60E-03	9.01E-04
VINYL CHLORIDE	--	7.18E-06	4.64E-05	2.03E-04	4.64E-05	1.16E-05
XYLENE	--	1.95E-04	1.26E-03	5.51E-03	1.26E-03	3.15E-04
SINGLE HAP	--	--	1.32E-01	5.80E-01	1.32E-01	3.31E-02
TOTAL HAP	--	--	2.05E-01	8.96E-01	2.05E-01	5.12E-02

Pollutant	Emission Factor			GHG Emissions		
	(kg/MMBtu)	(lb/MMBtu)	GWP	(lb/hr)	Potential (tpy)	Limited (tpy)
CO <sub>2</sub> <sup>1</sup>	53.06	116.98	1	756	3,307.64	188.79
Methane <sup>2</sup>	0.001	0.0022	25	0.01	0.062	0.004
N <sub>2</sub> O <sup>2</sup>	0.0001	0.00022	298	0.001	0.0062	0.0004
CO <sub>2</sub> e				756	3,311	189

Notes:

1. Emission factor based on 40 CFR 98, Subpart C, Table C-1.
2. Emission factor based on 40 CFR 98, Subpart C, Table C-2.

Notes:

1. Emission factors for NO<sub>x</sub>, VOC, and CO obtained from NSPS Subpart JJJJ, Table 1.
2. Emissions factors are based on AP-42 factors (AP-42 Section 3.2 Natural Gas-fired Reciprocating Engines, Table 3.2-3).
3. Emissions based on manufacturer emission factors, maximum horsepower, and 8760 hours per year (potential) or 500 hours per year (limited) for emergency engines
4. Emission factor shown is for PM. It is conservatively assumed that PM = PM<sub>10</sub> = PM<sub>2.5</sub>.

<b>Pollutant <sup>1</sup></b>	<b>Emission Factors (lb/MMscf) <sup>1</sup></b>
2-Methylnaphthalene	2.40E-05
3-Methylcholanthrene	1.80E-06
7,12-Dimethylbenz(a)anthracene	1.60E-05
Acenaphthene	1.80E-06
Acenaphthylene	1.80E-06
Anthracene	2.40E-06
Benz(a)anthracene	1.80E-06
Benzo(a)pyrene	1.20E-06
Benzo(b)fluoranthene	1.80E-06
Benzo(g,h,i)perylene	1.20E-06
Benzo(k)fluoranthene	1.80E-06
Chrysene	1.80E-06
Dibenzo(a,h)anthracene	1.20E-06
Fluoranthene	3.00E-06
Fluorene	2.80E-06
Indeno(1,2,3-cd)pyrene	1.80E-06
Phenanthrene	1.70E-05
Pyrene	5.00E-06
<b>POM</b>	<b>8.82E-05</b>

**FUGI 1, FUGI 2, FUGI 3**  
**POTENTIAL EMISSIONS SUMMARY**  
**PROCESS PIPING FUGITIVES (FS 001, FS 002, FS 003)**  
**HINCKLEY COMPRESSOR STATION**  
**NORTHERN NATURAL GAS COMPANY**

Component Type	Emission Unit ID	Type of Service <sup>1</sup>	Number of Components <sup>1</sup>	Emission Factors (lb/hr-component) <sup>2</sup>	Percent VOC <sup>3</sup>	Potential VOC Emission Rates <sup>4</sup>	
						(lb/hr)	(T/yr)
Valves	FUGI 3	Gas/Vapor	60	0.0591	5.00%	0.18	0.78
Compressor Seals	FUGI 2	Gas/Vapor	1	1.4021	5.00%	0.07	0.31
Flanges	FUGI 1	Gas/Vapor	115	0.00055	5.00%	0.0032	0.014
<b>Totals:</b>	--	--	<b>176</b>	--	--	<b>0.25</b>	<b>1.10</b>

Notes:

1. Number of each component and type of service from original permit application for site.
2. Emission factors from MPCA Form EC-14, Table EC-14.1.
3. Percent VOC from representative gas analysis is 1.05%. To estimate emissions conservatively, the VOC content is assumed to be 5%.
4. Emission rates based on 8,760 of operation hours per year.

**EXTENDED GAS ANALYSIS**  
**HINCKLEY COMPRESSOR STATION**  
**NORTHERN NATURAL GAS COMPANY**

<b>Component <sup>1</sup></b>	<b>Molecular Weight</b>	<b>Mol % <sup>2</sup></b>	<b>Molar Weight <sup>3</sup></b>	<b>Average Mass % <sup>4</sup></b>
Hydrogen Sulfide	34	0.000%	0.00	0.00%
Nitrogen	28	2.850%	0.80	4.59%
Carbon Dioxide	44	0.110%	0.05	0.28%
Methane	16	90.220%	14.44	83.01%
Ethane	30	6.420%	1.93	11.08%
Propane	44	0.360%	0.16	0.91%
i-Butane	58	0.010%	0.01	0.03%
n-Butane	58	0.030%	0.02	0.10%
i-Pentane	72	0.000%	0.00	0.00%
n-Pentane	72	0.000%	0.00	0.00%
Hexanes +	86	0.000%	0.00	0.00%
<b>Totals:</b>		<b>100.00%</b>	<b>17.39</b>	<b>100.00%</b>
<b><sup>5</sup> VOC Totals:</b>		<b>0.40%</b>	<b>0.18</b>	<b>1.05%</b>

Notes:

1. Typical components listed in gas analysis for field gas.
2. Mol % values obtained from the gas analysis from a representative facility.
3. Molar weight = Molecular weight x Mol % /100.
4. Average mass % = Molar weight / Total molar weight.
5. VOC Totals include the following components (C3+):
  - Propane
  - i-Butane
  - n-Butane
  - i-Pentane
  - n-Pentane
  - Hexanes +

**COMPRESSOR STATION  
MINOR SOURCE OPERATING PERMIT APPLICATION**

Facility Name (all caps): HINCKLEY COMPRESSOR STATION  
Company Name (all caps): NORTHERN NATURAL GAS COMPANY

**COMPRESSOR ENGINE INFORMATION:**

EU-#	Mfg./model # (EU-#)- all caps	Mfg./model # - not all caps	HP	Normal hr/yr	Normal HP	Less than 0 hr/yr	<0
EU 001	SOLAR TAURUS 70-10802S TURBINE (EU 001)	Solar Taurus 70-10802S Turbine	11,315	8,040	11377	720 hrs below 0	
EU 002	MMINS GTA28E EMERGENCY GENERATOR (EU 0	Cummins GTA28E Emergency Generator	770	500			

EU-#	(MMBTU/hr)	(MMBTU/hr) - below 0	STU/acf	Normal	Below 0
EU 001	82.58	84.78	BTU/acf	954.2	954.2
EU 002	6.456		BTU/acf	905	--
0	0.000		BTU/acf		--

EU-#	(MMBTU/hr)	Btu/hr (per Solar Turbines Inc.)	7452
EU 001	7,298	Btu/hr (per Solar Turbines Inc.)	
EU 002	8,384	Btu/hr (per Cummins spec sheet)	
0		Btu/hr (per Cat spec sheet)	

**Emission Factors:**

EU-#	Criteria Pollutant	Emission Factors		Normal	Less than 0								
		AP-42/Stack Test	Normal										
EQUI 1 Turbine	Nox	Manufacturer Data lb/hr	4.98	0.20	Less than 0 EIs verified Emission in lb/hr vary depending on elevation and temperature. Solar provided the lb/hr estimates for NNG								
	VOC	Manufacturer Data lb/hr	2.89	0.12									
	CO	Manufacturer Data lb/hr	5.04	0.20									
	CO2	40 CFR 98, Subpart C kg/MMBtu	53.06										
	PM	Manufacturer Recommendation?	0.015										
	SO2	Minn. R. 7011.2300,	0.0015										
	Formaldehyde	AP-42 lb/MMBtu	0.00071										
EQUI 2 Generator	Nox	NSPS JJJJ	2.00		Less than 0 <table border="1"> <tr> <td>g/hp-hr</td> <td>lb/hr</td> </tr> <tr> <td>g/hp-hr</td> <td>14.29</td> </tr> <tr> <td>g/hp-hr</td> <td>5.92</td> </tr> <tr> <td>g/hp-hr</td> <td>20.71</td> </tr> </table>	g/hp-hr	lb/hr	g/hp-hr	14.29	g/hp-hr	5.92	g/hp-hr	20.71
	g/hp-hr	lb/hr											
	g/hp-hr	14.29											
	g/hp-hr	5.92											
	g/hp-hr	20.71											
	CO	NSPS JJJJ	1.00										
	CO2	40 CFR 98, Subpart C kg/MMBtu	53.06										
PM	AP-42 lb/MMBtu	0.019											
SO2	Minn. R. 7011.2300,	0.0015											
Formaldehyde	AP-42 lb/MMBtu	0.02020											

120 lb  
1000000 lb  
150  
1000000  
50  
1000000

**Attachment 2 – Subject Item Inventory and Facility Requirements**

## List of SIs

Agency Interest: Northern Natural Gas Co - Hinckley













Agency Interest ID: 236312

Activity: IND20200001 (State Permit)

Details for:

SI Category: None

SI Type: All

Agency Interest Name	Subject Item ID	Subject Item Designation	Subject Item Descr..	
Northern Natural Gas Co - Hinckley	ACTV1	Null	All IAs	
	AISI236312	Null	Null	
	EQU11	Null	Natural Gas-Fired Turbine	
	EQU12	Null	Emergency Generator	
	FUG11	Null	Flanges	
	FUG12	Null	Compressor Seals	
	FUG13	Null	Valves	
	STRU1	Null	Turbine Exhaust	
	STRU2	Null	Emergency Generator	
	STRU4	Null	Compressor Building	
	STRU5	Null	Auxiliary Building	
	TFAC1	Null	Null	

Insignificant air emissions activity

Agency Interest: Northern Natural Gas Co - Hinckley


Agency Interest ID: 236312

Activity: IND20200001 (State Permit)

Details for:

SI Category: Activity

SI Type: Insignificant Air Emissions Activity

Agency Interest Na..	Activity ID	Subject Ite..	Subject Item Type Description	Subject Item ID	Subject Ite..	Subject Ite..	Status Desc..	Sub Attribute Description	
Northern Natural Gas Co - Hinckley	IND20200001	Activity	Insignificant Air Emissions Activity	ACTV1	Null	All IAs	Null	Minn. R. 7007.1300, subp. 3(B)(2)	

PTE by subject item

Agency Interest: None  
 Agency Interest ID: 236312  
 Activity: None (State Permit)

Details for:

SI Category: All  
 SI Type: All

Subject Item Category Description	Subject Item Type Description	Subject Item ID	Subject Item Designation	Subject Item Description	Pollutant	Potential (lbs/hr)	Unrestricted Potential (tons/yr)	Potential Limited (tons/yr)				
Equipment	Reciprocating IC Engine	EQUI2	Null	Emergency Generator	1,1-Dichloroethylene (Vin..	4.64e-05	0.000203	1.16e-05				
					1,1,2-Trichloroethane	9.88e-05	0.000433	2.47e-05				
					1,1,2,2-Tetrachloroethane	0.00968	0.000715	4.08e-05				
					1,2-Dibromoethane (Ethyl..	0.000138	0.000602	3.44e-05				
					1,3-Butadiene	0.00428	0.0187	0.00107				
					1,3-Dichloropropene	8.2e-05	0.000359	2.05e-05				
					Acetaldehyde	0.018	0.0789	0.0789				
					Acrolein	0.017	0.0744	0.00424				
					Benzene	0.0102	0.0447	0.00255				
					Carbon Dioxide	755.17	3,307.64	188.79				
					Carbon Dioxide Equivalent	755.95	3,311.05	188.99				
					Carbon Monoxide	6.79	29.74	1.7				
					Carbon tetrachloride	0.000114	0.0005	2.86e-05				
					Chlorobenzene (Monochlo..	8.33e-05	0.000365	2.08e-05				
					Chloroform	8.84e-05	0.000387	2.21e-05				
					Dichloromethane (Methyl..	0.000266	0.00116	6.65e-05				
					Ethylbenzene	0.00016	0.000701	4e-05				
					Formaldehyde	0.132	0.58	0.0331				
					HAPs - Total	0.205	0.896	0.0512				
					Methane	0.01	0.06	0				
					Methanol	0.0198	0.0865	0.00494				
					Naphthalene	0.000627	0.00275	0.000157				
					Nitrogen Oxides	3.4	14.87	0.85				
					Nitrous Oxide	0	0.01	0				
					Particulate Matter	0.13	0.55	0.03				
					PM < 2.5 micron	0.13	0.55	0.03				
					PM < 10 micron	0.13	0.55	0.03				
					Polycyclic organic matter	0.00091	0.00399	0.000228				
					Styrene	7.68e-05	0.000336	1.92e-05				
					Sulfur Dioxide	0.0097	0.042	0.0024				
					Toluene	0.0036	0.0158	0.000901				
					Volatile Organic Compoun..	1.7	7.44	0.42				
					Xylenes, Total	0.00126	0.00551	0.000315				
					Turbine	EQUI1	Null	Natural Gas-Fired Turbine	1,3-Butadiene	3.65e-05	0.000143	0.000143
									Acetaldehyde	0.00339	0.0133	0.0133
									Acrolein	0.000543	0.00212	0.00212
									Benzene	0.00102	0.00398	0.00398
									Carbon Dioxide	9,917.5	42,309.12	42,309.12
									Carbon Dioxide Equivalent	9,927.74	42,352.82	42,352.82
									Carbon Monoxide	20.71	27.72	27.72
									Ethylbenzene	0.00271	0.0106	0.0106
Formaldehyde	0.0602	0.236	0.236									
HAPs - Total	0.0871	0.341	0.341									
Methane	0.19	0.8	0.8									
Naphthalene	0.00011	0.000432	0.000432									
Nitrogen Oxides	14.29	25.08	25.08									
Nitrous Oxide	0.02	0.08	0.08									
Particulate Matter	1.27	4.98	4.98									
PM < 2.5 micron	1.27	4.98	4.98									
PM < 10 micron	1.27	4.98	4.98									
Polycyclic organic matter	0.000187	0.00073	0.00073									
Propylene oxide	0.00246	0.00963	0.00963									
Sulfur Dioxide	0.13	0.5	0.5									
Toluene	0.011	0.0432	0.0432									
Volatile Organic Compoun..	5.92	13.75	13.75									
Xylenes, Total	0.00543	0.0212	0.0212									
Fugitive	Equipment Leaks	FUG1	Null	Flanges	Volatile Organic Compoun..	0.003	0.014	0.014				
		FUG2	Null	Compressor Seals	Volatile Organic Compoun..	0.07	0.31	0.31				
		FUG3	Null	Valves	Volatile Organic Compoun..	0.18	0.78	0.78				

PTE by subject item

Agency Interest: None

Agency Interest ID: 236312

Activity: None (State Permit)

Details for:

SI Category: All

SI Type: All

Subject Item Category Description	Subject Item Type Description	Subject Item ID	Subject Item Designation	Subject Item Description	Pollutant	Actual Emissions (tons/yr)
Equipment	Reciprocating IC Engine	EQUI2	Null	Emergency Generator	1,1-Dichloroethylene (Vin..	
					1,1,2-Trichloroethane	
					1,1,2,2-Tetrachloroethane	
					1,2-Dibromoethane (Ethyl..	
					1,3-Butadiene	
					1,3-Dichloropropene	
					Acetaldehyde	
					Acrolein	
					Benzene	
					Carbon Dioxide	
					Carbon Dioxide Equivalent	
					Carbon Monoxide	
					Carbon tetrachloride	
					Chlorobenzene (Monochlo..	
					Chloroform	
					Dichloromethane (Methyl..	
					Ethylbenzene	
					Formaldehyde	
					HAPs - Total	
					Methane	
					Methanol	
					Naphthalene	
					Nitrogen Oxides	
					Nitrous Oxide	
					Particulate Matter	
					PM < 2.5 micron	
					PM < 10 micron	
					Polycyclic organic matter	
					Styrene	
					Sulfur Dioxide	
					Toluene	
					Volatile Organic Compoun..	
Xylenes, Total						
Turbine	EQUI1	Null	Natural Gas-Fired Turbine	1,3-Butadiene		
				Acetaldehyde		
				Acrolein		
				Benzene		
				Carbon Dioxide		
				Carbon Dioxide Equivalent		
				Carbon Monoxide		
				Ethylbenzene		
				Formaldehyde		
				HAPs - Total		
				Methane		
				Naphthalene		
				Nitrogen Oxides		
				Nitrous Oxide		
				Particulate Matter		
				PM < 2.5 micron		
				PM < 10 micron		
				Polycyclic organic matter		
				Propylene oxide		
				Sulfur Dioxide		
				Toluene		
Volatile Organic Compoun..						
Xylenes, Total						
Fugitive	Equipment Leaks	FUGI1	Null	Flanges	Volatile Organic Compoun..	
		FUGI2	Null	Compressor Seals	Volatile Organic Compoun..	
		FUGI3	Null	Valves	Volatile Organic Compoun..	

SI - SI relationships

Agency Interest: None



Agency Interest ID: 236312

Activity: None (State Permit)

Details for:

SI Category: Equipment

SI Type: All

Subject Item Category Description	Subject Item Type Description	Subject Item ID	Subject Item Designation	Subject Item Description	Relationship	Related Subject Item ID	% Flow	Related Subject Item Type Description	Start Date (Related Subject Item)	End Date (Related Subject Item)	
Equipment	Reciprocating IC Engine	EQUI2	Null	Emergency Generator	sends to	STRU2	100	Stack/Vent	9/22/2020	Null	
	Turbine	EQUI1	Null	Natural Gas-Fired Turbine	sends to	STRU1	100	Stack/Vent	9/22/2020	Null	

Emission Units 1

Agency Interest: None

Agency Interest ID: 236312

Activity: None (State Permit)

Details for:

SI Category: None

SI Type: Turbine


Subject Item Type	Subject Item ID	Subject Item Designation	Subject Item Description	Manufacturer	Model	Max Design Capacity	Max Design Capacity Units (numerator)	Max Design Capacity Units (denominator)	Material	Construction Start Date	Operation Start Date	Modification Date
Turbine	EQUI1	Null	Natural Gas-Fired Turbine	Solar Turbines, Inc.	Taurus 70-T10802S	11400	horsepower	each	Energy	TBD	TBD	Null

Emission Units 2

Agency Interest: None  
Agency Interest ID: 236312  
Activity: None (State Permit)

Details for:

SI Category: Equipment  
SI Type: Reciprocating IC Engine

Subject Item Type Description	Subject Item ID	Subject Item Designation	Subject Item Description	Manufacturer	Model	Max Design Capacity	Max Design Capacity Units (numerator)	Max Design Capacity Units (denominator)	Material	Construction Start Date	Operation Start Date	Modification Date	
Reciprocating IC Engine	EQUI2	Null	Emergency Generator	Cummins	GTA28E	770	horsepower	each	Energy	TBD	TBD	Null	

Emission Units 2 (continued)

Agency Interest: None


Agency Interest ID: 236312

Activity: None (State Permit)

Details for:

SI Category: Equipment

SI Type: Reciprocating IC Engine

Subject Item Type Description	Subject Item ID	Subject Item Designation	Subject Item Description	Firing Method	Engine Use	Engine Displacement	Engine Displacement Units	Subject to CSAPR?	Electric Generating Capacity (MW)	
Reciprocating IC Engine	EQUI2	Null	Emergency Generator	SI-4SRB	Emergency/blackstart	28005	total cubic centimeters	Null	Null	

## Fugitive Sources

Agency Interest: None

Agency Interest ID: 236312

Activity: None (State Permit)

### Details for:

SI Category: Fugitive

SI Type: Equipment Leaks

Subject Item Type Description	Subject Item ID	Subject Item Designation	Subject Item Description	Install Year	Pollutants Emitted	
Equipment Leaks	FUGI1	Null	Flanges	2021	Volatile Organic Compounds	■
	FUGI2	Null	Compressor Seals	2021	Volatile Organic Compounds	■
	FUGI3	Null	Valves	2021	Volatile Organic Compounds	■

## Buildings, General

Agency Interest: Northern Natural Gas Co - Hinckley



Agency Interest ID: 236312

Activity: IND20200001 (State Permit)

### Details for:

SI Category: Structure

SI Type: Building

Subject Item Type	Subject Item ID	Subject Item Designation	Subject Item Description	Height	Units (height)	Length	Units (length)	Width	Units (width)	
Building	STRU4	Null	Compressor Building	35	feet	42	feet	80	feet	
	STRU5	Null	Auxiliary Building	35	feet	60	feet	90	feet	

Stack/Vent, General

Agency Interest: None



Agency Interest ID: 236312

Activity: None (State Permit)

Details for:

SI Category: Structure

SI Type: Stack/Vent

Subject Item Type	Subject Item ID	Subject Item Designation	Subject Item Description	Stack Height (feet)	Stack Diameter (feet)	Stack Length (feet)	Stack Width (feet)	Stack Flow Rate (cubic ft/min)	Discharge Temperature (°F)	Flow Rate/Temp Information Source	Discharge Direction	
Stack/Vent	STRU1	Null	Turbine Exhaust	54	4.8	Null	Null	136127	854	Manufacturer	Upwards with no cap on stack/vent	
	STRU2	Null	Emergency Generator	26.2	0.83	Null	Null	6959	971	Manufacturer	Upwards with no cap on stack/vent	

SI Id	Sequence	Requirement
TFAC 1	1240	Permit Appendices: This permit contains appendices as listed in the permit Table of Contents. The Permittee shall comply with all requirements contained in the following Appendices: -Appendix A. Insignificant Activities and General Applicable Requirements; -Appendix B. 40 CFR Part 60, Subpart A - General Provisions; -Appendix C. 40 CFR Part 60, Subpart KKKK - Standards of Performance for Stationary Combustion Turbines; -Appendix D. 40 CFR Part 60, Subpart JJJ - Standards of Performance for Stationary Spark Ignition Internal Combustion Engines. [Minn. R. 7007.0800, subp. 2(A) & (B)]
TFAC 1	1245	The Permittee must comply with Minn. Stat. 116.385. The Permittee may not use trichloroethylene at its permitted facility after June 1, 2022, including in any manufacturing, processing, or cleaning processes, except as described in Minn. Stat. 116.385, subd. 2(b) and 4. This is a state-only requirement and is not enforceable by the U.S. Environmental Protection Agency (EPA) Administrator and citizens under the Clean Air Act. [Minn. Stat. 116.385]
TFAC 1	1260	PERMIT SHIELD: Subject to the limitations in Minn. R. 7007.1800, compliance with the conditions of this permit shall be deemed compliance with the specific provision of the applicable requirement identified in the permit as the basis of each condition. Subject to the limitations of Minn. R. 7007.1800 and 7017.0100, subp. 2, notwithstanding the conditions of this permit specifying compliance practices for applicable requirements, any person (including the Permittee) may also use other credible evidence to establish compliance or noncompliance with applicable requirements.  This permit shall not alter or affect the liability of the Permittee for any violation of applicable requirements prior to or at the time of permit issuance. [Minn. R. 7007.1800(A)(2)]
TFAC 1	1380	Circumvention: Do not install or use a device or means that conceals or dilutes emissions, which would otherwise violate a federal or state air pollution control rule, without reducing the total amount of pollutant emitted. [Minn. R. 7011.0020]
TFAC 1	1390	Air Pollution Control Equipment: Operate all pollution control equipment whenever the corresponding process equipment and emission units are operated. [Minn. R. 7007.0800, subp. 16(J), Minn. R. 7007.0800, subp. 2(A) & (B)]
TFAC 1	1400	Operation and Maintenance Plan: Retain at the stationary source an operation and maintenance plan for all air pollution control equipment. At a minimum, the O & M plan shall identify all air pollution control equipment and control practices and shall include a preventative maintenance program for the equipment and practices, a description of (the minimum but not necessarily the only) corrective actions to be taken to restore the equipment and practices to proper operation to meet applicable permit conditions, a description of the employee training program for proper operation and maintenance of the control equipment and practices, and the records kept to demonstrate plan implementation. [Minn. R. 7007.0800, subp. 14, Minn. R. 7007.0800, subp. 16(J)]
TFAC 1	1410	Operation Changes: In any shutdown, breakdown, or deviation the Permittee shall immediately take all practical steps to modify operations to reduce the emission of any regulated air pollutant. The Commissioner may require feasible and practical modifications in the operation to reduce emissions of air pollutants. No emissions units that have an unreasonable shutdown or breakdown frequency of process or control equipment shall be permitted to operate. [Minn. R. 7019.1000, subp. 4]
TFAC 1	1420	Fugitive Emissions: Do not cause or permit the handling, use, transporting, or storage of any material in a manner which may allow avoidable amounts of particulate matter to become airborne. Comply with all other requirements listed in Minn. R. 7011.0150. [Minn. R. 7011.0150]
TFAC 1	1430	Noise: The Permittee shall comply with the noise standards set forth in Minn. R. 7030.0010 to 7030.0080 at all times during the operation of any emission units. This is a state only requirement and is not enforceable by the EPA Administrator or citizens under the Clean Air Act. [Minn. R. 7030.0010-7030.0080]
TFAC 1	1440	Inspections: The Permittee shall comply with the inspection procedures and requirements as found in Minn. R. 7007.0800, subp. 9(A). [Minn. R. 7007.0800, subp. 9(A)]
TFAC 1	1450	The Permittee shall comply with the General Conditions listed in Minn. R. 7007.0800, subp. 16. [Minn. R. 7007.0800, subp. 16]
TFAC 1	1460	Performance Testing: Conduct all performance tests in accordance with Minn. R. ch. 7017 unless otherwise noted in this permit. [Minn. R. ch. 7017]

SI Id	Sequence	Requirement
TFAC 1	1470	<p>Performance Test Notifications and Submittals:</p> <p>Performance Test Notification and Plan: due 30 days before each Performance Test  Performance Test Pre-test Meeting: due seven days before each Performance Test  Performance Test Report: due 45 days after each Performance Test</p> <p>The Notification, Test Plan, and Test Report must be submitted in a format specified by the commissioner.  [Minn. R. 7017.2017, Minn. R. 7017.2030, subps. 1-4, Minn. R. 7017.2035, subps. 1-2]</p>
TFAC 1	1480	<p>Limits set as a result of a performance test (conducted before or after permit issuance) apply until superseded as stated in the MPCA's Notice of Compliance letter granting preliminary approval. Preliminary approval is based on formal review of a subsequent performance test on the same unit as specified by Minn. R. 7017.2025, subp. 3. The limit is final upon issuance of a permit amendment incorporating the change. [Minn. R. 7017.2025, subp. 3]</p>
TFAC 1	1490	<p>Monitoring Equipment Calibration - The Permittee shall either:</p> <ol style="list-style-type: none"> <li>1. Calibrate or replace required monitoring equipment every 12 months; or</li> <li>2. Calibrate at the frequency stated in the manufacturer's specifications.</li> </ol> <p>For each monitor, the Permittee shall maintain a record of all calibrations, including the date conducted, and any corrective action that resulted. The Permittee shall include the calibration frequencies, procedures, and manufacturer's specifications (if applicable) in the Operations and Maintenance Plan. Any requirements applying to continuous emission monitors are listed separately in this permit. [Minn. R. 7007.0800, subp. 4(D)]</p>
TFAC 1	1500	<p>Operation of Monitoring Equipment: Unless noted elsewhere in this permit, monitoring a process or control equipment connected to that process is not necessary during periods when the process is shutdown, or during checks of the monitoring systems, such as calibration checks and zero and span adjustments. If monitoring records are required, they should reflect any such periods of process shutdown or checks of the monitoring system. [Minn. R. 7007.0800, subp. 4(D)]</p>
TFAC 1	1510	<p>Recordkeeping: Retain all records at the stationary source, unless otherwise specified within this permit, for five (5) years from the date of monitoring, sample, measurement, or report. Records which must be retained at this location include all calibration and maintenance records, all original recordings for continuous monitoring instrumentation, and copies of all reports required by the permit. Records must conform to the requirements listed in Minn. R. 7007.0800, subp. 5(A). [Minn. R. 7007.0800, subp. 5(C)]</p>
TFAC 1	1520	<p>Recordkeeping: Maintain records describing any insignificant modifications (as required by Minn. R. 7007.1250, subp. 3) or changes contravening permit terms (as required by Minn. R. 7007.1350, subp. 2), including records of the emissions resulting from those changes. [Minn. R. 7007.0800, subp. 5(B)]</p>
TFAC 1	1530	<p>If the Permittee determines that no permit amendment or notification is required prior to making a change, the Permittee must retain records of all calculations required under Minn. R. 7007.1200. For non-expiring permits, these records shall be kept for a period of five years from the date that the change was made. The records shall be kept at the stationary source for the current calendar year of operation and may be kept at the stationary source or office of the stationary source for all other years. The records may be maintained in either electronic or paper format. [Minn. R. 7007.1200, subp. 4]</p>
TFAC 1	1610	<p>Shutdown Notifications: Notify the Commissioner at least 24 hours in advance of a planned shutdown of any control equipment or process equipment if the shutdown would cause any increase in the emissions of any regulated air pollutant. If the owner or operator does not have advance knowledge of the shutdown, notification shall be made to the Commissioner as soon as possible after the shutdown. However, notification is not required in the circumstances outlined in items A, B, and C of Minn. R. 7019.1000, subp. 3.</p> <p>At the time of notification, the owner or operator shall inform the Commissioner of the cause of the shutdown and the estimated duration. The owner or operator shall notify the Commissioner when the shutdown is over.  [Minn. R. 7019.1000, subp. 3]</p>

SI Id	Sequence	Requirement
TFAC 1	1620	<p>Breakdown Notifications: Notify the Commissioner within 24 hours of a breakdown of more than one hour duration of any control equipment or process equipment if the breakdown causes any increase in the emissions of any regulated air pollutant. The 24-hour time period starts when the breakdown was discovered or reasonably should have been discovered by the owner or operator. However, notification is not required in the circumstances outlined in items A, B, and C of Minn. R. 7019.1000, subp. 2.</p> <p>At the time of notification or as soon as possible thereafter, the owner or operator shall inform the Commissioner of the cause of the breakdown and the estimated duration. The owner or operator shall notify the Commissioner when the breakdown is over. [Minn. R. 7019.1000, subp. 2]</p>
TFAC 1	1630	<p>Notification of Deviations Endangering Human Health or the Environment: As soon as possible after discovery, notify the Commissioner or the state duty officer, either orally or by facsimile, of any deviation from permit conditions which could endanger human health or the environment. [Minn. R. 7019.1000, subp. 1]</p>
TFAC 1	1640	<p>Notification of Deviations Endangering Human Health or the Environment Report: Within two working days of discovery, notify the Commissioner in writing of any deviation from permit conditions which could endanger human health or the environment. Include the following information in this written description:</p> <ol style="list-style-type: none"> <li>1. the cause of the deviation;</li> <li>2. the exact dates of the period of the deviation, if the deviation has been corrected;</li> <li>3. whether or not the deviation has been corrected;</li> <li>4. the anticipated time by which the deviation is expected to be corrected, if not yet corrected; and</li> <li>5. steps taken or planned to reduce, eliminate, and prevent reoccurrence of the deviation. [Minn. R. 7019.1000, subp. 1]</li> </ol>
TFAC 1	1650	<p>The Permittee must submit a semiannual deviations report : Due semiannually, by the 30th of January and July. The first semiannual report submitted by the Permittee must cover the calendar half-year in which the permit is issued. The first report of each calendar year covers January 1 - June 30. The second report of each calendar year covers July 1 - December 31. Submit this on form DRF-2 (Deviation Reporting Form). If no deviations have occurred, submit the signed report certifying that there were no deviations. [Minn. R. 7007.0800, subp. 6(B)(2)]</p>
TFAC 1	1670	<p>Application for Permit Amendment: If a permit amendment is needed, submit an application in accordance with the requirements of Minn. R. 7007.1150 through Minn. R. 7007.1500. Submittal dates vary, depending on the type of amendment needed.</p> <p>Upon adoption of a new or amended federal applicable requirement, and if there are three or more years remaining in the permit term, the Permittee shall file an application for an amendment within nine months of promulgation of the applicable requirement, pursuant to Minn. R. 7007.0400, subp. 3. [Minn. R. 7007.0400, subp. 3, Minn. R. 7007.1150 - 7007.1500]</p>
TFAC 1	1680	<p>Extension Requests: The Permittee may apply for an Administrative Amendment to extend a deadline in a permit by no more than 120 days, provided the proposed deadline extension meets the requirements of Minn. R. 7007.1400, subp. 1(H). Performance testing deadlines from the General Provisions of 40 CFR pt. 60 and pt. 63 are examples of deadlines for which the MPCA does not have authority to grant extensions and therefore do not meet the requirements of Minn. R. 7007.1400, subp. 1(H). [Minn. R. 7007.1400, subp. 1(H)]</p>
TFAC 1	1700	<p>The Permittee must submit a compliance certification : Due annually, by the 31st of January (for the previous calendar year). Submit this on form CR-04 (Annual Compliance Certification Report). This report covers all deviations experienced during the calendar year. If no deviations have occurred, submit the signed report certifying that there were no deviations. [Minn. R. 7007.0800, subp. 6(D)]</p>
TFAC 1	1703	<p>Within 15 days of a request from the Commissioner, the Permittee must provide a complete summary of all performance tests required at the facility including the subject item, pollutant, most recent test date (if applicable), and the date of the next test in an approved format. [Minn. R. 7007.0800, subp. 16(L)]</p>
TFAC 1	1730	<p>Emission Inventory Report: due on or before April 1 of each calendar year following permit issuance. Submit in a format specified by the Commissioner. [Minn. R. 7019.3000-7019.3100]</p>

SI Id	Sequence	Requirement
TFAC 1	1740	Emission Fees: due 30 days after receipt of an MPCA bill. [Minn. R. 7002.0005-7002.0085]
EQUI 1	3090	The Permittee is authorized to construct and operate EQUI 1 meeting the following design requirements: 11,400 hp capacity, natural gas-fired turbine.  The authorization to start construction of this equipment expires 18 months after permit issuance of Air Emissions Permit No. 11500038-101. The units shall meet all applicable permit requirements. [Minn. R. 7007.0800, subp. 2(A)]
EQUI 1	3100	The Permittee shall submit a notification of the date construction began: Due 30 calendar days after Date of Construction Start (or reconstruction). Submit the name and number of the Subject Item and the date construction began.  The notification shall be submitted electronically on Form CS-02. [40 CFR 60.7(a)(1), Minn. R. 7007.0800, subp. 16(L), Minn. R. 7019.0100, subp. 1]
EQUI 1	3110	The Permittee shall submit a notification of the actual date of initial startup: Due 15 calendar days after Initial Startup Date. Submit the name and number of the Subject Item and the date of startup. Startup is as defined in Minn. R. 7005.0100, subp. 42a.  The notification shall be submitted electronically on Form CS-02. [40 CFR 60.7(a)(3), Minn. R. 7007.0800, subp. 16(L), Minn. R. 7019.0100, subp. 1]
EQUI 1	3520	Opacity <= 20 percent opacity once operating temperatures have been attained. [Minn. R. 7011.2300, subp. 1]
EQUI 1	3535	Sulfur Dioxide <= 0.0015 pounds per million Btu heat input The potential to emit from the unit is 0.0014 lb/MMBtu due to equipment design and allowable fuels. [Minn. R. 7011.2300, subp. 2(B)]
EQUI 1	3540	The Permittee shall limit emissions of Sulfur Dioxide <= 110 nanograms per joule (ng/J) (0.90 pounds per megawatt-hour (lb/MWh)) gross output. [40 CFR 60.4330(a)(1), Minn. R. 7011.2375]
EQUI 1	3560	The Permittee shall limit emissions of Nitrogen Oxides <= 25 parts per million at 15 percent oxygen or 150 ng/J of useful output (1.2 lb/MWh) when turbine is operating at or above 75 percent of peak load and when operating at 0 deg F or above. [40 CFR 60.4320(a), 40 CFR pt. 60, subp. KKKK (Table 1), Minn. R. 7011.2375]
EQUI 1	19920	Fuel type: Natural gas only by design. [Minn. R. 7005.0100, subp. 35a]
EQUI 1	19930	The Permittee shall keep records of fuel type and usage on a monthly basis. [Minn. R. 7007.0800, subp. 5]

SI Id	Sequence	Requirement
		<p>The Permittee must comply with all applicable requirements of 40 CFR pt. 60, subp. A as follows:</p> <p>40 CFR 60.1;  40 CFR 60.2;  40 CFR 60.3;  40 CFR 60.4;  40 CFR 60.5;  40 CFR 60.6;  40 CFR 60.7;  40 CFR 60.8;  40 CFR 60.9;  40 CFR 60.11;  40 CFR 60.12;  40 CFR 60.13;  40 CFR 60.14;  40 CFR 60.15;  40 CFR 60.17;  40 CFR 60.18; and  40 CFR 60.19.</p> <p>A copy of 40 CFR pt. 60, subp. A is included in Appendix B. If the standard changes or upon adoption of a new or amended federal applicable requirement, and if there are more than 3 years remaining in the permit term, the Permittee shall file an application for an amendment within nine months of promulgation of the applicable requirement, pursuant to Minn. R. 7007.0400, subp. 3. [40 CFR pt. 60, subp. A, 40 CFR pt. 60, subp. KKKK, Minn. R. 7007.0400, subp. 3, Minn. R. 7007.1150-7007.1500, Minn. R. 7011.0050, Minn. R. 7017.1010 &amp; 7017.2025, Minn. R. 7019.0100]</p>
EQUI 1	19931	
		<p>The Permittee must comply with all applicable requirements of 40 CFR pt. 60, subp. KKKK as follows:</p> <p>40 CFR 60.4300;  40 CFR 60.4305;  40 CFR 60.4315;  40 CFR 60.4320;  40 CFR 60.4330(a)(1);  40 CFR 60.4333(a);  40 CFR 60.4340(a);  40 CFR 60.4360;  40 CFR 60.4370(c)(1);  40 CFR 60.4375;  40 CFR 60.4385;  40 CFR 60.4395;  40 CFR 60.4400(a);  40 CFR 60.4400(b)(4);  40 CFR 60.4400(b)(6);  40 CFR 60.4415(a)(1)(ii);  40 CFR 60.4420; and  40 CFR pt. 60, subp. KKKK Table 1.</p> <p>A copy of 40 CFR pt. 60, subp. KKKK is included in Appendix C. If the standard changes or upon adoption of a new or amended federal applicable requirement, and if there are more than 3 years remaining in the permit term, the Permittee shall file an application for an amendment within nine months of promulgation of the applicable requirement, pursuant to Minn. R. 7007.0400, subp. 3. [40 CFR pt. 60, subp. KKKK, Minn. R. 7007.0400, subp. 3, Minn. R. 7011.2375]</p>
EQUI 1	19932	

SI Id	Sequence	Requirement
EQUI 1	19933	<p>Nitrogen Oxides: The Permittee shall conduct an initial performance test due 180 calendar days after Initial Startup Date and at a minimum every 12 months thereafter to measure emissions. If the Nitrogen Oxide emission result from the performance test is less than or equal to 75 percent of the Nitrogen Oxide emission limit for the turbine, you may reduce the frequency of subsequent performance tests to once every 2 years (no more than 26 calendar months following the previous performance test). If the results of any subsequent performance test exceed 75 percent of the Nitrogen Oxide emission limit for the turbine, you must resume annual performance tests.</p> <p>The performance test shall be conducted at normal operating conditions using EPA Reference Methods 7E, or other method approved by MPCA in the performance test plan approval. [40 CFR 60.4340(a), 40 CFR 60.8(a), Minn. R. 7011.2375, Minn. R. 7017.2020, subp. 1]</p>
EQUI 1	19934	<p>Sulfur Dioxide: The Permittee shall conduct an initial performance test due 180 calendar days after Initial Startup Date and at a minimum every 14 months thereafter to measure emissions.</p> <p>The performance test shall be conducted at normal operating conditions using EPA Reference Methods 6C, or other method approved by MPCA in the performance test plan approval. [40 CFR 60.4415(a)(1)(ii), 40 CFR 60.8(a), Minn. R. 7011.2375, Minn. R. 7017.2020, subp. 1]</p>
EQUI 1	19937	<p>Turbine Component Replacement Recordkeeping: The Permittee shall record the date and nature of each component replacement no later than 5 business days after completion of each replacement. For each replaced component, the Permittee shall maintain a record of the date the component was constructed or the date of the most recent overhaul, as applicable. The Permittee shall also record the total cost of the component replacement compared to the cost of an entirely new stationary gas turbine (as defined at 40 CFR Section 60.4420). This record of the component replacement cost compared to the cost of a new stationary gas turbine shall be made at least 30 days before a NOx test is conducted on the gas turbine (as a result of the component replacement), but no later than 180 days after each component replacement. [Minn. R. 7007.0800, subp. 2, Minn. R. 7007.0800, subps. 4-5]</p>
EQUI 1	19939	<p>The Permittee shall submit notification of the date replacement began: Due 60 calendar days before Date of Replacement Start (or as soon as practicable). Submit the information specified in 40 CFR Section 60.15(d)(1) through (7).</p> <p>The notification shall be submitted electronically on Form CS-02. [40 CFR 60.15(d), Minn. R. 7011.0050]</p>
EQUI 2	3010	<p>The Permittee is authorized to construct and operate EQUI 2 meeting the following design requirements: 770 hp, natural gas-fired, rich burn, four-stroke, spark ignition, emergency engine certified to meet the emission standards in 40 CFR pt. 60, subp. JJJ(Table 1).</p> <p>The authorization to start construction of this equipment expires 18 months after permit issuance of Air Emissions Permit No. 11500038-101. The units shall meet all applicable permit requirements. [Minn. R. 7007.0800, subp. 2(A)]</p>
EQUI 2	3020	<p>The Permittee shall limit Nitrogen Oxides <math>\leq</math> 2.0 grams per horsepower-hour. [40 CFR 60.4233(e), 40 CFR pt. 60, subp. JJJ(Table 1), Minn. R. 7011.2310]</p>
EQUI 2	3030	<p>The Permittee shall limit Carbon Monoxide <math>\leq</math> 4.0 grams per horsepower-hour. [40 CFR 60.4233(e), 40 CFR pt. 60, subp. JJJ(Table 1), Minn. R. 7011.2310]</p>
EQUI 2	3040	<p>The Permittee shall limit Volatile Organic Compounds <math>\leq</math> 1.0 grams per horsepower-hour. [40 CFR 60.4233(e), 40 CFR pt. 60, subp. JJJ(Table 1), Minn. R. 7011.2310]</p>
EQUI 2	3100	<p>Sulfur Dioxide <math>\leq</math> 0.0015 pounds per million Btu heat input. The potential to emit from the unit is 0.0015 lb/MMBtu due to equipment design and allowable fuels. [Minn. R. 7011.2300, subp. 2(B)]</p>
EQUI 2	3110	<p>Opacity <math>\leq</math> 20 percent opacity once operating temperatures have been attained. [Minn. R. 7011.2300, subp. 1]</p>
EQUI 2	3520	<p>Hours of Operation: The Permittee shall maintain documentation on site that the unit is an emergency generator by design that qualifies under the U.S. EPA memorandum entitled "Calculating Potential to Emit (PTE) for Emergency Generators" dated September 6, 1995, limiting operation to 500 hours per year. [Minn. R. 7007.0800, subps. 4-5]</p>

SI Id	Sequence	Requirement
EQUI 2	3535	<p>The Permittee shall submit a notification of the date construction began: Due 30 calendar days after Date of Construction Start (or reconstruction). Submit the name and number of the Subject Item and the date construction began.</p> <p>The notification shall be submitted electronically on Form CS-02. [40 CFR 60.4245(c), 40 CFR 60.7(a)(1), Minn. R. 7007.0800, subp. 16(L), Minn. R. 7019.0100, subp. 1]</p>
EQUI 2	3550	<p>The Permittee shall submit a notification of the actual date of initial startup: Due 15 calendar days after Initial Startup Date. Submit the name and number of the Subject Item and the date of startup. Startup is as defined in Minn. R. 7005.0100, subp. 42a.</p> <p>The notification shall be submitted electronically on Form CS-02. [40 CFR 60.7(a)(3), Minn. R. 7007.0800, subp. 16(L), Minn. R. 7019.0100, subp. 1]</p>
EQUI 2	3560	The Permittee shall keep records of fuel type and usage on a monthly basis. [Minn. R. 7007.0800, subp. 5]
EQUI 2	3565	EQUI 2 is a new affected source as defined under 40 CFR pt. 63, subp. ZZZZ, and the facility is an area source as defined at 40 CFR Section 63.2, and EQUI 2 is a spark ignition RICE. The Permittee shall meet the requirements of 40 CFR pt. 63, subp. ZZZZ by meeting the requirements of 40 CFR pt. 60, subp. JJJJ. No further requirements of 40 CFR pt. 63, subp. ZZZZ apply to EQUI 2. [40 CFR 63.6590(c), Minn. R. 7011.8150]
EQUI 2	19920	<p>The Permittee must comply with all applicable requirements of 40 CFR pt. 60, subp. A as follows:</p> <p>40 CFR 60.1;  40 CFR 60.2;  40 CFR 60.3;  40 CFR 60.4;  40 CFR 60.5;  40 CFR 60.6;  40 CFR 60.7;  40 CFR 60.8;  40 CFR 60.9;  40 CFR 60.10;  40 CFR 60.11, requirements as specified in subpart JJJJ;  40 CFR 60.12;  40 CFR 60.14;  40 CFR 60.15;  40 CFR 60.16;  40 CFR 60.17; and  40 CFR 60.19.</p> <p>A copy of 40 CFR pt. 60, subp. A is included in Appendix B. If the standard changes or upon adoption of a new or amended federal applicable requirement, and if there are more than 3 years remaining in the permit term, the Permittee shall file an application for an amendment within nine months of promulgation of the applicable requirement, pursuant to Minn. R. 7007.0400, subp. 3. [40 CFR pt. 60, subp. A, 40 CFR pt. 60, subp. JJJJ, Minn. R. 7007.0400, subp. 3, Minn. R. 7007.1150-7007.1500, Minn. R. 7011.0050, Minn. R. 7017.1010 &amp; 7017.2025, Minn. R. 7019.0100]</p>

SI Id	Sequence	Requirement
EQUI 2	19940	<p>The Permittee must comply with all applicable requirements of 40 CFR pt. 60, subp. JJJJ as follows:  40 CFR 60.4230(a)(4)(iv);  40 CFR 60.4230(a)(6);  40 CFR 60.4233(e), as it pertains to stationary SI ICE meeting the criteria in the first sentence of this item;  40 CFR 60.4234;  40 CFR 60.4237(a);  40 CFR 60.4243(b)(1);  40 CFR 60.4243(d);  40 CFR 60.4243(g);  40 CFR 60.4245(a)(1);  40 CFR 60.4245(a)(2);  40 CFR 60.4245(a)(3);  40 CFR 60.4245(e);  40 CFR 60.4246;  40 CFR 60.4248;  40 CFR pt. 60, subp JJJJ Table 1.and  40 CFR pt. 60, subp JJJJ Table 3.</p> <p>A copy of 40 CFR pt. 60, subp. JJJJ is included in Appendix D. If the standard changes or upon adoption of a new or amended federal applicable requirement, and if there are more than 3 years remaining in the permit term, the Permittee shall file an application for an amendment within nine months of promulgation of the applicable requirement, pursuant to Minn. R. 7007.0400, subp. 3. [40 CFR pt. 60, subp. JJJJ, 40 CFR pt. 63, subp. ZZZZ, Minn. R. 7007.0400, subp. 3, Minn. R. 7011.2310]</p>
FUGI 1	3090	The Permittee is authorized to construct and operate FUGI 1. The authorization to start construction of this equipment expires 18 months after permit issuance of Air Emissions Permit No. 11500038-101. The units shall meet all applicable permit requirements. [Minn. R. 7007.0800, subp. 2(A)]
FUGI 1	3100	<p>The Permittee shall submit a notification of the date construction began: Due 30 calendar days after Date of Construction Start (or reconstruction). Submit the name and number of the Subject Item and the date construction began.</p> <p>The notification shall be submitted electronically on Form CS-02. [Minn. R. 7007.0800, subp. 16(L)]</p>
FUGI 1	3110	<p>The Permittee shall submit a notification of the actual date of initial startup: Due 15 calendar days after Initial Startup Date. Submit the name and number of the Subject Item and the date of startup. Startup is as defined in Minn. R. 7005.0100, subp. 42a.</p> <p>The notification shall be submitted electronically on Form CS-02. [Minn. R. 7007.0800, subp. 16(L)]</p>
FUGI 2	3090	The Permittee is authorized to construct and operate FUGI 2. The authorization to start construction of this equipment expires 18 months after permit issuance of Air Emissions Permit No. 11500038-101. The units shall meet all applicable permit requirements. [Minn. R. 7007.0800, subp. 2(A)]
FUGI 2	3100	<p>The Permittee shall submit a notification of the date construction began: Due 30 calendar days after Date of Construction Start (or reconstruction). Submit the name and number of the Subject Item and the date construction began.</p> <p>The notification shall be submitted electronically on Form CS-02. [Minn. R. 7007.0800, subp. 16(L)]</p>
FUGI 2	3110	<p>The Permittee shall submit a notification of the actual date of initial startup: Due 15 calendar days after Initial Startup Date. Submit the name and number of the Subject Item and the date of startup. Startup is as defined in Minn. R. 7005.0100, subp. 42a.</p> <p>The notification shall be submitted electronically on Form CS-02. [Minn. R. 7007.0800, subp. 16(L)]</p>

SI Id	Sequence	Requirement
FUGI 3	3090	The Permittee is authorized to construct and operate FUGI 3. The authorization to start construction of this equipment expires 18 months after permit issuance of Air Emissions Permit No. 11500038-101. The units shall meet all applicable permit requirements. [Minn. R. 7007.0800, subp. 2(A)]
FUGI 3	3100	The Permittee shall submit a notification of the date construction began: Due 30 calendar days after Date of Construction Start (or reconstruction). Submit the name and number of the Subject Item and the date construction began.  The notification shall be submitted electronically on Form CS-02. [Minn. R. 7007.0800, subp. 16(L)]
FUGI 3	3110	The Permittee shall submit a notification of the actual date of initial startup: Due 15 calendar days after Initial Startup Date. Submit the name and number of the Subject Item and the date of startup. Startup is as defined in Minn. R. 7005.0100, subp. 42a.  The notification shall be submitted electronically on Form CS-02. [Minn. R. 7007.0800, subp. 16(L)]

**Attachment 3 – Points Calculator**

Points Calculator

1) AI ID No.:	236312	<b>Total Points</b>	<b>80</b>
2) Facility Name:	Northern Natural Gas Co - Hinckley		
3) Small business? y/n?	No		
4) Air Project Tracking Numbers (including all rolled) :	6732		
5) Date of each Application Received:	8/6/20		
6) Final Permit No.	11500038-101		
7) Permit Staff	Hannah Braatz		

Application Type	Air Project Tracking No.	Tempo Activity ID	Qty	Points	Total Points	Total Additional Cost	Details
Administrative Amendment			1	0		\$ -	
Minor Amendment			4	0		\$ -	
Applicability Request			10	0		\$ -	
Moderate Amendment			15	0		\$ -	
Major Amendment			25	0		\$ -	
Individual State Permit (not reissuance)	6732	IND20200001	1	50	50	\$ 14,250.00	
Individual Part 70 Permit (not reissuance)			75	0		\$ -	
<b>Additional Points</b>							
Modelling Review				15	0	\$ -	
BACT Review				15	0	\$ -	
LAER Review				15	0	\$ -	
CAA section 110(a)(2)(D)(i)(I) Review (i.e., Transport Rule/CAIR/CSAPR)				10	0	\$ -	
Part 75 CEM analysis				10	0	\$ -	
NSPS Review	6732	IND20200001	2	10	20	\$ 5,700.00	KKKK, JJJJ
NESHAP Review	6732	IND20200001	1	10	10	\$ 2,850.00	ZZZZ
Case-by-case MACT Review				20	0	\$ -	
Netting				10	0	\$ -	
Limits to remain below threshold				10	0	\$ -	
Plantwide Applicability Limit (PAL)				20	0	\$ -	
AERA review				15	0	\$ -	
Variance request under 7000.7000				35	0	\$ -	
Confidentiality request under 7000.1300				2	0	\$ -	
FAW review				0	0	\$ -	
Part 4410.4300, subparts 18, Item A; and 29				15	0	\$ -	
Part 4410.4300, subparts 8, Items A & B; 10, Items A to C; 16, Items A & D; 17, Items A to C & E to G; and 18, Items B & C				35	0	\$ -	
Part 4410.4300, subparts 4; 5 Items A & B; 13; 15; 16, Items B & C; and 17 Item D				70	0	\$ -	
				<b>Add'l Points</b>	<b>30</b>		

NOTES: