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40 CFR Ch. I (7–1–14 Edition)

cannot approve this rule into the SIP because it is inconsistent with the Act (*e.g.*, sections 110(a) and 110(l)), prior rulemakings and our guidance.

[57 FR 57347, Dec. 4, 1992, as amended at 57 FR 60486, Dec. 21, 1993; 60 FR 36722, July 18, 1995; 64 FR 68038, Dec. 6, 1999; 66 FR 42437, Aug. 13, 2001; 66 FR 55099, Nov. 1, 2001; 67 FR 22241, May 2, 2002; 68 FR 27911, May 22, 2003; 71 FR 4828, Jan. 30, 2006]

§§ 52.1385–52.1386 [Reserved]

§ 52.1387 Visibility protection.

(a) The requirements of section 169A of the Clean Air Act are not met because the plan does not include approvable procedures for protection of visibility in mandatory Class I Federal areas.

(b) *Long-term strategy.* The provisions of § 52.29 are hereby incorporated into the applicable plan for the State of Montana.

[52 FR 45138, Nov. 24, 1987]

§ 52.1388 Stack height regulations.

The State of Montana has committed to revise its stack height regulations should EPA complete rulemaking to respond to the decision in *NRDC v. Thomas*, 838 F. 2d 1224 (D.C. Cir. 1988). In a letter to Douglas M. Skie, EPA, dated May 6, 1988, Jeffrey T. Chaffee, Chief, Air Quality Bureau, stated:

* * * We are submitting this letter to allow EPA to continue to process our current SIP submittal with the understanding that if EPA's response to the NRDC remand modifies the July 8, 1985 regulations, EPA will notify the State of the rules that must be changed to comply with the EPA's modified requirements. The State of Montana agrees to make the appropriate changes.

[54 FR 24341, June 7, 1989. Redesignated at 55 FR 19262, May 9, 1990]

§ 52.1389 [Reserved]

§ 52.1390 Missoula variance provision.

The Missoula City-County Air Pollution Control Program's Chapter X, Variances, which was adopted by the Montana Board of Health and Environmental Sciences on June 28, 1991 and submitted by the Governor of Montana to EPA in a letter dated August 20, 1991, is disapproved. This rule is inconsistent with section 110(i) of the Clean

Air Act, which prohibits any State or EPA from granting a variance from any requirement of an applicable implementation plan with respect to a stationary source.

[59 FR 64139, Dec. 13, 1994]

§ 52.1391 Emission inventories.

(a) The Governor of the State of Montana submitted the 1990 carbon monoxide base year emission inventories for Missoula and Billings on July 18, 1995, as a revision to the State Implementation Plan (SIP). The Governor submitted the 1990 carbon monoxide base year emission inventory for Great Falls on April 23, 1997, as a revision to the SIP. The inventories address emissions from point, area, on-road mobile, and non-road sources. These 1990 base year carbon monoxide inventories satisfy the nonattainment area requirements of the Clean Air Act of section 187(a)(1) for Missoula and section 172(c)(3) for Billings and Great Falls.

(b) As part of the Thompson Falls Air Pollution Control Plan (approved at § 52.1370(c)(60)), the Governor of Montana submitted a PM-10 emission inventory for the Thompson Falls area as a SIP revision. The PM-10 emission inventory covers the time period of July 1, 1990 through June 30, 1991.

[62 FR 65616, Dec. 15, 1997, as amended at 69 FR 3012, Jan. 22, 2004]

§ 52.1392 Federal Implementation Plan for the Billings/Laurel Area.

(a) *Applicability.* This section applies to the owner(s) or operator(s), including any new owner(s) or operator(s) in the event of a change in ownership or operation, of the following facilities in the Billings/Laurel, Montana area: CHS Inc. Petroleum Refinery, Laurel Refinery, 803 Highway 212 South, Laurel, MT; ConocoPhillips Petroleum Refinery, Billings Refinery, 401 South 23rd St., Billings, MT; ExxonMobil Petroleum Refinery, 700 Exxon Road, Billings, MT; and Montana Sulphur & Chemical Company, 627 Exxon Road, Billings, MT.

(b) *Scope.* The facilities listed in paragraph (a) of this section are also subject to the Billings/Laurel SO₂ SIP, as approved at 40 CFR 52.1370(c)(46) and (52). In cases where the provisions of

this FIP address emissions activities differently or establish a different requirement than the provisions of the approved SIP, the provisions of this FIP take precedence.

(c) *Definitions.* For the purpose of this section, we are defining certain words or initials as described in this paragraph. Terms not defined below that are defined in the Clean Air Act or regulations implementing the Clean Air Act, shall have the meaning set forth in the Clean Air Act or such regulations.

(1) *Aliquot* means a fractional part of a sample that is an exact divisor of the whole sample.

(2) *Annual Emissions* means the amount of SO₂ emitted in a calendar year, expressed in pounds per year rounded to the nearest pound, where:

Annual emissions = Σ Daily emissions within the calendar year.

(3) *Calendar Day* means a 24-hour period starting at 12 midnight and ending at 12 midnight, 24 hours later.

(4) *Clock Hour* means a twenty-fourth ($\frac{1}{24}$) of a calendar day; specifically any of the standard 60-minute periods in a day that are identified and separated on a clock by the whole numbers one (1) through 12.

(5) *Continuous Emission Monitoring System or CEMS* means all continuous concentration and volumetric flow rate monitors, associated data acquisition equipment, and all other equipment necessary to meet the requirements of this section for continuous monitoring.

(6) *Daily Emissions* means the amount of SO₂ emitted in a calendar day, expressed in pounds per day rounded to the nearest tenth ($\frac{1}{10}$) of a pound, where:

Daily emissions = Σ 3-hour emissions within a calendar day.

(7) *EPA* means the United States Environmental Protection Agency.

(8) *Exhibit* means for a given facility named in paragraph (a) of this section, exhibit A to the stipulation of the Montana Department of Environmental Quality and that facility, adopted by the Montana Board of Environmental Review on either June 12, 1998, or March 17, 2000.

(9) *1998 Exhibit* means for a given facility named in paragraph (a) of this section, the exhibit adopted by the Montana Board of Environmental Review on June 12, 1998.

(10) *2000 Exhibit* means for a given facility named in paragraph (a) of this section, the exhibit adopted by the Montana Board of Environmental Review on March 17, 2000.

(11) *Flare* means a combustion device that uses an open flame to burn combustible gases with combustion air provided by uncontrolled ambient air around the flame. This term includes both ground and elevated flares.

(12) The initials *Hg* mean mercury.

(13) *Hourly* means or refers to each clock hour in a calendar day.

(14) *Hourly Average* means an arithmetic average of all valid and complete 15-minute data blocks in a clock hour. Four (4) valid and complete 15-minute data blocks are required to determine an hourly average for each CEMS per clock hour.

Exclusive of the above definition, an hourly CEMS average may be determined with two (2) valid and complete 15-minute data blocks, for two (2) of the 24 hours in any calendar day. A complete 15-minute data block for each CEMS shall have a minimum of one (1) data point value; however, each CEMS shall be operated such that all valid data points acquired in any 15-minute block shall be used to determine the 15-minute block's reported concentration and flow rate.

(15) *Hourly Emissions* means the pounds per clock hour of SO₂ emissions from a source (including, but not limited to, a flare, stack, fuel oil system, sour water system, or fuel gas system) determined using hourly averages and rounded to the nearest tenth ($\frac{1}{10}$) of a pound.

(16) The initials *H₂S* mean hydrogen sulfide.

(17) *Integrated sampling* means an automated method of obtaining a sample from the gas stream to the flare that produces a composite sample of individual aliquots taken over time.

(18) The initials *MBER* mean the Montana Board of Environmental Review.

(19) The initials *MDEQ* mean the Montana Department of Environmental Quality.

(20) The initials *mm* mean millimeters.

(21) The initials *MSCC* mean the Montana Sulphur & Chemical Company.

(22) *Pilot gas* means the gas used to maintain the presence of a flame for ignition of gases routed to a flare.

(23) *Purge gas* means a continuous gas stream introduced into a flare header, flare stack, and/or flare tip for the purpose of maintaining a positive flow that prevents the formation of an explosive mixture due to ambient air ingress.

(24) The initials *ppm* mean parts per million.

(25) The initials *SCFH* mean standard cubic feet per hour.

(26) The initials *SCFM* mean standard cubic feet per minute.

(27) *Standard Conditions* means (a) 20 °C (293.2 °K, 527.7 °R, or 68.0 °F) and one (1) atmosphere pressure (29.92 inches Hg or 760 mm Hg) for stack and flare gas emission calculations, and (b) 15.6 °C (288.7 °K, 520.0 °R, or 60.3 °F) and one (1) atmosphere pressure (29.92 inches Hg or 760 mm Hg) for refinery fuel gas emission calculations.

(28) The initials *SO₂* mean sulfur dioxide.

(29) The initials *SWS* mean sour water stripper.

(30) The term *3-hour emissions* means the amount of SO₂ emitted in each of the eight (8) non-overlapping 3-hour periods in a calendar day, expressed in pounds and rounded to the nearest tenth (¹/₁₀) of a pound, where:

3 hour emissions = Σ Hourly emissions within the 3-hour period.

(31) The term *3-hour period* means any of the eight (8) non-overlapping 3-hour periods in a calendar day: Midnight to 3 a.m., 3 a.m. to 6 a.m., 6 a.m. to 9 a.m., 9 a.m. to noon, noon to 3 p.m., 3 p.m. to 6 p.m., 6 p.m. to 9 p.m., 9 p.m. to midnight.

(32) *Turnaround* means a planned activity involving shutdown and startup of one or several process units for the purpose of performing periodic maintenance, repair, replacement of equipment, or installation of new equipment.

(33) *Valid* means data that are obtained from a monitor or meter serving as a component of a CEMS which meets the applicable specifications, operating requirements, and quality assurance and control requirements of section 6 of ConocoPhillips', CHS Inc.'s, ExxonMobil's, and MSCC's 1998 exhibits, respectively, and this section.

(d) *CHS Inc. emission limits and compliance determining methods.*

(1) *Introduction.* The provisions for CHS Inc. cover the following units:

(i) The flare.

(ii) Combustion sources, which consist of those sources identified in the combustion sources emission limit in section 3(A)(1)(d) of CHS Inc.'s 1998 exhibit.

(2) *Flare requirements.*

(i) *Emission limit.* The total emissions of SO₂ from the flare shall not exceed 150.0 pounds per 3-hour period.

(ii) *Compliance determining method.* Compliance with the emission limit in paragraph (d)(2)(i) of this section shall be determined in accordance with paragraph (h) of this section.

(3) *Combustion sources.*

(i) *Restrictions.* Sour water stripper overheads (ammonia (NH₃) and H₂S gases removed from the sour water in the sour water stripper) shall not be burned in the main crude heater. At all times, CHS Inc. shall keep a chain and lock on the valve that supplies sour water stripper overheads from the old sour water stripper to the main crude heater and shall keep such valve closed.

(ii) *Compliance determining method.* CHS Inc. shall log and report any non-compliance with the requirements of paragraph (d)(3)(i) of this section.

(4) *Data reporting requirements.*

(i) CHS Inc. shall submit quarterly reports beginning with the first calendar quarter following May 21, 2008. The quarterly reports shall be submitted within 30 days of the end of each calendar quarter. The quarterly reports shall be submitted to EPA at the following address: Air Program Contact, EPA Montana Operations Office, Federal Building, 10 West 15th Street, Suite 3200, Helena, MT 59626.

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The quarterly report shall be certified for accuracy in writing by a responsible CHS Inc. official. The quarterly report shall consist of both a comprehensive electronic-magnetic report and a written hard copy data summary report.

(ii) The electronic report shall be on magnetic or optical media, and such submittal shall follow the reporting format of electronic data being submitted to the MDEQ. EPA may modify the reporting format delineated in this section, and, thereafter, CHS Inc. shall follow the revised format. In addition to submitting the electronic quarterly reports to EPA, CHS Inc. shall also record, organize, and archive for at least five (5) years the same data, and upon request by EPA, CHS Inc. shall provide EPA with any data archived in accordance with this provision. The electronic report shall contain the following:

(A) Hourly average total sulfur concentrations as H₂S or SO₂ in ppm in the gas stream to the flare;

(B) Hourly average H₂S concentrations of the flare pilot and purge gases in ppm;

(C) Hourly average volumetric flow rates in SCFH of the gas stream to the flare;

(D) Hourly average volumetric flow rates in SCFH of the flare pilot and purge gases;

(E) Hourly average temperature (in °F) and pressure (in mm or inches of Hg) of the gas stream to the flare;

(F) Hourly emissions from the flare in pounds per clock hour; and

(G) Daily calibration data for all flare, pilot gas, and purge gas CEMS.

(iii) The quarterly written report shall contain the following information:

(A) The 3-hour emissions in pounds per 3-hour period from each flare;

(B) Periods in which only natural gas or an inert gas was used as flare pilot gas or purge gas or both;

(C) The results of all quarterly Cylinder Gas Audits (CGA), Relative Accuracy Audits (RAA), and annual Relative Accuracy Test Audits (RATA) for all total sulfur analyzer(s) and H₂S analyzer(s), and the results of all annual calibrations and verifications for the

volumetric flow, temperature, and pressure monitors;

(D) For all periods of flare volumetric flow rate monitoring system or total sulfur analyzer system downtime, flare pilot gas or purge gas volumetric flow or H₂S analyzer system downtime, or failure to obtain or analyze a grab or integrated sample, the written report shall identify:

(1) Dates and times of downtime or failure;

(2) Reasons for downtime or failure;

(3) Corrective actions taken to mitigate downtime or failure; and

(4) The other methods, approved by EPA in the flare monitoring plan required by paragraph (h)(5) of this section, used to determine flare emissions;

(E) For all periods that the range of the flare or any pilot or purge gas volumetric flow rate monitor(s), any flare total sulfur analyzer(s), or any pilot or purge gas H₂S analyzer(s) is exceeded, the written report shall identify:

(1) Date and time when the range of the volumetric flow monitor(s), total sulfur analyzer(s), or H₂S analyzer(s) was exceeded; and

(2) The other methods, approved by EPA in the flare monitoring plan required by paragraph (h)(5) of this section, used to determine flare emissions;

(F) For all periods that the flare volumetric flow monitor or monitors are recording flow, yet any Flare Water Seal Monitoring Device indicates there is no flow, the written report shall identify:

(1) Date, time, and duration when the flare volumetric flow monitor(s) recorded flow, yet any Flare Water Seal Monitoring Device indicated there was no flow;

(G) For each 3-hour period in which the flare emission limit is exceeded, the written report shall identify:

(1) The date, start time, and end time of the excess emissions;

(2) Total hours of operation with excess emissions, the hourly emissions, and the 3-hour emissions;

(3) All information regarding reasons for operating with excess emissions; and

(4) Corrective actions taken to mitigate excess emissions;

(H) The date and time of any non-compliance with the requirements of paragraph (d)(3)(i) of this section; and

(I) When no excess emissions have occurred or the continuous monitoring system(s) or manual system(s) have not been inoperative, repaired, or adjusted, such information shall be stated in the report.

(e) *ConocoPhillips emission limits and compliance determining methods.*

(1) *Introduction.* The provisions for ConocoPhillips cover the following units:

(i) The main flare, which consists of two flares—the north flare and the south flare—that are operated on alternating schedules. These flares are referred to herein as the north main flare and south main flare, or generically as the main flare.

(ii) The Jupiter Sulfur SRU flare, which is the flare at Jupiter Sulfur, ConocoPhillips' sulfur recovery unit.

(2) *Flare requirements.*

(i) *Emission limits.*

(A) Combined emissions of SO₂ from the main flare (which can be emitted from either the north or south main flare, but not both at the same time) shall not exceed 150.0 pounds per 3-hour period.

(B) Emissions of SO₂ from the Jupiter Sulfur SRU flare and the Jupiter Sulfur SRU/ATS stack (also referred to as the Jupiter Sulfur SRU stack) shall not exceed 75.0 pounds per 3-hour period, 600.0 pounds per calendar day, and 219,000 pounds per calendar year.

(ii) *Compliance determining method.*

(A) Compliance with the emission limit in paragraph (e)(2)(i)(A) of this section shall be determined in accordance with paragraph (h) of this section. In the event that a single monitoring location cannot be used for both the north and south main flare, ConocoPhillips shall monitor the flow and measure the total sulfur concentration at more than one location in order to determine compliance with the main flare emission limit. ConocoPhillips shall log and report any instances when emissions are vented from the north main flare and south main flare simultaneously.

(B) Compliance with the emission limits and requirements in paragraph (e)(2)(i)(B) of this section shall be de-

termined by summing the emissions from the Jupiter Sulfur SRU flare and SRU/ATS stack. Emissions from the Jupiter Sulfur SRU flare shall be determined in accordance with paragraph (h) of this section and the emissions from the Jupiter Sulfur SRU/ATS stack shall be determined pursuant to ConocoPhillips' 1998 exhibit (see section 4(A) of the exhibit).

(3) *Data reporting requirements.*

(i) ConocoPhillips shall submit quarterly reports on a calendar year basis, beginning with the first calendar quarter following May 21, 2008. The quarterly reports shall be submitted within 30 days of the end of each calendar quarter. The quarterly reports shall be submitted to EPA at the following address: Air Program Contact, EPA Montana Operations Office, Federal Building, 10 West 15th Street, Suite 3200, Helena, MT 59626.

The quarterly report shall be certified for accuracy in writing by a responsible ConocoPhillips official. The quarterly report shall consist of both a comprehensive electronic-magnetic report and a written hard copy data summary report.

(ii) The electronic report shall be on magnetic or optical media, and such submittal shall follow the reporting format of electronic data being submitted to the MDEQ. EPA may modify the reporting format delineated in this section, and, thereafter, ConocoPhillips shall follow the revised format. In addition to submitting the electronic quarterly reports to EPA, ConocoPhillips shall also record, organize, and archive for at least five (5) years the same data, and upon request by EPA, ConocoPhillips shall provide EPA with any data archived in accordance with this provision. The electronic report shall contain the following:

(A) Hourly average total sulfur concentrations as H₂S or SO₂ in ppm in the gas stream to the ConocoPhillips main flare and Jupiter Sulfur SRU flare;

(B) Hourly average H₂S concentrations of the ConocoPhillips main flare and Jupiter Sulfur SRU flare pilot and purge gases in ppm;

(C) Hourly average volumetric flow rates in SCFH of the gas streams to the

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ConocoPhillips main flare and Jupiter Sulfur SRU flare;

(D) Hourly average volumetric flow rates in SCFH of the ConocoPhillips main flare and Jupiter Sulfur SRU flare pilot and purge gases;

(E) Hourly average temperature (in °F) and pressure (in mm or inches of Hg) of the gas streams to the ConocoPhillips main flare and Jupiter Sulfur SRU flare;

(F) Hourly emissions in pounds per clock hour from the ConocoPhillips main flare and Jupiter Sulfur SRU flare; and

(G) Daily calibration data for all flare, pilot gas, and purge gas CEMS.

(iii) The quarterly written report shall contain the following information:

(A) The 3-hour emissions in pounds per 3-hour period from the ConocoPhillips main flare and the sum of the combined 3-hour emissions from the Jupiter Sulfur SRU/ATS stack and Jupiter Sulfur SRU flare in pounds per 3-hour period;

(B) Periods in which only natural gas or an inert gas was used as flare pilot gas or purge gas or both;

(C) The results of all quarterly Cylinder Gas Audits (CGA), Relative Accuracy Audits (RAA), and annual Relative Accuracy Test Audits (RATA) for all total sulfur analyzer(s) and H₂S analyzer(s), and the results of all annual calibrations and verifications for the volumetric flow, temperature, and pressure monitors;

(D) For all periods of flare volumetric flow rate monitoring system or total sulfur analyzer system downtime, flare pilot gas or purge gas volumetric flow or H₂S analyzer system downtime, or failure to obtain or analyze a grab or integrated sample, the written report shall identify:

(1) Dates and times of downtime or failure;

(2) Reasons for downtime or failure;

(3) Corrective actions taken to mitigate downtime or failure; and

(4) The other methods, approved by EPA in the flare monitoring plan required by paragraph (h)(5) of this section, used to determine flare emissions;

(E) For all periods that the range of the flare or any pilot or purge gas volumetric flow rate monitor(s), any flare

total sulfur analyzer(s), or any pilot or purge gas H₂S analyzer(s) is exceeded, the written report shall identify:

(1) Date and time when the range of the volumetric flow monitor(s), total sulfur analyzer(s), or H₂S analyzer(s) was exceeded, and

(2) The other methods, approved by EPA in the flare monitoring plan required by paragraph (h)(5) of this section, used to determine flare emissions;

(F) For all periods that the flare volumetric flow monitor or monitors are recording flow, yet any Flare Water Seal Monitoring Device indicates there is no flow, the written report shall identify:

(1) Date, time, and duration when the flare volumetric flow monitor(s) recorded flow, yet any Flare Water Seal Monitoring Device indicated there was no flow;

(G) Identification of dates, times, and duration of any instances when emissions were vented from the north and south main flares simultaneously;

(H) For each 3-hour period in which a flare emission limit is exceeded, the written report shall identify:

(1) The date, start time, and end time of the excess emissions;

(2) Total hours of operation with excess emissions, the hourly emissions, and the 3-hour emissions;

(3) All information regarding reasons for operating with excess emissions; and

(4) Corrective actions taken to mitigate excess emissions; and

(I) When no excess emissions have occurred or the continuous monitoring system(s) or manual system(s) have not been inoperative, repaired, or adjusted, such information shall be stated in the report.

(f) *ExxonMobil emission limits and compliance determining methods.*

(1) *Introduction.* The provisions for ExxonMobil cover the following units:

(i) The Primary process flare and the Turnaround flare. The Primary process flare is the flare normally used by ExxonMobil. The Turnaround flare is the flare ExxonMobil uses for about 30 to 40 days every 5 to 6 years when the facility's major SO₂ source, the fluid catalytic cracking unit, is not normally operating.

(ii) The following refinery fuel gas combustion units: The FCC CO Boiler, F-2 crude/vacuum heater, F-3 unit, F-3X unit, F-5 unit, F-700 unit, F-201 unit, F-202 unit, F-402 unit, F-551 unit, F-651 unit, standby boiler house (B-8 boiler), and Coker CO Boiler (only when the Yellowstone Energy Limited Partnership (YELP) facility is receiving ExxonMobil Coker unit flue gas or whenever the ExxonMobil Coker is not operating).

(iii) Coker CO Boiler stack.

(2) *Flare requirements.*

(i) *Emission limit.* The total combined emissions of SO₂ from the Primary process and Turnaround refinery flares shall not exceed 150.0 pounds per 3-hour period.

(ii) *Compliance determining method.* Compliance with the emission limit in paragraph (f)(2)(i) of this section shall be determined in accordance with paragraph (h) of this section. If volumetric flow monitoring device(s) installed and concentration monitoring methods used to measure the gas stream to the Primary Process flare cannot measure the gas stream to the Turnaround flare, ExxonMobil may apply to EPA for alternative measures to determine the volumetric flow rate and total sulfur concentration of the gas stream to the Turnaround flare. Before EPA will approve such alternative measures, ExxonMobil must agree that the Turnaround flare will be used only during refinery turnarounds of limited duration and frequency—no more than 60 days once every five (5) years—which restriction shall be considered an enforceable part of this FIP. Such alternative measures may consist of reliable flow estimation parameters to estimate volumetric flow rate and manual sampling of the gas stream to the flare to determine total sulfur concentrations, or such other measures that EPA finds will provide accurate estimations of SO₂ emissions from the Turnaround flare.

(3) *Refinery fuel gas combustion requirements.*

(i) *Emission limits.* The applicable emission limits are contained in section 3(A)(1) of ExxonMobil's 2000 exhibit and section 3(B)(2) of ExxonMobil's 1998 exhibit.

(ii) *Compliance determining method.* For the limits referenced in paragraph (f)(3)(i) of this section, the compliance determining methods specified in section 4(B) of ExxonMobil's 1998 exhibit shall be followed except when the H₂S concentration in the refinery fuel gas stream exceeds 1200 ppmv as measured by the H₂S CEMS required by section 6(B)(3) of ExxonMobil's 1998 exhibit (the H₂S CEMS.) When such value is exceeded, the following compliance monitoring method shall be employed:

(A) ExxonMobil shall measure the H₂S concentration in the refinery fuel gas according to the procedures in paragraph (f)(3)(ii)(B) of this section and calculate the emissions according to the equations in paragraph (f)(3)(ii)(C) of this section.

(B) Within four (4) hours after the H₂S CEMS measures an H₂S concentration in the refinery fuel gas stream greater than 1200 ppmv, ExxonMobil shall initiate sampling of the refinery fuel gas stream at the fuel header on a once-per-hour frequency using length-of-stain detector tubes pursuant to ASTM Method D4810-06, "Standard Test Method for Hydrogen Sulfide in Natural Gas Using Length-of-Stain Detector Tubes" (incorporated by reference, see paragraph (j) of this section) with the appropriate sample tube range. If the results exceed the tube's range, another tube of a higher range must be used until results are in the tube's range. ExxonMobil shall continue to use the length-of-stain detector tube method at this frequency until the H₂S CEMS measures an H₂S concentration in the refinery fuel gas stream equal to or less than 1200 ppmv continuously over a 3-hour period.

(C) When the length-of-stain detector tube method is required, SO₂ emissions from refinery fuel gas combustion shall be calculated as follows: the Hourly emissions shall be calculated using equation 1, 3-hour emissions shall be calculated using equation 2, and the Daily emissions shall be calculated using equation 3.

$$\text{Equation 1: } E_H = K * C_H * Q_H$$

Where:

E_H = Refinery fuel gas combustion hourly emissions in pounds per hour, rounded to the nearest tenth of a pound;

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$K = 1.688 \times 10^{-7}$ in (pounds/standard cubic feet (SCF))/parts per million (ppm);

C_H = Hourly refinery fuel gas H_2S concentration in ppm determined by the length-of-stain detector tube method as required by paragraph (f)(3)(ii)(B) of this section; and

Q_H = actual fuel gas firing rate in standard cubic feet per hour (SCFH), as measured by the monitor required by section 6(B)(8) of ExxonMobil's 1998 exhibit.

Equation 2: (Refinery fuel gas combustion 3-hour emissions) = Σ (Hourly emissions within the 3-hour period as determined by equation 1).

Equation 3: (Refinery fuel gas combustion daily emissions) = Σ (3-hour emissions within the day as determined by equation 2).

(4) Coker CO Boiler stack requirements.

(i) *Emission limits.* When ExxonMobil's Coker unit is operating and Coker unit flue gases are burned in the Coker CO Boiler, the applicable emission limits are contained in section 3(B)(1) of ExxonMobil's 2000 exhibit.

(ii) Compliance determining method.

(A) Compliance with the emission limits referenced in paragraph (f)(4)(i) of this section shall be determined by measuring the SO_2 concentration and flow rate in the Coker CO Boiler stack according to the procedures in paragraphs (f)(4)(ii)(B) and (C) of this section and calculating emissions according to the equations in paragraph (f)(4)(ii)(D) of this section.

(B) Beginning on May 21, 2008, ExxonMobil shall operate and maintain a CEMS to measure sulfur dioxide concentrations in the Coker CO Boiler stack. Whenever ExxonMobil's Coker unit is operating and Coker unit flue gases are exhausted through the Coker CO Boiler stack, the CEMS shall be operational and shall achieve a temporal sampling resolution of at least one (1) concentration measurement per minute, meet the requirements expressed in the definition of "hourly average" in paragraph (c)(14) of this section, and meet the CEMS Performance Specifications contained in section 6(C) of ExxonMobil's 1998 exhibit, except that ExxonMobil shall perform a Cylinder Gas Audit (CGA) or Relative Accuracy Audit (RAA) which meets the requirements of 40 CFR part 60, Appendix F, within eight (8) hours of when the Coker unit flue gases begin ex-

hausting through the Coker CO Boiler stack. ExxonMobil shall perform an annual Relative Accuracy Test Audit (RATA) on the CEMS and notify EPA in writing of each annual RATA a minimum of 25 working days prior to actual testing.

(C) Beginning on May 21, 2008, ExxonMobil shall operate and maintain a continuous stack flow rate monitor to measure the stack gas flow rates in the Coker CO Boiler stack. Whenever ExxonMobil's Coker unit is operating and Coker unit flue gases are exhausted through the Coker CO Boiler stack, this CEMS shall be operational and shall achieve a temporal sampling resolution of at least one (1) flow rate measurement per minute, meet the requirements expressed in the definition of "hourly average" in paragraph (c)(14) of this section, and meet the Stack Gas Flow Rate Monitor Performance Specifications of section 6(D) of ExxonMobil's 1998 exhibit, except that ExxonMobil shall perform an annual Relative Accuracy Test Audit (RATA) on the CEMS and notify EPA in writing of each annual RATA a minimum of 25 working days prior to actual testing.

(D) SO_2 emissions from the Coker CO Boiler stack shall be determined in accordance with the equations in sections 2(A)(1), (8), (11)(a), and (16) of ExxonMobil's 1998 exhibit.

(5) Data reporting requirements.

(i) ExxonMobil shall submit quarterly reports beginning with the first calendar quarter following May 21, 2008. The quarterly reports shall be submitted within 30 days of the end of each calendar quarter. The quarterly reports shall be submitted to EPA at the following address: Air Program Contact, EPA Montana Operations Office, Federal Building, 10 West 15th Street, Suite 3200, Helena, MT 59626.

The quarterly report shall be certified for accuracy in writing by a responsible ExxonMobil official. The quarterly report shall consist of both a comprehensive electronic-magnetic report and a written hard copy data summary report.

(ii) The electronic report shall be on magnetic or optical media, and such submittal shall follow the reporting

format of electronic data being submitted to the MDEQ. EPA may modify the reporting format delineated in this section, and, thereafter, ExxonMobil shall follow the revised format. In addition to submitting the electronic quarterly reports to EPA, ExxonMobil shall also record, organize, and archive for at least five (5) years the same data, and upon request by EPA, ExxonMobil shall provide EPA with any data archived in accordance with this provision. The electronic report shall contain the following:

(A) Hourly average total sulfur concentrations as H₂S or SO₂ in ppm in the gas stream to the flare(s);

(B) Hourly average H₂S concentrations of the flare pilot and purge gases in ppm;

(C) Hourly average SO₂ concentrations in ppm from the Coker CO Boiler stack;

(D) Hourly average volumetric flow rates in SCFH of the flare pilot and purge gases;

(E) Hourly average volumetric flow rates in SCFH in the gas stream to the flare(s) and in the Coker CO Boiler stack;

(F) Hourly average H₂S concentrations in ppm from the refinery fuel gas system;

(G) Hourly average refinery fuel gas combustion units' actual fuel firing rate in SCFH;

(H) Hourly average temperature (in °F) and pressure (in mm or inches of Hg) of the gas stream to the flare(s);

(I) Hourly emissions in pounds per clock hour from the flare(s), Coker CO Boiler stack, and refinery fuel gas combustion system; and

(J) Daily calibration data for the CEMS described in paragraphs (f)(2)(ii), (f)(3)(ii) and (f)(4)(ii) of this section.

(iii) The quarterly written report shall contain the following information:

(A) The 3-hour emissions in pounds per 3-hour period from the flare(s), Coker CO Boiler stack, and refinery fuel gas combustion system;

(B) Periods in which only natural gas or an inert gas was used as flare pilot gas or purge gas or both;

(C) Daily emissions in pounds per calendar day from the Coker CO Boiler

stack and refinery fuel gas combustion system;

(D) The results of all quarterly or other Cylinder Gas Audits (CGA), Relative Accuracy Audits (RAA), and annual Relative Accuracy Test Audits (RATA) for the CEMS described in paragraphs (f)(2)(ii) (flare total sulfur analyzer(s); pilot gas or purge gas H₂S analyzer(s)), (f)(3)(ii), and (f)(4)(ii) of this section, and the results of all annual calibrations and verifications for the volumetric flow, temperature, and pressure monitors;

(E) For all periods of flare volumetric flow rate monitoring system or total sulfur analyzer system downtime, Coker CO Boiler stack CEMS downtime, refinery fuel gas combustion system CEMS downtime, flare pilot gas or purge gas volumetric flow or H₂S analyzer system downtime, or failure to obtain or analyze a grab or integrated sample, the written report shall identify:

(1) Dates and times of downtime or failure;

(2) Reasons for downtime or failure;

(3) Corrective actions taken to mitigate downtime or failure; and

(4) The other methods, approved by EPA in the flare monitoring plan required by paragraph (h)(5) of this section, used to determine flare emissions;

(F) For all periods that the range of the flare or any pilot or purge gas volumetric flow rate monitor(s), any flare total sulfur analyzer(s), or any pilot or purge gas H₂S analyzer(s) is exceeded, the written report shall identify:

(1) Date and time when the range of the volumetric flow monitor(s), total sulfur analyzer(s), or H₂S analyzer(s) was exceeded, and

(2) The other methods, approved by EPA in the flare monitoring plan required by paragraph (h)(5) of this section, used to determine flare emissions;

(G) For all periods that the range of the refinery fuel gas CEMS is exceeded, the written report shall identify:

(1) Date, time, and duration when the range of the refinery fuel gas CEMS was exceeded;

(H) For all periods that the flare volumetric flow monitor or monitors are recording flow, yet any Flare Water Seal Monitoring Device indicates there

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is no flow, the written report shall identify:

(1) Date, time, and duration when the flare volumetric flow monitor(s) recorded flow, yet any Flare Water Seal Monitoring Device indicated there was no flow;

(I) For each 3-hour period and calendar day in which the flare emission limits, the Coker CO Boiler stack emission limits, or the fuel gas combustion system emission limits are exceeded, the written report shall identify:

(1) The date, start time, and end time of the excess emissions;

(2) Total hours of operation with excess emissions, the hourly emissions, the 3-hour emissions, and the daily emissions;

(3) All information regarding reasons for operating with excess emissions; and

(4) Corrective actions taken to mitigate excess emissions; and

(J) When no excess emissions have occurred or the continuous monitoring system(s) or manual system(s) have not been inoperative, repaired, or adjusted, such information shall be stated in the report.

(g) *Montana Sulphur & Chemical Company (MSCC) emission limits and compliance determining methods.*

(1) *Introduction.* The provisions for MSCC cover the following units:

(i) The flares, which consist of the 80-foot west flare, 125-foot east flare, and 100-meter flare.

(ii) The SRU 100-meter stack.

(iii) The auxiliary vent stacks and the units that can exhaust through the auxiliary vent stacks, which consist of the Railroad Boiler, the H-1 Unit, the H1-A unit, the H1-1 unit and the H1-2 unit.

(iv) The SRU 30-meter stack and the units that can exhaust through the SRU 30-meter stack. The units that can exhaust through the SRU 30-meter stack are identified in section 3(A)(2)(d) and (e) of MSCC's 1998 exhibit.

(2) *Flare requirements.*

(i) *Emission limit.* Total combined emissions of SO₂ from the 80-foot west flare, 125-foot east flare, and 100-meter flare shall not exceed 150.0 pounds per 3-hour period.

(ii) *Compliance determining method.* Compliance with the emission limit in paragraph (g)(2)(i) of this section shall be determined in accordance with paragraph (h) of this section. In the event MSCC cannot monitor all three flares from a single location, MSCC shall establish multiple monitoring locations.

(3) *SRU 100-meter stack requirements.*

(i) *Emission limits.* Emissions of SO₂ from the SRU 100-meter stack shall not exceed:

(A) 2,981.7 pounds per 3-hour period;

(B) 23,853.6 pounds per calendar day; and

(C) 9,088,000 pounds per calendar year.

(ii) *Compliance determining method.*

(A) Compliance with the emission limits contained in paragraph (g)(3)(i) of this section shall be determined by the CEMS and emission testing methods required by sections 6(B)(1) and (2) and section 5, respectively, of MSCC's 1998 exhibit.

(B) MSCC shall notify EPA in writing of each annual source test a minimum of 25 working days prior to actual testing.

(C) The CEMS referenced in paragraph (g)(3)(ii)(A) of this section shall achieve a temporal sampling resolution of at least one (1) concentration and flow rate measurement per minute, meet the requirements expressed in the definition of "hourly average" in paragraph (c)(14) of this section, and meet the "CEM Performance Specifications" in sections 6(C) and (D) of MSCC's 1998 exhibit, except that MSCC shall also notify EPA in writing of each annual Relative Accuracy Test Audit at least 25 working days prior to actual testing.

(4) *Auxiliary vent stacks.*

(i) *Emission limits.*

(A) Total combined emissions of SO₂ from the auxiliary vent stacks shall not exceed 12.0 pounds per 3-hour period;

(B) Total combined emissions of SO₂ from the auxiliary vent stacks shall not exceed 96.0 pounds per calendar day;

(C) Total combined emissions of SO₂ from the auxiliary vent stacks shall not exceed 35,040 pounds per calendar year; and

(D) The H₂S concentration in the fuel burned in the Railroad Boiler, the H-1 Unit, the H1-A unit, the H1-1 unit, and

the H1-2 unit, while any of these units is exhausting to the auxiliary vent stacks, shall not exceed 160 ppm per 3-hour period and 100 ppm per calendar day.

(ii) *Compliance determining method.*

(A) Compliance with the emission limits in paragraph (g)(4)(i) of this section shall be determined by measuring the H₂S concentration of the fuel burned in the Railroad Boiler, the H-1 Unit, the H1-A unit, the H1-1 unit, and the H1-2 unit (when fuel other than natural gas is burned in one or more of these units) according to the procedures in paragraph (g)(4)(ii)(C) of this section.

(B) Beginning June 20, 2008, MSCC shall maintain logs of:

(1) The dates and time periods that emissions are exhausted through the auxiliary vent stacks,

(2) The heaters and boilers that are exhausting to the auxiliary vent stacks during such time periods, and

(3) The type of fuel burned in the heaters and boilers during such time periods.

(C) Beginning June 20, 2008, MSCC shall measure the H₂S content of the fuel burned when fuel other than natural gas is burned in a heater or boiler that is exhausting to an auxiliary vent stack. MSCC shall begin measuring the H₂S content of the fuel at the fuel header within one (1) hour from when a heater or boiler begins exhausting to an auxiliary vent stack and on a once-per-3-hour period frequency until no heater or boiler is exhausting to an auxiliary vent stack. To determine the H₂S content of the fuel burned, MSCC shall use length-of-stain detector tubes pursuant to ASTM Method D4810-06, "Standard Test Method for Hydrogen Sulfide in Natural Gas Using Length-of-Stain Detector Tubes" (incorporated by reference, see paragraph (j) of this section) with the appropriate sample tube range. If the results exceed the tube's range, another tube of a higher range must be used until results are in the tube's range.

(5) *SRU 30-meter stack.*

(i) *Emission limits.*

(A) Emissions of SO₂ from the SRU 30-meter stack shall not exceed 12.0 pounds per 3-hour period;

(B) Emissions of SO₂ from the SRU 30-meter stack shall not exceed 96.0 pounds per calendar day;

(C) Emissions of SO₂ from the SRU 30-meter stack shall not exceed 35,040 pounds per calendar year; and

(D) The H₂S concentration in the fuel burned in the heaters and boilers described in paragraph (g)(1)(iv) of this section, while any of these units is exhausting to the SRU 30-meter stack, shall not exceed 160 ppm per 3-hour period and 100 ppm per calendar day.

(ii) *Compliance determining method.*

(A) Compliance with the emission limits in paragraph (g)(5)(i) of this section shall be determined by measuring the H₂S concentration of the fuel burned in the heaters and boilers described in paragraph (g)(1)(iv) of this section (when fuel other than natural gas is burned in one or more of these heaters or boilers) according to the procedures in paragraph (g)(5)(ii)(C) of this section.

(B) Beginning June 20, 2008, MSCC shall maintain logs of:

(1) The dates and time periods that emissions are exhausted through the SRU 30-meter stack,

(2) The heaters and boilers that are exhausting to the SRU 30-meter stack during such time periods, and

(3) The type of fuel burned in the heaters and boilers during such time periods.

(C) Beginning June 20, 2008, MSCC shall measure the H₂S content of the fuel burned when fuel other than natural gas is burned in a heater or boiler that is exhausting to the SRU 30-meter stack. MSCC shall begin measuring the H₂S content of the fuel at the fuel header within one (1) hour from when any heater or boiler begins exhausting to the SRU 30-meter stack and on a once-per-3-hour period frequency until no heater or boiler is exhausting to the SRU 30-meter stack. To determine the H₂S content of the fuel burned, MSCC shall use length-of-stain detector tubes pursuant to ASTM Method D4810-06, "Standard Test Method for Hydrogen Sulfide in Natural Gas Using Length-of-Stain Detector Tubes" (incorporated by reference, see paragraph (j) of this section) with the appropriate sample tube range. If the results exceed the tube's range, another tube of a higher

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range must be used until results are in the tube's range.

(6) Data reporting requirements:

(i) MSCC shall submit quarterly reports beginning with the first calendar quarter following May 21, 2008. The quarterly reports shall be submitted within 30 days of the end of each calendar quarter. The quarterly reports shall be submitted to EPA at the following address: Air Program Contact, EPA Montana Operations Office, Federal Building, 10 West 15th Street, Suite 3200, Helena, MT 59626.

The quarterly report shall be certified for accuracy in writing by a responsible MSCC official. The quarterly report shall consist of both a comprehensive electronic-magnetic report and a written hard copy data summary report.

(ii) The electronic report shall be on magnetic or optical media, and such submittal shall follow the reporting format of electronic data being submitted to the MDEQ. EPA may modify the reporting format delineated in this section, and, thereafter, MSCC shall follow the revised format. In addition to submitting the electronic quarterly reports to EPA, MSCC shall also record, organize, and archive for at least five (5) years the same data, and upon request by EPA, MSCC shall provide EPA with any data archived in accordance with this provision. The electronic report shall contain the following:

(A) Hourly average total sulfur concentrations as H₂S or SO₂ in ppm, in the gas stream to the flare(s);

(B) Hourly average H₂S concentrations of the flare pilot and purge gases in ppm;

(C) Hourly average SO₂ concentrations in ppm from the SRU 100-meter stack;

(D) Hourly average volumetric flow rates in SCFH in the gas stream to the flare(s) and in the SRU 100-meter stack;

(E) Hourly average volumetric flow rates in SCFH of the flare pilot and purge gases;

(F) Hourly average temperature (in °F) and pressure (in mm or inches of Hg) in the gas stream to the flare(s);

(G) Hourly emissions in pounds per clock hour from the flare(s) and SRU 100-meter stack;

(H) Daily calibration data for all flare CEMS, all pilot gas and purge gas CEMS, and the SRU 100-meter stack CEMS;

(iii) The quarterly written report shall contain the following information:

(A) The 3-hour emissions in pounds per 3-hour period from the flare(s) and SRU 100-meter stack, and 3-hour H₂S concentrations in the fuel burned in the heaters and boilers described in paragraphs (g)(1)(iii) and (iv) of this section while any of these units is exhausting to the SRU 30-meter stack or auxiliary vent stacks and burning fuel other than natural gas;

(B) Periods in which only natural gas or an inert gas was used as flare pilot gas or purge gas or both;

(C) Daily emissions in pounds per calendar day from the SRU 100-meter stack;

(D) Annual emissions of SO₂ in pounds per calendar year from the SRU 100-meter stack;

(E) The results of all quarterly Cylinder Gas Audits (CGA), Relative Accuracy Audits (RAA) and annual Relative Accuracy Test Audits (RATA) for all total sulfur analyzer(s), all H₂S analyzer(s), and the SRU 100-meter stack CEMS, and the results of all annual calibrations and verifications for the volumetric flow, temperature, and pressure monitors;

(F) For all periods of flare volumetric flow rate monitoring system or total sulfur analyzer system downtime, SRU 100-meter CEMS downtime, flare pilot gas or purge gas volumetric flow or H₂S analyzer system downtime, failure to obtain or analyze a grab or integrated sample, or failure to obtain an H₂S concentration sample as required by paragraphs (g)(4)(ii)(C) and (g)(5)(ii)(C) of this section, the written report shall identify:

(1) Dates and times of downtime or failure;

(2) Reasons for downtime or failure;

(3) Corrective actions taken to mitigate downtime or failure; and

(4) The other methods, approved by EPA in the flare monitoring plan required by paragraph (h)(5) of this section, used to determine flare emissions;

(G) For all periods that the range of the flare or any pilot or purge gas volumetric flow rate monitor(s), any flare total sulfur analyzer(s), or any pilot or purge gas H₂S analyzer(s), is exceeded, the written report shall identify:

(1) Date and time when the range of the volumetric flow monitor(s), total sulfur analyzer(s), or H₂S analyzer(s) was exceeded; and

(2) The other methods, approved by EPA in the flare monitoring plan required by paragraph (h)(5) of this section, used to determine flare emissions;

(H) For all periods that the flare volumetric flow monitor or monitors are recording flow, yet any Flare Water Seal Monitoring Device indicates there is no flow, the written report shall identify:

(1) Date, time, and duration when the flare volumetric flow monitor(s) recorded flow, yet any Flare Water Seal Monitoring Device indicated there was no flow;

(I) For each 3-hour period and calendar day in which the flare emission limit, the SRU 100-meter stack emission limits, the SRU 30-meter stack emission limits, or auxiliary vent stack emission limits are exceeded, the written report shall identify:

(1) The date, start time, and end time of the excess emissions;

(2) Total hours of operation with excess emissions, the hourly emissions, the 3-hour emissions, and the daily emissions;

(3) All information regarding reasons for operating with excess emissions; and

(4) Corrective actions taken to mitigate excess emissions;

(J) For instances in which emissions are exhausted through the auxiliary vent stacks or 30-meter stack, the quarterly written report shall identify:

(1) The dates and time periods that emissions were exhausted through the auxiliary vent stacks or the 30-meter stack;

(2) The heaters and boilers that were exhausting to the auxiliary vent stacks or 30-meter stack during such time periods; and

(3) The type of fuel burned in the heaters and boilers during such time periods; and

(K) When no excess emissions have occurred or the continuous monitoring system(s) or manual system(s) have not been inoperative, repaired, or adjusted, such information shall be stated in the report.

(h) *Flare compliance determining method.*

(1) Compliance with the emission limits in paragraphs (d)(2)(i), (e)(2)(i), (f)(2)(i) and (g)(2)(i) of this section shall be determined by measuring the total sulfur concentration and volumetric flow rate of the gas stream to the flare(s) (corrected to one (1) atmosphere pressure and 68 °F) and using the methods contained in the flare monitoring plan required by paragraph (h)(5) of this section. The volumetric flow rate of the gas stream to the flare(s) shall be determined in accordance with the requirements in paragraph (h)(2) of this section and the total sulfur concentration of the gas stream to the flare(s) shall be determined in accordance with paragraph (h)(3) of this section.

(2) *Flare flow monitoring:*

(i) Within 365 days after receiving EPA approval of the flare monitoring plan required by paragraph (h)(5) of this section, each facility named in paragraph (a) of this section shall install and calibrate, and, thereafter, calibrate, maintain and operate, a continuous flow monitoring system capable of measuring the volumetric flow of the gas stream to the flare(s) in accordance with the specifications contained in paragraphs (h)(2)(iii) through (vi) of this section. The flow monitoring system shall require more than one flow monitoring device or flow measurements at more than one location if one monitor cannot measure the total volumetric flow to each flare.

(ii) Volumetric flow monitors meeting the proposed volumetric flow monitoring specifications below should be able to measure the majority of volumetric flow in the gas streams to the flare. However, in rare events (e.g., upset conditions) the flow to the flare may exceed the range of the monitor. In such cases, or when the volumetric

flow monitor or monitors are not working, other methods approved by EPA in the flare monitoring plan required by paragraph (h)(5) of this section shall be used to determine the volumetric flow rate to the flare, which shall then be used to calculate SO₂ emissions. In quarterly reports, sources shall indicate when these other methods are used.

(iii) The flare gas stream volumetric flow rate shall be measured on an actual wet basis, converted to Standard Conditions, and reported in SCFH. The minimum detectable velocity of the flow monitoring device(s) shall be 0.1 feet per second (fps). The flow monitoring device(s) shall continuously measure the range of flow rates corresponding to velocities from 0.5 to 275 fps and have a manufacturer's specified accuracy of $\pm 5\%$ of the measured flow over the range of 1.0 to 275 fps and $\pm 20\%$ of the measured flow over the range of 0.1 to 1.0 fps. The volumetric flow monitor(s) shall feature automated daily calibrations at low and high ranges. The volumetric flow monitor(s) shall be calibrated annually according to manufacturer's specifications.

(iv) For correcting flow rate to standard conditions (defined as 68 °F and 760 mm, or 29.92 inches, of Hg), temperature and pressure shall be monitored continuously. Temperature and pressure shall be monitored in the same location as volumetric flow, and the temperature and pressure monitors shall be calibrated prior to installation according to manufacturer's specifications and, thereafter, annually to meet accuracy specifications as follows: The temperature monitor shall be calibrated to within $\pm 2.0\%$ at absolute temperature and the pressure monitor shall be calibrated to within ± 5.0 mmHg;

(v) The flow monitoring device(s) shall be calibrated prior to installation to demonstrate accuracy of the measured flow to within 5.0% at flow rates equivalent to 30%, 60%, and 90% of monitor full scale.

(vi) Each volumetric flow device shall achieve a temporal sampling resolution of at least one (1) flow rate measurement per minute, meet the requirements expressed in the definition of "hourly average" in paragraph

(c)(14) of this section, and be installed in a manner and at a location that will allow for accurate measurements of the total volume of the gas stream going to each flare. Each temperature and pressure monitoring device shall achieve a temporal sampling resolution of at least one (1) measurement per minute, meet the requirements expressed in the definition of "hourly average" in paragraph (c)(14) of this section, and be installed in a manner that will allow for accurate measurements.

(vii) In addition to the continuous flow monitors, facilities may use flare water seal monitoring devices to determine whether there is flow going to the flare. If used, owners or operators shall install, calibrate, operate, and maintain these devices according to manufacturer's specifications. The devices shall include a continuous monitoring system that:

(A) Monitors the status of the water seal to indicate when flow is going to the flare;

(B) Automatically records the time and duration when flow is going to the flare; and

(C) Verifies that the physical seal has been restored after flow has been sent to the flare.

If the water seal monitoring devices indicate that there is no flow going to the flare, yet the continuous flow monitor is indicating flow, the presumption will be that no flow is going to the flare.

(viii) Each facility named in paragraph (a) of this section, that does not certify that only natural gas or an inert gas is used for both the pilot gas and purge gas, shall determine the volumetric flow of each pilot gas and purge gas stream for which natural gas or inert gas is not used by one of the following methods:

(A) Measure the volumetric flow of the gas using continuous flow monitoring devices on an actual wet basis, converted to Standard Conditions, and reported in SCFH. Each flow monitoring device shall achieve a temporal sampling resolution of at least one (1) flow rate measurement per minute, meet the requirements expressed in the definition of "hourly average" in paragraph (c)(14) of this section, and be installed in a manner and at a location

that will allow for accurate measurements of the total volume of the gas. Gas flow rate monitor accuracy determinations shall be required at least once every 48 months or more frequently at routine refinery turn-around. In cases when the flow monitoring device or devices are not working or the range of the monitoring device(s) is exceeded, other methods approved by EPA in the flare monitoring plan required by paragraph (h)(5) of this section shall be used to determine volumetric flow of the gas which shall then be used to calculate SO₂ emissions. In quarterly reports, sources shall indicate when other methods are used; or

(B) Use parameters and methods approved by EPA in the flare monitoring plan required by paragraph (h)(5) of this section to calculate the volumetric flows of the gas, in SCFH.

(3) *Flare concentration monitoring:*

(i) Within 365 days after receiving EPA approval of the flare monitoring plan required by paragraph (h)(5) of this section, each facility named in paragraph (a) of this section shall determine the total sulfur concentration of the gas stream to the flare(s) using either continuous total sulfur analyzers or grab or integrated sampling with lab analysis, as described in the following paragraphs:

(A) Continuous total sulfur concentration monitoring. If a facility chooses to use continuous total sulfur concentration monitoring, the following requirements apply:

(1) The facility shall install and calibrate, and, thereafter, calibrate, maintain and operate, a continuous total sulfur concentration monitoring system capable of measuring the total sulfur concentration of the gas stream to each flare. Continuous monitoring shall occur at a location or locations that are representative of the gas combusted in the flare and be capable of measuring the normally expected range of total sulfur in the gas stream to the flare. The concentration monitoring system shall require more than one concentration monitoring device or concentration measurements at more than one location if one monitor cannot measure the total sulfur concentration to each flare. Total sulfur

concentration shall be reported as H₂S or SO₂ in ppm. In cases when the total sulfur analyzer or analyzers are not working or the concentration of the total sulfur exceeds the range of the analyzer(s), other methods, approved by EPA in the flare monitoring plan required by paragraph (h)(5) of this section, shall be used to determine total sulfur concentrations, which shall then be used to calculate SO₂ emissions. In quarterly reports, sources shall indicate when these other methods are used.

(2) The total sulfur analyzer(s) shall achieve a temporal sampling resolution of at least one (1) concentration measurement per 15 minutes, meet the requirements expressed in the definition of "hourly average" in paragraph (c)(14) of this section, be installed, certified (on a concentration basis), and operated in accordance with 40 CFR part 60, Appendix B, Performance Specification 5, and be subject to and meet the quality assurance and quality control requirements (on a concentration basis) of 40 CFR part 60, Appendix F.

(3) Each affected facility named in paragraph (a) of this section shall notify the Air Program Contact at EPA's Montana Operations Office, Federal Building, 10 West 15th Street, Suite 3200, Helena, MT 59626, in writing of each Relative Accuracy Test Audit a minimum of 25 working days prior to the actual testing.

(B) Grab or integrated total sulfur concentration monitoring: If a facility chooses grab or integrated sampling instead of continuous total sulfur concentration monitoring, the facility shall comply with the methods specified in either paragraph (h)(3)(i)(B)(1) ("Grab Sampling") or (h)(3)(i)(B)(2) ("Integrated Sampling"), and the requirements of paragraphs (h)(3)(i)(B)(3) ("Sample Analysis"), (h)(3)(i)(B)(4) ("Exemptions"), and (h)(3)(i)(B)(5) ("Missing or Unanalyzed Sample") of this section, as follows:

(1) Grab Sampling. Each facility that chooses to use grab sampling shall meet the following requirements: if the flow rate of the gas stream to the flare in any consecutive 15-minute period continuously exceeds 0.5 feet per second (fps) and the water seal monitoring device, if any, indicates that flow is

going to the flare, a grab sample shall be collected within 15 minutes. The grab sample shall be collected at a location that is representative of the gas combusted in the flare. Thereafter, the sampling frequency shall be one (1) grab sample every three (3) hours, which shall continue until the velocity of the gas stream going to the flare in any consecutive 15-minute period is continuously 0.5 fps or less. Samples shall be analyzed according to paragraph (h)(3)(i)(B)(3) of this section. The requirements of this paragraph (h)(3)(i)(B)(1) shall apply to each flare at a facility for which the sampling threshold is exceeded.

(2) Integrated Sampling. Each facility that chooses to use integrated sampling shall meet the following requirements: if the flow rate of the gas stream to the flare in any consecutive 15-minute period continuously exceeds 0.5 feet per second (fps) and the water seal monitoring device, if any, indicates that flow is going to the flare, a sample shall be collected within 15 minutes. The sample shall be collected at a location that is representative of the gas combusted in the flare. The sampling frequency, thereafter, shall be a minimum of one (1) aliquot for each 15-minute period until the sample container is full, or until the end of a 3-hour period is reached, whichever comes sooner. Within 30 minutes thereafter, a new sample container shall be placed in service, and sampling on this frequency, and in this manner, shall continue until the velocity of the gas stream going to the flare in any consecutive 15-minute period is continuously 0.5 fps or less. Samples shall be analyzed according to paragraph (h)(3)(i)(B)(3) of this section. The requirements of this paragraph (h)(3)(i)(B)(2) shall apply to each flare at a facility for which the sampling threshold is exceeded.

(3) Samples shall be analyzed using ASTM Method D4468-85 (Reapproved 2000) "Standard Test Method for Total Sulfur in Gaseous Fuels by Hydrogenolysis and Rateometric Colorimetry," (incorporated by reference, see paragraph (j) of this section) ASTM Method D5504-01 (Reapproved 2006) "Standard Test Method for Determination of Sulfur Compounds in Natural

Gas and Gaseous Fuels by Gas Chromatography and Chemiluminescence," (incorporated by reference, see paragraph (j) of this section) or 40 CFR part 60, Appendix A-5, Method 15A "Determination of Total Reduced Sulfur Emissions From the Sulfur Recovery Plants in Petroleum Refineries." Total sulfur concentration shall be reported as H₂S or SO₂ in ppm.

(4) Exemptions. For facilities using a sampling method specified in either paragraph (h)(3)(i)(B)(1) ("Grab Sampling") or (h)(3)(i)(B)(2) ("Integrated Sampling") of this section, obtaining a sample is not required if flaring is a result of a catastrophic or other unusual event, including a major fire or an explosion at the facility, such that collecting a sample at the EPA-approved location during the relevant period is infeasible or constitutes a safety hazard, provided that the owner or operator shall collect a sample at an alternative location if feasible, safe, and representative of the flaring event. The owner or operator shall demonstrate to EPA that it was infeasible or unsafe to collect a sample or to collect a sample at the sampling location approved by EPA in the flare monitoring plan required by paragraph (h)(5) of this section. The owner or operator shall also demonstrate to EPA that any sample collected at an alternative location is representative of the flaring incident. If a facility experiences ongoing difficulties collecting grab or integrated samples in accordance with its flare monitoring plan approved by EPA pursuant to paragraph (h)(5) of this section, EPA may require the facility to revise its flare monitoring plan and use continuous total sulfur concentration monitoring as described in paragraph (h)(3)(i)(A) of this section or other reliable method to determine total sulfur concentrations of the gas stream to the flare.

(5) Missing or Unanalyzed Samples. For facilities using a sampling method specified in either paragraph (h)(3)(i)(B)(1) ("Grab Sampling") or (h)(3)(i)(B)(2) ("Integrated Sampling") of this section, if a required sample is not obtained or analyzed for any reason, other methods approved by EPA in the flare monitoring plan required by paragraph (h)(5) of this section shall be

used to determine total sulfur concentrations, which shall then be used to calculate SO₂ emissions. In quarterly reports, sources shall indicate when these other methods are used.

(6) Reporting. For facilities using a sampling method specified in either paragraph (h)(3)(i)(B)(1) (“Grab Sampling”) or (h)(3)(i)(B)(2) (“Integrated Sampling”) of this section, since normally only one (1) sample per flare will be analyzed for a 3-hour period, the total sulfur concentration of a sample obtained during a given 3-hour period shall be substituted for each hour of such 3-hour period. If integrated sampling for a flare produces more than one (1) sample container during a 3-hour period, and the gas in each container is analyzed separately, the concentrations for the containers shall be averaged. For that flare, the resulting average shall be substituted for each hour of the 3-hour period during which the sampling occurred. The substituted hourly total sulfur concentrations determined per this paragraph shall be used to determine hourly emissions from the flare.

(ii) Each facility named in paragraph (a) of this section that does not certify that only natural gas or an inert gas is used for both the pilot gas and purge gas shall determine the H₂S concentration of each pilot gas and purge gas stream for which natural gas or inert gas is not used by one of the following methods:

(A) Measure the H₂S concentration of the gas by continuous H₂S analyzer. The H₂S concentration analyzer(s) shall achieve a temporal sampling resolution of at least one (1) concentration measurement per three (3) minutes, meet the requirements expressed in the definition of “hourly average” in paragraph (c)(14) of this section, be installed, certified (on a concentration basis), and operated in accordance with 40 CFR part 60, Appendix B, Performance Specification 2, and be subject to and meet the quality assurance and quality control requirements (on a concentration basis) of 40 CFR part 60, Appendix F. In cases where the H₂S analyzer or analyzers are not working or the H₂S concentration exceeds the range of the analyzer(s), other methods approved by EPA in the flare moni-

toring plan required by paragraph (h)(5) of this section shall be used to determine the H₂S concentration of the gas, which shall then be used to calculate SO₂ emissions. In quarterly reports, sources shall indicate when other methods are used; or

(B) Use methods approved by EPA as part of the facility’s flare monitoring plan required by paragraph (h)(5) of this section to estimate the H₂S concentration of the gas.

(4) *Calculation of SO₂ emissions from flares.* Methods for calculating hourly and 3-hour SO₂ emissions from flares shall be submitted to EPA as part of the flare monitoring plan required by paragraph (h)(5) of this section. Following approval by EPA, such methods shall be followed for calculating hourly and 3-hour SO₂ emissions from a facility’s flare(s).

(5) By October 20, 2008, each facility named in paragraph (a) of this section shall submit a flare monitoring plan. Each flare monitoring plan shall include, at a minimum, the following:

(i) A facility plot plan showing the location of each flare in relation to the general plant layout;

(ii) Drawing(s) with dimensions, preferably to scale, and an as-built process flow diagram of the flare(s) identifying major components, such as flare header, flare stack, flare tip(s) or burner(s), purge gas system, pilot gas system, water seal, knockout drum, and molecular seal;

(iii) A representative flow diagram showing the interconnections of the flare system(s) with vapor recovery system(s), process units, and other equipment as applicable;

(iv) A complete description of the gas flaring process for an integrated gas flaring system that describes the method of operation of the flares;

(v) A complete description of the vapor recovery system(s) which have interconnection to a flare, such as compressor description(s); design capacities of each compressor and the vapor recovery system; and the method currently used to determine and record the amount of vapors recovered;

(vi) A complete description of the proposed method to monitor, determine, and record the total volume and total sulfur concentration of gases

combusted in the flare, including drawing(s) with dimensions, preferably to scale, showing the following information for the proposed flare gas stream monitoring systems:

(A) The locations to be used for all monitoring and sampling, including, but not limited to: Flare flow monitors, total sulfur analyzers, concentration integrated sampling, concentration grab sampling, water seal monitoring devices, pilot and purge gas flow monitors, and pilot and purge gas concentration monitors;

(vii) A description of the method(s) used to determine, and reasoning behind, all monitoring and sampling locations;

(viii) The following information regarding pilot gas and purge gas for each flare:

(A) Type(s) of gas used;

(B) A complete description of the monitor(s) to be used, or the other parameters that will be used and monitored, to determine volumetric flows of the pilot gas and purge gas streams for which natural gas or inert gas is not used; and

(C) A complete description of the analyzer(s) to be used to determine, or other methods that will be used to estimate, the H₂S concentrations in the pilot gas and purge gas streams for which natural gas or inert gas is not used;

(ix) A detailed description of manufacturer's specifications, including, but not limited to, make, model, type, range, precision, accuracy, calibration, maintenance, quality assurance procedure, and any other relevant specifications and information referenced in paragraphs (h)(2) and (3) of this section for all existing and proposed flow monitoring devices and total sulfur analyzers;

(x) The following information if grab or integrated sampling is used:

(A) A complete description of proposed analytical and sampling methods if grab or integrated sampling methods will be used for determining the total sulfur concentration of the gas stream going to the flare;

(B) A detailed description of manufacturer's specifications, including, but not limited to, make, model, type, maintenance, and quality assurance

procedures for the integrated sampling device, if used; and

(C) A complete description of the proposed method to alert personnel designated to collect samples that the trigger for collecting a sample has occurred;

(xi) A complete description of the methods to be used to estimate flare emissions when any flare, pilot gas, or purge gas volumetric flow monitoring devices, total sulfur analyzers, or grab or integrated sampling methods, or pilot gas or purge gas H₂S analyzers are not working or available, or the operating range of the monitors or analyzers is exceeded;

(xii) A complete description of the proposed data recording, collection, and management system and any other relevant specifications and information referenced in paragraphs (h)(2) and (3) of this section for each flare monitoring system;

(xiii) The following information for each flare using a water seal monitoring device:

(A) A detailed description of manufacturer's specifications, including, but not limited to, make, model, type, maintenance, and quality assurance procedures;

(B) A complete description of the proposed methods to determine that the water seal is no longer intact and flow is going to the flare, and the data used to establish, and reasoning behind, these methods;

(xiv) A schedule for the installation and operation of each flare monitoring system consistent with the deadline in paragraphs (h)(2) and (h)(3) of this section; and

(xv) A complete description of the methods to be used for calculating hourly and 3-hour SO₂ emissions from flares.

(6) Thirty (30) days prior to installing any continuous monitor or integrated sampler pursuant to paragraphs (h)(2) and (3) of this section, each facility named in paragraph (a) of this section shall submit for EPA review a quality assurance/quality control (QA/QC) plan for each monitor or sampler being installed.

(i) *Affirmative defense provisions for exceedances of flare emission limits during malfunctions, startups, and shutdowns.*

(1) In response to an action to enforce the emission limits in paragraphs (d)(2)(i), (e)(2)(i), (f)(2)(i), and (g)(2)(i) of this section, owners and/or operators of the facilities named in paragraph (a) of this section may assert an affirmative defense to a claim for civil penalties for exceedances of such limits during periods of malfunction, startup, or shutdown. To establish the affirmative defense and to be relieved of a civil penalty in any action to enforce such a limit, the owner or operator of the facility must meet the notification requirements of paragraph (i)(2) of this section in a timely manner and prove by a preponderance of evidence that:

(i) For claims of malfunction:

(A) The excess emissions were caused by a sudden, unavoidable breakdown of equipment, or a sudden, unavoidable failure of a process to operate in the normal or usual manner, beyond the control of the owner or operator;

(B) The excess emissions:

(1) Did not stem from any activity or event that could have been foreseen and avoided, or planned for; and

(2) Could not have been avoided by better operation and maintenance practices;

(C) Repairs were made as expeditiously as possible when the applicable emission limitations were being exceeded. Off-shift and overtime labor were used, to the extent practicable;

(D) The amount and duration of the excess emissions (including any bypass) were minimized to the maximum extent practicable during periods of such emissions;

(ii) For claims of startup or shutdown:

(A) All or a portion of the facility was in startup or shutdown mode, resulting in the need to route gases to the flare;

(B) The periods of excess emissions that occurred during startup and shutdown were short and infrequent and could not have been prevented through careful planning and design or better operation and maintenance practices; and

(C) The frequency and duration of operation in startup or shutdown mode were minimized to the maximum extent practicable;

(iii) For claims of malfunction, startup, or shutdown:

(A) If the excess emissions resulted from a bypass of control equipment or a process, then the bypass was unavoidable to prevent loss of life, personal injury, or severe property damage;

(B) All possible steps were taken to minimize the impact of the excess emissions on ambient air quality;

(C) All emissions monitoring systems were kept in operation if at all possible;

(D) The owner or operator's actions in response to the excess emissions were documented by properly signed, contemporaneous operating logs;

(E) The excess emissions were not part of a recurring pattern indicative of inadequate design, operation, or maintenance;

(F) At all times, the facility was operated in a manner consistent with good practices for minimizing emissions; and

(G) During the period of excess emissions, there were no exceedances of the SO₂ NAAQS that could be attributed to the emitting source.

(2) Notification. The owner or operator of the facility experiencing an exceedance of its flare emission limit(s) during startup, shutdown, or malfunction shall notify EPA verbally as soon as possible, but no later than noon of EPA's next working day, and shall submit written notification to EPA within 30 days of the initial occurrence of the exceedance. The written notification shall explain whether and how the elements set forth in paragraph (i)(1) of this section were met, and include all supporting documentation.

(3) Injunctive relief. The Affirmative Defense Provisions contained in paragraph (i)(1) of this section shall not be available to claims for injunctive relief.

(j) *Incorporation by reference.* (1) The materials listed in this paragraph are incorporated by reference in the corresponding paragraphs noted. These incorporations by reference are approved by the Director of the Federal Register in accordance with 5 U.S.C. 552(a) and 1 CFR part 51. These materials are incorporated as they exist on the date of the approval, and notice of any change in these materials will be

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published in the FEDERAL REGISTER. The materials are available for purchase at the corresponding address noted below, and all are available for inspection at the National Archives and Records Administration (NARA) and at the Air Program, EPA, Region 8, 1595 Wynkoop Street, Denver, CO. For information on the availability of this material at NARA, call 202-741-6030, or go to: http://www.archives.gov/federal_register/code_of_federal_regulations/ibr_locations.html.

(2) The following materials are available for purchase from the following address: American Society for Testing and Materials (ASTM), 100 Barr Harbor Drive, Post Office Box C700, West Conshohocken, PA 19428-2959, www.astm.org, or by calling (610) 832-9585.

(i) ASTM Method D4468-85 (Re-approved 2000), Standard Test Method for Total Sulfur in Gaseous Fuels by Hydrogenolysis and Rateometric Colorimetry, IBR approved for paragraph (h)(3)(i)(B)(3) of this section.

(ii) ASTM Method D4810-06, Standard Test Method for Hydrogen Sulfide in Natural Gas Using Length-of-Stain Detector Tubes, IBR approved for paragraphs (f)(3)(ii)(B), (g)(4)(ii)(C), and (g)(5)(ii)(C) of this section.

(ii) ASTM Method D5504-01 (Re-approved 2006), Standard Test Method for Determination of Sulfur Compounds in Natural Gas and Gaseous Fuels by Gas Chromatography IBR approved for paragraph (h)(3)(i)(B)(3) of this section.

[73 FR 21454, Apr. 21, 2008]

§ 52.1393 Interstate transport requirements.

(a) The State of Montana added the Interstate Transport Rule Declaration to the State SIP, State of Montana Air Quality Control Implementation Plan, Volume I, Chapter 9, to satisfy the requirements of Clean Air Act Section 110(a)(2)(D)(i) for the 8-hour ozone and PM_{2.5} NAAQS promulgated in July 1997. The Montana Interstate Transport Rule Declaration, adopted and effective on the same date of February 12, 2007, was submitted to EPA on April 16, 2007. The April 16, 2007 Governor's letter included as an attachment a set of dated

replacement pages for the Montana Interstate Transport Rule Declaration. The new set of pages were sent as replacement for the set of undated pages submitted earlier with the February 12, 2007 Record of Adoption package. In a May 10, 2007 e-mail to Domenico Mastrangelo, EPA, Debra Wolfe, of the Montana Department of Environmental Quality, confirmed February 12, 2007 as the adoption/effective date for the Montana Interstate Transport Rule Declaration.

(b) On February 10, 2010, Montana Governor Brian Schweitzer submitted a letter certifying, in part, that Montana's SIP is adequate to meet the interstate transport requirements of CAA section 110(a)(2)(D)(i)(I) for the 2006 PM_{2.5} NAAQS.

[73 FR 10154, Feb. 26, 2008, as amended at 78 FR 45871, July 30, 2013]

§ 52.1394 Section 110(a)(2) infrastructure requirements.

(a) On December 22, 2009, David L. Klemp, Bureau Chief, Air Resources Management Bureau, of the Montana Department of Environmental Quality submitted a certification letter which provides the State of Montana's SIP provisions which meet the requirements of CAA Section 110(a)(1) and (2) relevant to the 1997 Ozone NAAQS.

(b) On February 10, 2010, Brian Schweitzer, Governor, State of Montana, submitted a certification letter which provides the State of Montana's SIP provisions which meet the requirements of CAA section 110(a)(1) and (2), elements (A), (B), (C) with respect to the requirement to have a minor NSR program that addresses PM_{2.5}; (E)(i), (E)(iii), (F), (G), (H), (J) with respect to the requirements of sections 121 and 127, (K), (L), and (M).

[76 FR 43923, July 22, 2011, as amended at 78 FR 45866, July 30, 2013]

§ 52.1395 Smoke management plan.

The Department considers smoke management techniques for agriculture and forestry management burning purposes as set forth in 40 CFR 51.308(d)(3)(v)(E). The Department considers the visibility impact of smoke