# AIR QUALITY DIVISION
## CHAPTER 6, SECTION 3
# OPERATING PERMIT

**WYOMING DEPARTMENT OF ENVIRONMENTAL QUALITY**
**AIR QUALITY DIVISION**
**122 West 25th Street**
**Cheyenne, Wyoming 82002**

**PERMIT NO. 3-1-046**

Issue Date: **August 30, 2007**
Expiration Date: **October 20, 2009**
Effective Date: **August 30, 2007**
Replaces Permit No.: **30-046**

In accordance with the provisions of W.S. §35-11-203 through W.S. §35-11-212 and Chapter 6, Section 3 of the Wyoming Air Quality Standards and Regulations,

**Devon Gas Services, L.P.**
**Beaver Creek Gas Plant**
**Section 10, T33N, R96W**
**Fremont County, Wyoming**

is authorized to operate a stationary source of air contaminants consisting of emission units described in this permit. The units described are subject to the terms and conditions specified in this permit. All terms and conditions of the permit are enforceable by the State of Wyoming. All terms and conditions of the permit, except those designated as not federally enforceable, are enforceable by EPA and citizens under the Act. A copy of this permit shall be kept on-site at the above named facility.

David A. Finley, Administrator
Air Quality Division

Date 8/30/07

John V. Corra, Director
Department of Environmental Quality

Date 9/12/07

# WAQSR CHAPTER 6, SECTION 3 OPERATING PERMIT

## WYOMING DEPARTMENT OF ENVIRONMENTAL QUALITY
### AIR QUALITY DIVISION

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## GENERAL INFORMATION

Company Name: **Devon Gas Services, L.P.**

Mailing Address: **20 North Broadway**

City: **Oklahoma City** State: **OK** Zip: **73102-8260**

Plant Name: **Beaver Creek Gas Plant**

Plant Location: **380 Beaver Creek Road, Section 10, Township 33 North, Range 96 West, Fremont County, WY (12.5 miles southeast of Riverton, WY)**

Plant Mailing Address: **380 Beaver Creek Road**

City: **Riverton** State: **WY** Zip: **82501**

| | | |
|---|---|---|
| Name of Owner: | **Devon Gas Services, L.P.** | Phone: **(307) 856-8111** |
| Responsible Official: | **Jerry Holsworth** | Phone: **(405) 235-3611** |
| | **Craig Shaw (Alternate)** | Phone: **(307) 856-8111** |
| Plant Manager/Contact: | **Bill Bender** | Phone: **(307) 856-8111** |
| DEQ Air Quality Contact: | **District 4 Engineer**<br>**510 Meadowview Drive**<br>**Lander, Wyoming 82520** | Phone: **(307) 332-6755** |

SIC Code: **1321**

Description of Process: **The Beaver Creek Gas Plant is a sour gas sweetening and liquids recovery plant located in central Wyoming. It consists of two facilities: the Phosphoria plant, capable of processing 15 MMSCF/day of sour gas; and the Joint Interest plant, capable of processing 40 MMSCF/day of a combination of the residue gas from the Phosphoria plant and sweet gas from nearby gas fields. The facility produces pipeline quality natural gas, condensate, and natural gas liquids.**

## SOURCE EMISSION POINTS

This table may not include any or all insignificant activities at this facility.

| SOURCE ID# | SOURCE DESCRIPTION | SIZE | CH. 6, SEC. 2 PERMITS |
|---|---|---|---|
| LO#1 | Lean Oil Heater - gas fired* | 25.0 MMBtu/hr | MD-401A |
| LO#2 | Lean Oil Heater – gas fired* | 31.25 MMBtu/hr | AP-5555 |
| PB#2 | #2 Wickes Boiler - gas fired | 29.5 MMBtu/hr | MD-401A |
| C-1 | Cooper-Bessemer GMXF-6 Compressor Engine | 495 hp | MD-401A |
| C-2 | Electric Propane Refrigeration Compressor | 1000 hp | MD-401A |
| C-3 | Cooper-Bessemer GMXE-4 Compressor Engine | 326 hp | MD-401A |
| C-4 | Sweet Inlet Electric Compressor | 1000 hp | none |
| C-5 | Sweet Inlet Electric Compressor | 1000 hp | none |
| C-6 | Waukesha L7042GSI Compressor Engine (NSCR) | 1230 hp | MD-401A |
| C-7A | Waukesha L7042GSI Compressor Engine (NSCR) | 1404 hp | MD-401A |
| C-8 | Clark HBA-6 Compressor Engine | 1320 hp | MD-401A |
| C-9 | Waukesha L7042GSI Compressor Engine (NSCR) | 1105 hp | MD-401A |
| C-10 | Waukesha L7042GSI Compressor Engine (NSCR) | 1105 hp | MD-401A |
| C-11 | Electric Drive Acid Gas Injection Compressor | 350 hp | MD-401A |
| C-12 | Electric Drive Field Gas Compressor | N/A | MD-401A |
| C-13A | Waukesha L7042GSI Compressor Engine (NSCR) | 1404 hp | MD-401A |
| C-14A/B | Sour Inlet Field Gas Electric Compressor | N/A | none |
| ST#1 | Solar Centaur T-4500 Turbine Engine | 3353 hp | MD-401A |
| SB#1 | Supplemental Boiler #1 | 30 MMBtu/hr | MD-401A |
| ST#2 | Solar Centaur T-4500 Turbine Engine | 3353 hp | MD-401A |
| SB#2 | Supplemental Boiler #2 | 40 MMBtu/hr | MD-401A |
| F-1 | Plant Flare | 0.15 MMBtu/hr | MD-401A |
| PEG | Plant Emergency Generator Engine | 100 hp | MD-401A |
| EGR-1 | EG Gas Dehydration Reboiler (Still Vent) | Steam heated | MD-401A |
| LO-1 | Truck Loadout Station | 4.54 MMgal/yr | MD-401A |
| none | Fugitive Leaks | N/A | MD-401A |
| none | Natural Gas Fired Furnaces | 100,000 Btu/hr each | none |
| none | Pressurized tanks (7) | 25,000 - 45,000 gal | none |
| none | Heavy Lean Oil Tank | 20 bbl | none |
| none | Effluent Condensate Tank | 210 bbl | none |
| none | Lean Oil Tanks (2) | 360 - 400 bbl each | none |

LO#1 to be replaced by LO#2. LO#2 is not yet operational.

## TOTAL FACILITY ESTIMATED EMISSIONS

For informational purposes only. These emissions are not to be assumed as permit limits.

| POLLUTANT | EMISSIONS (TPY) |
|---|---|
| CRITERIA POLLUTANT EMISSIONS | |
| Particulate Matter | 11.4 |
| $PM_{10}$ Particulate Matter | 11.4 |
| Sulfur Dioxide ($SO_2$) | 39.4 |
| Nitrogen Oxides ($NO_X$) | 738 |
| Carbon Monoxide (CO) | 285 |
| Volatile Organic Compounds (VOCs) | 123 |
| HAZARDOUS AIR POLLUTANT (HAP) EMISSIONS | 18.7 |
| Formaldehyde | 6.7 |

Emission estimates for PM, $SO_2$, total HAPs, and Formaldehyde are from information in the permit application. Estimates for $NO_x$ and CO are based on emission limitations. Estimates for VOC are based on AP-42 factors. Exceptions are estimated emissions from:

- The plant flare, which are based on the average of reported emissions from 2002-2005;
- The emergency generator, which are based on AP-42 factors;
- The Truck Loadout Station, which are based on maximum reported emissions since 1999;
- The EG Gas Dehydration Reboiler still vent, which are based on GRI-GLYCalc version 4.0; and
- Fugitive VOC leaks, which are from the permit application.

## FACILITY-SPECIFIC PERMIT CONDITIONS

Facility-Wide Permit Conditions

(F1) PERMIT SHIELD [WAQSR Sec 30 (k)]
Compliance with the conditions of this permit shall be deemed compliance with any applicable requirements as of the date of permit issuance.

(F2) SULFUR DIOXIDE EMISSIONS INVENTORY [WAQSR Ch 14, Sec 3]
The permittee shall comply with the requirements of WAQSR Ch 14, Sec 3. $SO_2$ emissions shall be estimated in accordance with Ch 14 Sec 3(b), and adjusted in accordance with Ch 14 Sec 3(c) if necessary.

Source-Specific Permit Conditions

(F3) VISIBLE EMISSIONS [WAQSR Ch 3, Sec 2; Ch 5, Sec 2(m); and 40 CFR Part 60 Subpart KKK]

- (a) Visible emissions of particulate discharged into the atmosphere from the #2 Wickes Boiler, the two Cooper-Bessemer compressor engines, and the plant emergency generator (units PB#2, C-1, C-3, and PEG) shall not exhibit greater than 40 percent opacity.
- (b) The Plant Flare (unit F-1) shall not exhibit visible emissions as determined by Method 22, except for periods not to exceed a total of five (5) minutes during any two (2) consecutive hours.
- (c) Unless a lower limit is specified elsewhere in this permit, visible emissions of any contaminant discharged into the atmosphere from any other single emission source shall not exhibit greater than 20 percent opacity except for one period or periods aggregating not more than six minutes in any one hour of not more than 40 percent opacity.

(F4) $NO_x$ AND CO EMISSION LIMITATIONS [WAQSR Ch 3, Sec 3(a) and Ch 6, Sec 2 Permit MD-401A]

- (a) Emissions from the units listed in Table I of this permit shall not exceed the specified limits.
- (b) $NO_X$ emissions from the LO#2 Lean Oil Heater shall be limited to 0.035 lb/MMBtu of heat input; $NO_X$ emissions from all other gas-fired furnaces shall be limited to 0.20 lb/MMBtu of heat input.
- (c) The permittee shall operate units C-7A and C-13A at an annual average $NO_x$ emission rate of 1 g/hp-hr.

**TABLE I: ALLOWABLE EMISSIONS**

| Source ID# | Source Description | $NO_x$ Emissions | | | CO Emissions | | |
|---|---|---|---|---|---|---|---|
| | | g/hp-hr | lb/hr | TPY | g/hp-hr | lb/hr | TPY |
| LO#1 | Lean Oil Heater[1] | | 3.4 | 14.9 | | 0.8 | 3.7 |
| LO#2 | Lean Oil Heater[1] | | 1.1 | 4.8 | | 1.3 | 5.5 |
| PB#2 | #2 Wickes Boiler | | 4.0 | 17.6 | | 1.0 | 4.4 |
| C-1 | Cooper-Bessemer GMXF-6 Compressor Engine | | 12.0 | 52.6 | | 1.5 | 6.7 |
| C-3 | Cooper-Bessemer GMXE-4 Compressor Engine | | 7.9 | 34.6 | | 1.0 | 4.4 |
| C-6 | Waukesha L7042GSI Compressor Engine | 2.0 | 5.4 | 23.8 | 4.0 | 10.8 | 47.5 |
| C-7A | Waukesha L7042GSI Compressor Engine[2] | 1.5 | 4.6 | 13.6 | 1.0 | 3.1 | 13.6 |
| C-8 | Clark HBA-6 Compressor Engine | | 69.0 | 302.2 | | 11.2 | 49.1 |
| C-9 | Waukesha L7042GSI Compressor Engine | 4.0 | 9.8 | 42.9 | 4.0 | 9.8 | 42.9 |
| C-10 | Waukesha L7042GSI Compressor Engine | 2.0 | 4.9 | 21.5 | 4.0 | 9.8 | 42.9 |
| C-13A | Waukesha L7042GSI Compressor Engine[2] | 1.5 | 4.6 | 13.6 | 1.0 | 3.1 | 13.6 |
| ST#1 | Solar Centaur T-4500 Turbine Engine | | 16.8 | 73.6 | | 5.0 | 21.9 |
| SB#1 | Supplemental Boiler #1 | | 4.1 | 17.9 | | 1.0 | 4.4 |

| TABLE I: ALLOWABLE EMISSIONS | | | | | | | |
|---|---|---|---|---|---|---|---|
| Source ID# | Source Description | $NO_x$ Emissions | | | CO Emissions | | |
| | | g/hp-hr | lb/hr | TPY | g/hp-hr | lb/hr | TPY |
| ST#2 | Solar Centaur T-4500 Turbine Engine | | 16.8 | 73.6 | | 5.0 | 21.9 |
| SB#2 | Supplemental Boiler #2 | | 5.5 | 23.9 | | 1.4 | 6.0 |

[1] After construction and startup, the LO#2 Lean Oil Heater will replace the LO#1 Lean Oil Heater.
[2] The annual average emission rate for these engines is 1.0 gm/hr-hr determined as described in Appendix D.

(F5) ACID GAS AND FLARE REQUIREMENTS [WAQSR Ch 6, Sec 2 Permit MD-401A]
- (a) All acid gas produced at the Beaver Creek Gas Plant shall be reinjected into the Phosphoria formation. During periods when the reinjection system is inoperable, the permittee shall follow the $SO_2$ Minimization Plan included in Appendix A of this permit. Revisions to the plan require Division approval and amendment of this permit prior to implementation.
- (b) The Plant Flare (unit F-1) shall be equipped and operated with an automatic ignitor or a continuous burning pilot, which must be maintained in good working order.

(F6) TEMPORARY ENGINE REPLACEMENT [WAQSR Ch 6, Sec 3(h)(i)(I)]
- (a) Should any of the compressor or turbine engines referenced in condition F4 of this permit break down or require an overhaul during the term of this permit, the permittee may bring on site and operate a temporary replacement engine until repairs are made. Permanent replacement of an engine must be evaluated by the Division under Chapter 6, Section 2 of WAQSR to determine appropriate permitting action and evaluate the need for additional requirements resulting from the permanent replacement.
- (b) The temporary replacement unit shall be identical or similar to the unit replaced with emission levels at or below those of the unit replaced.
- (c) The permittee shall notify the Division in writing of such replacement within five working days, and provide the date of startup of the replacement engine.

Testing Requirements

(F7) EMISSIONS TESTING [WS 35-11-110 and 40 CFR Part 60 Subpart GG]
- (a) The Division reserves the right to require testing as provided under condition G1 of this permit. Should testing be required:
  - (i) For visible emissions from the Plant Flare (unit F-1), Method 22 shall be used.
  - (ii) For visible emissions from other sources, Method 9 shall be used.
  - (iii) For $NO_x$ and $SO_2$ emissions from turbine engines, testing on a ppm basis shall follow the requirements of 40 CFR Part 60 Subpart GG, and testing on a lb/hr basis shall follow Methods 1-4, 6C, and 7E.
  - (iv) For $NO_x$ emissions from sources other than turbine engines, Methods 1-4, and 7 or 7E shall be used.
  - (v) For CO emission sources, Methods 1-4 and 10 shall be used.
  - (vi) For alternative test methods, or methods used for other pollutants, the approval of the Administrator must be obtained prior to using the test method to measure emissions.
- (b) The LO#2 Lean Oil Heater shall be tested for $NO_x$ and CO emissions within 30 days of achieving a maximum design rate but not later than 90 days following initial start-up. If the maximum design rate is not achieved within 90 days of start-up, the Division may require testing be done at the rate achieved and again when a maximum rate is achieved. Compliance tests shall consist of 3 1-hour tests using the following
  - (i) For $NO_x$ emissions, Methods 1-4, and 7 or 7E shall be used.
  - (ii) For CO emissions, Methods 1-4 and 10 shall be used.
- (c) Unless otherwise specified, testing shall be conducted in accordance with WAQSR Ch 5, Sec 2(h).

Monitoring Requirements

(F8) VISIBLE EMISSIONS MONITORING [WAQSR Ch 6, Sec 3(h)(i)(C)(I)]

(a) For periodic monitoring of visible emissions from the emission units listed in Table I of this permit and from the plant emergency generator engine (unit PEG), the permittee shall monitor the type of fuel used to ensure that natural gas is the sole fuel used for these units.

(b) Periodic monitoring for the plant flare (unit F-1) shall consist of the pilot flame monitoring required by condition P60-KKK1.

(F9) $NO_x$ AND CO EMISSIONS MONITORING [WAQSR Ch 6, Sec 3(h)(i)(C)(I)]

(a) The permittee shall measure $NO_x$ emissions from the following compressor engines at least once every calendar half for comparison with the emission limits specified in condition F4 of this permit:
   (i) The Cooper-Bessemer compressor engines, units C-1 and C-3;
   (ii) The unit C-6 Waukesha L7042GSI compressor engine; and
   (iii) The unit C-10 Waukesha L7042GSI compressor engine.

(b) The permittee shall measure $NO_X$ emissions from the following compressor and turbine engines at least once every quarter for comparison with the emission limits specified in condition F4 of this permit:
   (i) The Clark HBA-6 compressor engine, unit C-8;
   (ii) The Waukesha L7042GSI compressor engine, unit C-9; and
   (iii) The Solar Centaur turbine engines, units ST#1 and ST#2.

(c) The permittee shall measure $NO_X$ emissions from the engines described in paragraphs (a) and (b) of this condition using the Division's portable analyzer monitoring protocol, or the reference method tests described in condition F8 of this permit. The Division's monitoring protocol is attached as Appendix B of this permit.

(d) Periodic monitoring of $NO_X$ emissions for the heaters and boilers (units LO#1, LO#2, PB#2, SB#1, and SB#2), shall consist of operation and maintenance of the heaters and boilers in accordance with the manufacturer's or supplier's specifications and recommendations or good maintenance practices.

(e) Periodic monitoring of $NO_x$ emissions from the small gas-fired furnaces is not required. Based on the size of the small furnaces, and their potential impact on ambient standards, the Division is satisfied that no additional $NO_X$ monitoring is warranted for these sources.

(f) Periodic monitoring of CO emissions from the following units is not required:
   (i) Based on the size of the heaters and boilers (units LO#1, LO#2, PB#2, SB#1, and SB#2) and their potential impact on ambient standards, the Division is satisfied that no additional NOX monitoring is warranted for these sources;
   (ii) Based on the size of the CO emissions from the Cooper-Bessemer compressor engines (units C-1 and C-3) and their potential impact on ambient standards, the Division is satisfied that no additional monitoring is required. The engines have demonstrated compliance through source testing conducted in April of 1997;
   (iii) Based on the size of the CO emissions from the Clark HBA-6 compressor engine (unit C-8) and potential impact on ambient standards, the Division is satisfied that no additional monitoring is required. The engines have demonstrated compliance through source testing while operating at full load; and
   (iv) Based on the size of the CO emissions from the Solar Centaur turbine engines (units ST#1 and ST#2) and their potential impact on ambient standards, the Division is satisfied that no additional monitoring is required. The engines have demonstrated compliance through source testing conducted in April and January of 1999, respectively.

(F10) COMPLIANCE ASSURANCE MONITORING
[WAQSR Ch 6, Sec 2 Permit MD-401A, Ch 6, Sec 3(h)(i)(C)(I), and Ch 7, Sec 3 (c)(ii)]
The permittee shall adhere to the compliance assurance monitoring (CAM) plans attached as Appendix C of this permit and shall conduct monitoring as follows.

(a) For $NO_x$ and CO emissions from units C-7A and C-13A:
   (i) The permittee shall monitor temperature of the engine exhaust entering the catalyst at minimum, once daily.
   (ii) The permittee shall monitor pressure drop across the catalyst at least once per calendar month.

(iii) The permittee shall measure $NO_x$ and CO emissions at least once every calendar quarter for comparison with the emission limits specified in condition F4 of this permit, and to further verify the relationship between emissions and temperature/pressure drop.

(A) Compliance with the annual average $NO_x$ emission rate in condition F4 shall be determined as described in the Preventative Maintenance Plan, included in Appendix D of this permit.

(B) The permittee shall measure emissions using the Division's portable analyzer monitoring protocol, or the reference method tests described in condition F7 of this permit. The Division's monitoring protocol is attached as Appendix B of this permit.

(iv) The permittee shall operate the C-7A and C-13A engines and catalysts within the temperature and differential pressure ranges specified in the approved CAM plan.

(b) For CO emissions from units C-6, C-9, and C-10:

(i) The permittee shall monitor temperature of the engine exhaust entering the catalyst at minimum, once daily.

(ii) The permittee shall monitor pressure drop across the catalyst at least once per calendar month.

(iii) The permittee shall measure CO emissions at least once every calendar half for comparison with the emission limits specified in condition F4 of this permit, and to further verify the relationship between emissions and temperature/pressure drop. The permittee shall measure emissions using the Division's portable analyzer monitoring protocol, or the reference method tests described in condition F7 of this permit. The Division's monitoring protocol is attached as Appendix B of this permit.

(iv) The permittee shall operate the C-6, C-9, and C-10 engines and catalysts within the temperature and differential pressure ranges specified in the approved CAM plan.

(c) The permittee shall inspect and maintain the catalytically controlled compressor engines (units C-6, C-7A, C-9, C-10, and C-13A) in accordance with the Preventative Maintenance Plan in Appendix D and the inspection and maintenance procedures described in the approved CAM plan in Appendix C of this permit.

(d) Operation outside of the ranges established in the approved CAM plans shall trigger immediate corrective action.

(e) The permittee shall follow all other applicable requirements under conditions CAM-1 through CAM-4 of this permit.

(F11) $SO_2$ MINIMIZATION MONITORING [WAQSR Ch 6, Sec 3(h)(i)(C)(I)]
The permittee shall monitor events when the acid gas reinjection system is inoperable such that the records required by condition F15 may be prepared.

<u>Recordkeeping Requirements</u>

(F12) SULFUR DIOXIDE EMISSIONS INVENTORY RECORDS [WAQSR Ch 14, Sec 3(b)]

(a) The permittee shall maintain all records used in the calculation of $SO_2$ emissions, including but not limited to the following:

(i) Amount of fuel consumed;
(ii) Percent sulfur content of fuel and how the content was determined;
(iii) Quantity of product produced;
(iv) Emissions monitoring data;
(v) Operating data; and
(vi) How the emissions are calculated, including monitoring/estimation methodology with a demonstration that the selected methodology is acceptable under Chapter 14, Section 3.

(b) The permittee shall maintain records of any physical changes to facility operations or equipment, or any other changes (e.g. raw material or feed) that may affect emissions projections of $SO_2$.

(c) The permittee shall retain all records and support information for compliance with this condition and with the reporting requirements of condition F16 at the facility, for a period of **at least ten (10) years** from the date of establishment, or if the record was the basis for an adjustment to the milestone, five years after the date of an implementation plan revision, whichever is longer.

(F13) TESTING AND MONITORING RECORDS [WAQSR Ch 6, Sec 3(h)(i)(C)(II) and Ch 7, Sec 3 (i)(ii)]

(a) For any testing required under condition F7 of this permit and the monitoring required under conditions F9 and F10, other than Method 9 or Method 22 observations, the permittee shall record, as applicable, the following:
  (i) The date, place, and time of sampling or measurements;
  (ii) The date(s) the analyses were performed;
  (iii) The company or entity that performed the analyses;
  (iv) The analytical techniques or methods used;
  (v) The results of such analyses;
  (vi) The operating conditions as they existed at the time of sampling or measurement. For the emissions monitoring required under condition F10 of this permit, this shall include the engine exhaust temperature into the catalyst and the pressure differential across the catalyst; and
  (vii) If the sources monitored require adjustment, the permittee shall record both the "as found" and the "as adjusted" emission measurements.

(b) For any Method 9 observations required by the Division under condition F7, the permittee shall keep field records in accordance with Section 2.2 of Method 9. Any corrective measures taken shall also be recorded.

(c) For any Method 22 observations required by condition F7, the permittee shall keep field records in accordance with Sections 11.2 and 11.5 of Method 22, and record the operating conditions of the observed unit as they existed at the time of the observation. Any corrective measures taken upon observing visible emissions from the observed unit shall also be recorded.

(d) For the CAM required under condition F10, the permittee shall also maintain records of monitoring data, monitor performance data, corrective actions taken, any written quality improvement plan required pursuant to WAQSR Chapter 7, Section 3(h), any activities undertaken to implement a Quality Improvement Plan (QIP), and other supporting information required to be maintained under WAQSR Chapter 7, Section 3.

(e) For Waukesha engines C-7A and C-13A, the permittee shall also calculate and record the calendar year annual average $NO_x$ emission rate.

(f) The permittee shall retain on-site at the facility the records of each test, measurement, or observation and support information for a period of at least five years from the date of the test, measurement, or observation.

(F14) INSPECTION AND MAINTENANCE RECORDS [WAQSR Ch 6, Sec 3 (h)(i)(C)(II)]

(a) The permittee shall record all maintenance activities performed on the catalytically controlled compressor engines (units C-6, C-7A, C-9, C-10, and C-13A), and the heaters and boilers (units LO#1, LO#2, PB#2, SB#1, and SB#2).

(b) The record of maintenance activities for the equipment described in paragraph (a) of this condition shall include:
  (i) The maintenance activity performed;
  (ii) The date and place the activity was performed;
  (iii) The company and individual(s) that performed the activity;
  (iv) The purpose of the activity; and
  (v) An explanation for any deviations from the following:
    (A) The maintenance procedures described in the CAM plan included in Appendix C, or the Preventative Maintenance Plan in Appendix D of this permit, for the catalytically controlled compressor engines (units C-6, C-7A, C-9, C-10, and C-13A), and
    (B) The manufacturer's or supplier's specifications and recommendations or good maintenance practices for the heaters and boilers (units LO#1, LO#2, PB#2, SB#1, and SB#2).

(c) The permittee shall record the inspection activities required by the CAM plan for the catalytically controlled compressor engines (units C-6, C-7A, C-9, C-10, and C-13A), including the date of inspection, the individual(s) that performed the inspection, and an explanation for any deviations from the inspection procedures described in the CAM plan. This record can take the form of a checklist.

(d) The permittee shall retain on-site at the facility the records described in this condition for a period of at least five years from the date of the inspection or maintenance activity.

(F15) $SO_2$ MINIMIZATION RECORDS [WAQSR Ch 6, Sec 3 (h)(i)(C)(II)]
The permittee shall record the incidence of any event when the acid gas reinjection system is inoperable. This record shall include:
(a) The date, time, duration, and cause of the event.
(b) An estimate of the $SO_2$ emissions resulting from the event, including the calculations and assumptions used to make that estimate.
(c) Any records specified by the $SO_2$ Minimization Plan, attached as Appendix A of this permit.
(d) An explanation for any deviation from the $SO_2$ Minimization Plan attached as Appendix A of this permit.
(e) The permittee shall retain on-site at the facility the records described in this condition for a period of at least five years from the date of the inspection or maintenance activity.

Reporting Requirements

(F16) SULFUR DIOXIDE EMISSIONS INVENTORY REPORTS [WAQSR Ch 14, Sec 3(b) and (c)]
(a) The permittee shall report calendar year $SO_2$ emissions by April 15$^{th}$ of the following year. The inventory shall be submitted in the format specified by the Division.
(b) Emissions from startup, shutdown, and upset conditions shall be included in the inventory.
(c) If the permittee uses a different emission monitoring or calculation method than was used to report $SO_2$ emissions in 1998, the permittee shall adjust reported $SO_2$ emissions to be comparable to the emission monitoring or calculation method that was used in 1998. The calculations that are used to make this adjustment shall be included with the annual emission report.
(d) The annual reports shall be submitted in accordance with condition G4 of this permit.

(F17) MONITORING REPORTS
[WAQSR Ch 6, Sec 2 Permit MD-401A, Ch 6, Sec 3 (h)(i)(C)(III) and Ch 7, Sec 3 (i)(ii)]
(a) The following shall be reported to the Division by January 31 and July 31 each year:
  (i) Documentation that all emissions units are firing natural gas as specified in condition F8(a) of this permit.
  (ii) The results of the emissions monitoring required under condition F9(a) and (b), including the "as found" and "as adjusted" measurements if the sources required adjustment.
  (iii) The results of the CAM required under condition F10, including the following:
    (A) The results of the emissions monitoring required under condition F10, including the "as found" and "as adjusted" measurements if the catalytically controlled compressor engines required adjustment. For the quarterly emissions tests required by condition F10(a), test results shall include all calibrations.
    (B) For the January 31$^{st}$ report, the annual average $NO_x$ emission rate and total tons of $NO_x$ emissions, for the previous calendar year, from units C-7A and C-13A, based on the results of testing conducted in accordance with condition F10(a)(iii).
    (C) Summary information on the number, duration, and cause of excursions, as applicable, and the corrective actions taken;
    (D) Summary information on the number, duration, and cause for monitor downtime incidents; and
    (E) A description of the action taken to implement a QIP (if required) during the reporting period as specified in Chapter 7, Section 3 (h). Upon completion of a QIP, the permittee shall include in the next summary report documentation that the implementation of the plan has reduced the likelihood of similar excursions.
    (F) If no excursions or exceedances occurred during the reporting period, this shall be stated in the report.
(b) All instances of deviations from the conditions of this permit must be clearly identified in each report.
(c) A written report of the testing for the Lean Oil Heater (LO#2), required by condition F7(b) shall be submitted to the Division within 45 days of the test date.

(d) The reports required in this condition shall be submitted in accordance with condition G4 of this permit.

(F18) INSPECTION AND MAINTENANCE REPORTS [WAQSR Ch 6, Sec 3(h)(i)(C)(III)]

(a) The permittee shall report to the Division by January 31 and July 31 each year:

(i) Whether the permittee has adhered to the manufacturer's or supplier's recommendations or good maintenance practices for operating and maintaining the heaters and boilers (units LO#1, LO#2, PB#2, SB#1, and SB#2); and

(ii) Whether the permittee has adhered to the maintenance and inspection activities specified in the approved CAM plan included in Appendix C, and the Preventative Maintenance Plan in Appendix D of this permit, for units C-6, C-7A, C-9, C-10, and C-13A.

(b) Any deviations from the manufacturer's or supplier's specifications and recommendations, or the maintenance and inspection activities described in the CAM plan/ Preventative Maintenance Plan, must be clearly identified in each report.

(c) If the permittee has adhered to the requirements described in paragraph (a) of this condition for inspecting and maintaining these units during the reporting period, this shall be stated in the report.

(d) The semiannual reports shall be submitted in accordance with condition G4 of this permit.

(F19) $SO_2$ MINIMIZATION REPORTS [WAQSR Ch 6, Sec 3(h)(i)(C)(III)]

(a) The permittee shall notify the Division by the next business day if the acid gas reinjection system becomes inoperable.

(b) The permittee shall report the following to the Division within 30 days of an event which triggers implementation of the $SO_2$ Minimization plan. The report shall be submitted to the Division in accordance with condition G4 of this permit.

(i) The date, time, duration, and cause of the event.

(ii) An estimate of the $SO_2$ emissions resulting from the event.

(iii) An explanation for any deviation from the $SO_2$ Minimization Plan attached as Appendix A of this permit.

(F20) REPORTING EXCESS EMISSIONS & DEVIATIONS FROM PERMIT REQUIREMENTS [WAQSR Ch 6, Sec 3(h)(i)(C)(III)]

(a) General reporting requirements are described under the General Conditions of this permit. The Division reserves the right to require reports as provided under condition G1 of this permit.

(b) Emissions which exceed the limits specified in this permit and that are not reported to the Division under a different condition of this permit, shall be reported annually with the emission inventory unless specifically superseded by condition G17, condition G19, or other condition(s) of this permit. The probable cause of such exceedance, the duration of the exceedance, the magnitude of the exceedance, and any corrective actions or preventative measures taken shall be included in this annual report. For sources and pollutants which are not continuously monitored, if at any time emissions exceed the limits specified in this permit by 100 percent, or if a single episode of emission limit exceedance spans a period of 24 hours or more, such exceedance shall be reported to the Division within one working day of the exceedance. (Excess emissions due to an emergency shall be reported as specified in condition G17. Excess emissions due to unavoidable equipment malfunction shall be reported as specified in condition G19.)

(c) Any other deviation from the conditions of this permit shall be reported to the Division in writing within 30 days of the deviation or discovery of the deviation.

Accidental Release Prevention Requirements

(F21) ACCIDENTAL RELEASE PREVENTION REQUIREMENTS [40 CFR Part 68]

(a) The permittee shall meet all requirements of 40 CFR Part 68 as they apply to the facility.

(b) The permittee shall submit, as part of the annual compliance certification submitted under condition C1 of this permit, a certification statement concerning the facility's compliance with all requirements of 40 CFR Part 68, including the registration and submission of a Risk Management Plan.

Requirements for New Equipment

(F22) COMMENCEMENT OF CONSTRUCTION [WAQSR Ch 6, Sec 2 waiver AP-5555]
Approval to construct the 31.25 Lean Oil Heater (Unit LO#2) authorized by waiver AP-5555 shall become invalid if construction is discontinued for a period of 24 months or more. The Administrator may extend the period based on satisfactory justification of the requested extension.

(F23) NOTIFICATIONS [WAQSR Ch 6, Sec 2 Permit Waiver AP-5555]
- (a) For the new Lean Oil Heater, the permittee shall provide the following:
  - (i) Written notification of the actual date of initial startup is required within 15 days after startup.
  - (ii) For the performance testing required by condition F16, the permittee shall provide the Division at least 15 days prior notice of the test date.

**WAQSR CHAPTER 5, SECTION 2 NEW SOURCE PERFORMANCE STANDARDS (NSPS) AND 40 CFR PART 60 SUBPART GG REQUIREMENTS**

(Subpart GG is provided in Appendix E)

The permittee shall comply with the requirements of 40 CFR 60 Subpart GG and WAQSR Ch 5 Sec 2 as they apply to the Solar Centaur T-4500 Turbines (units ST#1 and ST#2) at the Beaver Creek gas plant.

(P60-GG1) $NO_X$ EMISSIONS [WAQSR Ch 6, Sec 3(h)(i)(A) and 40 CFR Part 60 Subpart GG]

The $NO_X$ exhaust gas concentration from the turbines shall not exceed 150 $ppm_v$ at 15 percent oxygen on a dry basis.

(P60-GG2) $SO_2$ EMISSIONS AND SULFUR IN FUEL [40 CFR PART 60 Subpart GG]

The permittee shall comply with one of the following:

(a) The $SO_2$ exhaust gas concentration from each turbine engine shall not exceed 0.015 percent by volume at 15 percent oxygen on a dry basis.

(b) The permittee shall not burn in any turbine engine any fuel which contains sulfur in excess of 0.8 percent by weight.

(P60-GG3) MONITORING FUEL SULFUR AND NITROGEN CONTENT

[40 CFR Part 60 Subpart GG and WAQSR Ch 6, Sec 2 Permit MD-401A]

(a) The permittee shall demonstrate that the fuel combusted in the Solar Centaur turbine engines meets the definition of natural gas in §60.331(u). The permittee shall use one of the following sources of information to make the required demonstration:

 (i) The gas quality characteristics in a current, valid purchase contract, tariff sheet or transportation contract for the gaseous fuel, specifying that the maximum total sulfur content of the fuel is 20.0 grains/100 scf or less; or

 (ii) Representative fuel sampling data which show that the sulfur content of the gaseous fuel does not exceed 20 grains/100 scf. 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.

(b) No monitoring of fuel nitrogen content is required as long as the permittee does not claim an allowance for fuel bound nitrogen as described in §60.332(a), and as long as natural gas is the fuel fired in the turbine engines.

(P60-GG4) RECORDKEEPING

[WAQSR Ch 5, Sec 2(g)(ii) and (g)(v), Ch 6, Sec 2 Permit MD-401A, and Ch 6 Sec 3(h)(i)(C)(II)]

(a) The permittee shall keep records demonstrating that the fuel used in the turbines (units ST#1 and ST#2) meets the definition of natural gas, as described in condition P60-GG3 of this permit.

(b) The permittee shall maintain records of the occurrence and duration of any startup, shutdown, or malfunction in the operation of the turbine engines.

(c) The permittee shall maintain records of all measurements, reports, and other information required by the P60 conditions of this permit in a permanent form suitable for inspection. These records shall be retained on-site at the facility for a period of at least five years from the date such records are generated. Records of the most recent demonstration that fuel meets the definition of natural gas shall be retained regardless of the date of record.

(P60-GG5) SUBPART GG REPORTS [WAQSR Ch 6, Sec 2 Permit MD-401A and 40 CFR 60 Subpart GG]

The permittee shall submit written documentation of any change in the information used in the demonstration required by condition P60-GG3 of this permit related to the fuel fired by the turbine engines, within 45 days of such change. The report shall be submitted in accordance with condition G4 of this permit.

(P60-GG6) GOOD AIR POLLUTION CONTROL PRACTICES [WAQSR Ch 5, Sec 2 (i)(iv)]

At all times, including periods of startup, shutdown, and malfunction, the permittee shall, to the extent practicable, maintain and operate each turbine engine in a manner consistent with good air pollution control practice for minimizing emissions.

## WAQSR CHAPTER 5, SECTION 2 NEW SOURCE PERFORMANCE STANDARDS (NSPS) AND 40 CFR 60 SUBPART KKK REQUIREMENTS

(Subparts KKK and VV are provided in Appendix F)

(P60-KKK1) SUBPART KKK STANDARDS [40 CFR 60 Subparts KKK and VV; WAQSR Ch 5, Sec 2; and WAQSR Ch 6, Sec 2 Permit MD-401A]

(a) The permittee shall meet all requirements of 40 CFR 60 Subpart KKK and WAQSR Ch 5, Sec 2 as they apply to the Beaver Creek gas plant, including units C-2, C-4, C-5, C-6, C-7A, C-12, C-13A, C-14A/B, and the EG Dehydration System.

(i) Compressors, pumps, valves, open-ended valves or lines, pressure relief devices, and flanges or other connectors in VOC service or in wet gas service shall meet the requirements of §60.632 with the exceptions described in §60.633.

(i) Closed vent systems subject to Subpart KKK, such as those routed to a flare, shall be inspected according to the requirements of §60.632.

(ii) The Plant Flare (unit F-1) shall be operated at all times when emissions may be vented to it and shall meet the requirements of WAQSR Chapter 5, Section 2(m), provided in Appendix G of this permit. 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.

(b) The permittee may apply to EPA for permission to use an alternative means of emission limitation under the provisions of §60.632(c).

(P60-KKK2) RECORDKEEPING [40 CFR 60 Subparts KKK and VV; WAQSR Ch 5, Sec 2(g)]

(a) The permittee shall meet all recordkeeping requirements as specified in §60.635.

(b) The permittee shall maintain records of the occurrence and duration of any startup, shutdown, or malfunction in the operation of processing equipment; any malfunction of the flare or other air pollution control equipment; or any periods during which a continuous monitoring system or monitoring device is inoperative.

(c) The permittee shall maintain records of all measurements, reports, observations, any corrective actions taken, and other information required by the P60 conditions of this permit in a permanent form suitable for inspection. These records shall be retained on-site at the facility for a period of at least five years from the date such records are generated.

(P60-KKK3) NOTIFICATION AND REPORTING
[40 CFR 60 Subparts KKK and VV and WAQSR Ch 6, Sec 3(h)(i)(C)(III)]

(a) The permittee shall submit semiannual reports to the Division by January 31 and July 31 each year. The reports shall include the following:

(i) Process unit identification;

(ii) Dates of process unit shutdowns which occurred within the semiannual reporting period;

(iii) Revisions to items previously reported as described in §60.636(b);

(iv) All other information described in §60.636.

(b) If the permittee elects to comply with an alternative standards for valves, they shall notify the Division at least 90 days before implementation as required by §60.636 and §60.487(d).

(c) The reports and notifications shall be submitted to the Division in accordance with condition G4 of this permit.

(P60-KKK4) GOOD AIR POLLUTION CONTROL PRACTICE [WAQSR Ch 5, Sec 2 (i)(iv)]

At all times, including periods of startup, shutdown, and malfunction, the permittee shall, to the extent practicable, maintain and operate the processing equipment subject to Subpart KKK, including associated air pollution control equipment, in a manner consistent with good air pollution control practice for minimizing emissions.

## WAQSR CHAPTER 7, SECTION 3
## COMPLIANCE ASSURANCE MONITORING (CAM) REQUIREMENTS

(Chapter 7, Section 3 is provided in Appendix H)

(CAM-1) COMPLIANCE ASSURANCE MONITORING REQUIREMENTS [WAQSR Ch 7, Sec 3 (b)and (c)]

The permittee shall follow the CAM plan attached as Appendix C of this permit and meet all CAM requirements of WAQSR Chapter 7, Section 3 as they apply to the catalytically controlled compressor engines (units C-6, C-7A, C-9, C-10, and C-13A). Compliance with the source specific monitoring, recordkeeping, and reporting requirements of this permit meets the monitoring, recordkeeping, and reporting requirements of WAQSR Chapter 7, Section 3, except for additional requirements specified under conditions CAM-2 through CAM-4.

(CAM-2) OPERATION OF APPROVED MONITORING [WAQSR Ch 7, Sec 3 (g)]

(a) At all times, the permittee shall maintain the monitoring under this section, including but not limited to, maintaining necessary parts for routine repairs of the monitoring equipment.

(b) Except for monitoring malfunctions, associated repairs, and required quality assurance or control activities, the permittee shall conduct all monitoring in continuous operation (or at all required intervals) at all times that the pollutant specific emissions unit is operating.

(c) Upon detecting an excursion, the permittee shall restore operation of the compressor engine to its normal or usual manner of operation as expeditiously as practicable in accordance with good air pollution control practices. The response shall include minimizing the period of any start-up, shutdown, or malfunction and taking any corrective actions to restore normal operation and prevent the likely recurrence of the cause of an excursion.

(d) If the permittee identifies a failure to achieve compliance with an emission limit for which the monitoring did not provide an indication of an excursion while providing valid data, or the results of compliance or performance testing documents a need to modify the existing indicator ranges, the permittee shall promptly notify the Division and, if necessary, submit a proposed modification to this permit to address the necessary monitoring changes.

(CAM-3) QUALITY IMPROVEMENT PLAN (QIP) REQUIREMENTS [WAQSR Ch 7, Sec 3 (h)]

(a) If the Division or the EPA Administrator determines, based on available information, that the permittee has used unacceptable procedures in response to an excursion or exceedance, the permittee may be required to develop and implement a Quality Improvement Plan (QIP).

(b) If required, the permittee shall maintain a written Quality Improvement Plan (QIP) and have it available for inspection.

(c) The plan shall include procedures for conducting one or more of the following:
   (i) Improved preventative maintenance practices.
   (ii) Process operation changes.
   (iii) Appropriate improvements to control methods.
   (iv) Other steps appropriate to correct control.
   (v) More frequent or improved monitoring (in conjunction with (i) - (iv) above).

(d) If a QIP is required, the permittee shall develop and implement a QIP as expeditiously as practicable and shall notify the Division if the period for completing the QIP exceeds 180 days from the date on which the need to implement the QIP was determined.

(e) Following implementation of a QIP, upon any subsequent determination under paragraph (a) above, the Division may require the permittee to make reasonable changes to the QIP if the QIP failed to address the cause of control device problems, or failed to provide adequate procedures for correcting control device problems as expeditiously as practicable.

(f) Implementation of a QIP shall not excuse the permittee from compliance with any existing emission limit(s) or any existing monitoring, testing, reporting, or recordkeeping requirements that may be applicable to the facility.

(CAM-4) SAVINGS PROVISIONS [WAQSR Ch 7, Sec 3 (j)]

Nothing in the CAM regulations shall excuse the permittee from compliance with any existing emission limit or standard, or any existing monitoring, testing, reporting, or recordkeeping requirement that may be applicable to the facility.

## COMPLIANCE CERTIFICATION AND SCHEDULE

Compliance Certification [WAQSR Ch 6, Sec 3 (h)(iii)(E)]

(C1) (a) The permittee shall submit by January 31 each year a certification addressing compliance with the requirements of this permit. The certification shall be submitted as a stand-alone document separate from any monitoring reports required under this permit.

(b) (i) For visible emissions, the permittee shall assess compliance with conditions F3(a) and (c) of this permit by verifying natural gas was the sole fuel used for the units as described in condition F8 of this permit.

(ii) For operation of and emissions from the Plant Flare (unit F-1), the permittee shall assess compliance with conditions F3(b), F5(b), and P60-KKK1 by reviewing the records kept in accordance with condition P60-KKK2 of this permit.

(iii) For $NO_x$ emissions from the heaters and boilers (units LO#1, LO#2, PB#2, SB#1, and SB#2), the permittee shall assess compliance with condition F4 of this permit by reviewing the records maintained in accordance with condition F14 of this permit.

(iv) For $NO_x$ emissions from compressor engines C-1, C-3, C-6, C-8, C-9, and C-10, the permittee shall assess compliance with condition F4 of this permit by conducting the monitoring required by condition F9 of this permit.

(v) For CO emissions from compressor engines C-6, C-9, and C-10, the permittee shall assess compliance with condition F4 of this permit by conducting the monitoring required by conditions F10 and CAM-1 through CAM-4 of this permit, and by reviewing the records required by condition F14 of this permit.

(vi) For $NO_x$ and CO emissions from compressor engines C-7A and C-13A, the permittee shall assess compliance with condition F4 of this permit by conducting the monitoring required by conditions F10 and CAM-1 through CAM-4 of this permit, and by reviewing the records required by condition F14 of this permit.

(vii) For $NO_x$ emissions from the turbine engines (units ST#1 and ST#2), the permittee shall assess compliance with condition F4 of this permit by conducting the monitoring required by condition F9, and with condition P60-GG1 by verifying natural gas was the sole fuel source for the turbines, as required by condition P60-GG3.

(viii) For the requirement to follow the $SO_2$ Minimization plan, the permittee shall assess compliance with condition F5(a) of this permit by conducting the monitoring required by condition F11 and reviewing the records maintained under condition F15, of this permit.

(ix) For $SO_2$ emissions from the turbine engines (units ST#1 and ST#2), the permittee shall assess compliance with condition P60-GG2 by verifying natural gas was the sole fuel source for the turbines, as required by condition P60-GG3.

(x) The permittee shall assess compliance with condition P60-KKK1 of this permit by reviewing the records maintained in accordance with condition P60-KKK2 of this permit.

(c) The compliance certification shall include:

(i) The permit condition or applicable requirement that is the basis of the certification;

(ii) The current compliance status;

(iii) Whether compliance was continuous or intermittent; and

(iv) The methods used for determining compliance.

(d) For any permit conditions or applicable requirements for which the source is not in compliance, the permittee shall submit with the compliance certification a proposed compliance plan and schedule for Division approval.

(e) The compliance certification shall be submitted to the Division in accordance with condition G4 of this permit and to the Assistant Regional Administrator, Office of Enforcement, Compliance, and Environmental Justice (8ENF-T), U.S. EPA - Region VIII, 1595 Wynkoop Street, Denver, CO 80202-1129.

(f) Determinations of compliance or violations of this permit are not restricted to the monitoring requirements listed in paragraph (b) of this condition; other credible evidence may be used.

Compliance Schedule [WAQSR Ch 6, Sec 3 (h)(iii)(C) and (D)]

(C2) The permittee shall continue to comply with the applicable requirements with which the permittee has certified that it is already in compliance.

(C3) The permittee shall comply in a timely manner with applicable requirements that become effective during the term of this permit.

# GENERAL PERMIT CONDITIONS

Powers of the Administrator: [W.S. 35-11-110]

(G1) (a) The Administrator may require the owner or operator of any point source to complete plans and specifications for any application for a permit required by the Wyoming Environmental Quality Act or regulations made pursuant thereto and require the submission of such reports regarding actual or potential violations of the Wyoming Environmental Quality Act or regulations thereunder.

(b) The Administrator may require the owner or operator of any point source to establish and maintain records; make reports; install, use and maintain monitoring equipment or methods; sample emissions, or provide such other information as may be reasonably required and specified.

Permit Renewal and Expiration: [WAQSR Ch 6, Sec 3(c)(i)(C), (d)(ii), (d)(iv)(B), and (h)(i)(B)] [W.S. 35-11-206(f)]

(G2) This permit is issued for a fixed term of five years. Permit expiration terminates the permittee's right to operate unless a timely and complete renewal application is submitted at least six months prior to the date of permit expiration. If the permittee submits a timely and complete application for renewal, the permittee's failure to have an operating permit is not a violation of WAQSR Chapter 6, Section 3 until the Division takes final action on the renewal application. This protection shall cease to apply after a completeness determination if the applicant fails to submit by the deadline specified in writing by the Division any additional information identified as being needed to process the application.

Duty to Supplement: [WAQSR Ch 6, Sec 3(c)(iii)]

(G3) The permittee, upon becoming aware that any relevant facts were omitted or incorrect information was submitted in the permit application, shall promptly submit such supplementary facts or corrected information. The permittee shall also provide additional information as necessary to address any requirements that become applicable to the facility after this permit is issued.

Submissions: [WAQSR Ch 6, Sec 3(c)(iv)] [W.S. 35-11-206(c)]

(G4) Any document submitted shall be certified as being true, accurate, and complete by a responsible official.

(a) Submissions to the Division.

(i) Any submissions to the Division including reports, certifications, and emission inventories required under this permit shall be submitted as separate, stand-alone documents and shall be sent to:

Administrator, Air Quality Division
122 West 25th Street
Cheyenne, Wyoming 82002

(ii) A copy of each submission to the Administrator under paragraph (a)(i) of this condition shall be sent to the DEQ Air Quality Contact listed on page 3 of this permit.

(b) Submissions to EPA.

(i) Each certification required under condition C1 of this permit shall also be sent to:

Assistant Regional Administrator
Office of Enforcement, Compliance, and Environmental Justice (8ENF-T)
U.S. EPA - Region VIII
1595 Wynkoop Street
Denver, CO 80202-1129.

(ii) All other required submissions to EPA shall be sent to:

Office of Partnerships and Regulatory Assistance
Air and Radiation Program (8P-AR)
U.S. EPA - Region VIII
1595 Wynkoop Street
Denver, CO 80202-1129.

Changes for Which No Permit Revision Is Required: [WAQSR Ch 6, Sec 3(d)(iii)]

(G5) The permittee may change operations without a permit revision provided that:
- (a) The change is not a modification under any provision of title I of the Clean Air Act;
- (b) The change has met the requirements of Chapter 6, Section 2 of the WAQSR and is not a modification under Chapter 5, Section 2 or Chapter 6, Section 4 of the WAQSR and the changes do not exceed the emissions allowed under the permit (whether expressed therein as a rate of emissions or in terms of total emissions); and
- (c) The permittee provides EPA and the Division with written notification at least 14 days in advance of the proposed change. The permittee, EPA, and the Division shall attach such notice to their copy of the relevant permit. For each such change, the written notification required shall include a brief description of the change within the permitted facility, the date on which the change will occur, any change in emissions, and any permit term or condition that is no longer applicable as a result of the change. The permit shield, if one exists for this permit, shall not apply to any such change made.

Transfer of Ownership or Operation: [WAQSR Ch 6, Sec 3(d)(v)(A)(IV)]

(G6) A change in ownership or operational control of this facility is treated as an administrative permit amendment if no other change in this permit is necessary and provided that a written agreement containing a specific date for transfer of permit responsibility, coverage, and liability between the current and new permittee has been submitted to the Division.

Reopening for Cause: [WAQSR Ch 6, Sec 3(d)(vii)] [W.S. 35-11-206(f)(ii) and (iv)]

(G7) The Division will reopen and revise this permit as necessary to remedy deficiencies in the following circumstances:
- (a) Additional applicable requirements under the Clean Air Act or the WAQSR that become applicable to this source if the remaining permit term is three or more years. Such reopening shall be completed not later than 18 months after promulgation of the applicable requirement. No reopening is required if the effective date of the requirement is later than the date on which the permit is due to expire, unless the original permit or any of its terms and conditions have been extended.
- (b) Additional requirements (including excess emissions requirements) become applicable to an affected source under the acid rain program. Upon approval by EPA, excess emissions offset plans shall be deemed to be incorporated into the permit.
- (c) The Division or EPA determines that the permit contains a material mistake or that inaccurate statements were made in establishing the emissions standards or other terms or conditions of the permit.
- (d) The Division or EPA determines that the permit must be revised or revoked to assure compliance with applicable requirements.

Annual Fee Payment: [WAQSR Ch 6, Sec 3(f)(i), (ii), and (vi)] [W.S. 35-11-211]

(G8) The permittee shall, as a condition of continued operations, submit an annual fee to the Division as established in Chapter 6, Section 3 (f) of the WAQSR. The Division shall give written notice of the amount of fee to be assessed and the basis for such fee assessment annually. The assessed fee is due on receipt of the notice unless the fee assessment is appealed pursuant to W.S. 35-11-211(d). If any part of the fee assessment is not appealed it shall be paid to the Division on receipt of the written notice. Any remaining fee which may be due after completion of the appeal is immediately due and payable upon issuance of the Council's decision. Failure to pay fees owed the Division is a violation of Chapter 6, Section 3 (f) and W.S. 35-11-203 and may be cause for the revocation of this permit.

Annual Emissions Inventories: [WAQSR Ch 6, Sec 3(f)(v)(G)]

(G9) The permittee shall submit an annual emission inventory for this facility to the Division for fee assessment and compliance determinations within 60 days following the end of the calendar year. The emissions inventory shall be in a format specified by the Division.

Severability Clause: [WAQSR Ch 6, Sec 3(h)(i)(E)]

(G10) The provisions of this permit are severable, and if any provision of this permit, or the application of any provision of this permit to any circumstance, is held invalid, the application of such provision to other circumstances, and the remainder of this permit, shall not be affected thereby.

Compliance: [WAQSR Ch 6, Sec 3(h)(i)(F)(I) and (II)] [W.S. 35-11-203(b)]

(G11) The permittee must comply with all conditions of this permit. Any permit noncompliance constitutes a violation of the Clean Air Act, Article 2 of the Wyoming Environmental Quality Act, and the WAQSR and is grounds for enforcement action; for permit termination, revocation and reissuance, or modification; or for denial of a permit renewal application. It shall not be a defense for a permittee in an enforcement action that it would have been necessary to halt or reduce the permitted activity in order to maintain compliance with the conditions of this permit.

Permit Actions: [WAQSR Ch 6, Sec 3(h)(i)(F)(III)] [W.S. 35-11-206(f)]

(G12) This permit may be modified, revoked, reopened, and reissued, or terminated for cause. The filing of a request by the permittee for a permit modification, revocation and reissuance, or termination, or of a notification of planned changes or anticipated noncompliance does not stay any permit condition.

Property Rights: [WAQSR Ch 6, Sec 3(h)(i)(F)(IV)]

(G13) This permit does not convey any property rights of any sort, or any exclusive privilege.

Duty to Provide Information: [WAQSR Ch 6, Sec 3(h)(i)(F)(V)]

(G14) The permittee shall furnish to the Division, within a reasonable time, any information that the Division may request in writing to determine whether cause exists for modifying, revoking and reissuing, or terminating the permit or to determine compliance with the permit. Upon request, the permittee shall also furnish to the Division copies of records required to be kept by the permit, including information claimed and shown to be confidential under W.S. 35-11-1101 (a) of the Wyoming Environmental Quality Act. Upon request by the Division, the permittee shall also furnish confidential information directly to EPA along with a claim of confidentiality.

Emissions Trading: [WAQSR Ch 6, Sec 3(h)(i)(H)]

(G15) There are no emissions trading provisions in this permit.

Inspection and Entry: [WAQSR Ch 6, Sec 3(h)(iii)(B)] [W.S. 35-11-206(c)]

(G16) Authorized representatives of the Division, upon presentation of credentials and other documents as may be required by law, shall be given permission to:
- (a) Enter upon the permittee's premises where a source is located or emissions related activity is conducted, or where records must be kept under the conditions of this permit;
- (b) Have access to and copy at reasonable times any records that must be kept under the conditions of this permit;
- (c) Inspect at reasonable times any facilities, equipment (including monitoring and air pollution control equipment), practices, or operations regulated or required under this permit;
- (d) Sample or monitor any substances or parameters at any location, during operating hours, for the purpose of assuring compliance with this permit or applicable requirements.

Excess Emissions Due to an Emergency: [WAQSR Ch 6, Sec 3(l)]

(G17) The permittee may seek to establish that noncompliance with a technology-based emission limitation under this permit was due to an emergency, as defined in Ch 6, Sec 3(l)(i) of the WAQSR. To do so, the permittee shall demonstrate the affirmative defense of emergency through properly signed, contemporaneous operating logs, or other relevant evidence that:
- (a) An emergency occurred and that the permittee can identify the cause(s) of the emergency;
- (b) The permitted facility was, at the time, being properly operated;
- (c) During the period of the emergency the permittee took all reasonable steps to minimize levels of emissions that exceeded the emissions standards, or other requirements in this permit;

(d) The permittee submitted notice of the emergency to the Division within one working day of the time when emission limitations were exceeded due to the emergency. This notice must contain a description of the emergency, any steps taken to mitigate emissions, and corrective actions taken.

Diluting and Concealing Emissions: [WAQSR Ch 1, Sec 4]

(G18) No person shall cause or permit the installation or use of any device, contrivance, or operational schedule which, without resulting in reduction of the total amount of air contaminant released to the atmosphere, shall dilute or conceal an emission from a source. This condition shall not apply to the control of odors.

Unavoidable Equipment Malfunction: [WAQSR Ch 1, Sec 5]

(G19) (a) Any source believing that any emissions in excess of established regulation limits or standards resulted from an unavoidable equipment malfunction, shall notify the Division within 24 hours of the incident via telephone, electronic mail, fax, or other similar method. A detailed description of the circumstances of the incident as described in paragraph 5(a)(i)(A) Chapter 1, including a corrective program directed at preventing future such incidents, must be submitted within 14 days of the onset of the incident. The Administrator may extend this 14-day time period for cause.

(b) The burden of proof is on the owner or operator of the source to provide sufficient information to demonstrate that an unavoidable equipment malfunction occurred.

Fugitive Dust: [WAQSR Ch 3, Sec 2(f)]

(G20) The permittee shall minimize fugitive dust in compliance with standards in Ch 3, Sec 2(f) of WAQSR for construction/demolition activities, handling and transportation of materials, and agricultural practices.

Carbon Monoxide: [WAQSR Ch 3, Sec 5]

(G21) The emission of carbon monoxide in stack gases from any stationary source shall be limited as may be necessary to prevent ambient standards from being exceeded.

Asbestos: [WAQSR Ch 3, Sec 8]

(G22) The permittee shall comply with emission standards for asbestos during abatement, demolition, renovation, manufacturing, spraying, and fabricating activities.

(a) No owner or operator shall build, erect, install, or use any article, machine, equipment, process, or method, 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 dilutants to achieve compliance with a visible emissions standard, and the piecemeal carrying out of an operation to avoid coverage by a standard that applies only to operations larger than a specified size.

(b) All owners and operators conducting an asbestos abatement project, including an abatement project on a residential building, shall be responsible for complying with Federal requirements and State standards for packaging, transportation, and delivery to an approved waste disposal facility as provided in paragraph (m) of Ch 3, Sec 8.

(c) The permittee shall follow State and Federal standards for any demolition and renovation activities conducted at this facility, including:

(i) A thorough inspection of the affected facility or part of the facility where the demolition or renovation activity will occur shall be conducted to determine the presence of asbestos, including Category I and Category II non-friable asbestos containing material. The results of the inspection will determine which notification and asbestos abatement procedures are applicable to the activity.

(ii) The owner or operator shall follow the appropriate notification requirements of Ch 3, Sec 8(i)(ii).

(iii) The owner or operator shall follow the appropriate procedures for asbestos emissions control, as specified in Ch 3, Sec 8(i)(iii).

(d) No owner or operator of a facility may install or reinstall on a facility component any insulating materials that contain commercial asbestos if the materials are either molded and friable or wet-applied and friable after drying. The provisions of this paragraph do not apply to spray-applied insulating materials regulated under paragraph (j) of Ch 3, Sec 8.

(e) The permittee shall comply with all other requirements of WAQSR Ch 3, Sec 8.

Open Burning Restrictions: [WAQSR Ch 10, Sec 2]

(G23) The permittee conducting an open burn shall comply with all rules and regulations of the Wyoming Department of Environmental Quality, Division of Air Quality, and with the Wyoming Environmental Quality Act.

(a) No person shall burn prohibited materials using an open burning method, except as may be authorized by permit. ***"Prohibited materials"*** means substances including, but not limited to; natural or synthetic rubber products, including tires; waste petroleum products, such as oil or used oil filters; insulated wire; plastic products, including polyvinyl chloride ("PVC") pipe, tubing and connectors; tar, asphalt, asphalt shingles, or tar paper; railroad ties; wood, wood waste, or lumber that is painted or chemically treated; explosives or ammunition; batteries; hazardous waste products; asbestos or asbestos containing materials; or materials which cause dense smoke discharges, excluding refuse and flaring associated with oil and gas well testing, completions and well workovers.

(b) No person or organization shall conduct or cause or permit open burning for the disposal of trade wastes, for a salvage operation, for the destruction of fire hazards if so designated by a jurisdictional fire authority, or for fire fighting training, except when it can be shown by a person or organization that such open burning is absolutely necessary and in the public interest. Any person or organization intending to engage in such open burning shall file a request to do so with the Division.

Sulfur Dioxide Emission Trading and Inventory Program [WAQSR Ch 14]

(G24) Any BART (Best Available Retrofit Technology) eligible facility, or facility which has actual emissions of $SO_2$ greater than 100 tpy in calendar year 2000 or any subsequent year, shall comply with the applicable requirements of WAQSR Ch 14, Sections 1 through 3, with the exceptions described in sections 2(c) and 3(a).

Stratospheric Ozone Protection Requirements: [40 CFR Part 82]

(G25) The permittee shall comply with all applicable Stratospheric Ozone Protection Requirements, including but not limited to:

(a) *Standards for Appliances* [40 CFR Part 82, Subpart F]
The permittee shall comply with the standards for recycling and emission reduction pursuant to 40 CFR Part 82, Subpart F - Recycling and Emissions Reduction, except as provided for motor vehicle air conditioners (MVACs) in Subpart B:

(i) Persons opening appliances for maintenance, service, repair, or disposal must comply with the required practices pursuant to §82.156.
(ii) Equipment used during the maintenance, service, repair, or disposal of appliances must comply with the standards for recycling and recovery equipment pursuant to §82.158.
(iii) Persons performing maintenance, service, repair, or disposal of appliances must be certified by an approved technician certification program pursuant to §82.161.
(iv) Persons disposing of small appliances, MVACs, and MVAC-like appliances must comply with record keeping requirements pursuant to §82.166. ("MVAC-like appliance" is defined at §82.152).
(v) Persons owning commercial or industrial process refrigeration equipment must comply with the leak repair requirements pursuant to §82.166.
(vi) Owners/operators of appliances normally containing 50 or more pounds of refrigerant must keep records of refrigerant purchased and added to such appliances pursuant to §82.166.
(vii) The permittee shall comply with all other requirements of Subpart F.

(b) *Standards for Motor Vehicle Air Conditioners* [40 CFR Part 82, Subpart B]
If the permittee performs a service on motor (fleet) vehicles when this service involves ozone-depleting substance refrigerant in the MVAC, the permittee is subject to all the applicable requirements as specified in 40 CFR Part 82, Subpart B, Servicing of Motor Vehicle Air Conditioners. The term "motor vehicle" as used in Subpart B does not include a vehicle in which final assembly of the vehicle has not been completed. The term "MVAC" as used in Subpart B does not include the air-tight sealed refrigeration system used as refrigerated cargo, or the system used on passenger buses using HCFC-22 refrigerant.

## STATE ONLY PERMIT CONDITIONS

The conditions listed in this section are State only requirements and are not federally enforceable.

Ambient Standards

(S1) The permittee shall operate the emission units described in this permit such that the following ambient standards are not exceeded:

| POLLUTANT | STANDARD | CONDITION | WAQSR CH. 2, SEC. |
|---|---|---|---|
| $PM_{10}$ particulate matter | 50 micrograms per cubic meter | annual arithmetic mean | 2 (a) |
| | 150 micrograms per cubic meter | 24-hr average concentration with not more than one exceedance per year | |
| $PM_{2.5}$ particulate matter | 15 micrograms per cubic meter | annual arithmetic mean | 2 (b) |
| | 65 micrograms per cubic meter | $98^{th}$ percentile 24-hour average concentration | |
| Nitrogen dioxide | 100 micrograms per cubic meter | annual arithmetic mean | 3 |
| Sulfur oxides | 60 micrograms per cubic meter | annual arithmetic mean | 4 |
| | 260 micrograms per cubic meter | max 24-hr concentration with not more than one exceedance per year | |
| | 1300 micrograms per cubic meter | max 3-hr concentration with not more than one exceedance per year | |
| Carbon monoxide | 10 milligrams per cubic meter | max 8-hr concentration with not more than one exceedance per year | 5 |
| | 40 milligrams per cubic meter | max 1-hr concentration with not more than one exceedance per year | |
| Ozone | 0.08 parts per million | daily maximum 8-hour average | 6 |
| Hydrogen sulfide | 70 micrograms per cubic meter | ½ hour average not to be exceeded more than two times per year | 7 |
| | 40 micrograms per cubic meter | ½ hour average not to be exceeded more than two times in any five consecutive days | |
| Suspended sulfate | 0.25 milligrams $SO_3$ per 100 square centimeters per day | maximum annual average | 8 |
| | 0.50 milligrams $SO_3$ per 100 square centimeters per day | maximum 30-day value | |
| Lead and its compounds | 1.5 micrograms per cubic meter | maximum arithmetic mean averaged over a calendar quarter | 10 |

Hydrogen Sulfide: [WAQSR Ch 3, Sec 7]

(S2) Any exit process gas stream containing hydrogen sulfide which is discharged to the atmosphere from any source shall be vented, incinerated, flared, or otherwise disposed of in such a manner that ambient sulfur dioxide and hydrogen sulfide standards are not exceeded.

Odors: [WAQSR Ch 2, Sec 11]

(S3) (a) The ambient air standard for odors from any source shall be limited to an odor emission at the property line which is undetectable at seven dilutions with odor free air as determined by a scentometer as manufactured by the Barnebey-Cheney Company or any other instrument, device, or technique designated by the Division as producing equivalent results. The occurrence of odors shall be measured so that at least two measurements can be made within a period of one hour, these determinations being separated by at least 15 minutes.

(b) Odor producing materials shall be stored, transported, and handled in a manner that odors produced from such materials are confined and that accumulation of such materials resulting from spillage or other escape is prevented.

## SUMMARY OF SOURCE EMISSION LIMITS AND REQUIREMENTS

Source ID#: **LO#1, LO#2, SB#1, and SB#2** Source Description: **Lean Oil Heater and Supplemental Boilers #1 and #2**

| Pollutant | Emissions Limit / Work Practice Standard | Corresponding Regulation(s) | Testing Requirements | Monitoring Requirements | Recordkeeping Requirements | Reporting Requirements |
|---|---|---|---|---|---|---|
| Particulate | 20 percent opacity [F3] | WAQSR Ch 3, Sec 2(a) | Testing if required [F7] | Verification of natural gas firing [F8] | Record the results of any testing [F13] | Report type of fuel fired [F17]<br>Report excess emissions and permit deviations [F20] |
| $NO_x$ | Limits listed in Table 1 [F4] | WAQSR Ch 6, Sec 2 Permit MD-401A | Testing if required [F7] | Operate and maintain in accordance with manufacturer's recommendations [F9] | Record maintenance [F14] | Report adherence to manufacturer's maintenance recommendations [F18]<br>Report excess emissions and permit deviations [F20] |
| CO | Limits listed in Table 1 [F4] | WAQSR Ch 6, Sec 2 Permit MD-401A | Testing if required [F7] | None [F9] | Record the results of any testing [F13] | Report excess emissions and permit deviations [F20] |

Source ID#: **PB#2** Source Description: **#2 Wickes Boiler**

| Pollutant | Emissions Limit / Work Practice Standard | Corresponding Regulation(s) | Testing Requirements | Monitoring Requirements | Recordkeeping Requirements | Reporting Requirements |
|---|---|---|---|---|---|---|
| Particulate | 40 percent opacity [F3] | WAQSR Ch 3, Sec 2(a) | Testing if required [F7] | Verification of natural gas firing [F8] | Record the results of any testing [F13] | Report type of fuel fired [F17]<br>Report excess emissions and permit deviations [F20] |
| $NO_x$ | 4.0 lb/hr, 17.6 tpy [F4] | WAQSR Ch 6, Sec 2 Permit MD-401A | Testing if required [F7] | Operate and maintain in accordance with manufacturer's recommendations [F9] | Record maintenance [F14] | Report adherence to manufacturer's maintenance recommendations [F18]<br>Report excess emissions and permit deviations [F20] |
| CO | 1.0 lb/hr, 4.4 tpy [F4] | WAQSR Ch 6, Sec 2 Permit MD-401A | Testing if required [F7] | None [F9] | Record the results of any testing [F13] | Report excess emissions and permit deviations [F20] |

These tables are intended only to highlight and summarize applicable requirements for each source. The corresponding permit conditions, listed in brackets, contain detailed descriptions of the compliance requirements. Compliance with the summary conditions in these tables may not be sufficient to meet permit requirements. These tables may not reflect all emission sources at this facility.

Source ID#: **C-1 and C-3** Source Description: **Cooper-Bessemer GMXF-6 and GMXE-4 Compressor Engines**

| Pollutant | Emissions Limit / Work Practice Standard | Corresponding Regulation(s) | Testing Requirements | Monitoring Requirements | Recordkeeping Requirements | Reporting Requirements |
|---|---|---|---|---|---|---|
| Particulate | 40 percent opacity [F3] | WAQSR Ch 3, Sec 2(a) | Testing if required [F7] | Verification of natural gas firing [F8] | Record the results of any testing [F13] | Report type of fuel fired [F17]<br>Report excess emissions and permit deviations [F20] |
| $NO_x$ | Limits listed in Table 1 [F4] | WAQSR Ch 6, Sec 2<br>Permit MD-401A | Testing if required [F7] | Semiannual emission monitoring [F9] | Record monitoring results [F13] | Report monitoring results [F17]<br>Report excess emissions and permit deviations [F20] |
| CO | Limits listed in Table 1 [F4] | WAQSR Ch 6, Sec 2<br>Permit MD-401A | Testing if required [F7] | None [F9] | Record the results of any testing [F13] | Report excess emissions and permit deviations [F20] |

Source ID#: **C-2, C-4, C-5, C-12, C-14A/B, EGR-1 and non-id'ed sources** Source Description: **Compressors and Equipment Leaks**

| Pollutant | Emissions Limit / Work Practice Standard | Corresponding Regulation(s) | Testing Requirements | Monitoring Requirements | Recordkeeping Requirements | Reporting Requirements |
|---|---|---|---|---|---|---|
| VOC | Inspect as required by Subpart KKK [P60-KKK1]] | WAQSR Ch 5, Sec 2; 40 CFR Part 60 Subparts KKK and VV<br>WAQSR Ch 6, Sec 2 Permit MD-401A | None | Monitor as required by Subpart KKK [P60-KKK1] | KKK recordkeeping [P60-KKK2] | Report excess emissions and permit deviations [F20]<br>Semiannual NSPS reports [P60-KKK3] |

These tables are intended only to highlight and summarize applicable requirements for each source. The corresponding permit conditions, listed in brackets, contain detailed descriptions of the compliance requirements. Compliance with the summary conditions in these tables may not be sufficient to meet permit requirements. These tables may not reflect all emission sources at this facility.

Source ID#: C-6 Source Description: **Waukesha L7042GSI Compressor Engine**

| Pollutant | Emissions Limit / Work Practice Standard | Corresponding Regulation(s) | Testing Requirements | Monitoring Requirements | Recordkeeping Requirements | Reporting Requirements |
|---|---|---|---|---|---|---|
| Particulate | 20 percent opacity [F3] | WAQSR Ch 3, Sec 2(a) | Testing if required [F7] | Verification of natural gas firing [F8] | Record the results of any testing [F13] | Report type of fuel fired [F17]<br>Report excess emissions and permit deviations [F20] |
| $NO_x$ | 2.0 g/hp-hr; 5.4 lb/hr; 23.8 tpy [F4] | WAQSR Ch 6, Sec 2 Permit MD-401A | Testing if required [F7] | Semiannual emission monitoring [F9] | Record monitoring results [F13] | Report monitoring results [F17]<br>Report excess emissions and permit deviations [F20] |
| CO | 4.0 g/hp-hr; 10.8 lb/hr; 47.5 tpy [F4] | WAQSR Ch 6, Sec 2 Permit MD-401A<br>WAQSR Ch 7, Sec 3 | Testing if required [F7] | CAM: daily temperature and monthly pressure drop monitoring; semiannual emission monitoring; inspection and maintenance [F10] | Record CAM results [F13]<br>Record maintenance [F14] | Report monitoring results [F17]<br>Report adherence to maintenance requirements [F18]<br>Report excess emissions and permit deviations [F20] |
| VOC | Inspect as required by Subpart KKK [P60-KKK1]] | WAQSR Ch 5, Sec 2; 40 CFR Part 60 Subparts KKK and VV<br>WAQSR Ch 6, Sec 2 Permit MD-401A | None | Monitor as required by Subpart KKK [P60-KKK1] | KKK recordkeeping [P60-KKK2] | Report excess emissions and permit deviations [F20]<br>Semiannual NSPS reports [P60-KKK3] |

These tables are intended only to highlight and summarize applicable requirements for each source. The corresponding permit conditions, listed in brackets, contain detailed descriptions of the compliance requirements. Compliance with the summary conditions in these tables may not be sufficient to meet permit requirements. These tables may not reflect all emission sources at this facility.

Source ID#: **C-7A and C-13A** Source Description: **Waukesha L7042GSI Compressor Engines**

| Pollutant | Emissions Limit / Work Practice Standard | Corresponding Regulation(s) | Testing Requirements | Monitoring Requirements | Recordkeeping Requirements | Reporting Requirements |
|---|---|---|---|---|---|---|
| Particulate | 20 percent opacity [F3] | WAQSR Ch 3, Sec 2(a) | Testing if required [F7] | Verification of natural gas firing [F8] | Record the results of any testing [F13] | Report type of fuel fired [F17]<br>Report excess emissions and permit deviations [F20] |
| $NO_x$ | 1.5 g/hp-hr, 1 g/hp-hr annual average;<br>4.6 lb/hr; 13.6 tpy [F4] | WAQSR Ch 6, Sec 2 Permit MD-401A<br>WAQSR Ch 7, Sec 3 | Testing if required [F7] | CAM: daily temperature and monthly pressure drop monitoring; quarterly emission monitoring; follow Preventative Maintenance Plan [F10] | Record CAM results [F13]<br>Record maintenance [F14] | Report monitoring results [F17]<br>Report adherence to maintenance requirements [F18]<br>Report excess emissions and permit deviations [F20] |
| CO | 1 g/hp-hr; 3.1 lb/hr; 13.6 tpy [F4] | WAQSR Ch 6, Sec 2 Permit MD-401A<br>WAQSR Ch 7, Sec 3 | Testing if required [F7] | CAM: daily temperature and monthly pressure drop monitoring; quarterly emission monitoring; follow Preventative Maintenance Plan [F10] | Record CAM results [F13]<br>Record maintenance [F14] | Report monitoring results [F17]<br>Report adherence to maintenance requirements [F18]<br>Report excess emissions and permit deviations [F20] |
| VOC | Inspect as required by Subpart KKK [P60-KKK1]] | WAQSR Ch 5, Sec 2; 40 CFR Part 60 Subparts KKK and VV<br>WAQSR Ch 6, Sec 2 Permit MD-401A | None | Monitor as required by Subpart KKK [P60-KKK1] | KKK recordkeeping [P60-KKK2] | Report excess emissions and permit deviations [F20]<br>Semiannual NSPS reports [P60-KKK3] |

These tables are intended only to highlight and summarize applicable requirements for each source. The corresponding permit conditions, listed in brackets, contain detailed descriptions of the compliance requirements. Compliance with the summary conditions in these tables may not be sufficient to meet permit requirements. These tables may not reflect all emission sources at this facility.

Source ID#: **C-8** Source Description: **Clark HBA-6 Compressor Engines**

| Pollutant | Emissions Limit / Work Practice Standard | Corresponding Regulation(s) | Testing Requirements | Monitoring Requirements | Recordkeeping Requirements | Reporting Requirements |
|---|---|---|---|---|---|---|
| Particulate | 20 percent opacity [F3] | WAQSR Ch 3, Sec 2(a) | Testing if required [F7] | Verification of natural gas firing [F8] | Record the results of any testing [F13] | Report type of fuel fired [F17]<br>Report excess emissions and permit deviations [F20] |
| $NO_x$ | 69 lb/hr; 302.2 tpy [F4] | WAQSR Ch 6, Sec 2 Permit MD-401A | Testing if required [F7] | Quarterly emission monitoring [F9] | Record monitoring results [F13] | Report monitoring results [F17]<br>Report excess emissions and permit deviations [F20] |
| CO | 11.2 lb/hr; 49.1 tpy [F4] | WAQSR Ch 6, Sec 2 Permit MD-401A | Testing if required [F7] | None [F9] | Record the results of any testing [F13] | Report excess emissions and permit deviations [F20] |

Source ID#: **C-9** Source Description: **Waukesha L7042GSI Compressor Engines**

| Pollutant | Emissions Limit / Work Practice Standard | Corresponding Regulation(s) | Testing Requirements | Monitoring Requirements | Recordkeeping Requirements | Reporting Requirements |
|---|---|---|---|---|---|---|
| Particulate | 20 percent opacity [F3] | WAQSR Ch 3, Sec 2(a) | Testing if required [F7] | Verification of natural gas firing [F8] | Record the results of any testing [F13] | Report type of fuel fired [F17]<br>Report excess emissions and permit deviations [F20] |
| $NO_x$ | 4.0 g/hp-hr; 9.8 lb/hr; 42.9 tpy [F4] | WAQSR Ch 6, Sec 2 Permit MD-401A | Testing if required [F7] | Quarterly emission monitoring [F9] | Record monitoring results [F13] | Report monitoring results [F17]<br>Report excess emissions and permit deviations [F20] |
| CO | 4.0 g/hp-hr; 9.8 lb/hr; 42.9 tpy [F4] | WAQSR Ch 6, Sec 2 Permit MD-401A<br>WAQSR Ch 7, Sec 3 | Testing if required [F7] | CAM: daily temperature and monthly pressure drop monitoring; semiannual emission monitoring; inspection and maintenance [F10] | Record CAM results [F13]<br>Record maintenance [F14] | Report monitoring results [F17]<br>Report adherence to maintenance requirements [F18]<br>Report excess emissions and permit deviations [F20] |

These tables are intended only to highlight and summarize applicable requirements for each source. The corresponding permit conditions, listed in brackets, contain detailed descriptions of the compliance requirements. Compliance with the summary conditions in these tables may not be sufficient to meet permit requirements. These tables may not reflect all emission sources at this facility.

Source ID#: **C-10** Source Description: **Waukesha L7042GSI Compressor Engine**

| Pollutant | Emissions Limit / Work Practice Standard | Corresponding Regulation(s) | Testing Requirements | Monitoring Requirements | Recordkeeping Requirements | Reporting Requirements |
|---|---|---|---|---|---|---|
| Particulate | 20 percent opacity [F3] | WAQSR Ch 3, Sec 2(a) | Testing if required [F7] | Verification of natural gas firing [F8] | Record the results of any testing [F13] | Report type of fuel fired [F17]<br>Report excess emissions and permit deviations [F20] |
| $NO_x$ | 2.0 g/hp-hr; 4.9 lb/hr; 21.5 tpy [F4] | WAQSR Ch 6, Sec 2 Permit MD-401A | Testing if required [F7] | Semiannual emission monitoring [F9] | Record monitoring results [F13] | Report monitoring results [F17]<br>Report excess emissions and permit deviations [F20] |
| CO | 4.0 g/hp-hr; 9.8 lb/hr; 42.9 tpy [F4] | WAQSR Ch 6, Sec 2 Permit MD-401A<br>WAQSR Ch 7, Sec 3 | Testing if required [F7] | CAM: daily temperature and monthly pressure drop monitoring; semiannual emission monitoring; inspection and maintenance [F10] | Record CAM results [F13]<br>Record maintenance [F14] | Report monitoring results [F17]<br>Report adherence to maintenance requirements [F18]<br>Report excess emissions and permit deviations [F20] |

These tables are intended only to highlight and summarize applicable requirements for each source. The corresponding permit conditions, listed in brackets, contain detailed descriptions of the compliance requirements. Compliance with the summary conditions in these tables may not be sufficient to meet permit requirements. These tables may not reflect all emission sources at this facility.

Source ID#: **ST#1 and ST#2** Source Description: **Solar Centaur T-4500 Turbine Engines**

| Pollutant | Emissions Limit / Work Practice Standard | Corresponding Regulation(s) | Testing Requirements | Monitoring Requirements | Recordkeeping Requirements | Reporting Requirements |
|---|---|---|---|---|---|---|
| Particulate | 20 percent opacity [F3] | WAQSR Ch 3, Sec 2(a) | Testing if required [F7] | Verification of natural gas firing [F8] | Record the results of any testing [F13] | Report type of fuel fired [F17]<br>Report excess emissions and permit deviations [F20] |
| $NO_x$ | 2.27 g/hp-hr; 16.8 lb/hr; 73.6 tpy [F4]<br>150 $ppm_v$ @ 15% $O_2$ [P60-GG1] | WAQSR Ch 6, Sec 2 Permit MD-401A<br>WAQSR Ch 5 Sec 2 and 40 CFR Part 60 Subpart GG | Testing if required [F7] | Quarterly emission monitoring [F9]<br>Demonstrate fuel meets GG definition of natural gas [P60-GG3] | Record monitoring results [F13]<br>Natural gas demonstration and NSPS records [P60-GG4] | Report monitoring results [F17]<br>Report excess emissions and permit deviations [F20]<br>Natural gas demonstration report [P60-GG5] |
| CO | 5.0 lb/hr; 21.9 tpy [F4] | WAQSR Ch 6, Sec 2 Permit MD-401A | Testing if required [F7] | None [F9] | Record the results of any testing [F13] | Report excess emissions and permit deviations [F20] |
| $SO_2$ | 0.015% @ 15% $O_2$; fuel sulfur $\leq$ 0.8% [P60-GG1] | WAQSR Ch 5 Sec 2 and 40 CFR Part 60 Subpart GG | Testing if required [F7] | Demonstrate fuel meets GG definition of natural gas [P60-GG3] | Natural gas demonstration and NSPS records [P60-GG4] | Natural gas demonstration report [P60-GG5] |

Source ID#: **F-1** Source Description: **Plant Flare**

| Pollutant | Emissions Limit / Work Practice Standard | Corresponding Regulation(s) | Testing Requirements | Monitoring Requirements | Recordkeeping Requirements | Reporting Requirements |
|---|---|---|---|---|---|---|
| Particulate | No visible emissions [F3]<br>Equip with an automatic ignitor or continuous burning pilot [F5] | WAQSR Ch 5, Sec 2(m)<br>WAQSR Ch 6, Sec 2 Permit MD-401A | Testing if required [F7] | KKK monitoring [F8] | Record the results of any testing [F13] | Report excess emissions and permit deviations [F20] |
| VOC | Operate at all times when emissions may be vented to it [P60-KKK1] | WAQSR Ch 5, Sec 2; 40 CFR Part 60 Subparts KKK and VV | Testing if required [F7] | Monitor for the presence of a pilot flame [P60-KKK1] | KKK recordkeeping [P60-KKK2] | Report excess emissions and permit deviations [F20]<br>Semiannual NSPS reports [P60-KKK3] |

These tables are intended only to highlight and summarize applicable requirements for each source. The corresponding permit conditions, listed in brackets, contain detailed descriptions of the compliance requirements. Compliance with the summary conditions in these tables may not be sufficient to meet permit requirements. These tables may not reflect all emission sources at this facility.

Source ID#: **PEG** Source Description: **Plant Emergency Generator Engine**

| Pollutant | Emissions Limit / Work Practice Standard | Corresponding Regulation(s) | Testing Requirements | Monitoring Requirements | Recordkeeping Requirements | Reporting Requirements |
|---|---|---|---|---|---|---|
| Particulate | 40 percent opacity [F3] | WAQSR Ch 3, Sec 2(a) | Testing if required [F7] | Verification of natural gas firing [F8] | Record the results of any testing [F13] | Report type of fuel fired [F17]<br>Report excess emissions and permit deviations [F20] |

These tables are intended only to highlight and summarize applicable requirements for each source. The corresponding permit conditions, listed in brackets, contain detailed descriptions of the compliance requirements. Compliance with the summary conditions in these tables may not be sufficient to meet permit requirements. These tables may not reflect all emission sources at this facility.

## ABBREVIATIONS

| | |
|---|---|
| AQD | Air Quality Division |
| BACT | Best available control technology (see Definitions) |
| Btu | British Thermal Unit |
| CAA | Clean Air Act |
| CAM | Compliance Assurance Monitoring |
| C.F.R. | Code of Federal Regulations |
| CO | Carbon monoxide |
| °F | Degrees Fahrenheit |
| DEQ | Wyoming Department of Environmental Quality |
| EPA | United States Environmental Protection Agency (see Definitions) |
| g | Gram(s) |
| g/hp-hr | Gram(s) per horsepower hour |
| gal | Gallon(s) |
| gr | Grain(s) |
| $H_2S$ | Hydrogen sulfide |
| HAP(s) | Hazardous air pollutant(s) |
| hp | Horsepower |
| hr | Hour(s) |
| ID# | Identification number |
| lb | Pound(s) |
| M | Thousand |
| MACT | Maximum available control technology (see Definitions) |
| mfr | Manufacturer |
| mg | Milligram(s) |
| MM | Million |
| MVAC | Motor Vehicle Air Conditioner |
| N/A | Not applicable |
| NMHC(s) | Non-methane hydrocarbon(s) |
| $NO_X$ | Oxides of nitrogen |
| $O_2$ | Oxygen |
| OPP | Operating Permit Program |
| PM | Particulate matter |
| $PM_{10}$ | Particulate matter less than or equal to a nominal diameter of 10 micrometers |
| ppmv | Parts per million (by volume) |
| ppmw | Parts per million (by weight) |
| QIP | Quality Improvement Plan |
| RVP | Reid Vapor Pressure |
| SCF | Standard cubic foot (feet) |
| SCFD | Standard cubic foot (feet) per day |
| SCM | Standard cubic meter(s) |
| SIC | Standard Industrial Classification |
| $SO_2$ | Sulfur dioxide |
| $SO_3$ | Sulfur trioxide |
| $SO_x$ | Oxides of sulfur |
| TBD | To be determined |
| TPY | Tons per year |
| U.S.C. | United States Code |
| µg | Microgram(s) |
| VOC(s) | Volatile organic compound(s) |
| W.S. | Wyoming Statute |
| WAQSR | Wyoming Air Quality Standards & Regulations (see Definitions) |

## DEFINITIONS

*"Act"* means the Clean Air Act, as amended, 42 U.S.C. 7401, *et seq.*

*"Administrator"* means Administrator of the Air Quality Division, Wyoming Department of Environmental Quality.

*"Applicable requirement"* means all of the following as they apply to emissions units at a source subject to Chapter 6, Section 3 of the WAQSR (including requirements with future effective compliance dates that have been promulgated or approved by the EPA or the State through rulemaking at the time of issuance of the operating permit):

(a) Any standard or other requirement provided for in the Wyoming implementation plan approved or promulgated by EPA under title I of the Act that implements the relevant requirements of the Act, including any revisions to the plan promulgated in 40 C.F.R. Part 52;

(b) Any standards or requirements in the WAQSR which are not a part of the approved Wyoming implementation plan and are not federally enforceable;

(c) Any term or condition of any preconstruction permits issued pursuant to regulations approved or promulgated through rulemaking under title I, including parts C or D of the Act and including Chapter 5, Section 2 and Chapter 6, Sections 2 and 4 of the WAQSR;

(d) Any standard or other requirement promulgated under Section 111 of the Act, including Section 111(d) and Chapter 5, Section 2 of the WAQSR;

(e) Any standard or other requirement under Section 112 of the Act, including any requirement concerning accident prevention under Section 112(r)(7) of the Act and including any regulations promulgated by EPA and the State pursuant to Section 112 of the Act;

(f) Any standard or other requirement of the acid rain program under title IV of the Act or the regulations promulgated thereunder;

(g) Any requirements established pursuant to Section 504(b) or Section 114(a)(3) of the Act concerning enhanced monitoring and compliance certifications;

(h) Any standard or other requirement governing solid waste incineration, under Section 129 of the Act;

(i) Any standard or other requirement for consumer and commercial products, under Section 183(e) of the Act (having to do with the release of volatile organic compounds under ozone control requirements);

(j) Any standard or other requirement of the regulations promulgated to protect stratospheric ozone under title VI of the Act, unless the EPA has determined that such requirements need not be contained in a title V permit;

(k) Any national ambient air quality standard or increment or visibility requirement under part C of title I of the Act, but only as it would apply to temporary sources permitted pursuant to Section 504(e) of the Act; and

(l) Any state ambient air quality standard or increment or visibility requirement of the WAQSR.

(m) Nothing under paragraphs (a) through (l) above shall be construed as affecting the allowance program and Phase II compliance schedule under the acid rain provision of Title IV of the Act.

***"BACT" or "Best available control technology"*** means an emission limitation (including a visible emission standard) based on the maximum degree of reduction of each pollutant subject to regulation under the WAQSR or regulation under the Federal Clean Air Act, which would be emitted from or which results for any proposed major emitting facility or major modification which the Administrator, on a case-by-case basis, taking into account energy, environmental, and economic impacts and other costs, determines is achievable for such source or modification through application or production processes and available methods, systems, and techniques, including fuel cleaning or treatment or innovative fuel combustion techniques for control of such pollutant. If the Administrator determines that technological or economic limitations on the application of measurement methodology to a particular class of sources would make the imposition of an emission standard infeasible, he may instead prescribe a design, equipment, work practice or operational standard or combination thereof to satisfy the requirement of Best Available Control Technology. Such standard shall, to the degree possible, set forth the emission reduction achievable by implementation of such design, equipment, work practice, or operation and shall provide for compliance by means which achieve equivalent results. Application of BACT shall not result in emissions in excess of those allowed under Chapter 5, Section 2 of the WAQSR and any other new source performance standard or national emission standards for hazardous air pollutants promulgated by EPA but not yet adopted by the state.

***"Department"*** means the Wyoming Department of Environmental Quality or its Director.

***"Director"*** means the Director of the Wyoming Department of Environmental Quality.

***"Division"*** means the Air Quality Division of the Wyoming Department of Environmental Quality or its Administrator.

***"Emergency"*** means any situation arising from sudden and reasonably unforeseeable events beyond the control of the source, including acts of God, which situation requires immediate corrective action to restore normal operation, and that causes the source to exceed a technology-based emission limitation under the permit, due to unavoidable increases in emissions attributable to the emergency. An emergency shall not include noncompliance to the extent caused by improperly designed equipment, lack of preventative maintenance, careless or improper operation, or operator error.

***"EPA"*** means the Administrator of the U.S. Environmental Protection Agency or the Administrator's designee.

***"Fuel-burning equipment"*** means any furnace, boiler apparatus, stack, or appurtenances thereto used in the process of burning fuel or other combustible material for the purpose of producing heat or power by indirect heat transfer.

***"Fugitive emissions"*** means those emissions which could not reasonably pass through a stack chimney, vent, or other functionally equivalent opening.

***"Insignificant activities"*** means those activities which are incidental to the facility's primary business activity and which result in emissions of less than one ton per year of a regulated pollutant not included in the Section 112 (b) list of hazardous air pollutants or emissions less than 1000 pounds per year of a pollutant regulated pursuant to listing under Section 112 (b) of the Act provided, however, such emission levels of hazardous air pollutants do not exceed exemptions based on insignificant emission levels established by EPA through rulemaking for modification under Section 112 (g) of the Act.

***"MACT" or "Maximum achievable control technology"*** means the maximum degree of reduction in emissions that is deemed achievable for new sources in a category or subcategory that shall not be less stringent than the emission control that is achieved in practice by the best controlled similar source, as determined by the Administrator. Emission standards promulgated for existing sources in a category or subcategory may be less stringent than standards for new sources in the same category or subcategory but shall not be less stringent, and may be more stringent than:

(a) the average emission limitation achieved by the best performing 12 percent of the existing sources (for which the Administrator has emission information), excluding those sources that have, within 18 months before the emission standard is proposed or within 30 months before such standard is promulgated, whichever is later, first achieved a level of emission rate or emission reduction which complies, or would comply if the source is not subject to such standard, with the lowest achievable emission rate applicable to the source category and prevailing at the time, in the category or subcategory for categories and subcategories with 30 or more sources, or

(b) the average emission limitation achieved by the best performing five sources (for which the Administrator has or could reasonably obtain emissions information) in the category or subcategory for categories or subcategories with fewer than 30 sources.

***"Modification"*** means any physical change in, or change in the method of operation of, an affected facility which increases the amount of any air pollutant (to which any state standards applies) emitted by such facility or which results in the emission of any such air pollutant not previously emitted.

***"Permittee"*** means the person or entity to whom a Chapter 6, Section 3 permit is issued.

***"Potential to emit"*** means the maximum capacity of a stationary source to emit any air pollutant under its physical and operational design. Any physical or operational limitation on the capacity of a source to emit an air pollutant, including air pollution control equipment and restrictions on hours of operation or on the type or amount of material combusted, stored or processed, shall be treated as part of its design if the limitation is enforceable by EPA and the Division. This term does not alter or affect the use of this term for any other purposes under the Act, or the term "capacity factor" as used in title IV of the Act or the regulations promulgated thereunder.

***"Regulated air pollutant"*** means the following:

(a) Nitrogen oxides ($NO_X$) or any volatile organic compound;

(b) Any pollutant for which a national ambient air quality standard has been promulgated;

(c) Any pollutant that is subject to any standard established in Chapter 5, Section 2 of the WAQSR or Section 111 of the Act;

(d) Any Class I or II substance subject to a standard promulgated under or established by title VI of the Act; or

(e) Any pollutant subject to a standard promulgated under Section 112 or other requirements established under Section 112 of the Act, including Sections 112(g), (j), and (r) of the Act, including the following:

(i) Any pollutant subject to requirements under Section 112(j) of the Act. If EPA fails to promulgate a standard by the date established pursuant to Section 112(e) of the Act, any pollutant for which a subject source would be major shall be considered to be regulated on the date 18 months after the applicable date established pursuant to Section 112(e) of the Act; and

(ii) Any pollutant for which the requirements of Section 112(g)(2) of the Act have been met, but only with respect to the individual source subject to Section 112(g)(2) requirement.

(f) Pollutants regulated solely under Section 112(r) of the Act are to be regulated only with respect to the requirements of Section 112(r) for permits issued under this Chapter 6, Section 3 of the WAQSR.

***"Renewal"*** means the process by which a permit is reissued at the end of its term.

***"Responsible official"*** means one of the following:

(a) For a corporation:

(i) A president, secretary, treasurer, or vice-president of the corporation in charge of a principal business function, or any other person who performs similar policy or decision-making functions for the corporation; or

(ii) A duly authorized representative of such person if the representative is responsible for the overall operation of one or more manufacturing, production, or operating facilities applying for or subject to a permit and either:

(A) the facilities employ more than 250 persons or have gross annual sales or expenditures exceeding $25 million (in second quarter 1980 dollars); or

(B) the delegation of authority to such representative is approved in advance by the Division;

(b) For a partnership or sole proprietorship: a general partner or the proprietor, respectively;

(c) For a municipality, State, Federal, or other public agency: Either a principal executive officer or ranking elected official. For the purposes of this part, a principal executive officer of a federal agency includes the chief executive officer having responsibility for the overall operations of a principal geographic unit of the agency; or

(d) For affected sources:

(i) The designated representative or alternate designated representative in so far as actions, standards, requirements, or prohibitions under title IV of the Act or the regulations promulgated thereunder are concerned; and

(ii) The designated representative, alternate designated representative, or responsible official under Chapter 6, Section 3 (b)(xxvi) of the WAQSR for all other purposes under this section.

***"WAQSR"*** means the Wyoming Air Quality Standards and Regulations promulgated under the Wyoming Environmental Quality Act, W.S. §35-11-101, *et seq.*

<u>APPENDIX A</u>

$SO_2$ Minimization Plan

devon
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# Sulfur Dioxide Minimization Plan
# Devon SFS Operating Inc.
# Beaver Creek Gas Plant, Fremont County, Wyoming
# June 17, 2002

For the Division's review, Devon SFS Operating, Inc. (Devon SFS) offers the following plan as an alternative to maintaining the Beaver Creek Gas Plant's sulfur recovery unit (SRU) on standby for use during downtime of the acid gas reinjection system. Devon SFS requests that permit 30-046 be modified to replace condition Al with the following plan.

## Background

The Beaver Creek Gas Plant (BCGP) processes natural gas containing hydrogen sulfide ($H_2S$), also known as sour gas. During processing, hydrogen sulfide and carbon dioxide is separated from the sour gas, and is concentrated into what is typically known as "acid gas".

Initially, the BCGP was approved to process this acid gas stream using a SRU. The SRU removed 95% of the sulfur from the acid gas and burned the remaining 5% in an incinerator. Incineration of the remaining $H_2S$ resulted in the release of approximately 1,000 tons per year (TPY) of sulfur dioxide ($SO_2$).

In 1995, the BCGP received approval to reinject acid gas into the Phosphoria formation instead of using the SRU to process the acid gas stream. This acid gas reinjection system resulted in a significant reduction in $SO_2$ emissions over the previously approved process. Various abnormal conditions or equipment malfunctions can result in the inoperability of the acid gas reinjection system. Permit number 30-046 currently requires that the SRU be maintained on standby in the event that the acid gas reinjection system becomes inoperable.

When the acid gas reinjection system is inoperable, Devon SFS Operating Inc. requests approval of this Sulfur Dioxide Minimization Plan to be used in lieu of the SRU to minimize $SO_2$ emissions at the BCGP. Initial acceptance of the plan was granted by the Division in the attached October 1, 2001 letter.

## Sulfur Dioxide Minimization Plan

### 1. Critical Spare Parts Inventory

Clearly, limiting $SO_2$ emission from the BCGP requires the prevention/minimization of acid gas reinjection system downtime. This can be accomplished in part by maintaining an inventory of parts that are critical to the operation of the C-11 acid gas compressor and reinjection well. These critical spare parts are listed below.

Replacement C-11 compressor crankshaft
Process controllers
Electrical switches/devices
$H_2S$ sensors
Valve repair kits
Other compressor parts

## 2. Equipment Vendors and Contractors

Vendors that supply parts and components not listed above are identified. Also, Devon SFS Operating Inc. retains the services of local roustabout, electrical, welding, and automation contractors, all of whom are available on short notice.

## 3. Permit a Backup Reinjection Well

An application to use the BCU 135 as a Class II acid gas disposal well was approved by the Wyoming Oil and Gas Conservation Commission on February 11, 2002. A copy of the approval is included. The workover needed to prepare the BCU 135 for acid gas injection service has already been completed. If the BCU 135 is needed, approximately three (3) working days will be required to tie it in to the existing acid gas injection line. The well will then be added to the preventative maintenance schedule described below.

## 4. Preventative Maintenance Schedule

The C-11 acid gas compressor, the acid gas flowline and the components of BCU 100 receive regularly scheduled inspections and preventative maintenance. This allows for the early detection of problems so that corrective actions can be made before any downtime is realized.

## 5. Operational Control

### I. Source Number 1 - Beaver Creek Phosphoria Production.

It is proposed that during times when the acid gas reinjection system is inoperable, acid gas and $H_2S$ containing gas streams normally processed at the BCGP will be flared at the BCGP flare with assist gas at a rate of 200Mscf/day. If the abnormal condition cannot be resolved within 48 hours, the Beaver Creek Phosphoria well production will be shut in. This would reduce total $SO_2$ emissions by approximately 75%, from 23 tpd to 6 tpd.

### II. Source Number 2: Sour Gas from Riverton Dome Oil Production.

The BCGP processes a sour stream from the Devon SFS Riverton Dome facility located to the north. The majority of this gas is a product of sour oil production at Riverton Dome. The EPA has recently issued a Part 71 permit (Permit V-WR-0002-00.01) for the Riverton Dome Gas Plant (RDGP). Under the provisions of the permit, the sour stream from the RDGP may be flared when it cannot be delivered to the BCGP so that oil production may continue. However, because the flaring of natural gas prevents natural gasoline liquid (NGL) and methane recovery, Devon SFS proposes that this sour stream continue to be processed and NGLs and methane recovered at the BCGP during periods when the acid gas reinjection system is inoperable. In contrast to flaring at Riverton Dome, processing this sour stream and flaring the $H_2S$ at the BCGP allows for the conservation of product while reducing overall atmospheric emissions. Potential $SO_2$ emissions from this sour source is estimated at approximately 5 tons/day or 22% of the total.

### III. Source Number 3: Sour Gas from Beaver Creek Oil Production.

Sour gas from both the Madison and Tensleep batteries is captured by a vapor recovery unit (VRU) and routed to the Beaver Creek Gas plant for processing. It is proposed that $H_2S$ from this source be flared at the BCGP during times when the acid gas reinjection system is inoperable. This source would account for approximately 0.5 tons/day or 3% of the total $SO_2$ emitted from the Beaver Creek flare, a quantity below the 5% allowed from the normal operation of the sulfur recovery unit (SRU) under the current operating permit 30-046.

### 6. Record Keeping.

The following record keeping procedures will be followed in association the flaring events that result in $SO_2$ emissions:

> Flaring events generating $SO_2$ emissions that last longer than 15 minutes will be recorded on the monthly flare report.
>
> A calculated $SO_2$ emission rate from all recorded $SO_2$ flaring events will be generated based on flare duration, production volumes of the applicable sour gas streams, the most recent $H_2S$ concentration for the applicable sour gas streams, and assuming 100% conversion of $H_2S$ to $SO_2$.

<u>APPENDIX B</u>

Portable Analyzer Monitoring Protocol

# STATE OF WYOMING AIR QUALITY DIVISION
# PORTABLE ANALYZER MONITORING PROTOCOL

## Determination of Nitrogen Oxides, Carbon Monoxide and Oxygen Emissions from Natural Gas-Fired Reciprocating Engines, Combustion Turbines, Boilers, and Process Heaters Using Portable Analyzers

WYOMING DEPARTMENT OF ENVIRONMENTAL QUALITY
AIR QUALITY DIVISION
122 West 25th Street
Cheyenne, Wyoming 82002

April 21, 1999
Revised January 25, 2006

Approved By:
Dan Olson
Administrator

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# 1. APPLICABILITY AND PRINCIPLE

**1.1 Applicability.** This method is applicable to the determination of nitrogen oxides (NO and $NO_2$), carbon monoxide (CO), and oxygen ($O_2$) concentrations in controlled and uncontrolled emissions from natural gas-fired reciprocating engines, combustion turbines, boilers, and process heaters using portable analyzers with electrochemical cells. The use of reference method equivalent analyzers is acceptable provided the appropriate reference method procedures in 40 CFR 60, Appendix A are used. Due to the inherent cross sensitivities of the electrochemical cells, this method is not applicable to other pollutants.

**1.2 Principle.** A gas sample is continuously extracted from a stack and conveyed to a portable analyzer for determination of NO, $NO_2$, CO, and $O_2$ gas concentrations using electrochemical cells. Analyzer design specifications, performance specifications, and test procedures are provided to ensure reliable data. Additions to or modifications of vendor-supplied analyzers (e.g. heated sample line, flow meters, etc.) may be required to meet the design specifications of this test method.

# 2. RANGE AND SENSITIVITY

**2.1 Analytical Range.** The analytical range for each gas component is determined by the electrochemical cell design. A portion of the analytical range is selected to be the nominal range by choosing a span gas concentration near the flue gas concentrations or permitted emission level in accordance with Sections 2.1.1, 2.1.2 and 2.1.3.

**2.1.1 CO and NO Span Gases.** Choose a span gas concentration such that the average stack gas reading for each test is greater than 25 percent of the span gas concentration. Alternatively, choose the span gas such that it is not greater than 3.33 times the concentration equivalent to the emission standard. If concentration results exceed 125 percent of the span gas at any time during the test, then the test for that pollutant is invalid.

**2.1.2 $NO_2$ Span Gas.** Choose a span gas concentration such that the average stack gas reading for each test is greater than 25 percent of the span gas concentration. Alternatively, choose the span gas concentration such that it is not greater than the ppm concentration value of the NO span gas. The tester should be aware $NO_2$ cells are generally designed to measure much lower concentrations than NO cells and the span gas should be chosen accordingly. If concentration results exceed 125 percent of the span gas at any time during the test, then the test for that pollutant is invalid.

**2.1.3 $O_2$ Span Gas.** The $O_2$ span gas shall be dry ambient air at 20.9% $O_2$.

## 3. DEFINITIONS

**3.1 Measurement System.** The total equipment required for the determination of gas concentration. The measurement system consists of the following major subsystems:

**3.1.1 Sample Interface.** That portion of a system used for one or more of the following: sample acquisition, sample transport, sample conditioning, or protection of the electrochemical cells from particulate matter and condensed moisture.

**3.1.2 External Interference Gas Scrubber.** A tube filled with scrubbing agent used to remove interfering compounds upstream of some electrochemical cells.

**3.1.3 Electrochemical (EC) Cell.** That portion of the system that senses the gas to be measured and generates an output proportional to its concentration. Any cell that uses diffusion-limited oxidation and reduction reactions to produce an electrical potential between a sensing electrode and a counter electrode.

**3.1.4 Data Recorder.** It is recommended that the analyzers be equipped with a strip chart recorder, computer, or digital recorder for recording measurement data. However, the operator may record the test results manually in accordance with the requirements of Section 7.5.

**3.2 Nominal Range.** The range of concentrations over which each cell is operated (25 to 125 percent of span gas value). Several nominal ranges may be used for any given cell as long as the linearity and stability check results remain within specification.

**3.3 Span Gas.** The high level concentration gas chosen for each nominal range.

**3.4 Zero Calibration Error.** For the NO, $NO_2$ and CO channels, the absolute value of the difference, expressed as a percent of the span gas, between the gas concentration exhibited by the gas analyzer when a zero level calibration gas is introduced to the analyzer and the known concentration of the zero level calibration gas. For the $O_2$ channel, the difference, expressed as percent $O_2$, between the gas concentration exhibited by the gas analyzer when a zero level calibration gas is introduced to the analyzer and the known concentration of the zero level calibration gas.

**3.5 Span Calibration Error.** For the NO, $NO_2$ and CO channels, the absolute value of the difference, expressed as a percent of the span gas, between the gas concentration exhibited by the gas analyzer when a span gas is introduced to the analyzer and the known concentration of the span gas. For the $O_2$ channel, the difference, expressed as percent $O_2$, between the gas concentration exhibited by the gas analyzer when a span gas is introduced to the analyzer and the known concentration of the span gas.

**3.6 Response Time.** The amount of time required for the measurement system to display 95 percent of a step change in the NO or CO gas concentration on the data recorder (90 percent of a step change for $NO_2$).

**3.7 Interference Check.** A method of quantifying analytical interferences from components in the stack gas other than the analyte.

**3.8 Linearity Check.** A method of demonstrating the ability of a gas analyzer to respond consistently over a range of gas concentrations.

**3.9 Stability Check.** A method of demonstrating an electrochemical cell operated over a given nominal range provides a stable response and is not significantly affected by prolonged exposure to the analyte.

**3.10 Stability Time.** As determined during the stability check; the elapsed time from the start of the gas injection until a stable reading has been achieved.

**3.11 Initial NO Cell Temperature.** The temperature of the NO cell during the pretest calibration error check. Since the NO cell can experience significant zero drift with cell temperature changes in some situations, the cell temperature must be monitored if the analyzer does not display negative concentration results. Alternatively, manufacturer's documentation may be submitted showing the analyzer incorporates a NO cell temperature control and temperature exceedance warning system.

**3.12 Test.** The collection of emissions data from a source for an equal amount of time at each sample point and for a minimum of 21 minutes total.

## 4. MEASUREMENT SYSTEM PERFORMANCE SPECIFICATIONS

**4.1 Zero Calibration Error.** Less than or equal to ±3 percent of the span gas value for NO, $NO_2$, and CO channels and less than or equal to ±0.3 percent $O_2$ for the $O_2$ channel.

**4.2 Span Calibration Error.** Less than or equal to ±5 percent of the span gas value for NO, $NO_2$, and CO channels and less than or equal to ±0.5 percent $O_2$ for the $O_2$ channel.

**4.3 Interference Response.** The CO and NO interference responses must be less than or equal to 5 percent as calculated in accordance with Section 7.7.

**4.4 Linearity.** For the zero, mid-level, and span gases, the absolute value of the difference, expressed as a percent of the span gas, between the gas value and the analyzer response shall not be greater than 2.5 percent for NO, CO and $O_2$ cells and not greater than 3.0 percent for $NO_2$ cells.

**4.5 Stability Check Response.** The analyzer responses to CO, NO, and $NO_2$ span gases shall not vary more than 3.0 percent of span gas value over a 30-minute period or more than 2.0 percent of the span gas value over a 15-minute period.

**4.6 CO Measurement, Hydrogen ($H_2$) Compensation.** It is recommended that CO measurements be performed using a hydrogen-compensated EC cell since CO-measuring EC cells can experience significant reaction to the presence of $H_2$ in the gas stream. Sampling systems equipped with a scrubbing agent prior to the CO cell to remove $H_2$ interferent gases may also be used.

## 5. APPARATUS AND REAGENTS

**5.1 Measurement System.** Use any measurement system that meets the performance and design specifications in Sections 4 and 5 of this method. The sampling system shall maintain the gas sample at a temperature above the dew point up to the moisture removal system. The sample conditioning system shall be designed so there are no entrained water droplets in the gas sample when it contacts the electrochemical cells. A schematic of an acceptable measurement system is shown in Figure 1. The essential components of the measurement system are described below:

**5.1.1 Sample Probe.** Glass, stainless steel, or other nonreactive material, of sufficient length to sample per the requirements of Section 7. If necessary to prevent condensation, the sampling probe shall be heated.

**5.1.2 Heated Sample Line.** Heated (sufficient to prevent condensation) nonreactive tubing such as teflon, stainless steel, glass, etc. to transport the sample gas to the moisture removal system. (Includes any particulate filters prior to the moisture removal system.)

**5.1.3 Sample Transport Lines.** Nonreactive tubing such as teflon, stainless steel, glass, etc. to transport the sample from the moisture removal system to the sample pump, sample flow rate control, and electrochemical cells.

**5.1.4 Calibration Assembly.** A tee fitting to attach to the probe tip or where the probe attaches to the sample line for introducing calibration gases at ambient pressure during the calibration error checks. The vented end of the tee should have a flow indicator to ensure sufficient calibration gas flow. Alternatively use any other method that introduces calibration gases at the probe at atmospheric pressure.

**5.1.5 Moisture Removal System.** A chilled condenser or similar device (e.g., permeation dryer) to remove condensate continuously from the sample gas while maintaining minimal contact between the condensate and the sample gas.

**5.1.6 Particulate Filter.** Filters at the probe or the inlet or outlet of the moisture removal system and inlet of the analyzer may be used to prevent accumulation of particulate material in the measurement system and extend the useful life of the components. All filters shall be fabricated of materials that are nonreactive to the gas being sampled.

**5.1.7 Sample Pump.** A leak-free pump to pull the sample gas through the system at a flow rate sufficient to minimize the response time of the measurement system. The pump may be constructed of any material that is nonreactive to the gas being sampled.

**5.1.8 Sample Flow Rate Control.** A sample flow rate control valve and rotameter, or equivalent, to maintain a constant sampling rate within 10 percent during sampling and calibration error checks. The components shall be fabricated of materials that are nonreactive to the gas being sampled.

**5.1.9 Gas Analyzer.** A device containing electrochemical cells to determine the NO, $NO_2$, CO, and $O_2$ concentrations in the sample gas stream and, if necessary, to correct for interference effects. The analyzer shall meet the applicable performance specifications of Section 4. A means of controlling the analyzer flow rate and a device for determining proper sample flow rate (e.g., precision rotameter, pressure gauge downstream of all flow controls, etc.) shall be provided at the analyzer. (Note: Housing the analyzer in a clean, thermally-stable, vibration-free environment will minimize drift in the analyzer calibration, but this is not a requirement of the method.)

**5.1.10 Data Recorder.** A strip chart recorder, computer, or digital recorder, for recording measurement data. The data recorder resolution (i.e., readability) shall be at least 1 ppm for CO, NO, and $NO_2$; 0.1 percent $O_2$ for $O_2$; and one degree (C or F) for temperature.

**5.1.11 External Interference Gas Scrubber.** Used by some analyzers to remove interfering compounds upstream of a CO electrochemical cell. The scrubbing agent should be visible and should have a means of determining when the agent is exhausted (e.g., color indication).

**5.1.12 NO Cell Temperature Indicator.** A thermocouple, thermistor, or other device must be used to monitor the temperature of the NO electrochemical cell. The temperature may be monitored at the surface of the cell, within the cell or in the cell compartment. Alternatively, manufacturer's documentation may be submitted showing the analyzer incorporates a NO cell temperature control and temperature exceedance warning system.

**5.1.13 Dilution Systems.** The use of dilution systems will be allowed with prior approval of the Air Quality Division.

**5.2 Calibration Gases.** The CO, NO, and $NO_2$ calibration gases for the gas analyzer shall be CO in nitrogen or CO in nitrogen and $O_2$, NO in nitrogen, and $NO_2$ in air or nitrogen. The mid-level $O_2$ gas shall be $O_2$ in nitrogen.

**5.2.1 Span Gases.** Used for calibration error, linearity, and interference checks of each nominal range of each cell. Select concentrations according to procedures in Section 2.1. Clean dry air may be used as the span gas for the $O_2$ cell as specified in Section 2.1.3.

**5.2.2 Mid-Level Gases.** Select concentrations that are 40-60 percent of the span gas concentrations.

**5.2.3 Zero Gas.** Concentration of less than 0.25 percent of the span gas for each component. Ambient air may be used in a well ventilated area for the CO, NO, and $NO_2$ zero gases.

**6. MEASUREMENT SYSTEM PERFORMANCE CHECK PROCEDURES.** Perform the following procedures before the measurement of emissions under Section 7.

**6.1 Calibration Gas Concentration Certification.** For the mid-level and span cylinder gases, use calibration gases certified according to EPA Protocol 1 procedures. Calibration gases must meet the criteria under 40 CFR 60, Appendix F, Section 5.1.2 (3). Expired Protocol 1 gases may be recertified using the applicable reference methods.

**6.2 Linearity Check.** Conduct the following procedure once for each nominal range to be used on each electrochemical cell (NO, $NO_2$, CO, and $O_2$). After a linearity check is completed, it remains valid for five consecutive calendar days. After the five calendar day period has elapsed, the linearity check must be reaccomplished. Additionally, reaccomplish the linearity check if the cell is replaced. (If the stack $NO_2$ concentration is less than 5% of the stack NO concentration as determined using the emission test procedures under Section 7, the $NO_2$ linearity check is not required. However, the $NO_2$ cell shall be calibrated in accordance with the manufacturer's instructions, the pretest calibration error check and post test calibration calibration error check shall be conducted in accordance with Section 7, and the test results shall be added to the NO test values to obtain a total $NO_X$ concentration.)

**6.2.1 Linearity Check Gases.** For each cell obtain the following gases: zero (0-0.25 percent of nominal range), mid-level (40-60 percent of span gas concentration), and span gas (selected according to Section 2.1).

**6.2.2 Linearity Check Procedure.** If the analyzer uses an external interference gas scrubber with a color indicator, using the analyzer manufacturer's recommended procedure, verify the scrubbing agent is not depleted. After calibrating the analyzer with zero and span gases, inject the zero, mid-level, and span gases appropriate for each nominal range to be used on each cell. Gases need not be injected through the entire sample handling system. Purge the analyzer briefly with ambient air between gas injections. For each gas injection, verify the flow rate is constant and the analyzer responses have stabilized before recording the responses on Form A.

**6.3 Interference Check.** A CO cell response to the NO and $NO_2$ span gases or an NO cell response to the $NO_2$ span gas during the linearity check may indicate interferences. If these cell responses are observed during the linearity check, it may be desirable to quantify the CO cell response to the NO and $NO_2$ span gases and the NO cell response to the $NO_2$ span gas during the linearity check and use estimated stack gas CO, NO and $NO_2$ concentrations to evaluate whether or not the portable analyzer will meet the post test interference check requirements of Section 7.7. This evaluation using the linearity check data is optional. However, the interference checks under Section 7.7 are manditory for each test.

**6.4 Stability Check.** Conduct the following procedure once for the maximum nominal range to be used on each electrochemical cell (NO, $NO_2$ and CO). After a stability check is completed, it remains valid for five consecutive calendar days. After the five calendar day period has elapsed, the stability check must be reaccomplished. Additionally, reaccomplish the stability check if the cell is replaced or if a cell is exposed to gas concentrations greater than 125 percent of the highest span gas concentration. (If the stack $NO_2$ concentration is less than 5% of the stack NO concentration as determined using the emission test procedures under Section 7, the $NO_2$ stability check is not required. However, the $NO_2$ cell shall be calibrated in accordance with the manufacturer's instructions, the pretest calibration error check and post test calibration calibration error check shall be conducted in accordance with Section 7, and the test results shall be added to the NO test values to obtain a total $NO_X$ concentration.)

**6.4.1 Stability Check Procedure.** Inject the span gas for the maximum nominal range to be used during the emission testing into the analyzer and record the analyzer response at least once per minute until the conclusion of the stability check. One-minute average values may be used instead of instantaneous readings. After the analyzer response has stabilized, continue to flow the span gas for at least a 30-minute stability check period. Make no adjustments to the analyzer during the stability check except to maintain constant flow. Record the stability time as the number of minutes elapsed between the start of the gas injection and the start of the 30-minute stability check period. As an alternative, if the concentration reaches a peak value within five minutes, you may choose to record the data for at least a 15-minute stability check period following the peak.

**6.4.2 Stability Check Calculations.** Determine the highest and lowest concentrations recorded during the 30-minute period and record the results on Form B. The absolute value of the difference between the maximum and minimum values recorded during the 30-minute period must be less than 3.0 percent of the span gas concentration. Alternatively, record stability check data in the same manner for the 15-minute period following the peak concentration. The difference between the maximum and minimum values for the 15-minute period must be less than 2.0 percent of the span gas concentration.

**7. EMISSION TEST PROCEDURES.** Prior to performing the following emission test procedures, calibrate/challenge all electrochemical cells in the analyzer in accordance with the manufacturer's instructions.

**7.1 Selection of Sampling Site and Sampling Points.**

**7.1.1 Reciprocating Engines.** Select a sampling site located at least two stack diameters downstream of any disturbance (e.g., turbocharger exhaust, crossover junction, or recirculation take-offs) and one half stack diameter upstream of the gas discharge to the atmosphere. Use a sampling location at a single point near the center of the duct.

**7.1.2 Combustion Turbines.** Select a sampling site and sample points according to the procedures in 40 CFR 60, Appendix A, Method 20. Alternatively, the tester may choose an alternative sampling location and/or sample from a single point in the center of the duct if previous test data demonstrate the stack gas concentrations of CO, $NO_X$, and $O_2$ do not vary significantly across the duct diameter.

**7.1.3 Boilers/Process Heaters.** Select a sampling site located at least two stack diameters downstream of any disturbance and one half stack diameter upstream of the gas discharge to the atmosphere. Use a sampling location at a single point near the center of the duct.

**7.2 Warm Up Period.** Assemble the sampling system and allow the analyzer and sample interface to warm up and adjust to ambient temperature at the location where the stack measurements will take place.

**7.3 Pretest Calibration Error Check.** Conduct a zero and span calibration error check before testing each new source. Conduct the calibration error check near the sampling location just prior to the start of an emissions test. Keep the analyzer in the same location until the post test calibration error check is conducted.

**7.3.1 Scrubber Inspection.** For analyzers that use an external interference gas scrubber tube, inspect the condition of the scrubbing agent and ensure it will not be exhausted during sampling. If scrubbing agents are recommended by the manufacturer, they should be in place during all sampling, calibration and performance checks.

**7.3.2 Zero and Span Procedures.** Inject the zero and span gases using the calibration assembly. Ensure the calibration gases flow through all parts of the sample interface. During this check, make no adjustments to the system except those necessary to achieve the correct calibration gas flow rate at the analyzer. Set the analyzer flow rate to the value recommended by the analyzer manufacturer. Allow each reading to stabilize before recording the result on Form C. The time allowed for the span gas to stabilize shall be no less than the stability time noted during the stability check. After achieving a stable response, disconnect the gas and briefly purge with ambient air.

**7.3.3 Response Time Determination.** Determine the NO and CO response times by observing the time required to respond to 95 percent of a step change in the analyzer response for both the zero and span gases. Note the longer of the two times as the response time. For the $NO_2$ span gas record the time required to respond to 90 percent of a step change.

**7.3.4 Failed Pretest Calibration Error Check.** If the zero and span calibration error check results are not within the specifications in Section 4, take corrective action and repeat the calibration error check until acceptable performance is achieved.

**7.4 NO Cell Temperature Monitoring.** Record the initial NO cell temperature during the pretest calibration error check on Form C and monitor and record the temperature regularly (at least once each 7 minutes) during the sample collection period on Form D. If at any time during sampling, the NO cell temperature is 85 degrees F or greater and has increased or decreased by more than 5 degrees F since the pretest calibration, stop sampling immediately and conduct a post test calibration error check per Section 7.6, re-zero the analyzer, and then conduct another pretest calibration error check per Section 7.3 before continuing. (It is recommended that testing be discontinued if the NO cell exceeds 85 degrees F since the design characteristics of the NO cell indicate a significant measurement error can occur as the temperature of the NO cell increases above this temperature. From a review of available data, these errors appear to result in a positive bias of the test results.)

Alternatively, manufacturer's documentation may be submitted showing the analyzer is configured with an automatic temperature control system to maintain the cell temperature below 85 degrees F (30 degrees centigrade) and provides automatic temperature reporting any time this temperature is exceeded. If automatic temperature control/exceedance reporting is used, test data collected when the NO cell temperature exceeds 85 degrees F is invalid.

**7.5 Sample Collection.** Position the sampling probe at the first sample point and begin sampling at the same rate used during the calibration error check. Maintain constant rate sampling (± 10 percent of the analyzer flow rate value used in Section 7.3.2) during the entire test. Sample for an equal period of time at each sample point. Sample the stack gas for at least twice the response time or the period of the stability time, whichever is greater, before collecting test data at each sample point. A 21 minute period shall be considered a test for each source. When sampling combustion turbines per Section 7.1.2, collect test data as required to meet the requirements of 40 CFR 60, Appendix A, Method 20. Data collection should be performed for an equal amount of time at each sample point and for a minimum of 21 minutes total. The concentration data must be recorded either (1) at least once each minute, or (2) as a block average for the test using values sampled at least once each minute. Do not break any seals in the sample handling system until after the post test calibration error check (this includes opening the moisture removal system to drain condensate).

**7.6 Post Test Calibration Error Check.** Immediately after the test, conduct a zero and span calibration error check using the procedure in Section 7.3. Conduct the calibration error check at the sampling location. Make no changes to the sampling system or analyzer calibration until all of the calibration error check results have been recorded. If the zero or span calibration error exceeds the specifications in Section 4, then all test data collected since the previous calibration error check are invalid. If the sampling system is disassembled or the analyzer calibration is adjusted, repeat the pretest calibration error check before conducting the next test.

**7.7 Interference Check.** Use the post test calibration error check results and average emission concentrations for the test to calculate interference responses ($I_{NO}$ and $I_{CO}$) for the CO and NO cells. If an interference response exceeds 5 percent, all emission test results since the last successful interference test for that compound are invalid.

**7.7.1 CO Interference Response.**

$$I_{CO} = [(\frac{R_{CO-NO}}{C_{NOG}})(\frac{C_{NOS}}{C_{COS}}) + (\frac{R_{CO-NO_2}}{C_{NO_2G}})(\frac{C_{NO_2S}}{C_{COS}})]x100$$

where:

| | | |
|---|---|---|
| $I_{CO}$ | = CO interference response (percent) |
| $R_{CO-NO}$ | = CO response to NO span gas (ppm CO) |
| $C_{NOG}$ | = concentration of NO span gas (ppm NO) |
| $C_{NOS}$ | = concentration of NO in stack gas (ppm NO) |
| $C_{COS}$ | = concentration of CO in stack gas (ppm CO) |
| $R_{CO-NO2}$ | = CO response to $NO_2$ span gas (ppm CO) |
| $C_{NO2G}$ | = concentration of $NO_2$ span gas (ppm $NO_2$) |

$C_{NO2S}$ = concentration of $NO_2$ in stack gas (ppm $NO_2$)

### 7.7.2 NO Interference Response.

$$I_{NO} = (\frac{R_{NO-NO_2}}{C_{NO_2G}})(\frac{C_{NO_2S}}{C_{NO_xS}})x100$$

where:

$I_{NO}$ = NO interference response (percent)

$R_{NO-NO2}$ = NO response to $NO_2$ span gas (ppm NO)

$C_{NO2G}$ = concentration of $NO_2$ span gas (ppm $NO_2$)

$C_{NO2S}$ = concentration of $NO_2$ in stack gas (ppm $NO_2$)

$C_{NOxS}$ = concentration of $NO_X$ in stack gas (ppm $NO_X$)

**7.8 Re-Zero.** At least once every three hours, recalibrate the analyzer at the zero level according to the manufacturer's instructions and conduct a pretest calibration error check before resuming sampling. If the analyzer is capable of reporting negative concentration data (at least 5 percent of the span gas below zero), then the tester is not required to re-zero the analyzer.

**8. DATA COLLECTION.** This section summarizes the data collection requirements for this protocol.

**8.1 Linearity Check Data.** Using Form A, record the analyzer responses in ppm NO, $NO_2$, and CO, and percent $O_2$ for the zero, mid-level, and span gases injected during the linearity check under Section 6.2.2. To evaluate any interferences, record the analyzer responses in ppm CO to the NO and $NO_2$ span gases and the analyzer response in ppm NO to the $NO_2$ span gas. Calculate the CO and NO interference responses using the equations under Sections 7.7.1 and 7.7.2, respectively, and estimated stack gas CO, NO and $NO_2$ concentrations.

**8.2 Stability Check Data.** Record the analyzer response at least once per minute during the stability check under Section 6.4.1. Use Form B for each pollutant (NO, $NO_2$, and CO). One-minute average values may be used instead of instantaneous readings. Record the stability time as the number of minutes elapsed between the start of the gas injection and the start of the 30-minute stability check period. If the concentration reaches a peak value within five minutes of the gas injection, you may choose to record the data for at least a 15-minute stability check period following the peak. Use the information recorded to determine the analyzer stability under Section 6.4.2.

**8.3 Pretest Calibration Error Check Data.** On Form C, record the analyzer responses to the zero and span gases for NO, $NO_2$, CO, and $O_2$ injected prior to testing each new source. Record the calibration zero and span gas concentrations for NO, $NO_2$, CO, and $O_2$. For NO, $NO_2$ and CO, record the absolute difference between the analyzer response and the calibration gas concentration, divide by the span gas concentration, and multiply by 100 to obtain the percent of span. For $O_2$, record the absolute value of the difference between the analyzer response and the $O_2$ calibration gas concentration. Record whether the calibration is valid by comparing the percent of span or difference between the calibration gas concentration and analyzer $O_2$ response, as applicable, with the specifications under Section 4.1 for the zero calibrations and Section 4.2 for the span calibrations. Record the response times for the NO, CO, and $NO_2$ zero and span gases as described under Section 7.3.3. Select the longer of the two times for each pollutant as the response time for that pollutant. Record the NO cell temperature during the pretest calibration.

**8.4 Test Data.** On Form D-1, D-2, or D-3, record the source operating parameters during the test. Record the test start and end times. Record the NO cell temperature after one third of the test (e.g., after seven minutes) and after two thirds of the test (e.g., after 14 minutes). From the analyzer responses recorded each minute during the test, obtain the average flue gas concentration of each pollutant. These are the uncorrected test results.

**8.5 Post Test Calibration Error Check Data.** On Form C, record the analyzer responses to the zero and span gases for NO, $NO_2$, CO, and $O_2$ injected immediately after the test. To evaluate any interferences, record the analyzer responses in ppm CO to the NO and $NO_2$ span gases and the analyzer response in ppm NO to the $NO_2$ span gas. Record the calibration zero and span gas concentrations for NO, $NO_2$, CO, and $O_2$. For NO, $NO_2$ and CO, record the absolute difference between the analyzer response and the calibration gas concentration, divide by the span gas concentration, and multiply by 100 to obtain the percent of span. For $O_2$, record the absolute value of the difference between the analyzer response and the $O_2$ calibration gas concentration. Record whether the calibration is valid by comparing the percent of span or difference between the calibration gas concentration and analyzer $O_2$ response, as applicable, with the specifications under Section 4.1 for the zero calibrations and Section 4.2 for the span calibrations. (If the pretest and post test calibration error check results are not within the limits specified in Sections 4.1 and 4.2, data collected during the test is invalid and the test must be repeated.) Record the NO cell temperature during the post test calibration. Calculate the average of the monitor readings during the pretest and post test calibration error checks for the zero and span gases for NO, $NO_2$, CO, and $O_2$. The pretest and post test calibration error check results are used to make the calibration corrections under Section 9.1. Calculate the CO and NO interference responses using the equations under Sections 7.7.1 and 7.7.2, respectively and measured stack gas CO, NO and $NO_2$ concentrations.

**8.6 Corrected Test Results.** Correct the test results using the equation under Section 9.1. Add the corrected NO and $NO_2$ concentrations together to obtain the corrected $NO_X$ concentration. Calculate the emission rates using the equations under Section 10 for comparison with the emission limits. Record the results on Form D-1, D-2, or D-3. Sign the certification regarding the accuracy and representation of the emissions from the source.

## 9. CALIBRATION CORRECTIONS

**9.1 Emission Data Corrections.** Emissions data shall be corrected for a test using the following equation. (Note: If the pretest and post test calibration error check results are not within the limits specified in Sections 4.1 and 4.2, the test results are invalid and the test must be repeated.)

$$C_{Corrected} = (C_R - C_O)\frac{C_{MA}}{C_M - C_O}$$

where: $C_{Corrected}$ = corrected flue gas concentration (ppm)

$C_R$ = flue gas concentration indicated by gas analyzer (ppm)

$C_o$ = average of pretest and post test analyzer readings during the zero checks (ppm)

$C_M$ = average of pretest and post test analyzer readings during the span checks (ppm)

$C_{MA}$ = actual concentration of span gas (ppm)

## 10. EMISSION CALCULATIONS

**10.1 Emission Calculations for Reciprocating Engines and Combustion Turbines.** Emissions shall be calculated and reported in units of the allowable emission limit as specified in the permit. The allowable may be stated in pounds per hour (lb/hr), grams per horsepower hour (gm/hp-hr), or both. EPA Reference Method 19 shall be used as the basis for calculating the emissions. As an alternative, EPA Reference Methods 1-4 may be used to obtain a stack volumetric flow rate.

**10.1.1 Reciprocating Engines and Combustion Turbines Above 500 Horsepower.** All reciprocating engines and combustion turbines above 500 horsepower (site-rated) should be equipped with fuel flow meters for measuring fuel consumption during the portable analyzer test.

The fuel meter shall be maintained and calibrated according to the manufacturer's recommendations. Records of all maintenance and calibrations shall be kept for five years. Reciprocating engines above 500 horsepower which are not equipped with fuel flow meters may use the site-rated horsepower and default specific fuel consumption factors, based on the higher heating value of the fuel, of 9,400 Btu/hp-hr for 4-cycle engines (controlled and uncontrolled) and 2-cycle lean burn engines and 11,000 Btu/hp-hr for 2-cycle uncontrolled (non-lean burn) engines to calculate emission rates. Emissions shall be calculated using the following methods.

**10.1.1.1 Reciprocating Engines and Combustion Turbines Equipped with Fuel Meters.** EPA Reference Method 19 and heat input per hour (MMBtu/hr) shall be used to calculate a pound per hour emission rate. Heat input per hour shall be based on the average hourly fuel usage rate during the test and the higher heating value of the fuel consumed. The emission rates shall be calculated using the following equations.

$$lb/hr\ NO_X = (ppm\ NO_{X_{corrected}})(1.19x10^{-7})(F\ Factor_{Note1})\left(\frac{20.9}{20.9 - O_2\%_{corrected}}\right)(Heat\ Input\ Per\ Hour_{Note2})$$

$$lb/hr\ CO = (ppm\ CO_{corrected})(7.27x10^{-8})(F\ Factor_{Note1})\left(\frac{20.9}{20.9 - O_2\%_{corrected}}\right)(Heat\ Input\ Per\ Hour_{Note2})$$

Note 1 - Use 8710 dscf/MMBtu unless calculated based on actual fuel gas composition and higher heating value of the fuel.

Note 2 - Heat input per hour (MMBtu/hr) shall be based on the average hourly fuel usage during the test and the higher heating value of the fuel consumed.

If the reciprocating engine or combustion turbine horsepower can be derived from operating conditions during the portable analyzer test, this derived horsepower should be used to calculate a gram per horsepower hour emission rate using the following equations. Information showing the derivation of the horsepower shall be provided with the test results.

$$gm/hp - hr\ CO = \frac{(lb/hr\ CO)(454)}{(Tested\ Horsepower_{Note\ 1})}$$

$$gm/hp - hr\ NO_X = \frac{(lb/hr\ NO_X)(454)}{(Tested\ Horsepower_{Note\ 1})}$$

Note 1 - Horsepower determined during the test.

If the reciprocating engine horsepower during the time of testing cannot determined from the operating data, the operating horsepower for the time of the test shall be calculated based on the heat input per hour during the test and the default values shown below for specific fuel consumption based on the higher heating value of the fuel. Heat input per hour (MMBtu/hr) shall be calculated based on the average hourly fuel usage during the test and the higher heating value of the fuel consumed. For 4-cycle engines (controlled and uncontrolled) and 2-cycle lean burn engines, use a default specific fuel consumption of 9,400 Btu/hp-hr. For 2-cycle uncontrolled (non-lean burn) engines, use a default specific fuel consumption of 11,000 Btu/hp-hr. Calculate the gram per horsepower hour emission rates using the following equations.

$$Engine\ Horsepower = \frac{(Heat\ Input\ Per\ Hour_{Note\ 1})(10^6)}{(Specific\ Fuel\ Consumption_{Note\ 2})}$$

$$gm/hp - hr\ NO_X = \frac{(lb/hr\ NO_X)(454)}{(Engine\ Horsepower)}$$

$$gm/hp - hr\ CO = \frac{(lb/hr\ CO)(454)}{(Engine\ Horsepower)}$$

Note 1 - Heat input per hour (MMBtu/hr) shall be based on the average hourly fuel usage during the test and the higher heating value of the fuel consumed.

Note 2 - Default Specific Fuel Consumption (Btu/hp-hr) shall be as defined above for the particular type of engine tested.

If the combustion turbine horsepower cannot be calculated during the testing, the emissions shall be reported in terms of concentration (ppm by volume, dry basis) corrected to 15 percent $O_2$. Compliance with the concentrations corrected to 15 percent $O_2$ as submitted in the air quality permit application and/or set as an allowable in the permit will demonstrate compliance with the gm/hp-hr allowable. Use the following equations to correct the concentrations to 15 percent $O_2$.

$$ppm\ NO_{X_{@15\%O_2}} = ppm\ NO_{X_{corrected}}\left(\frac{5.9}{20.9 - O_2\%_{corrected}}\right)$$

$$ppm\ CO_{@15\%O_2} = ppm\ CO_{corrected}\left(\frac{5.9}{20.9 - O_2\%_{corrected}}\right)$$

**10.1.1.2 Reciprocating Engines Above 500 Horsepower Not Equipped with Fuel Meters.** If reciprocating engines above 500 horsepower (site-rated) are not equipped with fuel flow meters during the test, emissions shall be calculated using the site-rated horsepower and default specific fuel consumption factors, based on the higher heating value of the fuel, of 9,400 Btu/hp-hr for 4-cycle engines (controlled and uncontrolled) and 2-cycle lean burn engines and 11,000 Btu/hp-hr for 2-cycle uncontrolled (non-lean burn) engines. The following equations shall be used to calculate emissions.

$$gm/hp\text{ - }hr\ NO_X = (ppm\ NO_{X\ corrected})(1.19x10^{-7})(F\ Factor_{Note\ 1})\left(\frac{20.9}{20.9 - O_2\%_{corrected}}\right)$$
$$(Specific\ Fuel\ Consumption_{Note\ 2})(10^{-6})(454)$$

$$lb/hr\ NO_X = \frac{(gm/hp\text{ - }hr\ NO_X)(Engine\ Horsepower_{Note\ 3})}{454}$$

$$gm/hp\text{ - }hr\ CO = (ppm\ CO_{corrected})(7.27x10^{-8})(F\ Factor_{Note\ 1})\left(\frac{20.9}{20.9 - O_2\%_{corrected}}\right)$$
$$(Specific\ Fuel\ Consumption_{Note\ 2})(10^{-6})(454)$$

$$lb/hr\ CO = \frac{(gm/hp\text{ - }hr\ CO)(Engine\ Horsepower_{Note\ 3})}{454}$$

Note 1 - Use 8710 dscf/MMBtu unless calculated based on actual fuel gas composition and higher heating value of the fuel.

Note 2 - Default Specific Fuel Consumption (Btu/hp-hr) shall be as defined above for the particular type of engine tested.

Note 3 - Site-rated engine horsepower.

**10.1.2 Reciprocating Engines Below 500 Horsepower.** Reciprocating engines below 500 horsepower may calculate emission rates using the derived horsepower for the operating conditions during the portable analyzer test (either from engine parameter measurements or calculated from compressor operating parameters) and the manufacturer's specific fuel consumption based on the higher heating value of the fuel consumed during the test. Information showing the derivation of the engine operating horsepower and manufacturer's specific fuel consumption shall be provided with the test results. The following equations shall be used to calculate emission rates.

$$gm/hp\text{-}hr\ NO_X = \frac{(ppm\ NO_{X\ corrected})(1.19x10^{-7})(F\ Factor_{Note\ 1})\left(\frac{20.9}{20.9 - O_2\%_{corrected}}\right)}{(Specific\ Fuel\ Consumption_{Note\ 2})(10^{-6})(454)}$$

$$gm/hp\text{-}hr\ CO = \frac{(ppm\ CO_{corrected})(7.27x10^{-8})(F\ Factor_{Note\ 1})\left(\frac{20.9}{20.9 - O_2\%_{corrected}}\right)}{(Specific\ Fuel\ Consumption_{Note\ 2})(10^{-6})(454)}$$

Note 1 - Use 8710 dscf/MMBtu unless calculated based on actual fuel gas composition and the higher heating value of the fuel.

Note 2 - Use manufacturer's specific fuel consumption based on the higher heating value of the fuel and include manufacturer's data with the test results. If the manufacturer reports the specific fuel consumption based on the lower heating value of the fuel, multiply by 1.11 to obtain the specific fuel consumption based on the higher heating value of the fuel.

Pound per hour emission rates shall be calculated using the gram per horsepower hour emission rates and the engine horsepower derived from engine or compressor operating parameter data. If engine horsepower data is not available, site-rated horsepower shall be used to calculate pound

$$lb/hr\ NO_X = \frac{(gm/hp\text{-}hr\ NO_X)(Engine\ Horsepower_{Note\ 1})}{(454)}$$

$$lb/hr\ CO = \frac{(gm/hp\text{-}hr\ CO)(Engine\ Horsepower_{Note\ 1})}{(454)}$$

per hour emissions. The following equations shall be used to calculate emission rates.

Note 1 - Use derived operating horsepower and include derivation method/calculations with the test results. If a derived horsepower is not available or cannot be obtained, use site-rated horsepower.

**10.2 Emission Calculations for Heaters/Boilers.** For heaters and boilers, pound per million Btu (lb/MMBtu) emission rates shall be calculated based on EPA Reference Method 19. The pound per million Btu emission rates shall be converted to pound per hour emission rates using heat input per hour (MMBtu/hr). The heat input per hour shall be calculated using the average hourly fuel usage rate during test and the higher heating value of the fuel consumed or the permitted maximum heat input per hour for the boiler or heater. If a fuel meter is used to obtain heat input per hour data, the fuel meter shall be maintained and calibrated according to the manufacturer's recommendations. Records of all maintenance and calibrations shall be kept for five years. As an alternative, EPA Reference Methods 1-4 may be used to obtain a stack volumetric flow rate. The following equations shall be used to calculate emission rates.

$$lb/MMBtu\ NO_X = (ppm\ NO_{X\ corrected})(1.19x10^{-7})(F\ Factor_{Note\ 1})\left(\frac{20.9}{20.9 - O_2\%_{corrected}}\right)$$

$$lb/MMBtu\ CO = (ppm\ CO_{corrected})(7.27x10^{-8})(F\ Factor_{Note\ 1})\left(\frac{20.9}{20.9 - O_2\%_{corrected}}\right)$$

$$lb/hr\ NO_X = (lb/MMBtu\ NO_X)(Heat\ Input_{Note\ 2})$$

$$lb/hr\ CO = (lb/MMBtu\ CO)(Heat\ Input_{Note\ 2})$$

Note 1 - Use 8710 dscf/MMBtu unless calculated based on actual fuel gas composition and the higher heating value of the fuel.

Note 2 - Heat input shall be based on the average hourly fuel usage rate during the test and the higher heating value of the fuel consumed if the boiler/heater is equipped with a fuel meter or the permitted maximum heat input if a fuel meter is not available.

## 11. REPORTING REQUIREMENTS AND RECORD KEEPING REQUIREMENTS

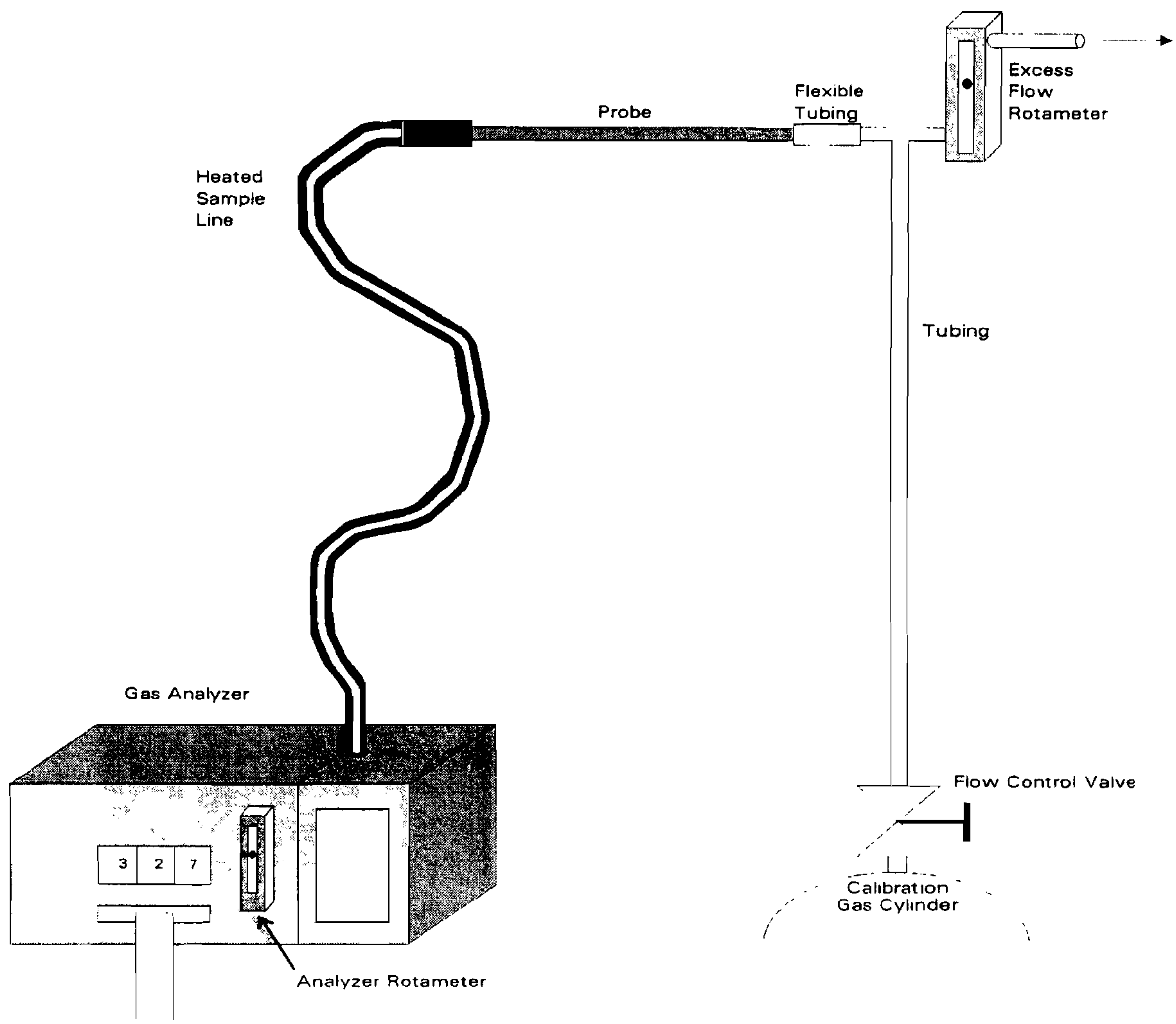
Test reports shall be submitted to the Air Quality Division within thirty (30) days of completing the test unless a specific reporting schedule is set by a condition of a permit. A separate test report shall be submitted for each emission source tested and, at a minimum, the following information shall be included:

- **Form A, Linearity Check Data Sheet,** Submit the linearity check as required by Section 6.2 for the nominal range tested.
- **Form B, Stability Check Data Sheet,** Submit the stability check as required by Section 6.4 for the nominal range tested.
- **Form C, Calibration Error Check Data Sheet**
- **Form D-1, D-2 or D-3,** Submit the appropriate test results form for type of source tested.
- If the manufacturer's specific fuel consumption is used, documentation from the manufacturer shall be submitted.
- If the horsepower is calculated during the test, information showing the derivation of the horsepower shall be included.

For sources subject to Section 30 of the Wyoming Air Quality Standards and Regulations, the submittal must be certified as truthful, accurate and complete by the facility's responsible official.

Records pertaining to the information above and supporting documentation shall be kept for five (5) years and made available upon request by this Division. Additionally, if the source is equipped with a fuel meter, records of all maintenance and calibrations of the fuel meter shall be kept for five (5) years from the date of the last maintenance or calibration.

# FIGURE 1.
# CALIBRATION SYSTEM SCHEMATIC



# Form A

## Linearity Check Data Sheet

**Date:**______________

**Analyst:**___________________________________

**Analyzer Manufacturer/Model #:**___________________________________________

**Analyzer Serial #:**__________________________________________

| LINEARITY CHECK | | | | | | | | | | |
|---|---|---|---|---|---|---|---|---|---|---|
| **Pollutant** | | **Calibration Gas Concentration (Indicate Units)** | **Analyzer Response ppm NO** | **Analyzer Response ppm $NO_2$** | **Analyzer Response ppm CO** | **Analyzer Response % $O_2$** | **Absolute Difference (Indicate Units)** | **Percent of Span** | **Linearity Valid (Yes or No)** |
| **NO** | **Zero** | | | | | | | | |
| | **Mid** | | | | | | | | |
| | **Span** | | | | | | | | |
| **$NO_2$** | **Zero** | | | | | | | | |
| | **Mid** | | | | | | | | |
| | **Span** | | | | | | | | |
| **CO** | **Zero** | | | | | | | | |
| | **Mid** | | | | | | | | |
| | **Span** | | | | | | | | |
| **$O_2$** | **Zero** | | | | | | | | |
| | **Mid** | | | | | | | | |
| | **Span** | | | | | | | | |

# Form B
## Stability Check Data Sheet

**Date:**____________ **Analyst:**________________________________

**Analyzer Manufacturer/Model #:**________________________________

**Analyzer Serial #:**________________________

**Pollutant: NO, $NO_2$, CO (Circle One)** **Span Gas Concentration (ppm):**____________

| STABILITY CHECK | | | | | |
|---|---|---|---|---|---|
| Elapsed Time (Minutes) | Analyzer Response | Elapsed Time (Continued) | Analyzer Response | Elapsed Time (Continued) | Analyzer Response |
| 1 | | 17 | | 33 | |
| 2 | | 18 | | 34 | |
| 3 | | 19 | | 35 | |
| 4 | | 20 | | 36 | |
| 5 | | 21 | | 37 | |
| 6 | | 22 | | 38 | |
| 7 | | 23 | | 39 | |
| 8 | | 24 | | 40 | |
| 9 | | 25 | | 41 | |
| 10 | | 26 | | 42 | |
| 11 | | 27 | | 43 | |
| 12 | | 28 | | 44 | |
| 13 | | 29 | | 45 | |
| 14 | | 30 | | 46 | |
| 15 | | 31 | | 47 | |
| 16 | | 32 | | 48 | |

**For 30-minute Stability Check Period:**

**Maximum Concentration (ppm):** ________ **Minimum Concentration (ppm):** ________

**For 15-minute Stability Check Period:**

**Maximum Concentration (ppm):** ________ **Minimum Concentration (ppm):** ________

**Maximum Deviation = 100*(Max. Conc. - Min. Conc.)/Span Gas Conc. =** ________ **percent**

**Stability Time (minutes):** ________

# Form C
## Calibration Error Check Data Sheet

**Company:**____________________ **Facility:**____________________

**Source Tested:**____________________ **Date:**____________________

**Analyst:**____________________ **Analyzer Serial #:**____________________

**Analyzer Manufacturer/Model #:**________________________________________

**PRETEST CALIBRATION ERROR CHECK**

| | | | A | B | \|A-B\| | \|A-B\|/SG*100 | | |
|---|---|---|---|---|---|---|---|---|
| | | Pump Flow Rate (Indicate Units) | Analyzer Reading (Indicate Units) | Calibration Gas Concentration (Indicate Units) | Absolute Difference (Indicate Units) | Percent of Span Note 1 | Calibration Valid (Yes or No) | Response Time (Minutes) |
| NO | Zero | | | | | | | |
| | Span | | | | | | | |
| $NO_2$ | Zero | | | | | | | |
| | Span | | | | | | | |
| CO | Zero | | | | | | | |
| | Span | | | | | | | |
| $O_2$ | Zero | | | | | | | |
| | Span | | | | | | | |
| | | Pretest Calibration NO Cell Temperature (°F): | | | | | | |

SG = Span Gas

**POST TEST CALIBRATION ERROR CHECK**

| | | | A | B | \|A-B\| | \|A-B\|/SG*100 | | | Interference Check | |
|---|---|---|---|---|---|---|---|---|---|---|
| | | Pump Flow Rate (Indicate Units) | Analyzer Reading (Indicate Units) | Calibration Gas Concentration (Indicate Units) | Absolute Difference (Indicate Units) | Percent of Span Note 1 | Calibration Valid (Yes or No) | Average of Pretest and Post Test Analyzer Readings (Indicate Units) | NO Monitor Response (ppm) | CO Monitor Response (ppm) |
| NO | Zero | | | | | | | | | |
| | Span | | | | | | | | | |
| $NO_2$ | Zero | | | | | | | | | |
| | Span | | | | | | | | | |
| CO | Zero | | | | | | | | | |
| | Span | | | | | | | | | |
| $O_2$ | Zero | | | | | | | | | |
| | Span | | | | | | | | | |
| | | Post Test Calibration NO Cell Temperature (°F): | | | | | | | | |
| | | CO Interference Response ($I_{CO}$, %): | | | | NO Interference Response ($I_{NO}$, %): | | | | |

SG= Span Gas

**Note 1**: The percent of span calculation is applicable to the NO, $NO_2$ and CO channels only.

# Form D-1
## Reciprocating Engine Test Results

**Company:**____________________ **Facility:**____________________

**Source Tested:**____________________ **Date:**____________________

**Source Manufacturer/Model #:**____________________

**Site-rated Horsepower:**____________________ **Source Serial #:**____________________

**Type of Emission Control:**____________________

**Analyst:**____________________ **Analyzer Serial #:**____________________

**Analyzer Manufacturer/Model #:**____________________

**Operating Conditions**

Source operating at 90 percent or greater site-rated horsepower during testing? yes no

| Suction/ Discharge Pressures (Indicate Units) | Engine RPM | Engine Gas Throughput (Indicate Units) | Engine Fuel Consumption (Indicate Units) | Fuel Heat Content (Btu/cf) | Engine Specific Fuel Consumption (Btu/hp-hr)[1] | Engine Tested Horsepower |
|---|---|---|---|---|---|---|
| | | | | | | |

[1] As reported by the Manufacturer

**Test Results**

Test Start Time:__________ NO Cell Temperature (°F) after 1/3 (e.g., 7 minutes) of the test:__________

Test End Time:__________ NO Cell Temperature (°F) after 2/3 (e.g., 14 minutes) of the test:__________

| $NO_X$ ($NO + NO_2$) | | | | | | | | |
|---|---|---|---|---|---|---|---|---|
| Avg. Tested NO ppm | $NO_{corrected}$ ppm | Avg. Tested $NO_2$ ppm | $NO_{2\ corrected}$ ppm | $NO_{X\ corrected}$ ppm | Tested gm/hp-hr | Tested lb/hr | Allowable gm/hp-hr | Allowable lb/hr |
| | | | | | | | | |

| $O_2$ | | CO | | | | | |
|---|---|---|---|---|---|---|---|
| Avg. Tested $O_2$ % | $O_{2\ corrected}$ % | Avg. Tested CO ppm | $CO_{corrected}$ ppm | Tested gm/hp-hr | Tested lb/hr | Allowable gm/hp-hr | Allowable lb/hr |
| | | | | | | | |

**I certify to the best of my knowledge the test results are accurate and representative of the emissions from this source.**

____________________ ____________________

Print Name Signature

# Form D-2
## Combustion Turbine Test Results

**Company:**____________________ **Facility:**____________________

**Source Tested:**____________________ **Date:**____________________

**Source Manufacturer/Model #:**____________________

**Site-rated Horsepower:**____________________ **Source Serial #:**____________________

**Type of Emission Control:**____________________

**Analyst:**____________________ **Analyzer Serial #:**____________________

**Analyzer Manufacturer/Model #:**____________________

**Operating Conditions**

Source operating at 90 percent or greater site-rated horsepower during testing? yes no

| Suction/ Discharge Pressures (Indicate Units) | Turbine $T_5$ Temperature (°F) | Turbine RPM | Turbine Gas Throughput (Indicate Units) | Turbine Fuel Consumption (Indicate Units) | Fuel Heat Content (Btu/cf) | Turbine Specific Fuel Consumption (Btu/hp-hr)[1] | Turbine Tested Horsepower |
|---|---|---|---|---|---|---|---|
| | | | | | | | |

[1] As reported by the Manufacturer

**Test Results**

Test Start Time:__________ NO Cell Temperature (°F) after 1/3 (e.g., 7 minutes) of the test:__________

Test End Time: __________ NO Cell Temperature (°F) after 2/3 (e.g., 14 minutes) of the test:__________

| $NO_X$ ($NO + NO_2$) | | | | | | | | | | |
|---|---|---|---|---|---|---|---|---|---|---|
| Avg. Tested NO ppm | $NO_{corrected}$ ppm | Avg. Tested $NO_2$ ppm | $NO_{2\ corrected}$ ppm | $NO_{X\ corrected}$ ppm | Tested gm/hp-hr | Tested lb/hr | Tested ppm @ 15% O2 | Allowable gm/hp-hr | Allowable lb/hr | Allowable ppm @ 15% O2 |
| | | | | | | | | | | |

| $O_2$ | | CO | | | | | | | |
|---|---|---|---|---|---|---|---|---|---|
| Avg. Tested $O_2$ % | $O_{2\ corrected}$ % | Avg. Tested CO ppm | $CO_{corrected}$ ppm | Tested gm/hp-hr | Tested lb/hr | Tested ppm @ 15% O2 | Allowable gm/hp-hr | Allowable lb/hr | Allowable ppm @ 15% O2 |
| | | | | | | | | | |

**I certify to the best of my knowledge the test results are accurate and representative of the emissions from this source.**

____________________ ____________________

Print Name Signature

# Form D-3
## Heater/Boiler Test Results

**Company:**____________________ **Facility:**____________________

**Source Tested:**____________________ **Date:**____________________

**Source Manufacturer/Model #:**________________________________________

**Design Firing Rate (MMBtu/hr):**__________ **Source Serial #:**____________________

**Type of Emission Control:**________________________________________

**Analyst:**____________________ **Analyzer Serial #:**____________________

**Analyzer Manufacturer/Model #:**________________________________________

**Operating Conditions**

Source operating at 90 percent or greater site-rated horsepower during testing? yes no

| Fuel Consumption (cf/hr) | Fuel Heat Content (Btu/cf) | Heater/Boiler Tested Firing Rate (MMBtu/hr) |
|---|---|---|
| | | |

**Test Results**

Test Start Time:__________ NO Cell Temperature (°F) after 1/3 (e.g., 7 minutes) of the test:__________

Test End Time: __________ NO Cell Temperature (°F) after 2/3 (e.g., 14 minutes) of the test:__________

| $NO_X$ ($NO + NO_2$) | | | | | | | | |
|---|---|---|---|---|---|---|---|---|
| Avg. Tested NO ppm | $NO_{corrected}$ ppm | Avg. Tested $NO_2$ ppm | $NO_{2\ corrected}$ ppm | $NO_{X\ corrected}$ ppm | Tested lb/MMBtu | Tested lb/hr | Allowable lb/MMBtu | Allowable lb/hr |
| | | | | | | | | |

| $O_2$ | | CO | | | | | |
|---|---|---|---|---|---|---|---|
| Avg. Tested $O_2$ % | $O_{2\ corrected}$ % | Avg. Tested CO ppm | $CO_{corrected}$ ppm | Tested lb/MMBtu | Tested lb/hr | Allowable lb/MMBtu | Allowable lb/hr |
| | | | | | | | |

**I certify to the best of my knowledge the test results are accurate and representative of the emissions from this source.**

____________________ ____________________

Print Name Signature

## APPENDIX C

Compliance Assurance Monitoring Plans

COMPLIANCE ASSURANCE MONITORING: CATALYST FOR NOx CONTROL
DEVON ENERGY BEAVER CREEK GAS PLANT

I. Background

A. Emissions Unit

| | |
|---|---|
| Description: | Waukesha L7042GSI Rich Burn Natural Gas Compressor Engines |
| ID: | C-7A, C-13A |
| Facility: | Beaver Creek Gas Plant, Riverton, Wyoming |

B. Applicable Regulation, Emission Limits, and Monitoring Requirements

Regulation: Permit MD-401

$NO_x$ Emission limits: 1.0 g/hp/hr (annual average), 13.6 t/y
1.5 g/hp-hr (maximum hourly), 4.6 lb/hr

Uncontrolled emissions: 106.0 t/y based on AP-42 factors

Monitoring requirements: Maintain and operate in accordance with the Preventative Maintenance Plan in MD-401

C. Control Technology:

Non-selective reductive catalyst and air/fuel ratio controller

II. Monitoring Approach

The key elements of the monitoring approach are presented in Table 1. Monitoring shall consist of measuring temperature of the exhaust gas into the catalyst bed daily, measuring pressure drop across the catalyst monthly, conducting inspection and maintenance in accordance with the Preventative Maintenance Plan, and quarterly measurement of $NO_x$ emissions.

Reference pressure drop, for comparison to monthly measurements, shall be established as follows:

1) Reference pressure drop shall be that measured during the first portable analyzer or EPA reference method test conducted after issuance of this operating permit showing compliance with $NO_x$ limits.
2) Within 30 days of installing fresh (new or washed) catalyst, portable analyzer or EPA reference method testing shall be performed to demonstrate compliance with $NO_x$ emission limits. Pressure differential across the catalyst shall be simultaneously measured to establish a new reference pressure drop.
3) If engine operating load levels change to such an extent that catalyst pressure drop changes by more than 2" of water due to the load change, a reference pressure drop for that operating load may be established by conducting portable analyzer or EPA reference method testing demonstrating compliance with $NO_x$ emission limits at that engine load.

Excursions trigger corrective action as expeditiously as practicable.

# TABLE 1. MONITORING APPROACH

| | Indicator No. 1 | Indicator No 2 | Indicator No. 3 | Indicator No. 4 |
|---|---|---|---|---|
| I. Indicator | Temperature of exhaust into catalyst | Pressure drop across the catalyst | Inspection/ maintenance | NOx concentration in exhaust |
| Measurement Approach | Exhaust gas temperature is measured daily using an in line thermocouple. | Pressure of the exhaust is measured before and after the catalyst with a manometer. | Inspection as described in the Preventative Maintenance Plan; maintenance performed as needed. | Quarterly monitoring of NOx emissions using the Portable Analyzer Monitoring Protocol or EPA reference methods for C-7A and C-13A. |
| II. Indicator Range | The indicator range is ≥ 750 °F and ≤ 1250 °F. | Pressure drop is not to change by more than 2" of water as compared to the reference pressure drop. | N/A | Average of two previous quarters must be no more than 1.0 gm/hp-hr, and in no case more than 1.5 gm/hp-hr on any one test. |
| III. Performance Criteria A. Data Representativeness | Temperature is measured at the inlet to the catalyst by a thermocouple. The minimum accuracy is ±5 °F. | Pressure differential is measured between the inlet and the outlet of the catalyst by a manometer. | Inspections are performed of the engine and the catalyst. | Gases are measured at the exhaust of the catalyst, under representative operating conditions. |
| B. Operational Status Verification | High temperature shutdown switch | Guarantee from manometer manufacture | NA | NA |
| C. QA/QC Practices and Criteria | Significant thermocouple drift is not expected in this service, calibration as needed | Manometer drift is not expected in this service, calibration as needed | Qualified personnel perform inspection. | Analyzer is calibrated before and after tests per Portable Analyzer Monitoring Protocol or as otherwise allowed by the DEQ. |
| D. Monitoring Frequency | Temperature measured continuously. | At least once per calendar month. | Daily inspection of engine operational parameters, quarterly inspection of catalyst. | Quarterly test of NOx emissions. |
| Data Collection Procedures | Temperature recorded daily by plant personnel Otherwise shutdown or alarms trigger action. | Recorded at least once per month. A note will be made on months when engine is not operated. | Records are maintained to document the daily inspection and any required maintenance. | Records are maintained to document the results of the quarterly tests, submitted semi-annually. |
| Averaging period | None, not to exceed minimums or max. | None, not to exceed minimums or max. | NA | Last two quarterly tests are averaged to determine NOx emissions. |

09-28-2006 031046

## MONITORING APPROACH JUSTIFICATION

### I. Background

Natural gas processing plants use natural gas fired engines to drive natural gas compressors, turbines, or generators. The "3-way" non-selective reduction catalyst lowers $NO_x$, CO and hydrocarbon emissions.

The monitoring approach outlined here applies to the non-selective catalysts on compressor engines C-7A and C-13A at Beaver Creek. The catalysts are passive units and have no mechanical components. The reduction reaction does not take place properly if the temperature of the engine exhaust gases into the catalyst is too low. Additionally a large increase in pressure drop across the catalyst can indicate problems with the unit.

### II. Rationale for Selection of Performance Indicators

The engine exhaust temperature at the inlet to the catalyst will be measured as temperature excursions can indicate problems with engine operation and can prevent the chemical reaction from taking place in the catalyst bed. Too low of a temperature will inhibit chemical reactions from taking place. Too high of a temperature could lead to catalyst damage. Daily monitoring of inlet exhaust gas temperature to the catalyst will help to ensure proper operation of the engine and catalyst.

Changes in pressure drop across the catalyst can indicate if the catalyst is damaged or fouled, resulting in decreased performance. Monthly monitoring will help to detect if the catalyst is working properly.

Implementation of an engine and catalyst inspection and maintenance (I/M) program provides assurance engine and catalyst are in good repair and are being operated properly. Once per day, proper operation of the engine is verified to ensure that the catalysts aren't being fouled. Proper operation of the engine facilitates catalyst reactions. Operation at high oxygen or low or high temperatures can inhibit proper chemical reaction and can cause fouling. Other items on the daily I/M checklist include inspecting the fuel/air ratio controller, visual inspection of probes to ensure there is no clogging, and inspection of temperature gauges and chart recording devices.

### III. Rationale for Selection of Indicator Ranges

The selected inlet exhaust gas temperature range of 750° F to 1250° F is based on generally accepted operating parameters for the desired chemical reaction to occur. Additionally, the selected range of inlet exhaust gas temperatures to the catalyst is consistent with the parameters found in NESHAP Subpart ZZZZ for reciprocating internal combustion engines.

The acceptable change in pressure drop across the catalyst shall be no greater than 2" of water compared to the reference pressure drop. This selected pressure drop criteria is based on general information from catalyst vendors which indicate that if the pressure drop changes by more than 2" of water, the catalyst should be inspected for damage or fouling. Additionally, the selected pressure drop criterion is consistent with the information found in NESHAP Subpart ZZZZ for reciprocating internal combustion engines.

# COMPLIANCE ASSURANCE MONITORING: CATALYST FOR CO CONTROL
# DEVON ENERGY BEAVER CREEK GAS PLANT

## I. Background

### A. Emissions Unit

Description: Waukesha L7042GSI Rich Burn Natural Gas Compressor Engines
ID: C-6, C-7A, C-9, C-10, and C-13A
Facility: Beaver Creek Gas Plant, Riverton, Wyoming

### B. Applicable Regulation, Emission Limits, and Monitoring Requirements

Regulation: Permit MD-401

CO Emission limits and uncontrolled emissions:

| Engine | Emission Limits | | | Uncontrolled | | |
|---|---|---|---|---|---|---|
| | lb/hr | t/y | g/hp-hr | lb/hr | t/y | g/hp-hr |
| C-6 | 10.8 | 47.5 | 4.0 | 35.7 | 156.3 | 13.17 |
| C-7A | 3.1 | 13.6 | 1.0 | 40.7 | 178.4 | 13.17 |
| C-9 | 9.8 | 42.9 | 4.0 | 32.1 | 140.4 | 13.17 |
| C-10 | 9.8 | 42.9 | 4.0 | 32.1 | 140.4 | 13.17 |
| C-13A | 3.1 | 13.6 | 1.0 | 40.7 | 178.4 | 13.17 |

Monitoring requirements: Maintain and operate C-7A and C-13A in accordance with the Preventative Maintenance Plan in MD-401

### C. Control Technology:

Non-selective reductive catalyst and air/fuel ratio controller

## II. Monitoring Approach

The key elements of the monitoring approach are presented in Table 1. Monitoring shall consist of measuring temperature of the exhaust gas into the catalyst bed daily, measuring pressure drop across the catalyst monthly, conducting inspection and maintenance in accordance with the Preventive Maintenance Plan, and quarterly/semiannual measurement of CO emissions.

Reference pressure drop, for comparison to monthly measurements, shall be established as follows:

1) Reference pressure drop shall be that measured during the first portable analyzer or EPA reference method test conducted after issuance of this operating permit showing compliance with CO limits.
2) Within 30 days of installing fresh (new or washed) catalyst, portable analyzer or EPA reference method testing shall be performed to demonstrate compliance with CO emission limits. Pressure differential across the catalyst shall be simultaneously measured to establish a new reference pressure drop.
3) If engine operating load levels change to such an extent that catalyst pressure drop changes by more than 2" of water due to the load change, a reference pressure drop for that operating load may be established by conducting portable analyzer or EPA reference method testing demonstrating compliance with CO emission limits at that engine load.

Excursions trigger corrective action as expeditiously as practicable

## TABLE 1. MONITORING APPROACH

| | Indicator No. 1 | Indicator No 2 | Indicator No. 3 | Indicator No. 4 |
|---|---|---|---|---|
| I. Indicator | Temperature of exhaust into catalyst. | Pressure drop across the catalyst. | Inspection/ maintenance | CO concentration in exhaust |
| Measurement Approach | Exhaust gas temperature is measured daily using an in line thermocouple. | Pressure of the exhaust is measured before and after the catalyst with a manometer | Inspection as described in the Preventative Maintenance Plan; maintenance performed as needed. | Quarterly monitoring of CO emissions using the Portable Analyzer Monitoring Protocol or EPA reference methods for C-7A. C-13A; semi-annual monitoring for C-6, C-9, and C-10. |
| II. Indicator Range | The indicator range is $\geq$ 750 °F and $\leq$ 1250 °F. | Pressure drop is not to change by more than 2" of water as compared to the reference pressure drop. | N/A | CO emissions must not exceed those listed on the controlled column in table in section I (B) of this CAM plan. |
| III. Performance Criteria A. Data Representativeness | Temperature is measured at the inlet to the catalyst by a thermocouple. The minimum accuracy is $\pm 5$ °F. | Pressure differential is measured between the inlet and the outlet of the catalyst by a manometer. | Inspections are performed of the engine and the catalyst. | Gases are measured at the exhaust of the catalyst, under representative operating conditions. |
| B. Operational Status Verification | High temperature shutdown switch | Guarantee from manometer manufacture | NA | NA |
| C.QA/QC Practices and Criteria | Significant thermocouple drift is not expected in this service, calibration as needed | Manometer drift is not expected in this service, calibration as needed | Qualified personnel perform inspection. | Analyzer is calibrated before and after tests per Portable Analyzer Monitoring Protocol or as otherwise allowed by the DEQ. |
| D. Monitoring Frequency | Temperature measured continuously. | At least once per calendar month. | Daily inspection of engine operational parameters, quarterly inspection of catalyst. | Quarterly test of CO emissions for C-7A and C-13A; semi-annual test for C-6, C-9, and C-10. |
| Data Collection Procedures | Temperature recorded daily by plant personnel<br>Otherwise shutdown or alarms trigger action | Recorded at least once per month. A note will be made on months when engine is not operated | Records are maintained to document the daily inspection and any required maintenance. | Records are maintained to document the results of the quarterly tests, submitted semi-annually. |
| Averaging period | None. not to exceed minimums or max. | None, not to exceed minimums or max. | NA | NA |

09-28-2005 031046

MONITORING APPROACH JUSTIFICATION

## I. Background

Natural gas processing plants use natural gas fired engines to drive natural gas compressors, turbines or generators. The "3-way" non-selective reduction catalyst lowers $NO_x$, CO and hydrocarbon emissions.

The monitoring approach outlined here applies to the non-selective catalysts on compressor engines C-6, C-7A, C-9, C-10, and C-13A at Beaver Creek. The catalysts are passive units and have no mechanical components. The reduction reaction does not take place properly if the temperature of the engine exhaust gases into the catalyst is too low. Additionally a large increase in pressure drop across the catalyst can indicate problems with the unit.

## II. Rationale for Selection of Performance Indicators

The engine exhaust temperature at the inlet to the catalyst will be measured as temperature excursions can indicate problems with engine operation and can prevent the chemical reaction from taking place in the catalyst bed. Too low of a temperature will inhibit chemical reactions from taking place. Too high of a temperature could lead to catalyst damage. Daily monitoring of inlet exhaust gas temperature to the catalyst will help to ensure proper operation of the engine and catalyst.

Changes in pressure drop across the catalyst can indicate if the catalyst is damaged or fouled, resulting in decreased performance. Monthly monitoring will help to detect if the catalyst is working properly.

Implementation of an engine and catalyst inspection and maintenance (I/M) program provides assurance engine and catalyst are in good repair and are being operated properly. Once per day, proper operation of the engine is verified to ensure that the catalysts aren't being fouled. Proper operation of the engine facilitates catalyst reactions. Operation at high oxygen or low or high temperatures can inhibit proper chemical reaction and can cause fouling. Other items on the daily I/M checklist include inspecting the fuel/air ratio controller, visual inspection of probes to ensure there is no clogging, and inspection of temperature gauges and chart recording devices. Note the I/M plan approved for C-7A and C-13A will now be required for C-6, C-9, and C-10 except testing will only be required semi-annually.

CO emissions monitoring will determine compliance with emission limits and verify proper operation of the engine and catalyst.

## III. Rationale for Selection of Indicator Ranges

The selected inlet exhaust gas temperature range of 750° F to 1250° F is based on generally accepted operating parameters for the desired chemical reaction to occur. Additionally, the selected range of inlet exhaust gas temperatures to the catalyst is consistent with the parameters found in NESHAP Subpart ZZZZ for reciprocating internal combustion engines.

The acceptable change in pressure drop across the catalyst shall be no greater than 2" of water compared to the reference pressure drop. This selected pressure drop criteria is based on general information from catalyst vendors which indicate that if the pressure drop changes by more than 2" of water, the catalyst should be inspected for damage or fouling. Additionally, the selected pressure drop criterion is consistent with the information found in NESHAP Subpart ZZZZ for reciprocating internal combustion engines.

APPENDIX D

Preventative Maintenance Plan for C-7A and C-14A Engines

Appendix I
Air Quality Permit MD-401A
<u>Beaver Creek Gas Plant</u>
*Preventative Maintenance Plan for C-7A and C-13A Engines with Catalytic Converters.*

The following constitutes the preventative maintenance plan currently in place at the Devon Gas Services, L.P. Beaver Creek gas plant for the engines designated as C-7A and C-13A that are equipped with emissions control systems. The purpose of the plan is to ensure optimum operation of all emissions equipment and identify problems so they may be corrected in a timely manner.

NOTE: All frequencies are approximated, there may be some variation and/or gaps. Actual maintenance will be scheduled and occur to best meet personnel, equipment, and operational needs while still maintaining compliance with all permit conditions.

Engine Operation:
Engine operations are checked physically by operations personnel daily, in addition these same parameters are recorded into a computerized operation log.

SFS personnel will strive to keep the engine performing within the desired design conditions. Operating parameters and lube oil analysis will be, used as indicators for the following maintenance functions. Any other corrective work that seems appropriate will be performed on a case by case basis.

| | | |
|---|---|---|
| Lube oil change | Check ignition timing | Check condition of carburetor |
| Oil filter change | Check valve train adjustment | Check coolant |
| Spark plug change | Grease unit | Check emissions system |
| Check compression values | Check drive belts | Check equipment tie downs |

**High Catalyst Temperature Shutdown:**
Each converter is equipped with a "high catalyst temperature" shutdown device to protect the converter from high operating temperatures due to incorrect engine operation. This device will be tested after every ±3,000 hours of operation by grounding the switch and creating an alarm on the control panel.

**Exhaust Temperature:**
Pre- and post-converter temperatures are monitored and will be maintained between appropriate set points.

**Air/fuel ratio controller (Altronic EPC 100 or similar)**
Air /fuel ratio controllers are used in conjunction with the catalytic converters to control emissions and are set at proper design settings. The controller is monitored daily by operations personnel and adjusted or maintained as necessary to ensure it is operating correctly.

Performance Monitoring:
A portable analyzer (ECOM-AC or equivalent) will be utilized by SFS on a quarterly basis to verify exhaust emissions and track performance of the converters. NOx and CO emission rates will be noted and compared to the unit's permitted operating limits. It is the intent of SFS to operate these engines with an annual average emissions level of 1 gm/bhp-hr NOx. In order to meet this performance goal the following process will be used:

Step 1: After each quarterly engine test the results will be compared with the engine test from the previous quarter. If the average of the two tests is 1 gm/bhp-hr NOx or less and can reasonably be expected to maintain compliance during the following quarter, then no further action will be required to be taken on that engine:

Step 2: If the average of the two successive engine tests exceeds 1 gm/bhp-hr NOx then appropriate engine or catalyst system preventive maintenance procedures will be implemented to lower the actual emission rate.

Step 3: Within 30 days of the quarterly test which resulted' in action being taken, the engine emissions will be re-tested and the results of that flew test will be the basis for calculating the average emission rate in the following quarter.

Step 4: If adjustments made do not result in emission rates of 1 gm/bhp-hr or less, the Wyoming Air Quality Division will be notified. If necessary an action plan will be provided that shows the proposed method to return the engine to desired emission levels.

APPENDIX E

40 CFR 60 Subpart GG

## Subpart GG — Standards of Performance for Stationary Gas Turbines

**§60.330 Applicability and designation of affected facility.**

(a) The provisions of this subpart are applicable to the following affected facilities: All stationary gas turbines with a heat input at peak load equal to or greater than 10.7 gigajoules (10 million Btu) per hour, based on the lower heating value of the fuel fired.

(b) Any facility under paragraph (a) of this section which commences construction, modification, or reconstruction after October 3, 1977, is subject to the requirements of this part except as provided in paragraphs (e) and (j) of §60.332.

[44 FR 52798, Sept. 10, 1979, as amended at 52 FR 42434, Nov. 5, 1987; 65 FR 61759, Oct. 17, 2000]

**§60.331 Definitions.**

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

(a) *Stationary gas turbine* means any simple cycle gas turbine, regenerative cycle gas turbine or any gas turbine portion of a combined cycle steam/electric generating system that is not self propelled. It may, however, be mounted on a vehicle for portability.

(b) *Simple cycle gas turbine* means any stationary gas turbine which does not recover heat from the gas turbine exhaust gases to preheat the inlet combustion air to the gas turbine, or which does not recover heat from the gas turbine exhaust gases to heat water or generate steam.

(c) *Regenerative cycle gas turbine* means any stationary gas turbine which recovers heat from the gas turbine exhaust gases to preheat the inlet combustion air to the gas turbine.

(d) *Combined cycle gas turbine* means any stationary gas turbine which recovers heat from the gas turbine exhaust gases to heat water or generate steam.

(e) *Emergency gas turbine* means any stationary gas turbine which operates as a mechanical or electrical power source only when the primary power source for a facility has been rendered inoperable by an emergency situation.

(f) *Ice fog* means an atmospheric suspension of highly reflective ice crystals.

(g) *ISO standard day conditions* means 288 degrees Kelvin, 60 percent relative humidity and 101.3 kilopascals pressure.

(h) *Efficiency* means the gas turbine manufacturer's rated heat rate at peak load in terms of heat input per unit of power output based on the lower heating value of the fuel.

(i) *Peak load* means 100 percent of the manufacturer's design capacity of the gas turbine at ISO standard day conditions.

(j) *Base load* means the load level at which a gas turbine is normally operated.

(k) *Fire-fighting turbine* means any stationary gas turbine that is used solely to pump water for extinguishing fires.

(l) *Turbines employed in oil/gas production or oil/gas transportation* means any stationary gas turbine used to provide power to extract crude oil/natural gas from the earth or to move crude oil/natural gas, or products refined from these substances through pipelines.

(m) A *Metropolitan Statistical Area* or *MSA* as defined by the Department of Commerce.

(n) *Offshore platform gas turbines* means any stationary gas turbine located on a platform in an ocean.

(o) *Garrison facility* means any permanent military installation.

(p) *Gas turbine model* means a group of gas turbines having the same nominal air flow, combuster inlet pressure, combuster inlet temperature, firing temperature, turbine inlet temperature and turbine inlet pressure.

(q) *Electric utility stationary gas turbine* means any stationary gas turbine constructed for the purpose of supplying more than one-third of its potential electric output capacity to any utility power distribution system for sale.

(r) *Emergency fuel* is a fuel fired by a gas turbine only during circumstances, such as natural gas supply curtailment or breakdown of delivery system, that make it impossible to fire natural gas in the gas turbine.

(s) *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.

(t) *Excess emissions* means a specified averaging period over which either:

(1) The $NO_X$ emissions are higher than the applicable emission limit in §60.332;

(2) The total sulfur content of the fuel being combusted in the affected facility exceeds the limit specified in §60.333; 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.

(u) *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. Natural gas contains 20.0 grains or less of total sulfur per 100 standard cubic feet. Equivalents of this in other units are as follows: 0.068 weight percent total sulfur, 680 parts per million by weight (ppmw) total sulfur, and 338 parts per million by volume (ppmv) at 20 degrees Celsius total sulfur. Additionally, natural gas must either be composed of at least 70 percent methane by volume or have a gross calorific value between 950 and 1100 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.

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

(w) *Lean premix stationary combustion turbine* means any stationary combustion turbine where the air and fuel are thoroughly mixed to form a lean mixture for combustion in the combustor. Mixing may occur before or in the combustion chamber. A unit which is capable of operating in both lean premix and diffusion flame modes is considered a lean premix stationary combustion turbine when it is in the lean premix mode, and it is considered a diffusion flame stationary combustion turbine when it is in the diffusion flame mode.

(x) *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. A unit which is capable of operating in both lean premix and diffusion flame modes is considered a lean premix stationary combustion turbine when it is in the lean premix mode, and it is considered a diffusion flame stationary combustion turbine when it is in the diffusion flame mode.

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

[44 FR 52798, Sept. 10, 1979, as amended at 47 FR 3770, Jan. 27, 1982; 65 FR 61759, Oct. 17, 2000; 69 FR 41359, July 8, 2004]

**§60.332 Standard for nitrogen oxides.**

(a) On and after the date on which the performance test required by §60.8 is completed, every owner or operator subject to the provisions of this subpart as specified in paragraphs (b), (c), and (d) of this section shall comply with one of the following, except as provided in paragraphs (e), (f), (g), (h), (i), (j), (k), and (l) of this section.

(1) No owner or operator subject to the provisions of this subpart shall cause to be discharged into the atmosphere from any stationary gas turbine, any gases which contain nitrogen oxides in excess of:

$$STD = 0.0075 \frac{(14.4)}{Y} + F$$

where:

STD = allowable ISO corrected (if required as given in §60.335(b)(1)) $NO_X$ emission concentration (percent by volume at 15 percent oxygen and on a dry basis),

Y = manufacturer's rated heat rate at manufacturer's rated load (kilojoules per watt hour) or, actual measured heat rate based on lower heating value of fuel as measured at actual peak load for the facility. The value of Y shall not exceed 14.4 kilojoules per watt hour, and

F = $NO_X$ emission allowance for fuel-bound nitrogen as defined in paragraph (a)(4) of this section.

(2) No owner or operator subject to the provisions of this subpart shall cause to be discharged into the atmosphere from any stationary gas turbine, any gases which contain nitrogen oxides in excess of:

$$STD = 0.0150 \frac{(14.4)}{Y} + F$$

where:

STD = allowable ISO corrected (if required as given in §60.335(b)(1)) $NO_X$ emission concentration (percent by volume at 15 percent oxygen and on a dry basis),

Y = manufacturer's rated heat rate at manufacturer's rated peak load (kilojoules per watt hour), or actual measured heat rate based on lower heating value of fuel as measured at actual peak load for the facility. The value of Y shall not exceed 14.4 kilojoules per watt hour, and

F = $NO_X$ emission allowance for fuel-bound nitrogen as defined in paragraph (a)(4) of this section.

(3) The use of F in paragraphs (a)(1) and (2) of this section is optional. That is, the owner or operator may choose to apply a $NO_X$ allowance for fuel-bound nitrogen and determine the appropriate F-value in accordance with paragraph (a)(4) of this section or may accept an F- value of zero.

(4) If the owner or operator elects to apply a $NO_X$ emission allowance for fuel-bound nitrogen, F shall be defined according to the nitrogen content of the fuel during the most recent performance test required under §60.8 as follows:

| Fuel-bound nitrogen (percent by weight) | F ($NO_X$ percent by volume) |
|---|---|
| $N \leq 0.015$ | 0 |
| $0.015 < N \leq 0.1$ | 0.04 (N) |
| $0.1 < N \leq 0.25$ | 0.004 + 0.0067 (N-0.1) |
| $N > 0.25$ | 0.005 |

Where:

N = the nitrogen content of the fuel (percent by weight).

or:

Manufacturers may develop and submit to EPA custom fuel-bound nitrogen allowances for each gas turbine model they manufacture. These fuel-bound nitrogen allowances shall be substantiated with data and must be approved for use by the Administrator before the initial performance test required by §60.8. Notices of approval of custom fuel-bound nitrogen allowances will be published in the Federal Register.

(b) Electric utility stationary gas turbines with a heat input at peak load greater than 107.2 gigajoules per hour (100 million Btu/hour) based on the lower heating value of the fuel fired shall comply with the provisions of paragraph (a)(1) of this section.

(c) Stationary gas turbines with a heat input at peak load equal to or greater than 10.7 gigajoules per hour (10 million Btu/hour) but less than or equal to 107.2 gigajoules per hour (100 million Btu/hour) based on the lower heating value of the fuel fired, shall comply with the provisions of paragraph (a)(2) of this section.

(d) Stationary gas turbines with a manufacturer's rated base load at ISO conditions of 30 megawatts or less except as provided in §60.332(b) shall comply with paragraph (a)(2) of this section.

(e) Stationary gas turbines with a heat input at peak load equal to or greater than 10.7 gigajoules per hour (10 million Btu/hour) but less than or equal to 107.2 gigajoules per hour (100 million Btu/hour) based on the lower heating value of the fuel fired and that have commenced construction prior to October 3, 1982 are exempt from paragraph (a) of this section.

(f) Stationary gas turbines using water or steam injection for control of $NO_X$ emissions are exempt from paragraph (a) when ice fog is deemed a traffic hazard by the owner or operator of the gas turbine.

(g) Emergency gas turbines, military gas turbines for use in other than a garrison facility, military gas turbines installed for use as military training facilities, and fire fighting gas turbines are exempt from paragraph (a) of this section.

(h) Stationary gas turbines engaged by manufacturers in research and development of equipment for both gas turbine emission control techniques and gas turbine efficiency improvements are exempt from paragraph (a) on a case-by-case basis as determined by the Administrator.

(i) Exemptions from the requirements of paragraph (a) of this section will be granted on a case-by-case basis as determined by the Administrator in specific geographical areas where mandatory water restrictions are required by governmental agencies because of drought conditions. These exemptions will be allowed only while the mandatory water restrictions are in effect.

(j) Stationary gas turbines with a heat input at peak load greater than 107.2 gigajoules per hour that commenced construction, modification, or reconstruction between the dates of October 3, 1977, and January 27, 1982, and were required in the September 10, 1979, Federal Register (44 FR 52792) to comply with paragraph (a)(1) of this section, except electric utility stationary gas turbines, are exempt from paragraph (a) of this section.

(k) Stationary gas turbines with a heat input greater than or equal to 10.7 gigajoules per hour (10 million Btu/hour) when fired with natural gas are exempt from paragraph (a)(2) of this section when being fired with an emergency fuel.

(l) Regenerative cycle gas turbines with a heat input less than or equal to 107.2 gigajoules per hour (100 million Btu/hour) are exempt from paragraph (a) of this section.

[44 FR 52798, Sept. 10, 1979, as amended at 47 FR 3770, Jan. 27, 1982; 65 FR 61759, Oct. 17, 2000; 69 FR 41359, July 8, 2004]

### §60.333 Standard for sulfur dioxide.

On and after the date on which the performance test required to be conducted by §60.8 is completed, every owner or operator subject to the provision of this subpart shall comply with one or the other of the following conditions:

(a) No owner or operator subject to the provisions of this subpart shall cause to be discharged into the atmosphere from any stationary gas turbine any gases which contain sulfur dioxide in excess of 0.015 · percent by volume at 15 percent oxygen and on a dry basis.

(b) No owner or operator subject to the provisions of this subpart shall burn in any stationary gas turbine any fuel which contains sulfur in excess of 0.8 percent by weight (8000 ppmw).

[44 FR 52798, Sept. 10, 1979; 69 FR 41360, July 8, 2004]

### §60.334 Monitoring of operations.

(a) Except as provided in paragraph (b) of this section, the owner or operator of any stationary gas turbine subject to the provisions of this subpart and using water or steam injection to control $NO_X$ emissions shall 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.

(b) The owner or operator of any stationary gas turbine that commenced construction, reconstruction or modification after October 3, 1977, but before July 8, 2004, and which uses water or steam injection to control $NO_X$ emissions may, as an alternative to operating the continuous monitoring system described in paragraph (a) of this section, install, certify, maintain, operate, and quality-assure a continuous emission monitoring system (CEMS) consisting of $NO_X$ and $O_2$ monitors. As an alternative, a $CO_2$ monitor may be used to adjust the measured $NO_X$ concentrations to 15 percent $O_2$ by either converting the $CO_2$ hourly averages to equivalent $O_2$ concentrations using Equation F-14a or F-14b in appendix F to part 75 of this chapter and making the adjustments to 15 percent $O_2$, or by using the $CO_2$ readings directly to make the adjustments, as described in Method 20. If the option to use a CEMS is chosen, the CEMS shall be installed, certified, maintained and operated as follows:

(1) Each CEMS must be installed and certified according to PS 2 and 3 (for diluent) of 40 CFR part 60, appendix B, except the 7-day calibration drift is based on unit operating days, not calendar days. Appendix F, Procedure 1 is not required. The relative accuracy test audit (RATA) of the $NO_X$ and diluent monitors may be performed individually or on a combined basis, i.e., the relative accuracy tests of the CEMS may be performed either:

(i) On a ppm basis (for $NO_X$) and a percent $O_2$ basis for oxygen; or

(ii) On a ppm at 15 percent $O_2$ basis; or

(iii) On a ppm basis (for $NO_X$) and a percent $CO_2$ basis (for a $CO_2$ monitor that uses the procedures in Method 20 to correct the $NO_X$ data to 15 percent $O_2$).

(2) As specified in §60.13(e)(2), during each full unit operating hour, each 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 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 to validate the hour.

(3) For purposes of identifying excess emissions, CEMS data must be reduced to hourly averages as specified in §60.13(h).

(i) For each unit operating hour in which a valid hourly average, as described in paragraph (b)(2) of this section, is obtained for both $NO_X$ and diluent, the data acquisition and handling system must calculate and record the hourly $NO_X$ emissions in the units of the applicable $NO_X$ emission standard under §60.332(a), i.e., percent $NO_X$ by volume, dry basis, corrected to 15 percent $O_2$ and International Organization for Standardization (ISO) standard conditions (if required as given in §60.335(b)(1)). For any hour in which the hourly average $O_2$ concentration exceeds 19.0 percent $O_2$, a diluent cap value of 19.0 percent $O_2$ may be used in the emission calculations.

(ii) A worst case ISO correction factor may be calculated and applied using historical ambient data. For the purpose of this calculation, substitute the maximum humidity of ambient air (Ho), minimum ambient temperature (Ta), and minimum combustor inlet absolute pressure (Po) into the ISO correction equation.

(iii) If the owner or operator has installed a $NO_X$ CEMS to meet the requirements of part 75 of this chapter, and is continuing to meet the ongoing requirements of part 75 of this chapter, the CEMS may be used to meet the requirements of this section, except that the missing data substitution methodology provided for at 40 CFR part 75, subpart D, is not required for purposes of identifying excess emissions. Instead, periods of missing CEMS data are to be reported as monitor downtime in the excess emissions and monitoring performance report required in §60.7(c).

(c) For any turbine that commenced construction, reconstruction or modification after October 3, 1977, but before July 8, 2004, and which does not use steam or water injection to control $NO_X$ emissions, the owner or operator may, but is not required to, for purposes of determining excess emissions, use a CEMS that meets the requirements of paragraph (b) of this section. Also, if the owner or operator has previously submitted and received EPA, State, or local permitting authority approval of a procedure for monitoring compliance with the applicable $NO_X$ emission limit under §60.332, that approved procedure may continue to be used.

(d) The owner or operator of any new turbine constructed after July 8, 2004, and which uses water or steam injection to control $NO_X$ emissions may elect to use either the requirements in paragraph (a) of this section for continuous water or steam to fuel ratio monitoring or may use a $NO_X$ CEMS installed, certified, operated, maintained, and quality-assured as described in paragraph (b) of this section.

(e) The owner or operator of any new turbine that commences construction after July 8, 2004, and which does not use water or steam injection to control $NO_X$ emissions, may, but is not required to, elect to use a $NO_X$ CEMS installed, certified, operated, maintained, and quality-assured as described in paragraph (b) of this section. Other acceptable monitoring approaches include periodic testing approved by EPA or the State or local permitting authority or continuous parameter monitoring as described in paragraph (f) of this section.

(f) The owner or operator of a new turbine that commences construction after July 8, 2004, which does not use water or steam injection to control $NO_X$ emissions may, but is not required to, perform continuous parameter monitoring as follows:

(1) For a diffusion flame turbine without add-on selective catalytic reduction controls (SCR), the owner or operator shall define at least four parameters indicative of the unit's $NO_X$ formation characteristics and shall monitor these parameters continuously.

(2) For any lean premix stationary combustion turbine, the owner or operator shall continuously monitor the appropriate parameters to determine whether the unit is operating in low- $NO_X$ mode.

(3) For any turbine that uses SCR to reduce $NO_X$ emissions, the owner or operator shall continuously monitor appropriate parameters to verify the proper operation of the emission controls.

(4) For affected units that are also regulated under part 75 of this chapter, if the owner or operator elects to monitor $NO_X$ emission rate using the methodology in appendix E to part 75 of this chapter, or the low mass emissions methodology in §75.19 of this chapter, the requirements of this paragraph (f) may be met by performing the parametric monitoring described in section 2.3 of appendix E or in §75.19(c)(1)(iv)(H) of this chapter.

(g) The steam or water to fuel ratio or other parameters that are continuously monitored as described in paragraphs (a), (d) or (f) of this section shall be monitored during the performance test required under §60.8, to establish acceptable values and ranges. The owner or operator 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. The owner or operator shall develop and keep on-site a parameter monitoring plan which explains the procedures used to document proper operation of the $NO_X$ emission controls. The plan shall include the parameter(s) monitored and the acceptable range(s) of the parameter(s) as well as the basis for designating the parameter(s) and acceptable range(s). Any supplemental data such as engineering analyses, design specifications, manufacturer's recommendations and other relevant information shall be included in the monitoring plan. For affected units that are also subject to part 75 of this chapter and that use the low mass emissions methodology in §75.19 of this chapter or the $NO_X$ emission measurement methodology in appendix E to part 75, the owner or operator may meet the requirements of this paragraph by developing and keeping on-site (or at a central location for unmanned facilities) a quality-assurance plan, as described in §75.19 (e)(5) or in section 2.3 of appendix E and section 1.3.6 of appendix B to part 75 of this chapter.

(h) The owner or operator of any stationary gas turbine subject to the provisions of this subpart:

(1) Shall monitor the total sulfur content of the fuel being fired in the turbine, except as provided in paragraph (h)(3) of this section. The sulfur content of the fuel must be determined using total sulfur methods described in §60.335(b)(10). Alternatively, if the total sulfur content of the gaseous fuel during the most recent performance test was less than 0.4 weight percent (4000 ppmw), ASTM D4084-82, 94, D5504-01, D6228-98, or Gas Processors Association Standard 2377-86 (all of which are incorporated by reference-see §60.17), which measure the major sulfur compounds may be used; and

(2) Shall monitor the nitrogen content of the fuel combusted in the turbine, if the owner or operator claims an allowance for fuel bound nitrogen (i.e., if an F-value greater than zero is being or will be used by the owner or operator to calculate STD in §60.332). The nitrogen content of the fuel shall be determined using methods described in §60.335(b)(9) or an approved alternative.

(3) Notwithstanding the provisions of paragraph (h)(1) of this section, the owner or operator may elect not to monitor the total sulfur content of the gaseous fuel combusted in the turbine, if the gaseous fuel is demonstrated to meet the definition of natural gas in §60.331(u), regardless of whether an existing custom schedule approved by the administrator for subpart GG requires such monitoring. The owner or operator shall use one of the following sources of information to make the required demonstration:

(i) The gas quality characteristics in a current, valid purchase contract, tariff sheet or transportation contract for the gaseous fuel, specifying that the maximum total sulfur content of the fuel is 20.0 grains/100 scf or less; or

(ii) Representative fuel sampling data which show that the sulfur content of the gaseous fuel does not exceed 20 grains/100 scf. 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.

(4) For any turbine that commenced construction, reconstruction or modification after October 3, 1977, but before July 8, 2004, and for which a custom fuel monitoring schedule has previously been approved, the owner or operator may, without submitting a special petition to the Administrator, continue monitoring on this schedule.

(i) The frequency of determining the sulfur and nitrogen content of the fuel shall be as follows:

(1) *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). If an emission allowance is being claimed for fuel-bound nitrogen, the nitrogen content of the oil shall be determined and recorded once per unit operating day.

(2) *Gaseous fuel.* Any applicable nitrogen content value of the gaseous fuel shall be determined and recorded once per unit operating day. For owners and operators that elect not to demonstrate sulfur content using options in paragraph (h)(3) of this section, and for which the fuel is supplied without intermediate bulk storage, the sulfur content value of the gaseous fuel shall be determined and recorded once per unit operating day.

(3) *Custom schedules.* Notwithstanding the requirements of paragraph (i)(2) 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 (i)(3)(i) and (i)(3)(ii) 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 §60.333.

(i) The two custom sulfur monitoring schedules set forth in paragraphs (i)(3)(i)(A) through (D) and in paragraph (i)(3)(ii) of this section are acceptable, without prior Administrative approval:

(A) 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 (i)(3)(i)(B), (C), or (D) of this section, as applicable.

(B) If none of the 30 daily measurements of the fuel's total sulfur content exceeds 0.4 weight percent (4000 ppmw), 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 between 0.4 and 0.8 weight percent (4000 and 8000 ppmw), follow the procedures in paragraph (i)(3)(i)(C) of this section. If any measurement exceeds 0.8 weight percent (8000 ppmw), follow the procedures in paragraph (i)(3)(i)(D) of this section.

(C) If at least one of the 30 daily measurements of the fuel's total sulfur content is between 0.4 and 0.8 weight percent (4000 and 8000 ppmw), but none exceeds 0.8 weight percent (8000 ppmw), then:

*(1)* Collect and analyze a sample every 30 days for three months. If any sulfur content measurement exceeds 0.8 weight percent (8000 ppmw), follow the procedures in paragraph (i)(3)(i)(D) of this section. Otherwise, follow the procedures in paragraph (i)(3)(i)(C)(2) of this section.

*(2)* Begin monitoring at 6-month intervals for 12 months. If any sulfur content measurement exceeds 0.8 weight percent (8000 ppmw), follow the procedures in paragraph (i)(3)(i)(D) of this section. Otherwise, follow the procedures in paragraph (i)(3)(i)(C)(3) of this section.

*(3)* Begin monitoring at 12-month intervals. If any sulfur content measurement exceeds 0.8 weight percent (8000 ppmw), follow the procedures in paragraph (i)(3)(i)(D) of this section. Otherwise, continue to monitor at this frequency.

(D) If a sulfur content measurement exceeds 0.8 weight percent (8000 ppmw), immediately begin daily monitoring according to paragraph (i)(3)(i)(A) of this section. Daily monitoring shall continue until 30 consecutive daily samples, each having a sulfur content no greater than 0.8 weight percent (8000 ppmw), are obtained. At that point, the applicable procedures of paragraph (i)(3)(i)(B) or (C) of this section shall be followed.

(ii) 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:

(A) If the maximum fuel sulfur content obtained from the 720 hourly samples does not exceed 20 grains/100 scf (i.e., the maximum total sulfur content of natural gas as defined in §60.331(u)), no additional monitoring of the sulfur content of the gas is required, for the purposes of this subpart.

(B) 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 0.4 weight percent (4000 ppmw), then the minimum required sampling frequency shall be one sample at 12 month intervals.

(C) If any sample result exceeds 0.4 weight percent sulfur (4000 ppmw), but none exceeds 0.8 weight percent sulfur (8000 ppmw), follow the provisions of paragraph (i)(3)(i)(C) of this section.

(D) If the sulfur content of any of the 720 hourly samples exceeds 0.8 weight percent (8000 ppmw), follow the provisions of paragraph (i)(3)(i)(D) of this section.

(j) For each affected unit that elects to continuously monitor parameters or emissions, or to periodically determine the fuel sulfur content or fuel nitrogen content under this subpart, the owner or operator shall submit reports of excess emissions and monitor downtime, in accordance with §60.7(c). Excess emissions shall be reported for all periods of unit operation, including startup, shutdown and malfunction. For the purpose of reports required under §60.7(c), periods of excess emissions and monitor downtime that shall be reported are defined as follows:

(1) Nitrogen oxides.

(i) For turbines using water or steam to fuel ratio monitoring:

(A) An excess emission shall be any unit operating hour for which the 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 §60.332, 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 shall also be considered an excess emission.

(B) A period of monitor downtime shall be 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.

(C) Each report shall include the average steam or water to fuel ratio, average fuel consumption, ambient conditions (temperature, pressure, and humidity), gas turbine load, and (if applicable) the nitrogen content of the fuel during each excess emission. You do not have to report ambient conditions if you opt to use the worst case ISO correction factor as specified in

§60.334(b)(3)(ii), or if you are not using the ISO correction equation under the provisions of §60.335(b)(1).

(ii) If the owner or operator elects to take an emission allowance for fuel bound nitrogen, then excess emissions and periods of monitor downtime are as described in paragraphs (j)(1)(ii)(A) and (B) of this section.

(A) An excess emission shall be the period of time during which the fuel-bound nitrogen (N) is greater than the value measured during the performance test required in §60.8 and used to determine the allowance. The excess emission begins on the date and hour of the sample which shows that N is greater than the performance test value, and ends with the date and hour of a subsequent sample which shows a fuel nitrogen content less than or equal to the performance test value.

(B) 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 that a required sample is taken, if invalid results are obtained. The period of monitor downtime ends on the date and hour of the next valid sample.

(iii) For turbines using $NO_X$ and diluent CEMS:

(A) An hour of excess emissions shall be any unit operating hour in which the 4-hour rolling average $NO_X$ concentration exceeds the applicable emission limit in §60.332(a)(1) or (2). For the purposes of this subpart, a ``4-hour rolling average $NO_X$ concentration" is the arithmetic average of the average $NO_X$ concentration measured by the CEMS for a given hour (corrected to 15 percent $O_2$ and, if required under §60.335(b)(1), to ISO standard conditions) and the three unit operating hour average $NO_X$ concentrations immediately preceding that unit operating hour.

(B) A period of monitor downtime shall be any unit operating hour in which sufficient data are not obtained to validate the hour, for either $NO_X$ concentration or diluent (or both).

(C) Each report shall include the ambient conditions (temperature, pressure, and humidity) at the time of the excess emission period and (if the owner or operator has claimed an emission allowance for fuel bound nitrogen) the nitrogen content of the fuel during the period of excess emissions. You do not have to report ambient conditions if you opt to use the worst case ISO correction factor as specified in §60.334(b)(3)(ii), or if you are not using the ISO correction equation under the provisions of §60.335(b)(1).

(iv) For owners or operators that elect, under paragraph (f) of this section, to monitor combustion parameters or parameters that document proper operation of the $NO_X$ emission controls:

(A) An excess emission shall be 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.

(B) A period of monitor downtime shall be a unit operating hour in which any of the required parametric data are either not recorded or are invalid.

(2) Sulfur dioxide. If the owner or operator is required to monitor the sulfur content of the fuel under paragraph (h) of this section:

(i) 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 gas turbine exceeds 0.8 weight percent and ending on the date and hour that a subsequent sample is taken that demonstrates compliance with the sulfur limit.

(ii) If the option to sample each delivery of fuel oil has been selected, the owner or operator shall 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 0.8 weight percent. The owner or operator shall continue to use one of the other sampling options until all of the oil from the delivery has been combusted, and shall evaluate excess emissions according to paragraph (j)(2)(i) of this section. When all of the fuel from the delivery has been burned, the owner or operator may resume using the as-delivered sampling option.

(iii) 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 shall include only unit operating hours, and ends on the date and hour of the next valid sample.

(3) *Ice fog.* Each period during which an exemption provided in §60.332(f) is in effect shall be reported in writing to the Administrator quarterly. For each period the ambient conditions existing during the period, the date and time the air pollution control system was deactivated, and the date and time the air pollution control system was reactivated shall be reported. All quarterly reports shall be postmarked by the 30th day following the end of each calendar quarter.

(4) *Emergency fuel.* Each period during which an exemption provided in §60.332(k) is in effect shall be included in the report required in §60.7(c). For each period, the type, reasons, and duration of the firing of the emergency fuel shall be reported.

(5) All reports required under §60.7(c) shall be postmarked by the 30th day following the end of each 6-month period.

[44 FR 52798, Sept. 10, 1979, as amended at 47 FR 3770, Jan. 27, 1982; 65 FR 61759, Oct. 17, 2000; 69 FR 41360, July 8, 2004; 71 FR 9457, Feb. 24, 2006]

**§60.335 Test methods and procedures.**

(a) The owner or operator shall conduct the performance tests required in §60.8, using either

(1) EPA Method 20,

(2) ASTM D6522-00 (incorporated by reference, see §60.17), or

(3) EPA Method 7E and either EPA Method 3 or 3A in appendix A to this part, to determine $NO_X$ and diluent concentration.

(4) Sampling traverse points are to be selected following Method 20 or Method 1, (non-particulate procedures) and sampled for equal time intervals. The sampling shall 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.

(5) Notwithstanding paragraph (a)(4) of this section, the owner or operator may test at few points than are specified in Method 1 or Method 20 if the following conditions are met:

(i) You may perform a stratification test for $NO_X$ and diluent pursuant to

(A) [Reserved]

(B) The procedures specified in section 6.5.6.1(a) through (e) appendix A to part 75 of this chapter.

(ii) Once the stratification sampling is completed, the owner or operator may use the following alternative sample point selection criteria for the performance test:

(A) If each of the individual traverse point $NO_X$ concentrations, normalized to 15 percent $O_2$, is within ±10 percent of the mean normalized concentration for all traverse points, then you may use 3 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 3 points shall be located along the measurement line that exhibited the highest average normalized $NO_X$ concentration during the stratification test; or

(B) If each of the individual traverse point $NO_X$ concentrations, normalized to 15 percent $O_2$, is within 5 percent of the mean normalized concentration for all traverse points, then you may sample at a single point, located at least 1 meter from the stack wall or at the stack centroid.

(6) Other acceptable alternative reference methods and procedures are given in paragraph (c) of this section.

(b) The owner or operator shall determine compliance with the applicable nitrogen oxides emission limitation in §60.332 and shall meet the performance test requirements of §60.8 as follows:

(1) For each run of the performance test, the mean nitrogen oxides emission concentration ($NO_{XO}$) corrected to 15 percent $O_2$ shall be corrected to ISO standard conditions using the

following equation. Notwithstanding this requirement, use of the ISO correction equation is optional for: Lean premix stationary combustion turbines; units used in association with heat recovery steam generators (HRSG) equipped with duct burners; and units equipped with add-on emission control devices:

$$NO_X=(NO_{XO})(P_r/P_o)^{0.5}e^{19(Ho-0.00633)}(288^{\circ}K/T_a)^{1.53}$$

where:

$NO_X$ = emission concentration of $NO_X$ at 15 percent $O_2$ and ISO standard ambient conditions, ppm by volume, dry basis,

$NO_{XO}$ = mean observed $NO_X$ concentration, ppm by volume, dry basis, at 15 percent $O_2$,

$P_r$ = reference combustor inlet absolute pressure at 101.3 kilopascals ambient pressure, mm Hg,

$P_o$ = observed combustor inlet absolute pressure at test, mm Hg,

$H_o$ = observed humidity of ambient air, g $H_2O$/g air,

e = transcendental constant, 2.718, and

$T_a$ = ambient temperature, °K.

(2) The 3-run performance test required by §60.8 must be performed within ±5 percent at 30, 50, 75, and 90-to-100 percent of peak load or at four evenly-spaced load points in the normal operating range of the gas turbine, including the minimum point in the operating range and 90-to-100 percent of peak load, or at the highest achievable load point if 90-to-100 percent of peak load cannot be physically achieved in practice. If the turbine combusts both oil and gas as primary or backup fuels, separate performance testing is required for each fuel. Notwithstanding these requirements, performance testing is not required for any emergency fuel (as defined in §60.331).

(3) For a combined cycle turbine system with supplemental heat (duct burner), the owner or operator may elect to measure the turbine $NO_X$ emissions after the duct burner rather than directly after the turbine. If the owner or operator elects to use this alternative sampling location, the applicable $NO_X$ emission limit in §60.332 for the combustion turbine must still be met.

(4) If water or steam injection is used to control $NO_X$ with no additional post-combustion $NO_X$ control and the owner or operator chooses to monitor the steam or water to fuel ratio in accordance with §60.334(a), then that monitoring system must be operated concurrently with each EPA Method 20, ASTM D6522-00 (incorporated by reference, see §60.17), or EPA Method 7E run and shall be used to determine the fuel consumption and the steam or water to fuel ratio necessary to comply with the applicable §60.332 $NO_X$ emission limit.

(5) If the owner operator elects to claim an emission allowance for fuel bound nitrogen as described in §60.332, then concurrently with each reference method run, a representative sample of the fuel used shall be collected and analyzed, following the applicable procedures described in §60.335(b)(9). These data shall be used to determine the maximum fuel nitrogen content for which the established water (or steam) to fuel ratio will be valid.

(6) If the owner or operator elects to install a CEMS, the performance evaluation of the CEMS may either be conducted separately (as described in paragraph (b)(7) of this section) or as part of the initial performance test of the affected unit.

(7) If the owner or operator elects to install and certify a $NO_X$ CEMS under §60.334(e), then the initial performance test required under §60.8 may be done in the following alternative manner:

(i) Perform a minimum of 9 reference method runs, with a minimum time per run of 21 minutes, at a single load level, between 90 and 100 percent of peak (or the highest physically achievable) load.

(ii) Use the test data both to demonstrate compliance with the applicable $NO_X$ emission limit under §60.332 and to provide the required reference method data for the RATA of the CEMS described under §60.334(b).

(iii) The requirement to test at three additional load levels is waived.

(8) If the owner or operator elects under §60.334(f) to monitor combustion parameters or parameters indicative of proper operation of $NO_X$ emission controls, the appropriate parameters shall 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 §60.334(g).

(9) To determine the fuel bound nitrogen content of fuel being fired (if an emission allowance is claimed for fuel bound nitrogen), the owner or operator may use equipment and procedures meeting the requirements of:

(i) For liquid fuels, ASTM D2597-94 (Reapproved 1999), D6366-99, D4629-02, D5762-02 (all of which are incorporated by reference, see §60.17); or

(ii) For gaseous fuels, shall use analytical methods and procedures that are accurate to within 5 percent of the instrument range and are approved by the Administrator.

(10) If the owner or operator is required under §60.334(i)(1) or (3) to periodically determine the sulfur content of the fuel combusted in the turbine, a minimum of three fuel samples shall be collected during the performance test. Analyze the samples for the total sulfur content of the fuel using:

(i) For liquid fuels, ASTM D129-00, D2622-98, D4294-02, D1266-98, D5453-00 or D1552-01 (all of which are incorporated by reference, see §60.17); or

(ii) For gaseous fuels, ASTM D1072-80, 90 (Reapproved 1994); D3246- 81, 92, 96; D4468-85 (Reapproved 2000); or D6667-01 (all of which are incorporated by reference, see §60.17). The applicable ranges of some ASTM methods mentioned above are not adequate to measure the levels of sulfur in some fuel gases. Dilution of samples before analysis (with verification of the dilution ratio) may be used, subject to the prior approval of the Administrator.

(11) The fuel analyses required under paragraphs (b)(9) and (b)(10) of this section may be performed by the owner or operator, a service contractor retained by the owner or operator, the fuel vendor, or any other qualified agency.

(c) The owner or operator may use the following as alternatives to the reference methods and procedures specified in this section:

(1) Instead of using the equation in paragraph (b)(1) of this section, manufacturers may develop ambient condition correction factors to adjust the nitrogen oxides emission level measured by the performance test as provided in §60.8 to ISO standard day conditions.

[69 FR 41363, July 8, 2004, as amended at 71 FR 9458, Feb. 24, 2006]

APPENDIX F

40 CFR 60 Subparts KKK and VV

## Subpart KKK-Standards of Performance for Equipment Leaks of VOC From Onshore Natural Gas Processing Plants

Source: 50 FR 26124, June 24, 1985, unless otherwise noted.

**§60.630 Applicability and designation of affected facility.**

(a)(1) The provisions of this subpart apply to affected facilities in onshore natural gas processing plants.

(2) A compressor in VOC service or in wet gas service is an affected facility.

(3) The group of all equipment except compressors (defined in §60.631) within a process unit is an affected facility.

(b) Any affected facility under paragraph (a) of this section that commences construction, reconstruction, or modification after January 20, 1984, is subject to the requirements of this subpart.

(c) Addition or replacement of equipment (defined in §60.631) for the purpose of process improvement that is accomplished without a capital expenditure shall not by itself be considered a modification under this subpart.

(d) Facilities covered by subpart VV or subpart GGG of 40 CFR part 60 are excluded from this subpart.

(e) A compressor station, dehydration unit, sweetening unit, underground storage tank, field gas gathering system, or liquefied natural gas unit is covered by this subpart if it is located at an onshore natural gas processing plant. If the unit is not located at the plant site, then it is exempt from the provisions of this subpart.

**§60.631 Definitions.**

As used in this subpart, all terms not defined herein shall have the meaning given them in the Act, in subpart A or subpart VV of part 60; and the following terms shall have the specific meanings given them.

*Alaskan North Slope* means the approximately 69,000 square-mile area extending from the Brooks Range to the Arctic Ocean.

*Equipment* means each pump, pressure relief device, open-ended valve or line, valve, compressor, and flange or other connector that is in VOC service or in wet gas service, and any device or system required by this subpart.

*Field gas* means feedstock gas entering the natural gas processing plant.

*In light liquid service* means that the piece of equipment contains a liquid that meets the conditions specified in §60.485(e) or §60.633(h)(2).

*In wet gas service* means that a piece of equipment contains or contacts the field gas before the extraction step in the process.

*Natural gas liquids* means the hydrocarbons, such as ethane, propane, butane, and pentane, that are extracted from field gas.

*Natural gas processing plant (gas plant)* means any processing site engaged in the extraction of natural gas liquids from field gas, fractionation of mixed natural gas liquids to natural gas products, or both.

*Nonfractionating plant* means any gas plant that does not fractionate mixed natural gas liquids into natural gas products.

*Onshore* means all facilities except those that are located in the territorial seas or on the outer continental shelf.

*Process unit* means equipment assembled for the extraction of natural gas liquids from field gas, the fractionation of the liquids into natural gas products, or other operations associated with the processing of natural gas products. A process unit can operate independently if supplied with sufficient feed or raw materials and sufficient storage facilities for the products.

*Reciprocating compressor* means a piece of equipment that increases the pressure of a process gas by positive displacement, employing linear movement of the driveshaft.

**§60.632 Standards.**

(a) Each owner or operator subject to the provisions of this subpart shall comply with the requirements of §60.482-1 (a), (b), and (d) and 60.482-2 through 60.482-10, except as provided in §60.633, as soon as practicable, but no later than 180 days after initial startup.

(b) An owner or operator may elect to comply with the requirements of §§60.483-1 and 60.483-2.

(c) An owner or operator may apply to the Administrator for permission to use an alternative means of emission limitation that achieves a reduction in emissions of VOC at least equivalent to that achieved by the controls required in this subpart. In doing so, the owner or operator shall comply with requirements of §60.634 of this subpart.

(d) Each owner or operator subject to the provisions of this subpart shall comply with the provisions of §60.485 except as provided in §60.633(f) of this subpart.

(e) Each owner or operator subject to the provisions of this subpart shall comply with the provisions of §§60.486 and 60.487 except as provided in §§60.633, 60.635, and 60.636 of this subpart.

(f) An owner or operator shall use the following provision instead of §60.485(d)(1): Each piece of equipment is presumed to be in VOC service or in wet gas service unless an owner or operator demonstrates that the piece of equipment is not in VOC service or in wet gas service. For a piece of equipment to be considered not in VOC service, it must be determined that the VOC content can be reasonably expected never to exceed 10.0 percent by weight. For a piece of equipment to be considered in wet gas service, it must be determined that it contains or contacts the field gas before the extraction step in the process. For purposes of determining the percent VOC content of the process fluid that is contained in or contacts a piece of equipment, procedures that conform to the methods described in ASTM E169-63, 77, or 93, E168-67, 77, or 92, or E260-73, 91, or 96 (incorporated by reference as specified in §60.17) shall be used.

[50 FR 26124, June 24, 1985, as amended at 65 FR 61773, Oct. 17, 2000]

**§60.633 Exceptions.**

(a) Each owner or operator subject to the provisions of this subpart may comply with the following exceptions to the provisions of subpart VV.

(b)(1) Each pressure relief device in gas/vapor service may be monitored quarterly and within 5 days after each pressure release to detect leaks by the methods specified in §60.485(b) except as provided in §60.632(c), paragraph (b)(4) of this section, and §60.482-4 (a) through (c) of subpart VV.

(2) If an instrument reading of 10,000 ppm or greater is measured, a leak is detected.

(3)(i) When a leak is detected, it shall be repaired as soon as practicable, but no later than 15 calendar days after it is detected, except as provided in §60.482-9.

(ii) A first attempt at repair shall be made no later than 5 calendar days after each leak is detected.

(4)(i) Any pressure relief device that is located in a nonfractionating plant that is monitored only by nonplant personnel may be monitored after a pressure release the next time the monitoring personnel are on site, instead of within 5 days as specified in paragraph (b)(1) of this section and §60.482-(b)(1) of subpart VV.

(ii) No pressure relief device described in paragraph (b)(4)(i) of this section shall be allowed to operate for more than 30 days after a pressure release without monitoring.

(c) Sampling connection systems are exempt from the requirements of §60.482-5.

(d) Pumps in light liquid service, valves in gas/vapor and light liquid service, and pressure relief devices in gas/vapor service that are located at a nonfractionating plant that does not have the design capacity to process 283,000 standard cubic meters per day (scmd) (10 million standard cubic feet per day (scfd)) or more of field gas are exempt from the routine monitoring requirements of §§60.482-2(a)(1) and 60.482-7(a), and paragraph (b)(1) of this section.

(e) Pumps in light liquid service, valves in gas/vapor and light liquid service, and pressure relief devices in gas/vapor service within a process unit that is located in the Alaskan North Slope are exempt from the routine monitoring requirements of §§60.482-2(a)(1), 60.482-7(a), and paragraph (b)(1) of this section.

(f) Reciprocating compressors in wet gas service are exempt from the compressor control requirements of §60.482-3.

(g) Flares used to comply with this subpart shall comply with the requirements of §60.18.

(h) An owner or operator may use the following provisions instead of §60 485(e):

(1) Equipment is in heavy liquid service if the weight percent evaporated is 10 percent or less at 150 °C (302 °F) as determined by ASTM Method D86-78, 82, 90, 95, or 96 (incorporated by reference as specified in §60.17).

(2) Equipment is in light liquid service if the weight percent evaporated is greater than 10 percent at 150 °C (302 °F) as determined by ASTM Method D86-78, 82, 90, 95, or 96 (incorporated by reference as specified in §60.17).

[50 FR 26124, June 24, 1985, as amended at 51 FR 2702, Jan. 21, 1986; 65 FR 61773, Oct. 17, 2000]

**§60.634 Alternative means of emission limitation.**

(a) If, in the Administrator's judgment, an alternative means of emission limitation will achieve a reduction in VOC emissions at least equivalent to the reduction in VOC emissions achieved under any design, equipment, work practice or operational standard, the Administrator will publish, in the Federal Register a notice permitting the use of that alternative means for the purpose of compliance with that standard. The notice may condition permission on requirements related to the operation and maintenance of the alternative means.

(b) Any notice under paragraph (a) of this section shall be published only after notice and an opportunity for a public hearing.

(c) The Administrator will consider applications under this section from either owners or operators of affected facilities, or manufacturers of control equipment.

(d) The Administrator will treat applications under this section according to the following criteria, except in cases where he concludes that other criteria are appropriate:

(1) The applicant must collect, verify and submit test data, covering a period of at least 12 months, necessary to support the finding in paragraph (a) of this section.

(2) If the applicant is an owner or operator of an affected facility, he must commit in writing to operate and maintain the alternative means so as to achieve a reduction in VOC emissions at least equivalent to the reduction in VOC emissions achieved under the design, equipment, work practice or operational standard.

**§60.635 Recordkeeping requirements.**

(a) Each owner or operator subject to the provisions of this subpart shall comply with the requirements of paragraphs (b) and (c) of this section in addition to the requirements of §60.486.

(b) The following recordkeeping requirements shall apply to pressure relief devices subject to the requirements of §60.633(b)(1) of this subpart.

(1) When each leak is detected as specified in §60.633(b)(2), a weatherproof and readily visible identification, marked with the equipment identification number, shall be attached to the leaking equipment. The identification on the pressure relief device may be removed after it has been repaired.

(2) When each leak is detected as specified in §60.633(b)(2), the following information shall be recorded in a log and shall be kept for 2 years in a readily accessible location:

(i) The instrument and operator identification numbers and the equipment identification number.

(ii) The date the leak was detected and the dates of each attempt to repair the leak.

(iii) Repair methods applied in each attempt to repair the leak.

(iv) "Above 10,000 ppm" if the maximum instrument reading measured by the methods specified in paragraph (a) of this section after each repair attempt is 10,000 ppm or greater.

(v) "Repair delayed" and the reason for the delay if a leak is not repaired within 15 calendar days after discovery of the leak.

(vi) The signature of the owner or operator (or designate) whose decision it was that repair could not be effected without a process shutdown.

(vii) The expected date of successful repair of the leak if a leak is not repaired within 15 days.

(viii) Dates of process unit shutdowns that occur while the equipment is unrepaired.

(ix) The date of successful repair of the leak.

(x) A list of identification numbers for equipment that are designated for no detectable emissions under the provisions of §60.482-4(a). The designation of equipment subject to the provisions of §60.482-4(a) shall be signed by the owner or operator.

(c) An owner or operator shall comply with the following requirement in addition to the requirement of §60.486(j): Information and data used to demonstrate that a reciprocating compressor is in wet gas service to apply for the exemption in §60.633(f) shall be recorded in a log that is kept in a readily accessible location.

**§60.636 Reporting requirements.**

(a) Each owner or operator subject to the provisions of this subpart shall comply with the requirements of paragraphs (b) and (c) of this section in addition to the requirements of §60.487.

(b) An owner or operator shall include the following information in the initial semiannual report in addition to the information required in §60.487(b) (1)-(4): Number of pressure relief devices subject to the requirements of §60.633(b) except for those pressure relief devices designated for no detectable emissions under the provisions of §60.482-4(a) and those pressure relief devices complying with §60.482-4(c).

(c) An owner or operator shall include the following information in all semiannual reports in addition to the information required in §60.487(c)(2) (i) through (vi):

(1) Number of pressure relief devices for which leaks were detected as required in §60.633(b)(2) and

(2) Number of pressure relief devices for which leaks were not repaired as required in §60.633(b)(3).

## Subpart VV – Standards of Performance for Equipment Leaks of VOC in the Synthetic Organic Chemicals Manufacturing Industry

Source: 48 FR 48335, Oct. 18, 1983, unless otherwise noted.

### §60.480 Applicability and designation of affected facility.

(a)(1) The provisions of this subpart apply to affected facilities in the synthetic organic chemicals manufacturing industry.

(2) The group of all equipment (defined in §60.481) within a process unit is an affected facility.

(b) Any affected facility under paragraph (a) of this section that commences construction or modification after January 5, 1981, shall be subject to the requirements of this subpart.

(c) Addition or replacement of equipment for the purpose of process improvement which is accomplished without a capital expenditure shall not by itself be considered a modification under this subpart.

(d)(1) If an owner or operator applies for one or more of the exemptions in this paragraph, then the owner or operator shall maintain records as required in §60.486(i).

(2) Any affected facility that has the design capacity to produce less than 1,000 Mg/yr (1,102 ton/yr) is exempt from §60.482.

(3) If an affected facility produces heavy liquid chemicals only from heavy liquid feed or raw materials, then it is exempt from §60.482.

(4) Any affected facility that produces beverage alcohol is exempt from §60.482.

(5) Any affected facility that has no equipment in VOC service is exempt from §60.482.

(e) *Alternative means of compliance* --

(1) *Option to comply with part 65.* Owners or operators may choose to comply with the provisions of 40 CFR part 65, subpart F, to satisfy the requirements of §§60.482 through 60.487 for an affected facility. When choosing to comply with 40 CFR part 65, subpart F, the requirements of §60.485(d), (e), and (f), and §60.486(i) and (j) still apply. Other provisions applying to an owner or operator who chooses to comply with 40 CFR part 65 are provided in 40 CFR 65.1.

(2) *Part 60, subpart A.* Owners or operators who choose to comply with 40 CFR part 65, subpart F must also comply with §§§§60.1, 60.2, 60.5, 60.6, 60.7(a)(1) and (4), 60.14, 60.15, and 60.16 for that equipment. All sections and paragraphs of subpart A of this part that are not mentioned in this paragraph (e)(2) do not apply to owners or operators of equipment subject to this subpart complying with 40 CFR part 65, subpart F, except that provisions required to be met prior to implementing 40 CFR part 65 still apply. Owners and operators who choose to comply with 40 CFR part 65, subpart F, must comply with 40 CFR part 65, subpart A.

[48 FR 48335, Oct. 18, 1983, as amended at 49 FR 22607, May 30, 1984; 65 FR 61762, Oct. 17, 2000; 65 FR 78276, Dec. 14, 2000]

### § 60.481 Definitions.

As used in this subpart, all terms not defined herein shall have the meaning given them in the Act or in subpart A of part 60, and the following terms shall have the specific meanings given them.

*Capital expenditure* means, in addition to the definition in 40 CFR part 60.2, an expenditure for a physical or operational change to an existing facility that:

(a) Exceeds P, the product of the facility's replacement cost, R, and an adjusted annual asset guideline repair allowance, A, as reflected by the following equation:

$P = R \times A$, where

(1) The adjusted annual asset guideline repair allowance, A, is the product of the percent of the replacement cost, Y, and the applicable basic annual asset guideline repair allowance, B, divided by 100 as reflected by the following equation:

$$A = Y \times (B \div 100);$$

(2) The percent Y is determined from the following equation: $Y = 1.0 - 0.575 \log X$, where X is 1982 minus the year of construction; and

(3) The applicable basic annual asset guideline repair allowance, B, is selected from the following table consistent with the applicable subpart:

TABLE FOR DETERMINING APPLICABLE FOR B

| Subpart applicable to facility | Value of B to be used in equation |
|---|---|
| VV | 12.5 |
| DDD | 12.5 |
| GGG | 7.0 |
| KKK | 4.5 |

*Closed vent system* means a system that is not open to the atmosphere and that is composed of hard-piping, ductwork, connections, and, if necessary, flow-inducing devices that transport gas or vapor from a piece or pieces of equipment to a control device or back to a process.

*Connector* means flanged, screwed, welded, or other joined fittings used to connect two pipe lines or a pipe line and a piece of process equipment.

*Control device* means an enclosed combustion device, vapor recovery system, or flare.

*Distance piece* means an open or enclosed casing through which the piston rod travels, separating the compressor cylinder from the crankcase.

*Double block and bleed system* means two block valves connected in series with a bleed valve or line that can vent the line between the two block valves.

*Duct work* means a conveyance system such as those commonly used for heating and ventilation systems. It is often made of sheet metal and often has sections connected by screws or crimping. Hard-piping is not ductwork.

*Equipment* means each pump, compressor, pressure relief device, sampling connection system, open-ended valve or line, valve, and flange or other connector in VOC service and any devices or systems required by this subpart.

*First attempt at repair* means to take rapid action for the purpose of stopping or reducing leakage of organic material to atmosphere using best practices.

*Fuel gas* means gases that are combusted to derive useful work or heat.

*Fuel gas system* means the offsite and onsite piping and flow and pressure control system that gathers gaseous stream(s) generated by onsite operations, may blend them with other sources of gas, and transports the gaseous stream for use as fuel gas in combustion devices or in-process combustion equipment, such as furnaces and gas turbines, either singly or in combination.

*Hard-piping* means pipe or tubing that is manufactured and properly installed using good engineering judgement and standards such as ASME B31.3, Process Piping (available from the American Society of Mechanical Engineers, PO Box 2900, Fairfield, NJ 07007-2900).

*In gas/vapor service* means that the piece of equipment contains process fluid that is in the gaseous state at operating conditions.

*In heavy liquid service* means that the piece of equipment is not in gas/vapor service or in light liquid service.

*In light liquid service* means that the piece of equipment contains a liquid that meets the conditions specified in §60.485(e).

*In-situ sampling systems* means nonextractive samplers or in-line samplers.

*In vacuum service* means that equipment is operating at an internal pressure which is at least 5 kilopascals (kPa)(0.7 psia) below ambient pressure.

*In VOC service* means that the piece of equipment contains or contacts a process fluid that is at least 10 percent VOC by weight. (The provisions of §60.485(d) specify how to determine that a piece of equipment is not in VOC service.)

*Liquids dripping* means any visible leakage from the seal including spraying, misting, clouding, and ice formation.

*Open-ended valve or line* means any valve, except safety relief valves, having one side of the valve seat in contact with process fluid and one side open to the atmosphere, either directly or through open piping.

*Pressure release* means the emission of materials resulting from system pressure being greater than set pressure of the pressure relief device.

*Process improvement* means routine changes made for safety and occupational health requirements, for energy savings, for better utility, for ease of maintenance and operation, for correction of design deficiencies, for bottleneck removal, for changing product requirements, or for environmental control.

*Process unit* means components assembled to produce, as intermediate or final products, one or more of the chemicals listed in §60.489 of this part. A process unit can operate independently if supplied with sufficient feed or raw materials and sufficient storage facilities for the product.

*Process unit shutdown* means a work practice or operational procedure that stops production from a process unit or part of a process unit. An unscheduled work practice or operational procedure that stops production from a process unit or part of a process unit for less than 24 hours is not a process unit shutdown. The use of spare equipment and technically feasible bypassing of equipment without stopping production are not process unit shutdowns.

*Quarter* means a 3-month period; the first quarter concludes on the last day of the last full month during the 180 days following initial startup.

*Repaired* means that equipment is adjusted, or otherwise altered, in order to eliminate a leak as indicated by one of the following: an instrument reading of 10,000 ppm or greater, indication of liquids dripping, or indication by a sensor that a seal or barrier fluid system has failed.

*Replacement cost* means the capital needed to purchase all the depreciable components in a facility.

*Sampling connection system* means an assembly of equipment within a process unit used during periods of representative operation to take samples of the process fluid. Equipment used to take nonroutine grab samples is not considered a sampling connection system.

*Sensor* means a device that measures a physical quantity or the change in a physical quantity such as temperature, pressure, flow rate, pH, or liquid level.

*Synthetic organic chemicals manufacturing industry* means the industry that produces, as intermediates or final products, one or more of the chemicals listed in §60.489.

*Volatile organic compounds* or VOC means, for the purposes of this subpart, any reactive organic compounds as defined in §60.2 Definitions.

[48 FR 48335, Oct. 18, 1983, as amended at 49 FR 22607, May 30, 1984; 49 FR 26738, June 29, 1984; 60 FR 43258, Aug. 18, 1995; 65 FR 61762, Oct. 17, 2000; 65 FR 78276, Dec. 14, 2000]

### § 60.482-1 Standards: General.

(a) Each owner or operator subject to the provisions of this subpart shall demonstrate compliance with the requirements of §60.482-1 through §60.482-10 or §60.480(e) for all equipment within 180 days of initial startup.

(b) Compliance with §§60.482-1 to 60.482-10 will be determined by review of records and reports, review of performance test results, and inspection using the methods and procedures specified in §60.485.

(c)(1) An owner or operator may request a determination of equivalence of a means of emission limitation to the requirements of §§60.482-2, 60.482-3, 60.482-5, 60.482-6, 60.482-7, 60.482-8, and 60.482-10 as provided in §60.484.

(2) If the Administrator makes a determination that a means of emission limitation is at least equivalent to the requirements of §§60.482-2, 60.482-3, 60.482-5, 60.482-6, 60.482-7, 60.482-8, or 60.482-10, an owner or operator shall comply with the requirements of that determination.

(d) Equipment that is in vacuum service is excluded from the requirements of §§60.482-2 to 60.482-10 if it is identified as required in §60.486(e)(5).

[48 FR 48335, Oct. 18, 1983, as amended at 49 FR 22608, May 30, 1984; 65 FR 78276, Dec. 14, 2000]

### §60.482-2 Standards: Pumps in light liquid service.

(a)(1) Each pump in light liquid service shall be monitored monthly to detect leaks by the methods specified in §60.485(b), except as provided in §60.482-1(c) and paragraphs (d), (e), and (f) of this section.

(2) Each pump in light liquid service shall be checked by visual inspection each calendar week for indications of liquids dripping from the pump seal.

(b)(1) If an instrument reading of 10,000 ppm or greater is measured, a leak is detected.

(2) If there are indications of liquids dripping from the pump seal, a leak is detected.

(c)(1) When a leak is detected, it shall be repaired as soon as practicable, but not later than 15 calendar days after it is detected, except as provided in §60.482-9.

(2) A first attempt at repair shall be made no later than 5 calendar days after each leak is detected.

(d) Each pump equipped with a dual mechanical seal system that includes a barrier fluid system is exempt from the requirements of paragraph (a), provided the following requirements are met:

(1) Each dual mechanical seal system is:

(i) Operated with the barrier fluid at a pressure that is at all times greater than the pump stuffing box pressure; or

(ii) Equipment with a barrier fluid degassing reservoir that is routed to a process or fuel gas system or connected by a closed vent system to a control device that complies with the requirements of §60.482-10; or

(iii) Equipped with a system that purges the barrier fluid into a process stream with zero VOC emissions to the atmosphere.

(2) The barrier fluid system is in heavy liquid service or is not in VOC service.

(3) Each barrier fluid system is equipped with a sensor that will detect failure of the seal system, the barrier fluid system, or both.

(4) Each pump is checked by visual inspection, each calendar week, for indications of liquids dripping from the pump seals.

(5)(i) Each sensor as described in paragraph (d)(3) is checked daily or is equipped with an audible alarm, and

(ii) The owner or operator determines, based on design considerations and operating experience, a criterion that indicates failure of the seal system, the barrier fluid system, or both.

(6)(i) If there are indications of liquids dripping from the pump seal or the sensor indicates failure of the seal system, the barrier fluid system, or both based on the criterion determined in paragraph (d)(5)(ii), a leak is detected.

(ii) When a leak is detected, it shall be repaired as soon as practicable, but not later than 15 calendar days after it is detected, except as provided in §60.482-9.

(iii) A first attempt at repair shall be made no later than 5 calendar days after each leak is detected.

(e) Any pump that is designated, as described in §§60.486(e)(1) and (2), for no detectable emission, as indicated by an instrument reading of less than 500 ppm above background, is exempt from the requirements of paragraphs (a), (c), and (d) of this section if the pump:

(1) Has no externally actuated shaft penetrating the pump housing,

(2) Is demonstrated to be operating with no detectable emissions as indicated by an instrument reading of less than 500 ppm above background as measured by the methods specified in §60.485(c), and

(3) Is tested for compliance with paragraph (e)(2) of this section initially upon designation, annually, and at other times requested by the Administrator.

(f) If any pump is equipped with a closed vent system capable of capturing and transporting any leakage from the seal or seals to a process or to a fuel gas system or to a control device that complies with the requirements of §60.482-10, it is exempt from paragraphs (a) through (e) of this section.

(g) Any pump that is designated, as described in §60.486(f)(1), as an unsafe-to-monitor pump is exempt from the monitoring and inspection requirements of paragraphs (a) and (d)(4) through (6) of this section if:

(1) The owner or operator of the pump demonstrates that the pump is unsafe-to-monitor because monitoring personnel would be exposed to an immediate danger as a

consequence of complying with paragraph (a) of this section; and

(2) The owner or operator of the pump has a written plan that requires monitoring of the pump as frequently as practicable during safe-to-monitor times but not more frequently than the periodic monitoring schedule otherwise applicable, and repair of the equipment according to the procedures in paragraph (c) of this section if a leak is detected.

(h) Any pump that is located within the boundary of an unmanned plant site is exempt from the weekly visual inspection requirement of paragraphs (a)(2) and (d)(4) of this section, and the daily requirements of paragraph (d)(5) of this section, provided that each pump is visually inspected as often as practicable and at least monthly.

[48 FR 48335, Oct. 18, 1983, as amended at 65 FR 61762, Oct. 17, 2000; 65 FR 78276, Dec. 14, 2000]

**§60.482-3 Standards: Compressors.**

(a) Each compressor shall be equipped with a seal system that includes a barrier fluid system and that prevents leakage of VOC to the atmosphere, except as provided in §60.482-1(c) and paragraph (h) and (i) of this section.

(b) Each compressor seal system as required in paragraph (a) shall be:

(1) Operated with the barrier fluid at a pressure that is greater than the compressor stuffing box pressure; or

(2) Equipped with a barrier fluid system degassing reservoir that is routed to a process or fuel gas system or connected by a closed vent system to a control device that complies with the requirements of §60.482-10; or

(3) Equipped with a system that purges the barrier fluid into a process stream with zero VOC emissions to the atmosphere.

(c) The barrier fluid system shall be in heavy liquid service or shall not be in VOC service.

(d) Each barrier fluid system as described in paragraph (a) shall be equipped with a sensor that will detect failure of the seal system, barrier fluid system, or both.

(e)(1) Each sensor as required in paragraph (d) shall be checked daily or shall be equipped with an audible alarm.

(2) The owner or operator shall determine, based on design considerations and operating experience, a criterion that indicates failure of the seal system, the barrier fluid system, or both.

(f) If the sensor indicates failure of the seal system, the barrier system, or both based on the criterion determined under paragraph (e)(2), a leak is detected.

(g)(1) When a leak is detected, it shall be repaired as soon as practicable, but not later than 15 calendar days after it is detected, except as provided in §60.482-9.

(2) A first attempt at repair shall be made no later than 5 calendar days after each leak is detected.

(h) A compressor is exempt from the requirements of paragraphs (a) and (b) of this section, if it is equipped with a closed vent system to capture and transport leakage from the compressor drive shaft back to a process or fuel gas system or to a control device that complies with the requirements of §60.482-10, except as provided in paragraph (i) of this section.

(i) Any compressor that is designated, as described in §§60.486(e) (1) and (2), for no detectable emissions, as indicated by an instrument reading of less than 500 ppm above background, is exempt from the requirements of paragraphs (a)-(h) if the compressor:

(1) Is demonstrated to be operating with no detectable emissions, as indicated by an instrument reading of less than 500 ppm above background, as measured by the methods specified in §60.485(c); and

(2) Is tested for compliance with paragraph (i)(1) of this section initially upon designation, annually, and at other times requested by the Administrator.

(j) Any existing reciprocating compressor in a process unit which becomes an affected facility under provisions of §60.14 or §60.15 is exempt from §§60.482(a), (b), (c), (d), (e), and (h), provided the owner or operator demonstrates that recasting the distance piece or replacing the compressor are the only options available to bring the compressor into compliance with the provisions of paragraphs (a) through (e) and (h) of this section.

[48 FR 48335, Oct. 18, 1983, as amended at 65 FR 61762, Oct. 17, 2000; 65 FR 78277, Dec. 14, 2000]

**§60.482-4 Standards: Pressure relief devices in gas/vapor service.**

(a) Except during pressure releases, each pressure relief device in gas/vapor service shall be operated with no detectable emissions, as indicated by an instrument reading of less than 500 ppm above background, as determined by the methods specified in §60.485(c).

(b)(1) After each pressure release, the pressure relief device shall be returned to a condition of no detectable emissions, as indicated by an instrument reading of less than 500 ppm above background, as soon as practicable, but no later than 5 calendar days after the pressure release, except as provided in §60.482-9.

(2) No later than 5 calendar days after the pressure release, the pressure relief device shall be monitored to confirm the conditions of no detectable emissions, as indicated by an instrument reading of less than 500 ppm above background, by the methods specified in §60.485(c).

(c) Any pressure relief device that is routed to a process or fuel gas system or equipped with a closed vent system capable of capturing and transporting leakage through the pressure relief device to a control device as described in §60.482-10 is exempted from the requirements of paragraphs (a) and (b) of this section.

(d)(1) Any pressure relief device that is equipped with a rupture disk upstream of the pressure relief device is exempt from the requirements of paragraphs (a) and (b) of this section, provided the owner or operator complies with the requirements in paragraph (d)(2) of this section.

(2) After each pressure release, a new rupture disk shall be installed upstream of the pressure relief device as soon as practicable, but no later than 5 calendar days after each pressure release, except as provided in §60.482-9.

[48 FR 48335, Oct. 18, 1983, as amended at 65 FR 61762, Oct. 17, 2000; 65 FR 78277, Dec. 14, 2000]

**§60.482-5 Standards: Sampling connection systems.**

(a) Each sampling connection system shall be equipped with a closed-purged, closed-loop, or closed-vent system, except as provided in §60.482-1(c). Gases displaced during filling of the sample container are not required to be collected or captured.

(b) Each closed-purge, closed-loop, or closed-vent system as required in paragraph (a) of this section shall comply with the requirements specified in paragraphs (b)(1) through (4) of this section:

(1) Return the purged process fluid directly to the process line; or

(2) Collect and recycle the purged process fluid to a process; or

(3) Be designed and operated to capture and transport all the purged process fluid to a control device that complies with the requirements of §60.482-10; or

(4) Collect, store, and transport the purged process fluid to any of the following systems or facilities:

(i) A waste management unit as defined in 40 CFR 63.111, if the waste management unit is subject to, and operated in compliance with the provisions of 40 CFR part 63, subpart G, applicable to Group 1 wastewater streams;

(ii) A treatment, storage, or disposal facility subject to regulation under 40 CFR part 262, 264, 265, or 266; or

(iii) A facility permitted, licensed, or registered by a State to manage municipal or industrial solid waste, if the process fluids are not hazardous waste as defined in 40 CFR part 261.

(c) In situ sampling systems and sampling systems without purges are exempt from the requirements of paragraphs (a) and (b) of this section.

[60 FR 43258, Aug. 18, 1995, as amended at 65 FR 61762, Oct. 17, 2000; 65 FR 78277, Dec. 14, 2000]

**§60.482-6 Standards: Open-ended valves or lines.**

(a)(1) Each open-ended valve or line shall be equipped with a cap, blind flange, plug, or a second valve, except as provided in §60.482-1(c).

(2) The cap, blind flange, plug, or second valve shall seal the open end at all times except during operations requiring process fluid flow through the open-ended valve or line.

(b) Each open-ended valve or line equipped with a second valve shall be operated in a manner such that the valve on the process fluid end is closed before the second valve is closed.

(c) When a double block-and-bleed system is being used, the bleed valve or line may remain open during operations that require venting the line between the block valves but shall comply with paragraph (a) at all other times.

(d) Open-ended valves or lines in an emergency shutdown system which are designed to open automatically in the event of a process upset are exempt from the requirements of paragraphs (a), (b) and (c) of this section.

(e) Open-ended valves or lines containing materials which would autocatalytically polymerize or would present an explosion, serious overpressure, or other safety hazard if capped or equipped with a double block and bleed system as specified in paragraphs (a) through (c) of this section are exempt from the requirements of paragraphs (a) through (c) of this section.

[48 FR 48335, Oct. 18, 1983, as amended at 49 FR 22607, May 30, 1984; 65 FR 78277, Dec. 14, 2000]

**§60.482-7 Standards: Valves in gas/vapor service in light liquid service.**

(a) Each valve shall be monitored monthly to detect leaks by the methods specified in §60.485(b) and shall comply with paragraphs (b) through (e), except as provided in paragraphs (f), (g), and (h), §60.483-1, 2, and §60.482-1(c).

(b) If an instrument reading of 10,000 ppm or greater is measured, a leak is detected.

(c)(1) Any valve for which a leak is not detected for 2 successive months may be monitored the first month of every quarter, beginning with the next quarter, until a leak is detected.

(2) If a leak is detected, the valve shall be monitored monthly until a leak is not detected for 2 successive months.

(d)(1) When a leak is detected, it shall be repaired as soon as practicable, but no later than 15 calendar days after the leak is detected, except as provided in §60.482-9.

(2) A first attempt at repair shall be made no later than 5 calendar days after each leak is detected.

(e) First attempts at repair include, but are not limited to, the following best practices where practicable:

(1) Tightening of bonnet bolts;

(2) Replacement of bonnet bolts;

(3) Tightening of packing gland nuts;

(4) Injection of lubricant into lubricated packing.

(f) Any valve that is designated, as described in §60.486(e)(2), for no detectable emissions, as indicated by an instrument reading of less than 500 ppm above background, is exempt from the requirements of paragraph (a) if the valve:

(1) Has no external actuating mechanism in contact with the process fluid,

(2) Is operated with emissions less than 500 ppm above background as determined by the method specified in §60.485(c), and

(3) Is tested for compliance with paragraph (f)(2) of this section initially upon designation, annually, and at other times requested by the Administrator.

(g) Any valve that is designated, as described in §60.486(f)(1), as an unsafe-to-monitor valve is exempt from the requirements of paragraph (a) if:

(1) The owner or operator of the valve demonstrates that the valve is unsafe to monitor because monitoring personnel would be exposed to an immediate danger as a consequence of complying with paragraph (a), and

(2) The owner or operator of the valve adheres to a written plan that requires monitoring of the valve as frequently as practicable during safe-to-monitor times.

(h) Any valve that is designated, as described in §60.486(f)(2), as a difficult-to-monitor valve is exempt from the requirements of paragraph (a) if:

(1) The owner or operator of the valve demonstrates that the valve cannot be monitored without elevating the monitoring personnel more than 2 meters above a support surface.

(2) The process unit within which the valve is located either becomes an affected facility through §60.14 or §60.15 or the owner or operator designates less than 3.0 percent of the total number of valves as difficult-to-monitor, and

(3) The owner or operator of the valve follows a written plan that requires monitoring of the valve at least once per calendar year.

[48 FR 48335, Oct. 18, 1983, as amended at 49 FR 22608, May 30, 1984; 65 FR 61762, Oct. 17, 2000]

**§60.482-8 Standards: Pumps and valves in heavy liquid service, pressure relief devices in light liquid or heavy liquid service, and flanges and other connectors.**

(a) If evidence of a potential leak is found by visual, audible, olfactory, or any other detection method at pumps and valves in heavy liquid service, pressure relief devices in light liquid or heavy liquid service, and connectors, the owner or operator shall follow either one of the following procedures:

(1) The owner or operator shall monitor the equipment within 5 days by the method specified in §60.485(b) and shall comply with the requirements of paragraphs (b) through (d) of this section.

(2) The owner or operator shall eliminate the visual, audible, olfactory, or other indication of a potential leak.

(b) If an instrument reading of 10,000 ppm or greater is measured, a leak is detected.

(c)(1) When a leak is detected, it shall be repaired as soon as practicable, but not later than 15 calendar days after it is detected, except as provided in §60.482-9.

(2) The first attempt at repair shall be made no later than 5 calendar days after each leak is detected.

(d) First attempts at repair include, but are not limited to, the best practices described under §60.482-7(e).

[48 CFR 48335, Oct. 18, 1983, as amended at 65 FR 78277, Dec. 14, 2000]

**§0.482-9 Standards: Delay of repair.**

(a) Delay of repair of equipment for which leaks have been detected will be allowed if repair within 15 days is technically infeasible without a process unit shutdown. Repair of this equipment shall occur before the end of the next process unit shutdown.

(b) Delay of repair of equipment will be allowed for equipment which is isolated from the process and which does not remain in VOC service.

(c) Delay of repair for valves will be allowed if:

(1) The owner or operator demonstrates that emissions of purged material resulting from immediate repair are greater than the fugitive emissions likely to result from delay of repair, and

(2) When repair procedures are effected, the purged material is collected and destroyed or recovered in a control device complying with §60.482-10.

(d) Delay of repair for pumps will be allowed if:

(1) Repair requires the use of a dual mechanical seal system that includes a barrier fluid system, and

(2) Repair is completed as soon as practicable, but not later than 6 months after the leak was detected.

(e) Delay of repair beyond a process unit shutdown will be allowed for a valve, if valve assembly replacement is necessary during the process unit shutdown, valve assembly supplies have been depleted, and valve assembly supplies had been sufficiently stocked before the supplies were depleted. Delay of repair beyond the next process unit shutdown will not be allowed unless the next process unit shutdown occurs sooner than 6 months after the first process unit shutdown.

[48 FR 48335, Oct. 18, 1983, as amended at 65 FR 78277, Dec. 14, 2000]

**§60.482-10 Standards: Closed vent systems and control devices.**

(a) Owners or operators of closed vent systems and control devices used to comply with provisions of this subpart shall comply with the provisions of this section.

(b) Vapor recovery systems (for example, condensers and absorbers) shall be designed and operated to recover the VOC emissions vented to them with an efficiency of 95 percent or greater, or to an exit concentration of 20 parts per million by volume, whichever is less stringent.

(c) Enclosed combustion devices shall be designed and operated to reduce the VOC emissions vented to them with an efficiency of 95 percent or greater, or to an exit concentration of 20 parts per million by volume, on a dry basis, corrected to 3 percent oxygen, whichever is less stringent or to provide a minimum residence time of 0.75 seconds at a minimum temperature of 816 °C.

(d) Flares used to comply with this subpart shall comply with the requirements of §60.18.

(e) Owners or operators of control devices 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.

(f) Except as provided in paragraphs (i) through (k) of this section, each closed vent system shall be inspected according to the procedures and schedule specified in paragraphs (f)(1) and (f)(2) of this section.

(1) If the vapor collection system or closed vent system is constructed of hard-piping, the owner or operator shall comply with the requirements specified in paragraphs (f)(1)(i) and (f)(1)(ii) of this section:

(i) Conduct an initial inspection according to the procedures in §60.485(b); and

(ii) Conduct annual visual inspections for visible, audible, or olfactory indications of leaks.

(2) If the vapor collection system or closed vent system is constructed of ductwork, the owner or operator shall:

(i) Conduct an initial inspection according to the procedures in §60.485(b); and

(ii) Conduct annual inspections according to the procedures in §60.485(b).

(g) Leaks, as indicated by an instrument reading greater than 500 parts per million by volume above background or by visual inspections, shall be repaired as soon as practicable except as provided in paragraph (h) of this section.

(1) A first attempt at repair shall be made no later than 5 calendar days after the leak is detected.

(2) Repair shall be completed no later than 15 calendar days after the leak is detected.

(h) Delay of repair of a closed vent system for which leaks have been detected is allowed if the repair is technically infeasible without a process unit shutdown or if the owner or operator determines that emissions resulting from immediate repair would be greater than the fugitive emissions likely to result from delay of repair. Repair of such equipment shall be complete by the end of the next process unit shutdown.

(i) If a vapor collection system or closed vent system is operated under a vacuum, it is exempt from the inspection requirements of paragraphs (f)(1)(i) and (f)(2) of this section.

(j) Any parts of the closed vent system that are designated, as described in paragraph (l)(1) of this section, as unsafe to inspect are exempt from the inspection requirements of paragraphs (f)(1)(i) and (f)(2) of this section if they comply with the requirements specified in paragraphs (j)(1) and (j)(2) of this section:

(1) The owner or operator determines that the equipment is unsafe to inspect because inspecting personnel would be exposed to an imminent or potential danger as a consequence of complying with paragraphs (f)(1)(i) or (f)(2) of this section; and

(2) The owner or operator has a written plan that requires inspection of the equipment as frequently as practicable during safe-to-inspect times.

(k) Any parts of the closed vent system that are designated, as described in paragraph (l)(2) of this section, as difficult to inspect are exempt from the inspection requirements of paragraphs (f)(1)(i) and (f)(2) of this section if they comply with the requirements specified in paragraphs (k)(1) through (k)(3) of this section:

(1) The owner or operator determines that the equipment cannot be inspected without elevating the inspecting personnel more than 2 meters above a support surface; and

(2) The process unit within which the closed vent system is located becomes an affected facility through §60.14 or §60.15, or the owner or operator designates less than 3.0 percent of the total number of closed vent system equipment as difficult to inspect; and

(3) The owner or operator has a written plan that requires inspection of the equipment at least once every 5 years. A closed vent system is exempt from inspection if it is operated under a vacuum.

(l) The owner or operator shall record the information specified in paragraphs (l)(1) through (l)(5) of this section.

(1) Identification of all parts of the closed vent system that are designated as unsafe to inspect, an explanation of why the equipment is unsafe to inspect, and the plan for inspecting the equipment.

(2) Identification of all parts of the closed vent system that are designated as difficult to inspect, an explanation of why the equipment is difficult to inspect, and the plan for inspecting the equipment.

(3) For each inspection during which a leak is detected, a record of the information specified in §60.486(c).

(4) For each inspection conducted in accordance with §60.485(b) during which no leaks are detected, a record that the inspection was performed, the date of the inspection, and a statement that no leaks were detected.

(5) For each visual inspection conducted in accordance with paragraph (f)(1)(ii) of this section during which no leaks are detected, a record that the inspection was performed, the date of the inspection, and a statement that no leaks were detected.

(m) Closed vent systems and control devices used to comply with provisions of this subpart shall be operated at all times when emissions may be vented to them.

[48 FR 48335, Oct. 18, 1983, as amended at 51 FR 2702, Jan. 21, 1986; 60 FR 43258, Aug. 18, 1995; 61 FR 29878, June 12, 1996; 65 FR 78277, Dec. 14, 2000]

**§60.483-1 Alternative standards for valves-allowable percentage of valves leaking.**

(a) An owner or operator may elect to comply with an allowable percentage of valves leaking of equal to or less than 2.0 percent.

(b) The following requirements shall be met if an owner or operator wishes to comply with an allowable percentage of valves leaking:

(1) An owner or operator must notify the Administrator that the owner or operator has elected to comply with the allowable percentage of valves leaking before implementing this alternative standard, as specified in §60.487(b).

(2) A performance test as specified in paragraph (c) of this section shall be conducted initially upon designation, annually, and at other times requested by the Administrator.

(3) If a valve leak is detected, it shall be repaired in accordance with §60.482-7(d) and (e).

(c) Performance tests shall be conducted in the following manner:

(1) All valves in gas/vapor and light liquid service within the affected facility shall be monitored within 1 week by the methods specified in §60.485(b).

(2) If an instrument reading of 10,000 ppm or greater is measured, a leak is detected.

(3) The leak percentage shall be determined by dividing the number of valves for which leaks are detected by the number of valves in gas/vapor and light liquid service within the affected facility.

(d) Owners and operators who elect to comply with this alternative standard shall not have an affected facility with a leak percentage greater than 2.0 percent.

[48 FR 48335, Oct. 18, 1983, as amended at 65 FR 61762, Oct. 17, 2000; 65 FR 78278, Dec. 14, 2000]

**§60.483-2 Alternative standards for valves-skip period leak detection and repair.**

(a)(1) An owner or operator may elect to comply with one of the alternative work practices specified in paragraphs (b)(2) and (3) of this section.

(2) An owner or operator must notify the Administrator before implementing one of the

alternative work practices, as specified in §60.487(b).

(b)(1) An owner or operator shall comply initially with the requirements for valves in gas/vapor service and valves in light liquid service, as described in §60.482-7.

(2) After 2 consecutive quarterly leak detection periods with the percent of valves leaking equal to or less than 2.0, an owner or operator may begin to skip 1 of the quarterly leak detection periods for the valves in gas/vapor and light liquid service.

(3) After 5 consecutive quarterly leak detection periods with the percent of valves leaking equal to or less than 2.0, an owner or operator may begin to skip 3 of the quarterly leak detection periods for the valves in gas/vapor and light liquid service.

(4) If the percent of valves leaking is greater than 2.0, the owner or operator shall comply with the requirements as described in §60.482-7 but can again elect to use this section.

(5) The percent of valves leaking shall be determined by dividing the sum of valves found leaking during current monitoring and valves for which repair has been delayed by the total number of valves subject to the requirements of this section.

(6) An owner or operator must keep a record of the percent of valves found leaking during each leak detection period.

[48 FR 48335, Oct. 18, 1983, as amended at 65 FR 61762, Oct. 17, 2000; 65 FR 78278, Dec. 14, 2000]

**§60.484 Equivalence of means of emission limitation.**

(a) Each owner or operator subject to the provisions of this subpart may apply to the Administrator for determination of equivalence for any means of emission limitation that achieves a reduction in emissions of VOC at least equivalent to the reduction in emissions of VOC achieved by the controls required in this subpart.

(b) Determination of equivalence to the equipment, design, and operational requirements of this subpart will be evaluated by the following guidelines:

(1) Each owner or operator applying for an equivalence determination shall be responsible for collecting and verifying test data to demonstrate equivalence of means of emission limitation.

(2) The Administrator will compare test data for the means of emission limitation to test data for the equipment, design, and operational requirements.

(3) The Administrator may condition the approval of equivalence on requirements that may be necessary to assure operation and maintenance to achieve the same emission reduction as the equipment, design, and operational requirements.

(c) Determination of equivalence to the required work practices in this subpart will be evaluated by the following guidelines:

(1) Each owner or operator applying for a determination of equivalence shall be responsible for collecting and verifying test data to demonstrate equivalence of an equivalent means of emission limitation.

(2) For each affected facility for which a determination of equivalence is requested, the emission reduction achieved by the required work practice shall be demonstrated.

(3) For each affected facility, for which a determination of equivalence is requested, the emission reduction achieved by the equivalent means of emission limitation shall be demonstrated.

(4) Each owner or operator applying for a determination of equivalence shall commit in writing to work practice(s) that provide for emission reductions equal to or greater than the emission reductions achieved by the required work practice.

(5) The Administrator will compare the demonstrated emission reduction for the equivalent means of emission limitation to the demonstrated emission reduction for the required work practices and will consider the commitment in paragraph (c)(4).

(6) The Administrator may condition the approval of equivalence on requirements that may be necessary to assure operation and maintenance to achieve the same emission reduction as the required work practice.

(d) An owner or operator may offer a unique approach to demonstrate the equivalence of any equivalent means of emission limitation.

(e)(1) After a request for determination of equivalence is received, the Administrator will publish a notice in the *Federal Register* and provide the opportunity for public hearing if the Administrator judges that the request may be approved.

(2) After notice and opportunity for public hearing, the Administrator will determine the equivalence of a means of emission limitation and will publish the determination in the *Federal Register*.

(3) Any equivalent means of emission limitations approved under this section shall constitute a required work practice, equipment, design, or operational standard within the meaning of section 111(h)(1) of the Clean Air Act.

(f)(1) Manufacturers of equipment used to control equipment leaks of VOC may apply to the Administrator for determination of equivalence for any equivalent means of emission limitation that achieves a reduction in emissions of VOC achieved by the equipment, design, and operational requirements of this subpart.

(2) The Administrator will make an equivalence determination according to the provisions of paragraphs (b), (c), (d), and (e) of this section.

[48 FR 48335, Oct. 18, 1983, as amended at 65 FR 61762, Oct. 17, 2000]

**§60.485 Test methods and procedures.**

(a) In conducting the performance tests required in §60.8, the owner or operator shall use as reference methods and procedures the test methods in appendix A of this part or other methods and procedures as specified in this section, except as provided in §60.8(b).

(b) The owner or operator shall determine compliance with the standards in §§60.482, 60.483, and 60.484 as follows:

(1) Method 21 shall be used to determine the presence of leaking sources. The instrument shall be calibrated before use each day of its use by the procedures specified in Method 21. The following calibration gases shall be used:

(i) Zero air (less than 10 ppm of hydrocarbon in air); and

(ii) A mixture of methane or n-hexane and air at a concentration of about, but less than, 10,000 ppm methane or n-hexane.

(c) The owner or operator shall determine compliance with the no detectable emission standards in §§60.482-2(e), 60.482-3(i), 60.482-4, 60.482-7(f), and 60.482-10(e) as follows:

(1) The requirements of paragraph (b) shall apply.

(2) Method 21 shall be used to determine the background level. All potential leak interfaces shall be traversed as close to the interface as possible. The arithmetic difference between the maximum concentration indicated by the instrument and the background level is compared with 500 ppm for determining compliance.

(d) The owner or operator shall test each piece of equipment unless he demonstrates that a process unit is not in VOC series, i.e., that the VOC content would never be reasonably expected to exceed 10 percent by weight. For purposes of this demonstration, the following methods and procedures shall be used:

(1) Procedures that conform to the general methods in ASTM E260-73, 91, or 96, E168-67, 77, or 92, E169-63, 77, or 93 (incorporated by reference -- see §60.17) shall be used to determine the percent VOC content in the process fluid that is contained in or contacts a piece of equipment.

(2) Organic compounds that are considered by the Administrator to have negligible photochemical reactivity may be excluded from the total quantity of organic compounds in determining the VOC content of the process fluid.

(3) Engineering judgment may be used to estimate the VOC content, if a piece of equipment had not been shown previously to be in service. If the Administrator disagrees with the judgment, paragraphs (d) (1) and (2) of this section shall be used to resolve the disagreement.

(e) The owner or operator shall demonstrate that an equipment is in light liquid service by showing that all the following conditions apply:

(1) The vapor pressure of one or more of the components is greater than 0.3 kPa at 20 °C (1.2 in. $H_2O$ at 68 °F). Standard reference texts or ASTM D2879-83, 96, or 97 (incorporated by reference -- see §60.17) shall be used to determine the vapor pressures.

(2) The total concentration of the pure components having a vapor pressure greater than 0.3 kPa at 20 °C (1.2 in. $H_2O$ at 68 °F) is equal to or greater than 20 percent by weight.

(3) The fluid is a liquid at operating conditions.

(f) Samples used in conjunction with paragraphs (d), (e), and (g) of this section shall be representative of the process fluid that is contained in or contacts the equipment or the gas being combusted in the flare.

(g) The owner or operator shall determine compliance with the standards of flares as follows:

(1) Method 22 shall be used to determine visible emissions.

(2) A thermocouple or any other equivalent device shall be used to monitor the presence of a pilot flame in the flare.

(3) The maximum permitted velocity for air assisted flares shall be computed using the following equation:

$$V_{max} = K_1 + K_2 H_T$$

Where:

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

$H_T$ = Net heating value of the gas being combusted, MJ/scm (Btu/scf).

$K_1$ = 8.706 m/sec (metric units)

= 28.56 ft/sec (English units)

$K_2$ = 0.7084 $m^4$/(MJ-sec) (metric units)

= 0.087 $ft^4$/(Btu-sec) (English units)

(4) The net heating value ($H_T$) of the gas being combusted in a flare shall be computed using the following equation:

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

Where:

K = Conversion constant, $1.740 \times 10^7$ (g-mole)(MJ)/(ppm-scm-kcal) (metric units)

= $4.674 \times 10^8$ [(g-mole)(Btu)/(ppm-scf-kcal)] (English units)

$C_i$ = Concentration of sample component "i," ppm.

$H_i$ = net heat of combustion of sample component "i" at 25 °C and 760 mm Hg (77 °F and 14.7 psi), kcal/g-mole

(5) Method 18 and ASTM D2504-67, 77, or 88 (Reapproved 1993) (incorporated by reference -- see §60.17) shall be used to determine the concentration of sample component "i."

(6) ASTM D2382-76 or 88 or D4809-95 (incorporated by reference -- see §60.17) shall be used to determine the net heat of combustion of component "I" if published values are not available or cannot be calculated.

(7) Method 2, 2A, 2C, or 2D, as appropriate, shall be used to determine the actual exit velocity of a flare. If needed, the unobstructed (free) cross-sectional area of the flare tip shall be used.

[54 FR 6678, Feb. 14, 1989, as amended at 54 FR 27016, June 27, 1989; 65 FR 61763, Oct. 17, 2000]

**§60.486 Recordkeeping requirements.**

(a)(1) Each owner or operator subject to the provisions of this subpart shall comply with the recordkeeping requirements of this section.

(2) An owner or operator of more than one affected facility subject to the provisions of this subpart may comply with the recordkeeping requirements for these facilities in one recordkeeping system if the system identifies each record by each facility.

(b) When each leak is detected as specified in §§60.482-2, 60.482-3, 60.482-7, 60.482-8, and 60.483-2, the following requirements apply:

(1) A weatherproof and readily visible identification, marked with the equipment identification number, shall be attached to the leaking equipment.

(2) The identification on a valve may be removed after it has been monitored for 2 successive months as specified in §60.482-7(c) and no leak has been detected during those 2 months.

(3) The identification on equipment except on a valve, may be removed after it has been repaired.

(c) When each leak is detected as specified in §§60.482-2, 60.482-3, 60.482-7, 60.482-8, and 60.483-2, the following information shall be recorded in a log and shall be kept for 2 years in a readily accessible location:

(1) The instrument and operator identification numbers and the equipment identification number.

(2) The date the leak was detected and the dates of each attempt to repair the leak.

(3) Repair methods applied in each attempt to repair the leak.

(4) "Above 10,000" if the maximum instrument reading measured by the methods specified in §60.485(a) after each repair attempt is equal to or greater than 10,000 ppm.

(5) "Repair delayed" and the reason for the delay if a leak is not repaired within 15 calendar days after discovery of the leak.

(6) The signature of the owner or operator (or designate) whose decision it was that repair could not be effected without a process shutdown.

(7) The expected date of successful repair of the leak if a leak is not repaired within 15 days.

(8) Dates of process unit shutdown that occur while the equipment is unrepaired.

(9) The date of successful repair of the leak.

(d) The following information pertaining to the design requirements for closed vent systems and control devices described in §60.482-10 shall be recorded and kept in a readily accessible location:

(1) Detailed schematics, design specifications, and piping and instrumentation diagrams.

(2) The dates and descriptions of any changes in the design specifications.

(3) A description of the parameter or parameters monitored, as required in §60.482-10(e), to ensure that control devices are operated and maintained in conformance with their design and an explanation of why that parameter (or parameters) was selected for the monitoring.

(4) Periods when the closed vent systems and control devices required in §§60.482-2, 60.482-3, 60.482-4, and 60.482-5 are not operated as designed, including periods when a flare pilot light does not have a flame.

(5) Dates of startups and shutdowns of the closed vent systems and control devices required in §§60.482-2, 60.482-3, 60.482-4, and 60.482-5.

(e) The following information pertaining to all equipment subject to the requirements in §§60.482-1 to 60.482-10 shall be recorded in a log that is kept in a readily accessible location:

(1) A list of identification numbers for equipment subject to the requirements of this subpart.

(2)(i) A list of identification numbers for equipment that are designated for no detectable emissions under the provisions of §§60.482-2(e), 60.482-3(i) and 60.482-7(f).

(ii) The designation of equipment as subject to the requirements of §60.482-2(e), §60.482-3(i), or §60.482-7(f) shall be signed by the owner or operator.

(3) A list of equipment identification numbers for pressure relief devices required to comply with §60.482-4.

(4)(i) The dates of each compliance test as required in §§60.482-2(e), 60.482-3(i), 60.482-4, and 60.482-7(f).

(ii) The background level measured during each compliance test.

(iii) The maximum instrument reading measured at the equipment during each compliance test.

(5) A list of identification numbers for equipment in vacuum service.

(f) The following information pertaining to all valves subject to the requirements of §60.482-7(g) and (h) and to all pumps subject to the requirements of §60.482-2(g) shall be recorded in a log that is kept in a readily accessible location:

(1) A list of identification numbers for valves and pumps that are designated as unsafe-to-monitor, an explanation for each valve or pump stating why the valve or pump is unsafe-to-monitor, and the plan for monitoring each valve or pump.

(2) A list of identification numbers for valves that are designated as difficult-to-monitor, an explanation for each valve stating why the valve is difficult-to-monitor, and the schedule for monitoring each valve.

(g) The following information shall be recorded for valves complying with §60.483-2:

(1) A schedule of monitoring.

(2) The percent of valves found leaking during each monitoring period.

(h) The following information shall be recorded in a log that is kept in a readily accessible location:

(1) Design criterion required in §§60.482-2(d)(5) and 60.482-3(e)(2) and explanation of the design criterion; and

(2) Any changes to this criterion and the reasons for the changes.

(i) The following information shall be recorded in a log that is kept in a readily accessible location for use in determining exemptions as provided in §60.480(d):

(1) An analysis demonstrating the design capacity of the affected facility,

(2) A statement listing the feed or raw materials and products from the affected facilities and an analysis demonstrating whether these chemicals are heavy liquids or beverage alcohol, and

(3) An analysis demonstrating that equipment is not in VOC service.

(j) Information and data used to demonstrate that a piece of equipment is not in VOC service shall be recorded in a log that is kept in a readily accessible location.

(k) The provisions of §60.7 (b) and (d) do not apply to affected facilities subject to this subpart.

[48 FR 48335, Oct. 18, 1983, as amended at 65 FR 61763, Oct. 17, 2000; 65 FR 78278, Dec. 14, 2000]

**§60.487 Reporting requirements.**

(a) Each owner or operator subject to the provisions of this subpart shall submit semi-annual reports to the Administrator beginning six months after the initial startup date.

(b) The initial semiannual report to the Administrator shall include the following information:

(1) Process unit identification.

(2) Number of valves subject to the requirements of §60.482-7, excluding those valves designated for no detectable emissions under the provisions of §60.482-7(f).

(3) Number of pumps subject to the requirements of §60.482-2, excluding those pumps designated for no detectable emissions under the provisions of §60.482-2(e) and those pumps complying with §60.482-2(f).

(4) Number of compressors subject to the requirements of §60.482-3, excluding those compressors designated for no detectable emissions under the provisions of §60.482-3(i) and those compressors complying with §60.482-3(h).

(c) All semiannual reports to the Administrator shall include the following information, summarized from the information in §60.486:

(1) Process unit identification.

(2) For each month during the semiannual reporting period,

(i) Number of valves for which leaks were detected as described in §60.482(7)(b) or §60.483-2,

(ii) Number of valves for which leaks were not repaired as required in §60.482-7(d)(1),

(iii) Number of pumps for which leaks were detected as described in §60.482-2(b) and (d)(6)(i),

(iv) Number of pumps for which leaks were not repaired as required in §60.482-2(c)(1) and (d)(6)(ii),

(v) Number of compressors for which leaks were detected as described in §60.482-3(f),

(vi) Number of compressors for which leaks were not repaired as required in §60.482-3(g)(1), and

(vii) The facts that explain each delay of repair and, where appropriate, why a process unit shutdown was technically infeasible.

(3) Dates of process unit shutdowns which occurred within the semiannual reporting period.

(4) Revisions to items reported according to paragraph (b) if changes have occurred since the initial report or subsequent revisions to the initial report.

(d) An owner or operator electing to comply with the provisions of §§60.483-1 and 60.483-2 shall notify the Administrator of the alternative standard selected 90 days before implementing either of the provisions.

(e) An owner or operator shall report the results of all performance tests in accordance with §60.8 of the General Provisions. The provisions of §60.8(d) do not apply to affected facilities subject to the provisions of this subpart except that an owner or operator must notify the Administrator of the schedule for the initial performance tests at least 30 days before the initial performance tests.

(f) The requirements of paragraphs (a) through (c) of this section remain in force until and unless EPA, in delegating enforcement authority to a State under section 111(c) of the Act, approves reporting requirements or an alternative means of compliance surveillance adopted by such State. In that event, affected sources within the State will be relieved of the obligation to comply with the requirements of paragraphs (a) through (c) of this section, provided that they comply with the requirements established by the State.

[48 FR 48335, Oct. 18, 1983, as amended at 49 FR 22608, May 30, 1984; 65 FR 61763, Oct. 17, 2000]

**§60.488 Reconstruction.**

For the purposes of this subpart:

(a) The cost of the following frequently replaced components of the facility shall not be considered in calculating either the "fixed capital cost of the new components" or the "fixed capital costs that would be required to construct a comparable new facility" under §60.15: pump seals, nuts and bolts, rupture disks, and packings.

(b) Under §60.15, the "fixed capital cost of new components" includes the fixed capital cost of all depreciable components (except components specified in §60.488 (a)) which are or will be replaced pursuant to all continuous programs of component replacement which are commenced within any 2-year period following the applicability date for the appropriate subpart. (See the "Applicability and designation of affected facility" section of the appropriate subpart.) For purposes of this paragraph, "commenced" means that an owner or operator has undertaken a continuous program of component replacement or that an owner or operator has entered into a contractual obligation to undertake and complete, within a reasonable time, a continuous program of component replacement.

[49 FR 22608, May 30, 1984]

**§60.489 List of chemicals produced by affected facilities.**

(a) The following chemicals are produced, as intermediates or final products, by process units covered under this subpart. The applicability date for process units producing one or more of these chemicals is January 5, 1981

| CAS No.[a] | Chemical | CAS No.[a] | Chemical | CAS No.[a] | Chemical |
|---|---|---|---|---|---|
| 105-57-7 | Acetal. | 67-64-1 | Acetone. | 79-06-1 | Acrylamide. |
| 75-07-0 | Acetaldehyde. | 75-86-5 | Acetone cyanohydrin. | 79-10-7 | Acrylic acid. |
| 107-89-1 | Acetaldol. | 75-05-8 | Acetonitrile. | 107-13-1 | Acrylonitrile. |
| 60-35-5 | Acetamide. | 98-86-2 | Acetophenone. | 124-04-9 | Adipic acid. |
| 103-84-4 | Acetanilide. | 75-36-5 | Acetyl chloride. | 111-69-3 | Adiponitrile. |
| 64-19-7 | Acetic acid. | 74-86-2 | Acetylene. | (b)............. | Alkyl naphthalenes. |
| 108-24-7 | Acetic anhydride. | 107-02-8 | Acrolein. | 107-18-6 | Allyl alcohol. |

| CAS No.[a] | Chemical |
|---|---|
| 107-05-1 | Allyl chloride. |
| 1321-11-5 | Aminobenzoic acid. |
| 111-41-1 | Aminoethylethanolamine. |
| 123-30-8 | p-Aminophenol. |
| 628-63-7, 123-92-2. | Amyl acetates. |
| 71-41-0(c) | Amyl alcohols. |
| 110-58-7 | Amyl amine. |
| 543-59-9 | Amyl chloride. |
| 110-66-7(c) | Amyl mercaptans. |
| 1322-06-1 | Amyl phenol. |
| 62-53-3 | Aniline. |
| 142-04-1 | Aniline hydrochloride. |
| 29191-52-4 | Anisidine. |
| 100-66-3 | Anisole. |
| 118-92-3 | Anthranilic acid. |
| 84-65-1 | Anthraquinone. |
| 100-52-7 | Benzaldehyde. |
| 55-21-0 | Benzamide. |
| 71-43-2 | Benzene. |
| 98-48-6 | Benzenedisulfonic acid. |
| 98-11-3 | Benzenesulfonic acid. |
| 134-81-6 | Benzil. |
| 76-93-7 | Benzilic acid. |
| 65-85-0 | Benzoic acid. |
| 119-53-9 | Benzoin. |
| 100-47-0 | Benzonitrile. |
| 119-61-9 | Benzophenone. |
| 98-07-7 | Benzotrichloride. |
| 98-88-4 | Benzoyl chloride. |
| 100-51-6 | Benzyl alcohol. |
| 100-46-9 | Benzylamine. |
| 120-51-4 | Benzyl benzoate. |
| 100-44-7 | Benzyl chloride. |
| 98-87-3 | Benzyl dichloride. |
| 92-52-4 | Biphenyl. |
| 80-05-7 | Bisphenol A. |
| 10-86-1 | Bromobenzene. |
| 27497-51-4 | Bromonaphthalene. |
| 106-99-0 | Butadiene. |
| 106-98-9 | 1-butene. |
| 123-86-4 | n-butyl acetate. |
| 141-32-2 | n-butyl acrylate. |
| 71-36-3 | n-butyl alcohol. |
| 78-92-2 | s-butyl alcohol. |
| 75-65-0 | t-butyl alcohol. |
| 109-73-9 | n-butylamine. |
| 13952-84-6 | s-butylamine. |
| 75-64-9 | t-butylamine. |
| 98-73-7 | p-tert-butyl benzoic acid. |
| 107-88-0 | 1,3-butylene glycol. |
| 123-72-8 | n-butyraldehyde. |
| 107-92-6 | Butyric acid. |
| 106-31-0 | Butyric anhydride. |
| 109-74-0 | Butyronitrile. |
| 105-60-2 | Caprolactam. |
| 75-1-50 | Carbon disulfide. |
| 558-13-4 | Carbon tetrabromide. |
| 56-23-5 | Carbon tetrachloride. |
| 9004-35-7 | Cellulose acetate. |
| 79-11-8 | Chloroacetic acid. |
| 108-42-9 | m-chloroaniline. |
| 95-51-2 | o-chloroaniline. |
| 106-47-8 | p-chloroaniline. |
| 35913-09-8 | Chlorobenzaldehyde. |
| 108-90-7 | Chlorobenzene. |
| 118-91-2, 535-80-8, 74-11-3(c). | Chlorobenzoic acid. |
| 2136-81-4, 2136-89-2, 5216-25-1(c) | Chlorobenzotrichloride. |
| 1321-03-5 | Chlorbenzoyl chloride. |
| 25497-29-4 | Chlorodifluoromethane. |
| 75-45-6 | Chlorodifluoroethane. |
| 67-66-3 | Chloroform. |
| 25586-43-0 | Chloronapthalene. |
| 88-73-3 | o-chloronitrobenzene. |
| 100-00-5 | p-chloronitrobenzene. |
| 25167-80-0 | Chlorophenols. |
| 126-99-8 | Chloroprene. |
| 7790-94-5 | Chlorosulfonic acid. |
| 108-41-8 | m-chlorotoluene. |
| 95-49-8 | o-chlorotoluene. |
| 106-43-4 | p-chlorotoluene. |
| 75-72-9 | Chlorotrifluoromethane. |
| 108-39-4 | m-cresol. |
| 95-48-7 | o-cresol. |
| 106-44-5 | p-cresol. |
| 1319-77-3 | Mixed cresols. |
| 1319-77-3 | Cresylic acid. |
| 4170-30-0 | Crotonaldehyde. |
| 3724-65-0 | Crotonic acid. |
| 98-82-8 | Cumene. |
| 80-15-9 | Cumene hydroperoxide. |
| 372-09-8 | Cyanoacetic acid. |
| 506-77-4 | Cyanogen chloride. |
| 108-80-5 | Cyanuric acid. |
| 108-77-0 | Cyanuric chloride. |
| 110-82-7 | Cyclohexane. |
| 108-93-0 | Cyclohexanol. |
| 108-94-1 | Cyclohexanone. |
| 110-83-8 | Cyclohexene. |
| 108-91-8 | Cyclohexylamine. |
| 111-78-4 | Cyclooctadiene. |
| 112-30-1 | Decanol. |
| 123-42-2 | Diacetone alcohol. |
| 27576-04-1 | Diaminobenzoic acid. |
| 95-76-1, 95-82-9, 554-00-7, 608-27-5, 608-31-1, 626-43-7, 27134-27-6, 57311-92-9(c) | Dichloroaniline. |
| 541-73-1 | m-dichlorobenzene. |
| 95-50-1 | o-dichlorobenzene. |
| 106-46-7 | p-dichlorobenzene. |
| 75-71-8 | Dichlorodifluoromethane. |
| 111-44-4 | Dichloroethyl ether. |
| 107-06-2 | 1,2-dichloroethane (EDC). |
| 96-23-1 | Dichlorohydrin. |
| 26952-23-8 | Dichloropropene. |
| 101-83-7 | Dicyclohexylamine. |
| 109-89-7 | Diethylamine. |
| 111-46-6 | Diethylene glycol. |
| 112-36-7 | Diethylene glycol diethyl ether. |
| 111-96-6 | Diethylene glycol dimethyl ether. |
| 112-34-5 | Diethylene glycol monobutyl ether. |
| 124-17-7 | Diethylene glycol monobutyl ether acetate. |
| 111-90-0 | Diethylene glycol monoethyl ether. |
| 112-15-2 | Diethylene glycol monoethyl ether acetate. |
| 111-77-3 | Diethylene glycol monomethyl ether. |
| 64-67-5 | Diethyl sulfate. |
| 75-37-6 | Difluoroethane. |
| 25167-70-8 | Diisobutylene. |
| 26761-40-0 | Diisodecyl phthalate. |
| 27554-26-3 | Diisooctyl phthalate. |
| 674-82-8 | Diketene. |
| 124-40-3 | Dimethylamine. |
| 121-69-7 | N,N-dimethylaniline. |
| 115-10-6 | N,N-dimethyl ether. |
| 68-12-2 | N,N-dimethylformamide. |
| 57-14-7 | Dimethylhydrazine. |
| 77-78-1 | Dimethyl sulfate. |
| 75-18-3 | Dimethyl sulfide. |
| 67-68-5 | Dimethyl sulfoxide. |
| 120-61-6 | Dimethyl terephthalate. |
| 99-34-3 | 3,5-dinitrobenzoic acid. |
| 51-28-5 | Dinitrophenol. |
| 25321-14-6 | Dinitrotoluene. |
| 123-91-1 | Dioxane. |
| 646-06-0 | Dioxilane. |
| 122-39-4 | Diphenylamine. |
| 101-84-8 | Diphenyl oxide. |
| 102-08-9 | Diphenyl thiourea. |
| 25265-71-8 | Dipropylene glycol. |
| 25378-22-7 | Dodecene. |
| 28675-17-4 | Dodecylaniline. |
| 27193-86-8 | Dodecylphenol. |
| 106-89-8 | Epichlorohydrin. |
| 64-17-5 | Ethanol. |
| 141-43-5(c) | Ethanolamines. |
| 141-78-6 | Ethyl acetate. |
| 141-97-9 | Ethyl acetoacetate. |
| 140-88-5 | Ethyl acrylate. |
| 75-04-7 | Ethylamine. |
| 100-41-4 | Ethylbenzene. |
| 74-96-4 | Ethyl bromide. |
| 9004-57-3 | Ethylcellulose. |
| 75-00-3 | Ethyl chloride. |
| 105-39-5 | Ethyl chloroacetate. |
| 105-56-6 | Ethylcyanoacetate. |
| 74-85-1 | Ethylene. |
| 96-49-1 | Ethylne carbonate. |
| 107-07-3 | Ethylene chlorohydrin. |
| 107-15-3 | Ethylenediamine. |
| 106-93-4 | Ethylene dibromide. |
| 107-21-1 | Ethylene glycol. |
| 111-55-7 | Ethylene glycol diacetate. |
| 110-71-4 | Ethylene glycol dimethyl ether |
| 111-76-2 | Ethylene glycol monobutyl ether |
| 112-07-2 | Ethylene glycol monobutyl ether acetate. |
| 110-80-5 | Ethylene glycol monoethy ether |
| 111-15-9 | Ethylene glycol monethyl ether acetate. |
| 109-86-4 | Ethylene glycol monomethyl ether. |
| 110-49-6 | Ethylene glycol monomethyl ether acetate. |
| 122-99-6 | Ethylene glycol monophenyl ether. |
| 2807-30-9 | Ethylene glycol monopropyl ether. |
| 75-21-8 | Ethylene oxide. |
| 60-29-7 | Ethyl ether |

| CAS No.[a] | Chemical | CAS No.[a] | Chemical | CAS No.[a] | Chemical |
|---|---|---|---|---|---|
| 104-76-7 | 2-ethylhexanol. | 80-62-6 | Methyl methacrylate. | 139-02-6 | Sodium phenate. |
| 122-51-0 | Ethyl orthoformate. | 77-75-8 | Methylpentynol. | 110-44-1 | Sorbic acid. |
| 95-92-1 | Ethyl oxalate. | 98-83-9 | a-methylstyrene. | 100-42-5 | Styrene. |
| 41892-71-1 | Ethyl sodium oxalacetate. | 110-91-8 | Morpholine. | 110-15-6 | Succinic acid. |
| 50-00-0 | Formaldehyde. | 85-47-2 | a-naphthalene sulfonic acid. | 110-61-2 | Succinonitrile. |
| 75-12-7 | Formamide. | 120-18-3 | b-naphthalene sulfonic acid. | 121-57-3 | Sulfanilic acid. |
| 64-18-6 | Formic acid. | 90-15-3 | a-naphthol. | 126-33-0 | Sulfolane. |
| 110-17-8 | Fumaric acid | 135-19-3 | b-naphthol. | 1401-55-4 | Tannic acid. |
| 98-01-1 | Furfural. | 75-98-9 | Neopentanoic acid. | 100-21-0 | Terephthalic acid. |
| 56-81-5 | Glycerol. | 88-74-4 | o-nitroaniline. | 79-34-5(c) | Tetrachloroethanes. |
| 26545-73-7 | Glycerol dichlorohydrin. | 100-01-6 | p-nitroaniline. | 117-08-8 | Tetrachlorophthalic anhydride. |
| 25791-96-2 | Glycerol triether. | 91-23-6 | o-nitroanisole. | 78-00-2 | Tetraethyl lead. |
| 56-40-6 | Glycine. | 100-17-4 | p-nitroanisole. | 119-64-2 | Tetrahydronapthalene. |
| 107-22-2 | Glyoxal. | 98-95-3 | Nitrobenzene. | 85-43-8 | Tetrahydrophthalic anhydride. |
| 118-74-1 | Hexachlorobenzene. | 27178-83-2(c) | Nitrobenzoic acid (o, m, and p) | 75-74-1 | Tetramethyl lead. |
| 67-72-1 | Hexachloroethane. | 79-24-3 | Nitroethane. | 110-60-1 | Tetramethylenediamine. |
| 36653-82-4 | Hexadecyl alcohol. | 75-52-5 | Nitromethane. | 110-18-9 | Tetramethylethylenediamine |
| 124-09-4 | Hexamethylenediamine. | 88-75-5 | 2-Nitrophenol. | 108-88-3 | Toluene. |
| 629-11-8 | Hexamethylene glycol. | 25322-01-4 | Nitropropane. | 95-80-7 | Toluene-2,4-diamine. |
| 100-97-0 | Hexamethylenetetramine. | 1321-12-6 | Nitrotoluene. | 584-84-9 | Toluene-2,4-diisocyanate. |
| 74-90-8 | Hydrogen cyanide. | 27215-95-8 | Nonene. | 26471-62-5 | Toluene diisocyanates (mixture) |
| 123-31-9 | Hydroquinone. | 25154-52-3 | Nonylphenol. | 1333-07-9 | Toluenesulfonamide. |
| 99-96-7 | p-hydroxybenzoic acid. | 27193-28-8 | Octylphenol. | 104-15-4(c) | Toluenesulfonic acids. |
| 26760-64-5 | Isoamylene. | 123-63-7 | Paraldehyde. | 98-59-9 | Toluenesulfonyl chloride. |
| 78-83-1 | Isobutanol. | 115-77-5 | Pentaerythritol. | 26915-12-8 | Toluidines. |
| 110-19-0 | Isobutyl acetate. | 109-66-0 | n-pentane. | 87-61-6, 108-70-3, 120-82-1(c) | Trichlorobenzenes. |
| 115-11-7 | Isobutylene. | 109-67-1 | 1-pentene | | |
| 78-84-2 | Isobutyraldehyde. | 127-18-4 | Perchloroethylene. | | |
| 79-31-2 | Isobutyric acid. | 594-42-3 | Perchloromethyl mercaptan. | 71-55-6 | 1,1,1-trichloroethane. |
| 25339-17-7 | Isodecanol. | 94-70-2 | o-phenetidine. | 79-00-5 | 1,1,2-trichloroethane. |
| 26952-21-6 | Isooctyl alcohol. | 156-43-4 | p-phenetidine. | 79-01-6 | Trichloroethylene. |
| 78-78-4 | Isopentane. | 108-95-2 | Phenol. | 75-69-4 | Trichlorofluoromethane. |
| 78-59-1 | Isophorone. | 98-67-9, 585-38-6, 609-46-1, 1333-39-7(c) | Phenolsulfonic acids. | 96-18-4 | 1,2,3-trichloropropane. |
| 121-91-5 | Isophthalic acid. | | | 76-13-1 | 1,1,2-trichloro-1,2,2-trifluoro ethane |
| 78-79-5 | Isoprene. | | | | |
| 67-63-0 | Isopropanol. | | | 121-44-8 | Triethylamine. |
| 108-21-4 | Isopropyl acetate. | 91-40-7 | Phenyl anthranilic acid. | 112-27-6 | Triethylene glycol. |
| 75-31-0 | Isopropylamine. | (b).............. | Phenylenediamine. | 112-49-2 | Triethylene glycol dimethyl ether |
| 75-29-6 | Isopropyl chloride. | 75-44-5 | Phosgene. | 7756-94-7 | Triisobutylene. |
| 25168-06-3 | Isopropylphenol. | 85-44-9 | Phthalic anhydride. | 75-50-3 | Trimethylamine. |
| 463-51-4 | Ketene. | 85-41-6 | Phthalimide. | 57-13-6 | Urea. |
| (b)............... | Linear alkyl sulfonate. | 108-99-6 | b-picoline. | 108-05-4 | Vinyl acetate. |
| 123-01-3 | Linear alkylbenzene (linear dodecylbenzene). | 110-85-0 | Piperazine. | 75-01-4 | Vinyl chloride. |
| | | 9003-29-6, 25036-29-7(c) | Polybutenes. | 75-35-4 | Vinylidene chloride. |
| 110-16-7 | Maleic acid. | | | 25013-15-4 | Vinyl toluene. |
| 108-31-6 | Maleic anhydride. | | | 1330-20-7 | Xylenes (mixed). |
| 6915-15-7 | Malic acid. | 25322-68-3 | Polyethylene glycol. | 95-47-6 | o-xylene. |
| 141-79-7 | Mesityl oxide. | 25322-69-4 | Polypropylene glycol. | 106-42-3 | p-xylene. |
| 121-47-1 | Metanilic acid. | 123-38-6 | Propional dehyde. | 1300-71-6 | Xylenol. |
| 79-41-4 | Methacrylic acid. | 79-09-4 | Propionic acid. | 1300-73-8 | Xylidine. |
| 563-47-3 | Methallyl chloride. | 71-23-8 | n-propyl alcohol. | | |
| 67-56-1 | Methanol. | 107-10-8 | Propylamine. | | |
| 79-20-9 | Methyl acetate. | 540-54-5 | Propyl chloride. | | |
| 105-45-3 | Methyl acetoacetate. | 115-07-1 | Propylene. | | |
| 74-89-5 | Methylamine. | 127-00-4 | Propylene chlorohydrin. | | |
| 100-61-8 | n-methylaniline. | 78-87-5 | Propylene dichloride. | | |
| 74-83-9 | Methyl bromide. | 57-55-6 | Propylene glycol. | | |
| 37365-71-2 | Methyl butynol. | 75-56-9 | Propylene oxide. | | |
| 74-87-3 | Methyl chloride. | 110-86-1 | Pyridine. | | |
| 108-87-2 | Methylcyclohexane. | 106-51-4 | Quinone. | | |
| 1331-22-2 | Methylcyclohexanone. | 108-46-3 | Resorcinol. | | |
| 75-09-2 | Methylene chloride. | 27138-57-4 | Resorcylic acid. | | |
| 101-77-9 | Methylene dianiline. | 69-72-7 | Salicylic acid. | | |
| 101-68-8 | Methylene diphenyl deisocyanate | 127-09-3 | Sodium acetate. | | |
| 78-93-3 | Methyl ethyl ketone. | 532-32-1 | Sodium benzoate. | | |
| 107-31-3 | Methyl formate. | 9004-32-4 | Sodium carboxymethyl cellulose | | |
| 108-11-2 | Methyl isobutyl carbinol. | 3926-62-3 | Sodium chloroacetate. | | |
| 108-10-1 | Methyl isobutyl ketone. | 141-53-7 | Sodium formate. | | |

(a) CAS numbers refer to the Chemical Abstracts Registry numbers assigned to specific chemicals, isomers, or mixtures of chemicals. Some isomers or mixtures that are covered by the standards do not have CAS numbers assigned to them. The standards apply to all of the chemicals listed, whether CAS numbers have been assigned or not.

(b) No CAS number(s) have been assigned to this chemical, its isomers, or mixtures containing these chemicals.

(c) CAS numbers for some of the isomers are listed; the standards apply to all of the isomers and mixtures, even if CAS numbers have not been assigned.

[48 FR 48335, Oct. 18, 1983, as amended at 65 FR 61763, Oct. 17, 2000

APPENDIX G

WAQSR Chapter 5, Section 2(m)

*(i)* This section contains requirements for control devices used to comply with applicable subparts of Chapter 5, Section 2. The requirements are placed here for administrative convenience and only apply to facilities covered by subparts referring to this Section.*(ii)* ***Flares:***

(A) General Design:

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

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

(III) Flares shall be used only with the net heating value of the gas being combusted being 300 Btu/Scf (11.2 MJ/scm) or greater if the flare is steam-assisted or air-assisted or with the net heating value of the gas being combusted being 200 Btu/scf (7.45 MJ/scm) 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 (D).

(IV) Steam-assisted and nonassisted flare shall be designed for and operated with an exit velocity as determined by the methods specified in paragraph (D)(IV), less than 60 ft/sec (18.3 m/sec) except as follows:

(1.) Steam-assisted and nonassisted flares designed for and operated with an exit velocity, as determined by the methods specified in paragraph (D)(IV) equal to or greater than 60 ft/sec (18.3 m/sec) but less than 400 ft/sec (122 m/sec) are allowed if the net heating value of the gas being combusted is greater than 1000 Btu/scf (37.3 MJ/scm).

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

(V) 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 (D)(VI).

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

(B) Owners or operators of flares used to comply with the provisions of this section 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.

(C) Flares used to comply with the provisions of an applicable subpart shall be operated at all times when emissions may be vented to them.

(D) Determinations:

(I) Reference Method 22 shall be used to determine the compliance of flares with the visible emission provisions of this Section. The observation period is 2 hours and shall be used according to Method 22.

(II) 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.

(III) 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 value corresponding to one mole is 20°C.

K = Constant, $1.740 \times 10^{-7}$(1/ppm)(gmole/scm)(MJ/kcal) where the standard temperature of (gmole/scm) 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.

$H_i$ = 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 if published values are not available or cannot be calculated.

(IV) 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.

(V) The maximum permitted velocity Vmax, for flares complying with paragraph (A)(IV)(2.) shall be determined by the following equation:

$$Log_{10}(V_{max}) = \frac{H_T + 28.80}{31.7}$$

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

28.8 = Constant

31.7 = Constant

$H_T$ = The net heating value as determined in paragraph (D)(III)

(VI) The maximum permitted velocity, Vmax, 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 (D)(III).

APPENDIX H

WAQSR Chapter 7 Section 3

***(a) Definitions.*** For purposes of this section:

***"Act"*** means the Clean Air Act, as amended by Pub.L. 101-549, 42 U.S.C. 7401, et seq.

***"Applicable requirement"*** means all of the following as they apply to emissions units at a source subject to this section (including requirements with future effective compliance dates that have been promulgated or approved by the EPA or the State through rulemaking at the time of issuance of the operating permit):

(i) Any standard or other requirement provided for in the Wyoming implementation plan approved or promulgated by the EPA under title I of the Act that implements the relevant requirements of the Act, including any revisions to the plan promulgated in 40 CFR part 52;

(ii) Any standards or requirements in the WAQSR which are not a part of the approved Wyoming implementation plan and are not federally enforceable;

(iii) Any term or condition of any preconstruction permits issued pursuant to regulations approved or promulgated through rulemaking under title I, including parts C or D of the Act and including Chapter 5, Section 2 and Chapter 6, Sections 2 and 4 of the WAQSR;

(iv) Any standard or other requirement promulgated under section 111 of the Act, including section 111(d) and Chapter 5, Section 2 of the WAQSR;

(v) Any standard or other requirement under section 112 of the Act, including any requirement concerning accident prevention under section 112(r)(7) of the Act and including any regulations promulgated by the EPA and the State pursuant to section 112 of the Act;

(vi) Any standard or other requirement of the acid rain program under title IV of the Act or the regulations promulgated thereunder;

(vii) Any requirements established pursuant to section 504(b) or section 114(a)(3) of the Act concerning enhanced monitoring and compliance certifications;

(viii) Any standard or other requirement governing solid waste incineration, under section 129 of the Act;

(ix) Any standard or other requirement for consumer and commercial products, under section 183(e) of the Act (having to do with the release of volatile organic compounds under ozone control requirements);

(x) Any standard or other requirement of the regulations promulgated to protect stratospheric ozone under title VI of the Act, unless the EPA has determined that such requirements need not be contained in a title V permit;

(xi) Any national ambient air quality standard or increment or visibility requirement under part C of title I of the Act, but only as it would apply to temporary sources permitted pursuant to section 504(e) of the Act; and

(xii) Any state ambient air quality standard or increment or visibility requirement of the WAQSR.

(xiii) Nothing under Chapter 6, Section 3(b)(v) shall be construed as affecting the allowance program and Phase II compliance schedule under the acid rain provision of title IV of the Act.

***"Capture system"*** means the equipment (including but not limited to hoods, ducts, fans, and booths) used to contain, capture and transport a pollutant to a control device.

***"Continuous compliance determination method"*** means a method, specified by the applicable standard or an applicable permit condition, which:

(i) Is used to determine compliance with an emission limitation or standard on a continuous basis, consistent with the averaging period established for the emission limitation or standard; and

(ii) Provides data either in units of the standard or correlated directly with the compliance limit.

***"Control device"*** means equipment, other than inherent process equipment, that is used to destroy or remove air pollutant(s) prior to discharge to the atmosphere. The types of equipment that may commonly be used as control devices include, but are not limited to, fabric filters, mechanical collectors, electrostatic precipitators, inertial separators, afterburners, thermal or catalytic incinerators, adsorption devices (such as carbon beds), condensers, scrubbers (such as wet collection and gas absorption devices), selective catalytic or non-catalytic reduction systems, flue gas recirculation systems, spray dryers, spray towers, mist eliminators, acid plants, sulfur recovery plants, injection systems (such as water, steam, ammonia, sorbent or limestone injection), and combustion devices independent of the particular process being conducted at an emissions unit (e.g., the destruction of emissions achieved by venting process emission streams to flares, boilers or process heaters). For purposes of this part, a control device does not include passive control measures that act to prevent pollutants from forming, such as the use of seals, lids, or roofs to prevent the release of pollutants, use of low-polluting fuel or feedstocks, or the use of combustion or other process design features or characteristics. If an applicable requirement establishes that particular equipment which otherwise meets this definition of a control device does not constitute a control device as applied to a particular pollutant-specific emissions unit, then that definition shall be binding for purposes of this part.

***"Data"*** means the results of any type of monitoring or method, including the results of instrumental or non-instrumental monitoring, emission calculations, manual sampling procedures, recordkeeping procedures, or any other form of information collection procedure used in connection with any type of monitoring or method.

***"Emission limitation or standard"*** means any applicable requirement that constitutes an emission limitation, emission standard, standard of performance or means of emission limitation as defined under the Act. An emission limitation or standard may be expressed in terms of the pollutant, expressed either as a specific quantity, rate or concentration of emissions (e.g., pounds of $SO_2$ per hour, pounds of $SO_2$ per million British thermal units of fuel input, kilograms of VOC per liter of applied coating solids, or parts per million by volume of $SO_2$) or as the relationship of uncontrolled to controlled emissions (e.g., percentage capture and destruction efficiency of VOC or percentage reduction of $SO_2$). An emission limitation or standard may also be expressed either as a work practice, process or control device parameter, or other form of specific design, equipment, operational, or operation and maintenance requirement. For purposes of this part, an emission limitation or standard shall not include general operation requirements that an owner or operator may be required to meet, such as requirements to obtain a permit, to operate and maintain sources in accordance with good air pollution control practices, to develop and maintain a malfunction abatement plan, to keep records, submit reports, or conduct monitoring.

***"Emissions unit"*** means any part or activity of a stationary source that emits or has the potential to emit any regulated air pollutant or any pollutant listed under section 112(b) of the Act. This term is not meant to alter or affect the definition of the term "unit" for purposes of title IV of the Act.

***"Exceedence"*** shall mean a condition that is detected by monitoring that provides data in terms of an emission limitation or standard and that indicates that emissions (or opacity) are greater than the applicable emission limitation or standard (or less than the applicable standard in the case of a percent reduction requirement) consistent with any averaging period specified for averaging the results of the monitoring.

***"Excursion"*** shall mean a departure from an indicator range established for monitoring under this part, consistent with any averaging period specified for averaging the results of the monitoring.

***"Inherent process equipment"*** means equipment that is necessary for the proper or safe functioning of the process, or material recovery equipment that the owner or operator documents is installed and operated primarily for purposes other than compliance with air pollution regulations. Equipment that must be operated at an efficiency higher than that achieved during normal process operations in order to comply with the applicable emission limitation or standard is not inherent process equipment. For the purposes of this part, inherent process equipment is not considered a control device.

***"Major source"*** means any stationary source (or any group of stationary sources that are located on one or more contiguous or adjacent properties, and are under common control of the same person or persons under common control) belonging to a single major industrial grouping and that is described in paragraphs (i), (ii), or (iii) of this definition. For the purpose of defining "major source", a stationary source or group of stationary sources shall be considered part of a single industrial grouping if all of the pollutant emitting activities at such source or group of sources on contiguous or adjacent properties belong to the same Major Group (i.e., all have the same two-digit code) as described in the Standard Industrial Classification Manual, 1987.

(i) A major source under section 112 of the Act, which is defined as:

(A) For pollutants other than radionuclides, any stationary source or group of stationary sources located within a contiguous area and under common control that emits or has the potential to emit, in the aggregate, 10 tons per year (tpy) or more of any hazardous air pollutant which has been listed pursuant to section 112(b) of the Act, 25 tpy or more of any combination of such hazardous air pollutants, or such lesser quantity as the EPA may establish by rule. Notwithstanding the preceding sentence, emissions from any oil or gas exploration or production well (with its associated equipment) and emissions from any pipeline compressor or pump station shall not be aggregated with emissions from other similar units, whether or not such units are in a contiguous area or under common control, to determine whether such units or stations are major sources; or

(B) For radionuclides, "major source" shall have the meaning specified by the EPA by rule.

(ii) A major stationary source of air pollutants, as defined in section 302 of the Act, that directly emits or has the potential to emit, 100 tpy or more of any air pollutant (including any major source of fugitive emissions of any such pollutant, as determined by rule by the EPA). Emissions of air pollutants regulated solely due to section 112(r) of the Act shall not be considered in determining whether a source is a "major source" for purposes of Chapter 6, Section 3 applicability. The fugitive emissions of a stationary source shall not be considered in determining whether it is a major stationary source unless the source belongs to one of the following categories of stationary sources:

(A) Stationary sources listed in Chapter 6, Section 4(a)(i)(a) of the WAQSR; or

(B) Any other stationary source category, which as of August 7, 1980 is being regulated under section 111 or 112 of the Act.

(iii) A major stationary source as defined in part D of title I of the Act (in reference to sources located in non-attainment areas).

***"Monitoring"*** means any form of collecting data on a routine basis to determine or otherwise assess compliance with emission limitations or standards. Recordkeeping may be considered monitoring where such records are used to determine or assess compliance with an emission limitation or standard (such as records of raw material content and usage, or records documenting compliance with work practice requirements). The conduct of compliance method tests, such as the procedures in 40 CFR part 60, Appendix A, on a routine periodic basis may be considered monitoring (or as a supplement to other monitoring), provided that requirements to conduct such tests on a one-time basis or at such times as a regulatory authority may require on a non-regular basis are not considered monitoring requirements for purposes of this paragraph. Monitoring may include one or more than one of the following data collection techniques, where appropriate for a particular circumstance:

(i) Continuous emission or opacity monitoring systems;

(ii) Continuous process, capture system, control device or other relevant parameter monitoring systems or procedures, including a predictive emission monitoring system;

(iii) Emission estimation and calculation procedures (e.g., mass balance or stoichiometric calculations);

(iv) Maintenance and analysis of records of fuel or raw materials usage;

(v) Recording results of a program or protocol to conduct specific operation and maintenance procedures;

(vi) Verification of emissions, process parameters, capture system parameters, or control device parameters using portable or in situ measurement devices;

(vii) Visible emission observations;

(viii) Any other form of measuring, recording, or verifying on a routine basis emissions, process parameters, capture system parameters, control device parameters or other factors relevant to assessing compliance with emission limitations or standards.

***"Operating permit"*** means any permit or group of permits covering a source under Chapter 6, Section 3, Operating Permits that is issued, renewed, amended, or revised pursuant to Chapter 6, Section 3.

***"Operating permit application"*** shall mean an application (including any supplement to a previously submitted application) that is submitted by the owner or operator in order to obtain a Chapter 6, Section 3, operating permit.

***"Owner or operator"*** means any person who owns, leases, operates, controls or supervises a stationary source subject to this part.

***"Pollutant-specific emissions unit"*** means an emissions unit considered separately with respect to each regulated air pollutant.

***"Potential to emit"*** means the maximum capacity of a stationary source to emit any air pollutant under its physical and operational design. Any physical or operational limitation on the capacity of a source to emit an air pollutant, including air pollution control equipment and restrictions on hours of operation or on the type or amount of material combusted, stored or processed, shall be treated as part of its design if the limitation is enforceable by the EPA and the Division. This term does not alter or affect the use of this term for any other purposes under the Act, or the term "capacity factor" as used in title IV of the Act or the regulations promulgated thereunder.

***"Predictive emission monitoring system (PEMS)"*** means a system that uses process and other parameters as inputs to a computer program or other data reduction system to produce values in terms of the applicable emission limitation or standard.

***"Regulated air pollutant"*** means the following:

(i) Nitrogen oxides ($NO_x$) or any volatile organic compound;

(ii) Any pollutant for which a national ambient air quality standard has been promulgated;

(iii) Any pollutant that is subject to any standard established in Chapter 5, Section 2 of the WAQSR or section 111 of the Act;

(iv) Any Class I or II substance subject to a standard promulgated under or established by title VI of the Act; or

(v) Any pollutant subject to a standard promulgated under section 112 or other requirements established under section 112 of the Act, including sections 112(g), (j), and (r) of the Act, including the following:

(A) Any pollutant subject to requirements under section 112(j) of the Act. If the EPA fails to promulgate a standard by the date established pursuant to section 112(e) of the Act, any pollutant for which a subject source would be major shall be considered to be regulated on the date 18 months after the applicable date established pursuant to section 112(e) of the Act; and

(B) Any pollutant for which the requirements of section 112(g)(2) of the Act have been met, but only with respect to the individual source subject to section 112(g)(2) requirement.

(vi) Pollutants regulated solely under section 112(r) of the Act are to be regulated only with respect to the requirements of section 112(r) for permits issued under Chapter 6, Section 3, Operating Permits.

***"Stationary source"*** means any building, structure, facility, or installation that emits or may emit any regulated air pollutant or any pollutant listed under section 112(b) of the Act.

***(b) Applicability.***

***(i) General applicability***. Except for backup utility units that are exempt under paragraph (ii)(B) of this subsection (b), the requirements of this part shall apply to a pollutant-specific emissions unit at a major source that is required to obtain a Chapter 6, Section 3, operating permit if the unit satisfies all of the following criteria:

(A) The unit is subject to an emission limitation or standard for the applicable regulated air pollutant (or a surrogate thereof), other than an emission limitation or standard that is exempt under paragraph (ii)(A) of this subsection (b);

(B) The unit uses a control device to achieve compliance with any such emission limitation or standard; and

(C) The unit has potential pre-control device emissions of the applicable regulated air pollutant that are equal to or greater than 100 percent of the amount, in tons per year, required for a source to be classified as a major source. For purposes of this paragraph, "potential pre-control device emissions" shall have the same meaning as "potential to emit", as defined in Chapter 7, Section 3(a), except that emission reductions achieved by the applicable control device shall not be taken into account.

***(ii) Exemptions.***

(A) Exempt emission limitations or standards. The requirements of this part shall not apply to any of the following emission limitations or standards:

(I) Emission limitations or standards proposed by the EPA Administrator after November 15, 1990 pursuant to section 111 or 112 of the Act;

(II) Stratospheric ozone protection requirements under title VI of the Act;

(III) Acid Rain Program requirements pursuant to sections 404, 405, 406, 407(a), 407(b), or 410 of the Act;

(IV) Emission limitations or standards or other applicable requirements that apply solely under an emissions trading program approved or promulgated by the Administrator under the Act that allows for trading emissions within a source or between sources;

(V) A federally enforceable emissions cap included in the Chapter 6, Section 3 operating permit;

(VI) Emission limitations or standards for which a Chapter 6, Section 3, operating permit specifies a continuous compliance determination method, as defined in Chapter 7, Section 3(a). The exemption provided in (b)(ii)(A)(VI) of this section shall not apply if the applicable compliance method includes an assumed control device emission reduction factor that could be affected by the actual operation and maintenance of the control device (such as a surface coating line controlled by an incinerator for which continuous compliance is determined by calculating emissions on the basis of coating records and an assumed control device efficiency factor based on an initial performance test; in this example, this part would apply to the control device and capture system, but not to the remaining elements of the coating line, such as raw material usage).

(B) Exemption for backup utility power emissions units. The requirements of this part shall not apply to a utility unit, as defined in §72.2 of Chapter 11, Section 2(b) that is municipally-owned if the owner or operator provides documentation in a Chapter 6, Section 3, operating permit application that:

(I) The utility unit is exempt from all monitoring requirements in Chapter 11, Section 2(b), Acid Rain, Continuous emission monitoring (including the appendices thereto);

(II) The utility unit is operated for the sole purpose of providing electricity during periods of peak electrical demand or emergency situations and will be operated consistent with that purpose throughout the Chapter 6, Section 3, operating permit term. The owner or operator shall provide historical operating data and relevant contractual obligations to document that this criterion is satisfied; and

(III) The actual emissions from the utility unit, based on the average annual emissions over the last three calendar years of operation (or such shorter time period that is available for units with fewer than three years of operation) are less than 50 percent of the amount in tons per year required for a source to be classified as a major source and are expected to remain so.

***(c) Monitoring design criteria.***

***(i) General criteria***. To provide a reasonable assurance of compliance with emission limitations or standards for the anticipated range of operations at a pollutant-specific emissions unit, monitoring under this part shall meet the following general criteria:

(A) The owner or operator shall design the monitoring to obtain data for one or more indicators of emission control performance for the control device, any associated capture system and, if necessary to satisfy paragraph (c)(i)(B) of this section, processes at a pollutant-specific emissions unit. Indicators of performance may include, but are not limited to, direct or predicted emissions (including visible emissions or opacity), process and control device parameters that affect control device (and capture system) efficiency or emission rates, or recorded findings of inspection and maintenance activities conducted by the owner or operator.

(B) The owner or operator shall establish an appropriate range(s) or designated condition(s) for the selected indicator(s) such that operation within the ranges provides a reasonable assurance of ongoing compliance with emission limitations or standards for the anticipated range of operating conditions. Such range(s) or condition(s) shall reflect the proper operation and maintenance of the control device (and associated capture system), in accordance with applicable design properties, for minimizing emissions over the anticipated range of operating conditions at least to the level required to achieve compliance with the applicable requirements. The reasonable assurance of compliance will be assessed by maintaining performance within the indicator range(s) or designated condition(s). The ranges shall be established in accordance with the design and performance requirements in this section and documented in accordance with the requirements in Chapter 7, Section 3(d). If necessary to assure that the control device and associated capture system can satisfy this criterion, the owner or operator shall monitor appropriate process operational parameters (such as total throughput where necessary to stay within the rated capacity for a control device). In addition, unless specifically stated otherwise by an applicable requirement, the owner or operator shall monitor indicators to detect any bypass of the control device (or capture system) to the atmosphere, if such bypass can occur based on the design of the pollutant-specific emissions unit.

(C) The design of indicator ranges or designated conditions may be:

(I) Based on a single maximum or minimum value if appropriate (e.g., maintaining condenser temperatures a certain number of degrees below the condensation temperature of the applicable compound(s) being processed) or at multiple levels that are relevant to distinctly different operating conditions (e.g., high versus low load levels);

(II) Expressed as a function of process variables (e.g., an indicator range expressed as minimum to maximum pressure drop across a venturi throat in a particulate control scrubber);

(III) Expressed as maintaining the applicable parameter in a particular operational status or designated condition (e.g., position of a damper controlling gas flow to the atmosphere through a by-pass duct);

(IV) Established as interdependent between more than one indicator.

***(ii) Performance criteria.*** The owner or operator shall design the monitoring to meet the following performance criteria:

(A) Specifications that provide for obtaining data that are representative of the emissions or parameters being monitored (such as detector location and installation specifications, if applicable);

(B) For new or modified monitoring equipment, verification procedures to confirm the operational status of the monitoring prior to the date by which the owner or operator must conduct monitoring under this part as specified in Chapter 7, Section 3(g)(i). The owner or operator shall consider the monitoring equipment manufacturer's requirements or recommendations for installation, calibration, and start-up operation;

(C) Quality assurance and control practices that are adequate to ensure the continuing validity of the data. The owner or operator shall consider manufacturer recommendations or requirements applicable to the monitoring in developing appropriate quality assurance and control practices;

(D) Specifications for the frequency of conducting the monitoring, the data collection procedures that will be used (e.g., computerized data acquisition and handling, alarm sensor, or manual log entries based on gauge readings), and, if applicable, the period over which discrete data points will be averaged for the purpose of determining whether an excursion or exceedance has occurred.

(I) At a minimum, the owner or operator shall design the period over which data are obtained and, if applicable, averaged consistent with the characteristics and typical variability of the pollutant-specific emissions unit (including the control device and associated capture system). Such intervals shall be commensurate with the time period over which a change in control device performance that would require actions by owner or operator to return operations within normal ranges or designated conditions is likely to be observed.

(II) For all pollutant-specific emissions units with the potential to emit, calculated including the effect of control devices, the applicable regulated air pollutant in an amount equal to or greater than 100 percent of the amount, in tons per year, required for a source to be classified as a major source, for each parameter monitored, the owner or operator shall collect four or more data values equally spaced over each hour and average the values, as applicable, over the applicable averaging period as determined in accordance with paragraph (c)(ii)(D)(I) of this section. The Division may approve a reduced data collection frequency, if appropriate, based on information presented by the owner or operator concerning the data collection mechanisms available for a particular parameter for the particular pollutant-specific emissions unit (e.g., integrated raw material or fuel analysis data, noninstrumental measurement of waste feed rate or visible emissions, use of a portable analyzer or an alarm sensor).

(III) For other pollutant-specific emissions units, the frequency of data collection may be less than the frequency specified in subparagraph (c)(ii)(D)(II) of this section but the monitoring shall include some data collection at least once per 24-hour period (e.g., a daily inspection of a carbon adsorber operation in conjunction with a weekly or monthly check of emissions with a portable analyzer).

***(iii) Evaluation factors.*** In designing monitoring to meet the requirements in paragraphs (c)(i) and (c)(ii) of this section, the owner or operator shall take into account site-specific factors including the applicability of existing monitoring equipment and procedures, the ability of the monitoring to account for process and control device operational variability, the reliability and latitude built into the control technology, and the level of actual emissions relative to the compliance limitation.

***(iv) Special criteria for the use of continuous emission, opacity or predictive monitoring systems.***

(A) If a continuous emission monitoring system (CEMS), continuous opacity monitoring system (COMS) or predictive emission monitoring system (PEMS) is required pursuant to other authority under the Act or state or local law, the owner or operator shall use such system to satisfy the requirements of this section.

(B) The use of a CEMS, COMS, or PEMS that satisfies any of the following monitoring requirements shall be deemed to satisfy the general design criteria in paragraphs (c)(i) and (c)(ii) of this section, provided that a COMS may be subject to the criteria for establishing indicator ranges under paragraph (c)(i) of this section:

(I) Section 51.214 and Appendix P of 40 CFR part 51,

(II) Chapter 5, Section 2(j) and Section 2(b)(i), 40 CFR part 60, Appendix B;

(III) Chapter 5, Section 3(j) and any applicable performance specifications required pursuant to the applicable subpart of Chapter 5, Section 3;

(IV) Chapter 11, Section 2b, Acid Rain, Continuous emission monitoring;

(V) 40 CFR part 266, Subpart H and appendix IX; or

(VI) If an applicable requirement does not otherwise require compliance with the requirements listed in the preceding paragraphs (c)(iv)(B)(I)-(V) of this section, comparable requirements and specifications established by the Division.

(C) The owner or operator shall design the monitoring system subject to subsection (c)(iv) to:

(I) Allow for reporting of exceedances (or excursions if applicable to a COMS used to assure compliance with a particulate matter standard), consistent with any period for reporting of exceedances in an underlying requirement. If an underlying requirement does not contain a provision for establishing an averaging period for the reporting of exceedances or excursions, the criteria used to develop an averaging period in (c)(ii)(D) of this section shall apply; and

(II) Provide an indicator range consistent with paragraph (c)(i) of this section for a COMS used to assure compliance with a particulate matter standard. If an opacity standard applies to the pollutant-specific emissions unit, such limit may be used as the appropriate indicator range unless the opacity limit fails to meet the criteria in paragraph (c)(i) of this section after considering the type of control device and other site-specific factors applicable to the pollutant-specific emissions unit.

***(d) Submittal requirements.***

***(i)*** The owner or operator shall submit to the Division monitoring that satisfies the design requirements in Chapter 7, Section 3(c). The submission shall include the following information:

(A) The indicators to be monitored to satisfy Chapter 7, Section 3(c)(i)(A)-(B);

(B) The ranges or designated conditions for such indicators, or the process by which such indicator ranges or designated conditions shall be established;

(C) The performance criteria for the monitoring to satisfy Chapter 7, Section 3(c)(ii); and

(D) If applicable, the indicator ranges and performance criteria for a CEMS, COMS or PEMS pursuant to Chapter 7, Section 3(c)(iv).

***(ii)*** As part of the information submitted, the owner or operator shall submit a justification for the proposed elements of the monitoring. If the performance specifications proposed to satisfy Chapter 7, Section 3(c)(ii)(B) or (C) include differences from manufacturer recommendations, the owner or operator shall explain the reasons for the differences between the requirements proposed by the owner or operator and the manufacturer's recommendations or requirements. The owner or operator also shall submit any data supporting the justification, and may refer to generally available sources of information used to support the justification (such as generally available air pollution engineering manuals, or EPA publications on appropriate monitoring for various types of control devices or capture systems). To justify the appropriateness of the monitoring elements proposed, the owner or operator may rely in part on existing applicable requirements that establish the monitoring for the applicable pollutant-specific emissions unit or a similar unit. If an owner or operator relies on presumptively acceptable monitoring, no further justification for the appropriateness of that monitoring should be necessary other than an explanation of the applicability of such monitoring to the unit in question, unless data or information is brought forward to rebut the assumption. Presumptively acceptable monitoring includes:

(A) Presumptively acceptable or required monitoring approaches, established by the Division in a rule that constitutes part of the applicable implementation plan required pursuant to title I of the Act, that are designed to achieve compliance with this section for particular pollutant-specific emissions units;

(B) Continuous emission, opacity or predictive emission monitoring systems that satisfy applicable monitoring requirements and performance specifications as specified in Chapter 7, Section 3(c)(iv);

(C) Excepted or alternative monitoring methods allowed or approved pursuant to Chapter 11, Section 2(b), Acid Rain, Continuous emission monitoring;

(D) Monitoring included for standards exempt from this section pursuant to Chapter 7, Section 3(b)(ii)(A)(I) or (VI) to the extent such monitoring is applicable to the performance of the control device (and associated capture system) for the pollutant-specific emissions unit; and

(E) Presumptively acceptable monitoring identified in guidance by EPA. Such guidance will address the requirements under Chapter 7, Section 3(d)(i),(ii) and (iii) to the extent practicable.

***(iii)*** (A) Except as provided in Chapter 7, Section 3(d)(iv), the owner or operator shall submit control device (and process and capture system, if applicable) operating parameter data obtained during the conduct of the applicable compliance or performance test conducted under conditions specified by the applicable rule. If the applicable rule does not specify testing conditions or only partially specifies test conditions, the performance test generally shall be conducted under conditions representative of maximum emissions potential under anticipated operating conditions at the pollutant-specific emissions unit. Such data may be supplemented, if desired, by engineering assessments and manufacturer's recommendations to justify the indicator ranges (or, if applicable, the procedures for establishing such indicator ranges). Emission testing is not required to be conducted over the entire indicator range or range of potential emissions.

(B) The owner or operator must document that no changes to the pollutant-specific emissions unit, including the control device and capture system, have taken place that could result in a significant change in the control system performance or the selected ranges or designated conditions for the indicators to be monitored since the performance or compliance tests were conducted.

***(iv)*** If existing data from unit-specific compliance or performance testing specified in Chapter 7, Section 3(d)(iii) are not available, the owner or operator:

(A) Shall submit a test plan and schedule for obtaining such data in accordance with Chapter 7, Section 3(d)(v); or

(B) May submit indicator ranges (or procedures for establishing indicator ranges) that rely on engineering assessments and other data, provided that the owner or operator demonstrates that factors specific to the type of monitoring, control device, or pollutant-specific emissions unit make compliance or performance testing unnecessary to establish indicator ranges at levels that satisfy the criteria in Chapter 7, Section 3(c)(i).

***(v)*** If the monitoring submitted by the owner or operator requires installation, testing, or other necessary activities prior to use of the monitoring for purposes of this part, the owner or operator shall include an implementation plan and schedule for installing, testing and performing any other appropriate activities prior to use of the monitoring. The implementation plan and schedule shall provide for use of the monitoring as expeditiously as practicable after approval of the monitoring in the Chapter 6, Section 3 operating permit pursuant to Chapter 7, Section 3(f), but in no case shall the schedule for completing installation and beginning operation of the monitoring exceed 180 days after approval of the permit.

***(vi)*** If a control device is common to more than one pollutant-specific emissions unit, the owner or operator may submit monitoring for the control device and identify the pollutant-specific emissions units affected and any process or associated capture device conditions that must be maintained or monitored in accordance with Chapter 7, Section 3(c)(i) rather than submit separate monitoring for each pollutant-specific emissions unit.

***(vii)*** If a single pollutant-specific emissions unit is controlled by more than one control device similar in design and operation, the owner or operator may submit monitoring that applies to all the control devices and identify the control devices affected and any process or associated capture device conditions that must be maintained or monitored in accordance with Chapter 7, Section 3(c)(i) rather than submit a separate description of monitoring for each control device.

***(e) Deadlines for submittals.***

***(i) Large pollutant-specific emissions units.*** For all pollutant-specific emissions units with the potential to emit (taking into account control devices to the extent appropriate under the definition of this term in Chapter 7, Section 3(a) the applicable regulated air pollutant in an amount equal to or greater than 100 percent of the amount, in tons per year, required for a source to be classified as a major source, the owner or operator shall submit the information required under Chapter 7, Section 3(d) at the following times:

(A) On or after April 20, 1998, the owner or operator shall submit information as part of an application for an initial Chapter 6, Section 3 operating permit if, by that date, the application either:

(I) Has not been filed; or

(II) Has not yet been determined to be complete by the Division.

(B) On or after April 20, 1998, the owner or operator shall submit information as part of an application for a significant permit revision under Chapter 6, Section 3, but only with respect to those pollutant-specific emissions units for which the proposed permit revision is applicable.

(C) The owner or operator shall submit any information not submitted under the deadlines set forth in Chapter 7, Section 3(e)(i)(A) and (B) as part of the application for the renewal of a Chapter 6, Section 3 operating permit.

***(ii) Other pollutant-specific emissions units.*** For all other pollutant-specific emissions units subject to this part and not subject to Chapter 7, Section 3(e)(i), the owner or operator shall submit the information required under Chapter 7, Section 3(d) as part of an application for a renewal of a Chapter 6, Section 3 operating permit.

***(iii)*** The effective date for the requirement to submit information under Chapter 7, Section 3(d) shall be as specified pursuant to Chapter 7, Section 3(e)(i)-(iii) and a permit reopening to require the submittal of information under this section shall not be required pursuant to Chapter 6, Section 3(d)(vii)(A)(I), provided, however, that, if a Chapter 6, Section 3 operating permit is reopened for cause by EPA or the Division pursuant to Chapter 6, Section 3(d)(vii)(A)(III) or (IV), the applicable agency may require the submittal of information under this section for those pollutant-specific emissions units that are subject to this part and that are affected by the permit reopening.

***(iv)*** Prior to approval of monitoring that satisfies this part, the owner or operator is subject to the requirements of Chapter 6, Section 3(h)(i)(C)(I)(2.).

***(f) Approval of monitoring.***

***(i)*** Based on an application that includes the information submitted in accordance with Chapter 7, Section 3(e), the Division shall act to approve the monitoring submitted by the owner or operator by confirming that the monitoring satisfies the requirements in Chapter 7, Section 3(c).

***(ii)*** In approving monitoring under this section, the Division may condition the approval on the owner or operator collecting additional data on the indicators to be monitored for a pollutant-specific emissions unit, including required compliance or performance testing, to confirm the ability of the monitoring to provide data that are sufficient to satisfy the requirements of this part and to confirm the appropriateness of an indicator range(s) or designated condition(s) proposed to satisfy Chapter 7, Section 3(c)(i)(B) and (C) and consistent with the schedule in Chapter 7, Section 3(d)(v).

***(iii)*** If the Division approves the proposed monitoring, the Division shall establish one or more permit terms or conditions that specify the required monitoring in accordance with Chapter 6, Section 3(h)(i)(c)(I). At a minimum, the permit shall specify:

(A) The approved monitoring approach that includes all of the following:

(I) The indicator(s) to be monitored (such as temperature, pressure drop, emissions, or similar parameter);

(II) The means or device to be used to measure the indicator(s) (such as temperature measurement device, visual observation, or CEMS); and

(III) The performance requirements established to satisfy Chapter 7, Section 3(c)(ii) or (iv), as applicable.

(B) The means by which the owner or operator will define an exceedance or excursion for purposes of responding to and reporting exceedances or excursions under Chapter 7, Section 3(g) and (h). The permit shall specify the level at which an excursion or exceedance will be deemed to occur, including the appropriate averaging period associated with such exceedance or excursion. For defining an excursion from an indicator range or designated condition, the permit may either include the specific value(s) or condition(s) at which an excursion shall occur, or the specific procedures that will be used to establish that value or condition. If the latter, the permit shall specify appropriate notice procedures for the owner or operator to notify the Division upon any establishment or reestablishment of the value.

(C) The obligation to conduct the monitoring and fulfill the other obligations specified in Chapter 7, Section 3(g) through (i).

(D) If appropriate, a minimum data availability requirement for valid data collection for each averaging period, and, if appropriate, a minimum data availability requirement for the averaging periods in a reporting period.

***(iv)*** If the monitoring proposed by the owner or operator requires installation, testing or final verification of operational status, the Chapter 6, Section 3 operating permit shall include an enforceable schedule with appropriate milestones for completing such installation, testing, or final verification consistent with the requirements in Chapter 7, Section 3(d)(v).

***(v)*** If the Division disapproves the proposed monitoring, the following applies:

(A) The draft or final permit shall include, at a minimum, monitoring that satisfies the requirements of Chapter 6, Section 3(h)(i)(C)(I)(2.);

(B) The Division shall include in the draft or final permit a compliance schedule for the source owner to submit monitoring that satisfies Chapter 7, Section 3(c) and (d), but in no case shall the owner or operator submit revised monitoring more than 180 days from the date of issuance of the Chapter 6, Section 3 operating permit; and

(C) If the source owner or operator does not submit the monitoring in accordance with the compliance schedule as required in Chapter 7, Section 3(f)(v)(B) or if the Division disapproves the monitoring submitted, the source owner or operator shall be deemed not in compliance with Chapter 7, Section 3, unless the source owner or operator successfully challenges the disapproval.

***(g) Operation of approved monitoring.***

***(i) Commencement of operation.*** The owner or operator shall conduct the monitoring required under this part upon issuance of a Chapter 6, Section 3 operating permit that includes such monitoring, or by such later date specified in the permit pursuant to Chapter 7, Section 3(f)(v).

***(ii) Proper maintenance.*** At all times, the owner or operator shall maintain the monitoring, including but not limited to, maintaining necessary parts for routine repairs of the monitoring equipment.

***(iii) Continued operation.*** Except for, as applicable, monitoring malfunctions, associated repairs, and required quality assurance or control activities (including, as applicable, calibration checks and required zero and span adjustments), the owner or operator shall conduct all monitoring in continuous operation (or shall collect data at all required intervals) at all times that the pollutant-specific emissions unit is operating. Data recorded during monitoring malfunctions, associated repairs, and required quality assurance or control activities shall not be used for purposes of this part, including data averages and calculations, or fulfilling a minimum data availability requirement, if applicable. The owner or operator shall use all the data collected during all other periods in assessing the operation of the control device and associated control system. A monitoring malfunction is any sudden, infrequent, not reasonably preventable failure of the monitoring to provide valid data. Monitoring failures that are caused in part by poor maintenance or careless operation are not malfunctions.

***(iv) Response to excursions or exceedances.***

(A) Upon detecting an excursion or exceedance, the owner or operator shall restore operation of the pollutant-specific emissions unit (including the control device and associated capture system) to its normal or usual manner of operation as expeditiously as practicable in accordance with good air pollution control practices for minimizing emissions. The response shall include minimizing the period of any startup, shutdown or malfunction and taking any necessary corrective actions to restore normal operation and prevent the likely recurrence of the cause of an excursion or exceedance (other than those caused by excused startup or shutdown conditions). Such actions may include initial inspection and evaluation, recording that operations returned to normal without operator action (such as through response by a computerized distribution control system), or any necessary follow-up actions to return operation to within the indicator range, designated condition, or below the applicable emission limitation or standard, as applicable.

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

***(v) Documentation of need for improved monitoring.*** After approval of monitoring under this part, if the owner or operator identifies a failure to achieve compliance with an emission limitation or standard for which the approved monitoring did not provide an indication of an excursion or exceedance while providing valid data, or the results of compliance or performance testing document a need to modify the existing indicator ranges or designated conditions, the owner or operator shall promptly notify the Division and, if necessary, submit a proposed modification to the Chapter 6, Section 3 operating permit to address the necessary monitoring changes. Such a modification may include, but is not limited to, reestablishing indicator ranges or designated conditions, modifying the frequency of conducting monitoring and collecting data, or the monitoring of additional parameters.

***(h) Quality improvement plan (QIP) requirements.***

***(i)*** Based on the results of a determination made under Chapter 7, Section 3(g)(iv)(B), the Administrator or the Division may require the owner or operator to develop and implement a QIP. Consistent with Chapter 7, Section 3(f)(iii)(C), the Chapter 6, Section 3 operating permit may specify an appropriate threshold, such as an accumulation of exceedances or excursions exceeding 5 percent duration of a pollutant-specific emissions unit's operating time for a reporting period, for requiring the implementation of a QIP. The threshold may be set at a higher or lower percent or may rely on other criteria for purposes of indicating whether a pollutant-specific emissions unit is being maintained and operated in a manner consistent with good air pollution control practices.

***(ii) Elements of a QIP.***

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

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

(I) Improved preventive maintenance practices.

(II) Process operation changes.

(III) Appropriate improvements to control methods.

(IV) Other steps appropriate to correct control performance.

(V) More frequent or improved monitoring (only in conjunction with one or more steps under Chapter 7, Section 3(h)(ii)(B)(I) -(IV)).

***(iii)*** If a QIP is required, the owner or operator shall develop and implement a QIP as expeditiously as practicable and shall notify the Division if the period for completing the improvements contained in the QIP exceeds 180 days from the date on which the need to implement the QIP was determined.

***(iv)*** Following implementation of a QIP, upon any subsequent determination pursuant to Chapter 7, Section 3(g)(iv)(B), the Administrator or the Division may require that an owner or operator make reasonable changes to the QIP if the QIP is found to have:

(A) Failed to address the cause of the control device performance problems; or

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

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

***(i) Reporting and recordkeeping requirements.***

***(i) General reporting requirements.***

(A) On and after the date specified in Chapter 7, Section 3(g)(i) by which the owner or operator must use monitoring that meets the requirements of this part, the owner or operator shall submit monitoring reports to the Division in accordance with Chapter 6, Section 3(h)(i)(C)(III).

(B) A report for monitoring under this part shall include, at a minimum, the information required under Chapter 6, Section 3(h)(i)(C)(III) and the following information, as applicable:

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

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

(III) A description of the actions taken to implement a QIP during the reporting period as specified in Chapter 7, Section 3(h). Upon completion of a QIP, the owner or operator shall include in the next summary report documentation that the implementation of the plan has been completed and reduced the likelihood of similar levels of excursions or exceedances occurring.

***(ii) General recordkeeping requirements.***

(A) The owner or operator shall comply with the recordkeeping requirements specified in Chapter 6, Section 3(h)(i)(C)(II). The owner or operator shall maintain records of monitoring data, monitor performance data, corrective actions taken, any written quality improvement plan required pursuant to Chapter 7, Section 3(h) and any activities undertaken to implement a quality improvement plan, and other supporting information required to be maintained under this part (such as data used to document the adequacy of monitoring, or records of monitoring maintenance or corrective actions).

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

***(j) Savings provisions.***

***(i) Nothing in this part shall:***

(A) Excuse the owner or operator of a source from compliance with any existing emission limitation or standard, or any existing monitoring, testing, reporting or recordkeeping requirement that may apply under federal, state, or local law, or any other applicable requirements under the Act. The requirements of this part shall not be used to justify the approval of monitoring less stringent than the monitoring which is required under separate legal authority and are not intended to establish minimum requirements for the purpose of determining the monitoring to be imposed under separate authority under the Act, including monitoring in permits issued pursuant to Chapter 6, Section 2. The purpose of this part is to require, as part of the issuance of a permit under Chapter 6, Section 3, improved or new monitoring at those emissions units where monitoring requirements do not exist or are inadequate to meet the requirements of this part.

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

(C) Restrict or abrogate the authority of the Administrator or Division to take any enforcement action under the Act for any violation of an applicable requirement or of any person to take action under section 304 of the Act.