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(e) Each owner or operator subject to § 60.104(b) who has demonstrated compliance with one of the provisions of § 60.104(b) but a later date seeks to comply with another of the provisions of § 60.104(b) shall begin conducting daily performance tests as specified under paragraph (d) of this section immediately upon electing to become subject to one of the other provisions of § 60.104(b). The owner or operator shall furnish the Administrator with a written notification of the change in the semiannual report required by § 60.107(f).

[54 FR 34030, Aug. 17, 1989, as amended at 55 FR 40178, Oct. 2, 1990; 64 FR 7466, Feb. 12, 1999; 73 FR 35867, June 24, 2008]

§ 60.109 Delegation of authority.

(a) In delegating implementation and enforcement authority to a State under section 111(c) of the Act, the authorities contained in paragraph (b) of this section shall be retained by the Administrator and not transferred to a State.

(b) Authorities which shall not be delegated to States:

- (1) Section 60.105(a)(13)(iii),
- (2) Section 60.106(i)(12).

[54 FR 34031, Aug. 17, 1989, as amended at 55 FR 40178, Oct. 2, 1990]

Subpart Ja—Standards of Performance for Petroleum Refineries for Which Construction, Reconstruction, or Modification Commenced After May 14, 2007

SOURCE: 73 FR 35867, June 24, 2008, unless otherwise noted.

§ 60.100a Applicability, designation of affected facility, and reconstruction.

(a) The provisions of this subpart apply to the following affected facilities in petroleum refineries: fluid catalytic cracking units (FCCU), fluid coking units (FCU), delayed coking units, fuel gas combustion devices (including process heaters), flares and sulfur recovery plants. The sulfur recovery plant need not be physically located within the boundaries of a petroleum refinery to be an affected facility, pro-

vided it processes gases produced within a petroleum refinery.

(b) Except for flares and delayed coking units, the provisions of this subpart apply only to affected facilities under paragraph (a) of this section which commence construction, modification or reconstruction after May 14, 2007. For flares, the provisions of this subpart apply only to flares which commence construction, modification or reconstruction after June 24, 2008. For the purposes of this subpart, a modification to a flare commences when a project that includes any of the activities in paragraphs (c)(1) or (2) of this section is commenced. For delayed coking units, the provisions of this subpart apply to delayed coking units that commence construction, reconstruction or modification on the earliest of the following dates:

(1) May 14, 2007, for such activities that involve a “delayed coking unit” defined as follows: one or more refinery process units in which high molecular weight petroleum derivatives are thermally cracked and petroleum coke is produced in a series of closed, batch system reactors;

(2) December 22, 2008, for such activities that involve a “delayed coking unit” defined as follows: a refinery process unit in which high molecular weight petroleum derivatives are thermally cracked and petroleum coke is produced in a series of closed, batch system reactors. A delayed coking unit consists of the coke drums and associated fractionator;

(3) September 12, 2012, for such activities that involve a “delayed coking unit” as defined in § 60.101a.

(c) For all affected facilities other than flares, the provisions in § 60.14 regarding modification apply. As provided in § 60.14(f), the special provisions set forth under this subpart shall supersede the provisions in § 60.14 with respect to flares. For the purposes of this subpart, a modification to a flare occurs as provided in paragraphs (c)(1) or (2) of this section.

(1) Any new piping from a refinery process unit, including ancillary equipment, or a fuel gas system is physically connected to the flare (*e.g.*, for direct

emergency relief or some form of continuous or intermittent venting). However, the connections described in paragraphs (c)(1)(i) through (vii) of this section are not considered modifications of a flare.

(i) Connections made to install monitoring systems to the flare.

(ii) Connections made to install a flare gas recovery system or connections made to upgrade or enhance components of a flare gas recovery system (*e.g.*, addition of compressors or recycle lines).

(iii) Connections made to replace or upgrade existing pressure relief or safety valves, provided the new pressure relief or safety valve has a set point opening pressure no lower and an internal diameter no greater than the existing equipment being replaced or upgraded.

(iv) Connections made for flare gas sulfur removal.

(v) Connections made to install back-up (redundant) equipment associated with the flare (such as a back-up compressor) that does not increase the capacity of the flare.

(vi) Replacing piping or moving an existing connection from a refinery process unit to a new location in the same flare, provided the new pipe diameter is less than or equal to the diameter of the pipe/connection being replaced/moved.

(vii) Connections that interconnect two or more flares.

(2) A flare is physically altered to increase the flow capacity of the flare.

(d) For purposes of this subpart, under § 60.15, the "fixed capital cost of the new components" includes the fixed capital cost of all depreciable components which are or will be replaced pursuant to all continuous programs of component replacement which are commenced within any 2-year period following the relevant applicability date specified in paragraph (b) of this section.

[73 FR 35867, June 24, 2008, as amended at 77 FR 56464, Sep. 12, 2012]

§ 60.101a Definitions.

Terms used in this subpart are defined in the Clean Air Act (CAA), in § 60.2 and in this section.

Air preheat means a device used to heat the air supplied to a process heater generally by use of a heat exchanger to recover the sensible heat of exhaust gas from the process heater.

Ancillary equipment means equipment used in conjunction with or that serve a refinery process unit. *Ancillary equipment* includes, but is not limited to, storage tanks, product loading operations, wastewater treatment systems, steam- or electricity-producing units (including coke gasification units), pressure relief valves, pumps, sampling vents and continuous analyzer vents.

Cascaded flare system means a series of flares connected to one flare gas header system arranged with increasing pressure set points so that discharges will be initially directed to the first flare in the series (*i.e.*, the primary flare). If the discharge pressure exceeds a set point at which the flow to the primary flare would exceed the primary flare's capacity, flow will be diverted to the second flare in the series. Similarly, flow would be diverted to a third (or fourth) flare if the pressure in the flare gas header system exceeds a threshold where the flow to the first two (or three) flares would exceed their capacities.

Co-fired process heater means a process heater that employs burners that are designed to be supplied by both gaseous and liquid fuels on a routine basis. Process heaters that have gas burners with emergency oil back-up burners are not considered co-fired process heaters.

Coke burn-off means the coke removed from the surface of the FCCU catalyst by combustion in the catalyst regenerator. The rate of coke burn-off is calculated by the formula specified in § 60.104a.

Contact material means any substance formulated to remove metals, sulfur, nitrogen, or any other contaminant from petroleum derivatives.

Corrective action means the design, operation and maintenance changes that one takes consistent with good engineering practice to reduce or eliminate the likelihood of the recurrence of the primary cause and any other contributing cause(s) of an event identified by a root cause analysis as having resulted in a discharge of gases to an

affected flare in excess of specified thresholds.

Corrective action analysis means a description of all reasonable interim and long-term measures, if any, that are available, and an explanation of why the selected corrective action(s) is/are the best alternative(s), including, but not limited to, considerations of cost effectiveness, technical feasibility, safety and secondary impacts.

Delayed coking unit means a refinery process unit in which high molecular weight petroleum derivatives are thermally cracked and petroleum coke is produced in a series of closed, batch system reactors. A *delayed coking unit* includes, but is not limited to, all of the coke drums associated with a single fractionator; the fractionator, including the bottoms receiver and the overhead condenser; the coke drum cutting water and quench system, including the jet pump and coker quench water tank; and the coke drum blowdown recovery compressor system.

Emergency flare means a flare that combusts gas exclusively released as a result of malfunctions (and not start-up, shutdown, routine operations or any other cause) on four or fewer occasions in a rolling 365-day period. For purposes of this rule, a flare cannot be categorized as an *emergency flare* unless it maintains a water seal.

Flare means a combustion device that uses an uncontrolled volume of air to burn gases. The *flare* includes the foundation, flare tip, structural support, burner, igniter, flare controls, including air injection or steam injection systems, flame arrestors and the flare gas header system. In the case of an interconnected flare gas header system, the *flare* includes each individual flare serviced by the interconnected flare gas header system and the interconnected flare gas header system.

Flare gas header system means all piping and knockout pots, including those in a subheader system, used to collect and transport gas to a flare either from a process unit or a pressure relief valve from the fuel gas system, regardless of whether or not a flare gas recovery system draws gas from the *flare gas header system*. The *flare gas header system* includes piping inside the battery limit of a process unit if the purpose of the

piping is to transport gas to a flare or knockout pot that is part of the flare.

Flare gas recovery system means a system of one or more compressors, piping and the associated water seal, rupture disk or similar device used to divert gas from the flare and direct the gas to the fuel gas system or to a fuel gas combustion device.

Flexicoking unit means a refinery process unit in which high molecular weight petroleum derivatives are thermally cracked and petroleum coke is continuously produced and then gasified to produce a synthetic fuel gas.

Fluid catalytic cracking unit means a refinery process unit in which petroleum derivatives are continuously charged and hydrocarbon molecules in the presence of a catalyst suspended in a fluidized bed are fractured into smaller molecules, or react with a contact material suspended in a fluidized bed to improve feedstock quality for additional processing and the catalyst or contact material is continuously regenerated by burning off coke and other deposits. The unit includes the riser, reactor, regenerator, air blowers, spent catalyst or contact material stripper, catalyst or contact material recovery equipment, and regenerator equipment for controlling air pollutant emissions and for heat recovery. When *fluid catalyst cracking unit* regenerator exhaust from two separate fluid catalytic cracking units share a common exhaust treatment (e.g., CO boiler or wet scrubber), the *fluid catalytic cracking unit* is a single affected facility.

Fluid coking unit means a refinery process unit in which high molecular weight petroleum derivatives are thermally cracked and petroleum coke is continuously produced in a fluidized bed system. The *fluid coking unit* includes the coking reactor, the coking burner, and equipment for controlling air pollutant emissions and for heat recovery on the fluid coking burner exhaust vent.

Forced draft process heater means a process heater in which the combustion air is supplied under positive pressure produced by a fan at any location in the inlet air line prior to the point where the combustion air enters the process heater or air preheat. For the

purposes of this subpart, a process heater that uses fans at both the inlet air side and the exhaust air side (*i.e.*, balanced draft system) is considered to be a *forced draft process heater*.

Fuel gas means any gas which is generated at a petroleum refinery and which is combusted. *Fuel gas* includes natural gas when the natural gas is combined and combusted in any proportion with a gas generated at a refinery. *Fuel gas* does not include gases generated by catalytic cracking unit catalyst regenerators, coke calciners (used to make premium grade coke) and fluid coking burners, but does include gases from flexicoking unit gasifiers and other gasifiers. *Fuel gas* does not include vapors that are collected and combusted in a thermal oxidizer or flare installed to control emissions from wastewater treatment units other than those processing sour water, marine tank vessel loading operations or asphalt processing units (*i.e.*, asphalt blowing stills).

Fuel gas combustion device means any equipment, such as process heaters and boilers, used to combust fuel gas. For the purposes of this subpart, *fuel gas combustion device* does not include flares or facilities in which gases are combusted to produce sulfur or sulfuric acid.

Fuel gas system means a system of compressors, piping, knock-out pots, mix drums, and units used to remove sulfur contaminants from the fuel gas (*e.g.*, amine scrubbers) that collects refinery fuel gas from one or more sources for treatment as necessary prior to combusting in process heaters or boilers. A *fuel gas system* may have an overpressure vent to a flare but the primary purpose for a fuel gas system is to provide fuel to the refinery.

Natural draft process heater means any process heater in which the combustion air is supplied under ambient or negative pressure without the use of an inlet air (forced draft) fan. For the purposes of this subpart, a *natural draft process heater* is any process heater that is not a forced draft process heater, including induced draft systems.

Non-emergency flare means any flare that is not an emergency flare as defined in this subpart.

Oxidation control system means an emission control system which reduces emissions from sulfur recovery plants by converting these emissions to sulfur dioxide (SO₂) and recycling the SO₂ to the reactor furnace or the first-stage catalytic reactor of the Claus sulfur recovery plant or converting the SO₂ to a sulfur product.

Petroleum means the crude oil removed from the earth and the oils derived from tar sands, shale, and coal.

Petroleum refinery means any facility engaged in producing gasoline, kerosene, distillate fuel oils, residual fuel oils, lubricants, asphalt (bitumen) or other products through distillation of petroleum or through redistillation, cracking or reforming of unfinished petroleum derivatives. A facility that produces only oil shale or tar sands-derived crude oil for further processing at a petroleum refinery using only solvent extraction and/or distillation to recover diluent is not a *petroleum refinery*.

Primary flare means the first flare in a cascaded flare system.

Process heater means an enclosed combustion device used to transfer heat indirectly to process stream materials (liquids, gases, or solids) or to a heat transfer material for use in a process unit instead of steam.

Process upset gas means any gas generated by a petroleum refinery process unit or by ancillary equipment as a result of startup, shutdown, upset or malfunction.

Purge gas means gas introduced between a flare's water seal and a flare's tip to prevent oxygen infiltration (backflow) into the flare tip. For flares with no water seals, the function of *purge gas* is performed by sweep gas (*i.e.*, flares without water seals do not use *purge gas*).

Reduced sulfur compounds means hydrogen sulfide (H₂S), carbonyl sulfide, and carbon disulfide.

Reduction control system means an emission control system which reduces emissions from sulfur recovery plants by converting these emissions to H₂S and either recycling the H₂S to the reactor furnace or the first-stage catalytic reactor of the Claus sulfur recovery plant or converting the H₂S to a sulfur product.

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Refinery process unit means any segment of the petroleum refinery in which a specific processing operation is conducted.

Root cause analysis means an assessment conducted through a process of investigation to determine the primary cause, and any other contributing cause(s), of a discharge of gases in excess of specified thresholds.

Secondary flare means a flare in a cascaded flare system that provides additional flare capacity and pressure relief to a flare gas system when the flare gas flow exceeds the capacity of the primary flare. For purposes of this subpart, a *secondary flare* is characterized by infrequent use and must maintain a water seal.

Sulfur pit means the storage vessel in which sulfur that is condensed after each Claus catalytic reactor is initially accumulated and stored. A *sulfur pit* does not include secondary sulfur storage vessels downstream of the initial Claus reactor sulfur pits.

Sulfur recovery plant means all process units which recover sulfur from H₂S and/or SO₂ from a common source of sour gas produced at a petroleum refinery. The *sulfur recovery plant* also includes sulfur pits used to store the recovered sulfur product, but it does not include secondary sulfur storage vessels or loading facilities downstream of the sulfur pits. For example, a Claus sulfur recovery plant includes: Reactor furnace and waste heat boiler, catalytic reactors, sulfur pits and, if present, oxidation or reduction control systems or incinerator, thermal oxidizer or similar combustion device. Multiple sulfur recovery units are a single affected facility only when the units share the same source of sour gas. *Sulfur recovery plants* that receive source gas from completely segregated sour gas treatment systems are separate affected facilities.

Sweep gas means the gas introduced in a flare gas header system to maintain a constant flow of gas to prevent oxygen buildup in the flare header. For flares with no water seals, *sweep gas* also performs the function of pre-

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venting oxygen infiltration (backflow) into the flare tip.

[73 FR 35867, June 24, 2008, as amended at 77 FR 56464, Sep. 12, 2012; 78 FR 76756, Dec. 19, 2013]

§ 60.102a Emissions limitations.

(a) Each owner or operator that is subject to the requirements of this subpart shall comply with the emissions limitations in paragraphs (b) through (i) of this section on and after the date on which the initial performance test, required by § 60.8, is completed, but not later than 60 days after achieving the maximum production rate at which the affected facility will be operated or 180 days after initial startup, whichever comes first.

(b) An owner or operator subject to the provisions of this subpart shall not discharge or cause the discharge into the atmosphere from any FCCU or FCU:

(1) Particulate matter (PM) in excess of the limits in paragraphs (b)(1)(i), (ii), or (iii) of this section.

(i) 1.0 kilogram per Megagram (kg/Mg)(1 pound (lb) per 1,000 lb) coke burn-off or, if a PM continuous emission monitoring system (CEMS) is used, 0.040 grain per dry standard cubic feet (gr/dscf) corrected to 0 percent excess air for each modified or reconstructed FCCU.

(ii) 0.5 gram per kilogram (g/kg) coke burn-off (0.5 lb PM/1,000 lb coke burn-off) or, if a PM CEMS is used, 0.020 gr/dscf corrected to 0 percent excess air for each newly constructed FCCU.

(iii) 1.0 kg/Mg (1 lb/1,000 lb) coke burn-off; or if a PM CEMS is used, 0.040 grain per dry standard cubic feet (gr/dscf) corrected to 0 percent excess air for each affected FCU.

(2) Nitrogen oxides (NO_x) in excess of 80 parts per million by volume (ppmv), dry basis corrected to 0 percent excess air, on a 7-day rolling average basis.

(3) Sulfur dioxide (SO₂) in excess of 50 ppmv dry basis corrected to 0 percent excess air, on a 7-day rolling average basis and 25 ppmv, dry basis corrected to 0 percent excess air, on a 365-day rolling average basis.

(4) Carbon monoxide (CO) in excess of 500 ppmv, dry basis corrected to 0 percent excess air, on an hourly average basis.

(c) The owner or operator of a FCCU or FCU that uses a continuous parameter monitoring system (CPMS) according to §60.105a(b)(1) shall comply with the applicable control device parameter operating limit in paragraph (c)(1) or (2) of this section.

(1) If the FCCU or FCU is controlled using an electrostatic precipitator:

(i) The 3-hour rolling average total power and secondary current to the entire system must not fall below the level established during the most recent performance test; and

(ii) The daily average exhaust coke burn-off rate must not exceed the level established during the most recent performance test.

(2) If the FCCU or FCU is controlled using a wet scrubber:

(i) The 3-hour rolling average pressure drop must not fall below the level established during the most recent performance test; and

(ii) The 3-hour rolling average liquid-to-gas ratio must not fall below the level established during the most recent performance test.

(d) If an FCCU or FCU uses a continuous opacity monitoring system (COMS) according to the alternative monitoring option in §60.105a(e), the 3-hour rolling average opacity of emissions from the FCCU or FCU as measured by the COMS must not exceed the site-specific opacity limit established during the most recent performance test.

(e) The owner or operator of a FCCU or FCU that is exempted from the requirement for a CO continuous emissions monitoring system under §60.105a(h)(3) shall comply with the parameter operating limits in paragraph (e)(1) or (2) of this section.

(1) For a FCCU or FCU with no post-combustion control device:

(i) The hourly average temperature of the exhaust gases exiting the FCCU or FCU must not fall below the level established during the most recent performance test.

(ii) The hourly average oxygen (O₂) concentration of the exhaust gases

exiting the FCCU or FCU must not fall below the level established during the most recent performance test.

(2) For a FCCU or FCU with a post-combustion control device:

(i) The hourly average temperature of the exhaust gas vent stream exiting the control device must not fall below the level established during the most recent performance test.

(ii) The hourly average O₂ concentration of the exhaust gas vent stream exiting the control device must not fall below the level established during the most recent performance test.

(f) Except as provided in paragraph (f)(3), each owner or operator of an affected sulfur recovery plant shall comply with the applicable emission limits in paragraphs (f)(1) or (2) of this section.

(1) For a sulfur recovery plant with a capacity greater than 20 long tons per day (LTD):

(i) For a sulfur recovery plant with an oxidation control system or a reduction control system followed by incineration, the owner or operator shall not discharge or cause the discharge of any gases into the atmosphere in excess of 250 ppm by volume (dry basis) of sulfur dioxide (SO₂) at zero percent excess air. If the sulfur recovery plant consists of multiple process trains or release points the owner or operator shall comply with the 250 ppmv limit for each process train or release point or comply with a flow rate weighted average of 250 ppmv for all release points from the sulfur recovery plant; or

(ii) For a sulfur recovery plant with a reduction control system not followed by incineration, the owner or operator shall not discharge or cause the discharge of any gases into the atmosphere in excess of 300 ppmv of reduced sulfur compounds and 10 ppmv of H₂S, each calculated as ppmv SO₂ (dry basis) at 0-percent excess air; or

(iii) For systems using oxygen enrichment, the owner or operator shall calculate the applicable emission limit using Equation 1 of this section:

$$E_{LS} = k_1 \times (-0.038 * (\%O_2)^2 + 11.53 * \%O_2 + 25.6) \quad (\text{Eq. 1})$$

Where:

E_{LS} = Emission rate of SO₂ for large sulfur recovery plant, ppmv;

k_1 = Constant factor for emission limit conversion: $k_1 = 1$ for converting to SO₂ limit and $k_1 = 1.2$ for converting to the reduced sulfur compounds limit; and

$\%O_2$ = O₂ concentration to the SRP, percent by volume (dry basis).

(2) For a sulfur recovery plant with a capacity of 20 LTD or less:

(i) For a sulfur recovery plant with an oxidation control system or a reduction control system followed by incineration, the owner or operator shall not discharge or cause the discharge of any gases into the atmosphere in excess of 2,500 ppm by volume (dry basis) of SO₂ at zero percent excess air. If the sulfur recovery plant consists of multiple process trains or release points

the owner or operator shall comply with the 2,500 ppmv limit for each process train or release point or comply with a flow rate weighted average of 2,500 ppmv for all release points from the sulfur recovery plant; or

(ii) For sulfur recovery plant with a reduction control system not followed by incineration, the owner or operator shall not discharge or cause the discharge of any gases into the atmosphere in excess of 3,000 ppm by volume of reduced sulfur compounds and 100 ppm by volume of hydrogen sulfide (H₂S), each calculated as ppm SO₂ by volume (dry basis) at zero percent excess air; or

(iii) For systems using oxygen enrichment, the owner or operator shall calculate the applicable emission limit using Equation 2 of this section:

$$E_{SS} = k_1 \times (-0.38 * (\%O_2)^2 + 115.3 * \%O_2 + 256) \quad (\text{Eq. 2})$$

Where:

E_{SS} = Emission rate of SO₂ for small sulfur recovery plant, ppmv.

(3) Periods of maintenance of the sulfur pit, during which the emission limits in paragraphs (f)(1) and (2) shall not apply, shall not exceed 240 hours per year. The owner or operator must document the time periods during which the sulfur pit vents were not controlled and measures taken to minimize emissions during these periods. Examples of these measures include not adding fresh sulfur or shutting off vent fans.

(g) Each owner or operator of an affected fuel gas combustion device shall comply with the emissions limits in paragraphs (g)(1) and (2) of this section.

(1) Except as provided in (g)(1)(iii) of this section, for each fuel gas combustion device, the owner or operator shall comply with either the emission limit in paragraph (g)(1)(i) of this section or the fuel gas concentration limit in paragraph (g)(1)(ii) of this section.

(i) The owner or operator shall not discharge or cause the discharge of any gases into the atmosphere that contain SO₂ in excess of 20 ppmv (dry basis, corrected to 0-percent excess air) determined hourly on a 3-hour rolling average basis and SO₂ in excess of 8 ppmv (dry basis, corrected to 0-percent excess air), determined daily on a 365 successive calendar day rolling average basis; or

(ii) The owner or operator shall not burn in any fuel gas combustion device any fuel gas that contains H₂S in excess of 162 ppmv determined hourly on a 3-hour rolling average basis and H₂S in excess of 60 ppmv determined daily on a 365 successive calendar day rolling average basis.

(iii) The combustion in a portable generator of fuel gas released as a result of tank degassing and/or cleaning is exempt from the emissions limits in paragraphs (g)(1)(i) and (ii) of this section.

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(2) For each process heater with a rated capacity of greater than 40 million British thermal units per hour (MMBtu/hr) on a higher heating value basis, the owner or operator shall not discharge to the atmosphere any emissions of NO_x in excess of the applicable limits in paragraphs (g)(2)(i) through (iv) of this section.

(i) For each natural draft process heater, comply with the limit in either paragraph (g)(2)(i)(A) or (B) of this section. The owner or operator may comply with either limit at any time, provided that the appropriate parameters for each alternative are monitored as specified in §60.107a; if fuel gas composition is not monitored as specified in §60.107a(d), the owner or operator must comply with the concentration limits in paragraph (g)(2)(i)(A) of this section.

(A) 40 ppmv (dry basis, corrected to 0-percent excess air) determined daily on a 30-day rolling average basis; or

(B) 0.040 pounds per million British thermal units (lb/MMBtu) higher heating value basis determined daily on a 30-day rolling average basis.

(ii) For each forced draft process heater, comply with the limit in either

paragraph (g)(2)(ii)(A) or (B) of this section. The owner or operator may comply with either limit at any time, provided that the appropriate parameters for each alternative are monitored as specified in §60.107a; if fuel gas composition is not monitored as specified in §60.107a(d), the owner or operator must comply with the concentration limits in paragraph (g)(2)(ii)(A) of this section.

(A) 60 ppmv (dry basis, corrected to 0-percent excess air) determined daily on a 30-day rolling average basis; or

(B) 0.060 lb/MMBtu higher heating value basis determined daily on a 30-day rolling average basis.

(iii) For each co-fired natural draft process heater, comply with the limit in either paragraph (g)(2)(iii)(A) or (B) of this section. The owner or operator must choose one of the emissions limits with which to comply at all times:

(A) 150 ppmv (dry basis, corrected to 0-percent excess air) determined daily on a 30 successive operating day rolling average basis; or

(B) The daily average emissions limit calculated using Equation 3 of this section:

$$ER_{NOx} = \frac{0.06 Q_{gas} HHV_{gas} + 0.35 Q_{oil} HHV_{oil}}{Q_{gas} HHV_{gas} + Q_{oil} HHV_{oil}} \quad (\text{Eq. 3})$$

Where:

ER_{NO_x} = Daily allowable average emission rate of NO_x, lb/MMBtu (higher heating value basis);

Q_{gas} = Daily average volumetric flow rate of fuel gas, standard cubic feet per day (scf/day);

Q_{oil} = Daily average volumetric flow rate of fuel oil, scf/day;

HHV_{gas} = Daily average higher heating value of gas fired to the process heater, MMBtu/scf; and

HHV_{oil} = Daily average higher heating value of fuel oil fired to the process heater, MMBtu/scf.

(iv) For each co-fired forced draft process heater, comply with the limit in either paragraph (g)(2)(iv)(A) or (B) of this section. The owner or operator must choose one of the emissions limits with which to comply at all times:

(A) 150 ppmv (dry basis, corrected to 0-percent excess air) determined daily on a 30 successive operating day rolling average basis; or

(B) The daily average emissions limit calculated using Equation 4 of this section:

$$ER_{NO_x} = \frac{0.11 Q_{gas} HHV_{gas} + 0.40 Q_{oil} HHV_{oil}}{Q_{gas} HHV_{gas} + Q_{oil} HHV_{oil}} \quad (\text{Eq. 4})$$

Where:

- ER_{NO_x} = Daily allowable average emission rate of NO_x, lb/MMBtu (higher heating value basis);
- Q_{gas} = Daily average volumetric flow rate of fuel gas, scf/day;
- Q_{oil} = Daily average volumetric flow rate of fuel oil, scf/day;
- HHV_{gas} = Daily average higher heating value of gas fired to the process heater, MMBtu/scf; and
- HHV_{oil} = Daily average higher heating value of fuel oil fired to the process heater, MMBtu/scf.

(h) [Reserved]

(i) For a process heater that meets any of the criteria of paragraphs (i)(1)(i) through (iv) of this section, an owner or operator may request approval from the Administrator for a NO_x emissions limit which shall apply specifically to that affected facility. The request shall include information as described in paragraph (i)(2) of this section. The request shall be submitted and followed as described in paragraph (i)(3) of this section.

(1) A process heater that meets one of the criteria in paragraphs (i)(1)(i) through (iv) of this section may apply for a site-specific NO_x emissions limit:

(i) A modified or reconstructed process heater that lacks sufficient space to accommodate installation and proper operation of combustion modification-based technology (e.g., ultra-low NO_x burners); or

(ii) A modified or reconstructed process heater that has downwardly firing induced draft burners; or

(iii) A co-fired process heater; or

(iv) A process heater operating at reduced firing conditions for an extended period of time (*i.e.*, operating in turn-down mode). The site-specific NO_x emissions limit will only apply for those operating conditions.

(2) The request shall include sufficient and appropriate data, as determined by the Administrator, to allow the Administrator to confirm that the process heater is unable to comply with the applicable NO_x emissions limit in paragraph (g)(2) of this section.

At a minimum, the request shall contain the information described in paragraphs (i)(2)(i) through (iv) of this section.

(i) The design and dimensions of the process heater, evaluation of available combustion modification-based technology, description of fuel gas and, if applicable, fuel oil characteristics, information regarding the combustion conditions (temperature, oxygen content, firing rates) and other information needed to demonstrate that the process heater meets one of the four classes of process heaters listed in paragraph (i)(1) of this section.

(ii) An explanation of how the data in paragraph (i)(2)(i) demonstrate that ultra-low NO_x burners, flue gas recirculation, control of excess air or other combustion modification-based technology (including combinations of these combustion modification-based technologies) cannot be used to meet the applicable emissions limit in paragraph (g)(2) of this section.

(iii) Results of a performance test conducted under representative conditions using the applicable methods specified in §60.104a(i) to demonstrate the performance of the technology the owner or operator will use to minimize NO_x emissions.

(iv) The means by which the owner or operator will document continuous compliance with the site-specific emissions limit.

(3) The request shall be submitted and followed as described in paragraphs (i)(3)(i) through (iii) of this section.

(i) The owner or operator of a process heater that meets one of the criteria in paragraphs (i)(1)(i) through (iv) of this section may request approval from the Administrator within 180 days after initial startup of the process heater for a NO_x emissions limit which shall apply specifically to that affected facility.

(ii) The request must be submitted to the Administrator for approval. The owner or operator must comply with

the request as submitted until it is approved.

(iii) The request shall also be submitted to the following address: U.S. Environmental Protection Agency, Office of Air Quality Planning and Standards, Sector Policies and Programs Division, U.S. EPA Mailroom (E143-01), Attention: Refinery Sector Lead, 109 T.W. Alexander Drive, Research Triangle Park, NC 27711. Electronic copies in lieu of hard copies may also be submitted to refinerynsps@epa.gov.

(4) The approval process for a request for a facility-specific NO_x emissions limit is described in paragraphs (i)(4)(i) through (iii) of this section.

(i) Approval by the Administrator of a facility-specific NO_x emissions limit request will be based on the completeness, accuracy and reasonableness of the request. Factors that the EPA will consider in reviewing the request for approval include, but are not limited to, the following:

(A) A demonstration that the process heater meets one of the four classes of process heaters outlined in paragraphs (i)(1) of this section;

(B) A description of the low-NO_x burner designs and other combustion modifications considered for reducing NO_x emissions;

(C) The combustion modification option selected; and

(D) The operating conditions (firing rate, heater box temperature and excess oxygen concentration) at which the NO_x emission level was established.

(ii) If the request is approved by the Administrator, a facility-specific NO_x emissions limit will be established at the NO_x emission level demonstrated in the approved request.

(iii) If the Administrator finds any deficiencies in the request, the request must be revised to address the deficiencies and be re-submitted for approval.

[73 FR 35867, June 24, 2008, as amended at 77 FR 56466, Sep. 12, 2012]

§ 60.103a Design, equipment, work practice or operational standards.

(a) Except as provided in paragraph (g) of this section, each owner or operator that operates a flare that is subject to this subpart shall develop and implement a written flare management

plan no later than the date specified in paragraph (b) of this section. The flare management plan must include the information described in paragraphs (a)(1) through (7) of this section.

(1) A listing of all refinery process units, ancillary equipment, and fuel gas systems connected to the flare for each affected flare.

(2) An assessment of whether discharges to affected flares from these process units, ancillary equipment and fuel gas systems can be minimized. The flare minimization assessment must (at a minimum) consider the items in paragraphs (a)(2)(i) through (iv) of this section. The assessment must provide clear rationale in terms of costs (capital and annual operating), natural gas offset credits (if applicable), technical feasibility, secondary environmental impacts and safety considerations for the selected minimization alternative(s) or a statement, with justifications, that flow reduction could not be achieved. Based upon the assessment, each owner or operator of an affected flare shall identify the minimization alternatives that it has implemented by the due date of the flare management plan and shall include a schedule for the prompt implementation of any selected measures that cannot reasonably be completed as of that date.

(i) Elimination of process gas discharge to the flare through process operating changes or gas recovery at the source.

(ii) Reduction of the volume of process gas to the flare through process operating changes.

(iii) Installation of a flare gas recovery system or, for facilities that are fuel gas rich, a flare gas recovery system and a co-generation unit or combined heat and power unit.

(iv) Minimization of sweep gas flow rates and, for flares with water seals, purge gas flow rates.

(3) A description of each affected flare containing the information in paragraphs (a)(3)(i) through (vii) of this section.

(i) A general description of the flare, including the information in paragraphs (a)(3)(i)(A) through (G) of this section.

(A) Whether it is a ground flare or elevated (including height).

(B) The type of assist system (e.g., air, steam, pressure, non-assisted).

(C) Whether it is simple or complex flare tip (e.g., staged, sequential).

(D) Whether the flare is part of a cascaded flare system (and if so, whether the flare is primary or secondary).

(E) Whether the flare serves as a backup to another flare.

(F) Whether the flare is an emergency flare or a non-emergency flare.

(G) Whether the flare is equipped with a flare gas recovery system.

(ii) Description and simple process flow diagram showing the interconnection of the following components of the flare: flare tip (date installed, manufacturer, nominal and effective tip diameter, tip drawing); knockout or surge drum(s) or pot(s) (including dimensions and design capacities); flare header(s) and subheader(s); assist system; and ignition system.

(iii) Flare design parameters, including the maximum vent gas flow rate; minimum sweep gas flow rate; minimum purge gas flow rate (if any); maximum supplemental gas flow rate; maximum pilot gas flow rate; and, if the flare is steam-assisted, minimum total steam rate.

(iv) Description and simple process flow diagram showing all gas lines (including flare, purge (if applicable), sweep, supplemental and pilot gas) that are associated with the flare. For purge, sweep, supplemental and pilot gas, identify the type of gas used. Designate which lines are exempt from sulfur, H₂S or flow monitoring and why (e.g., natural gas, inherently low sulfur, pilot gas). Designate which lines are monitored and identify on the process flow diagram the location and type of each monitor.

(v) For each flow rate, H₂S, sulfur content, pressure or water seal monitor identified in paragraph (a)(3)(iv) of this section, provide a detailed description of the manufacturer's specifications, including, but not limited to, make, model, type, range, precision, accuracy, calibration, maintenance and quality assurance procedures.

(vi) For emergency flares, secondary flares and flares equipped with a flare gas recovery system designed, sized and operated to capture all flows ex-

cept those resulting from startup, shutdown or malfunction:

(A) Description of the water seal, including the operating range for the liquid level.

(B) Designation of the monitoring option elected (flow and sulfur monitoring or pressure and water seal liquid level monitoring).

(vii) For flares equipped with a flare gas recovery system:

(A) A description of the flare gas recovery system, including number of compressors and capacity of each compressor.

(B) A description of the monitoring parameters used to quantify the amount of flare gas recovered.

(C) For systems with staged compressors, the maximum time period required to begin gas recovery with the secondary compressor(s), the monitoring parameters and procedures used to minimize the duration of releases during compressor staging and a justification for why the maximum time period cannot be further reduced.

(4) An evaluation of the baseline flow to the flare. The baseline flow to the flare must be determined after implementing the minimization assessment in paragraph (a)(2) of this section. Baseline flows do not include pilot gas flow or purge gas flow (*i.e.*, gas introduced after the flare's water seal) provided these gas flows remain reasonably constant (*i.e.*, separate flow monitors for these streams are not required). Separate baseline flow rates may be established for different operating conditions provided that the management plan includes:

(i) A primary baseline flow rate that will be used as the default baseline for all conditions except those specifically delineated in the plan;

(ii) A description of each special condition for which an alternate baseline is established, including the rationale for each alternate baseline, the daily flow for each alternate baseline and the expected duration of the special conditions for each alternate baseline; and

(iii) Procedures to minimize discharges to the affected flare during each special condition described in paragraph (a)(4)(ii) of this section, unless procedures are already developed for these cases under paragraph (a)(5)

through (7) of this section, as applicable.

(5) Procedures to minimize or eliminate discharges to the flare during the planned startup and shutdown of the refinery process units and ancillary equipment that are connected to the affected flare, together with a schedule for the prompt implementation of any procedures that cannot reasonably be implemented as of the date of the submission of the flare management plan.

(6) Procedures to reduce flaring in cases of fuel gas imbalance (*i.e.*, excess fuel gas for the refinery's energy needs), together with a schedule for the prompt implementation of any procedures that cannot reasonably be implemented as of the date of the submission of the flare management plan.

(7) For flares equipped with flare gas recovery systems, procedures to minimize the frequency and duration of outages of the flare gas recovery system and procedures to minimize the volume of gas flared during such outages, together with a schedule for the prompt implementation of any procedures that cannot reasonably be implemented as of the date of the submission of the flare management plan.

(b) Except as provided in paragraph (g) of this section, each owner or operator required to develop and implement a written flare management plan as described in paragraph (a) of this section must submit the plan to the Administrator as described in paragraphs (b)(1) through (3) of this section.

(1) The owner or operator of a newly constructed or reconstructed flare must develop and implement the flare management plan by no later than the date that the flare becomes an affected facility subject to this subpart, except for the selected minimization alternatives in paragraph (a)(2) and/or the procedures in paragraphs (a)(5) through (a)(7) of this section that cannot reasonably be implemented by that date, which the owner or operator must implement in accordance with the schedule in the flare management plan. The owner or operator of a modified flare must develop and implement the flare management plan by no later than November 11, 2015 or upon startup of the modified flare, whichever is later.

(2) The owner or operator must comply with the plan as submitted by the date specified in paragraph (b)(1) of this section. The plan should be updated periodically to account for changes in the operation of the flare, such as new connections to the flare or the installation of a flare gas recovery system, but the plan need be re-submitted to the Administrator only if the owner or operator adds an alternative baseline flow rate, revises an existing baseline as described in paragraph (a)(4) of this section, installs a flare gas recovery system or is required to change flare designations and monitoring methods as described in § 60.107a(g). The owner or operator must comply with the updated plan as submitted.

(3) All versions of the plan submitted to the Administrator shall also be submitted to the following address: U.S. Environmental Protection Agency, Office of Air Quality Planning and Standards, Sector Policies and Programs Division, U.S. EPA Mailroom (E143-01), Attention: Refinery Sector Lead, 109 T.W. Alexander Drive, Research Triangle Park, NC 27711. Electronic copies in lieu of hard copies may also be submitted to refinerynsps@epa.gov.

(c) Except as provided in paragraphs (f) and (g) of this section, each owner or operator that operates a fuel gas combustion device, flare or sulfur recovery plant subject to this subpart shall conduct a root cause analysis and a corrective action analysis for each of the conditions specified in paragraphs (c)(1) through (3) of this section.

(1) For a flare:

(i) Any time the SO₂ emissions exceed 227 kilograms (kg) (500 lb) in any 24-hour period; or

(ii) Any discharge to the flare in excess of 14,160 standard cubic meters (m³) (500,000 standard cubic feet (scf)) above the baseline, determined in paragraph (a)(4) of this section, in any 24-hour period; or

(iii) If the monitoring alternative in § 60.107a(g) is elected, any period when the flare gas line pressure exceeds the water seal liquid depth, except for periods attributable to compressor staging that do not exceed the staging time specified in paragraph (a)(3)(vii)(C) of this section.

(2) For a fuel gas combustion device, each exceedance of an applicable short-term emissions limit in § 60.102a(g)(1) if the SO₂ discharge to the atmosphere is 227 kg (500 lb) greater than the amount that would have been emitted if the emissions limits had been met during one or more consecutive periods of excess emissions or any 24-hour period, whichever is shorter.

(3) For a sulfur recovery plant, each time the SO₂ emissions are more than 227 kg (500 lb) greater than the amount that would have been emitted if the SO₂ or reduced sulfur concentration was equal to the applicable emissions limit in § 60.102a(f)(1) or (2) during one or more consecutive periods of excess emissions or any 24-hour period, whichever is shorter.

(d) Except as provided in paragraphs (f) and (g) of this section, a root cause analysis and corrective action analysis must be completed as soon as possible, but no later than 45 days after a discharge meeting one of the conditions specified in paragraphs (c)(1) through (3) of this section. Special circumstances affecting the number of root cause analyses and/or corrective action analyses are provided in paragraphs (d)(1) through (5) of this section.

(1) If a single continuous discharge meets any of the conditions specified in paragraphs (c)(1) through (3) of this section for 2 or more consecutive 24-hour periods, a single root cause analysis and corrective action analysis may be conducted.

(2) If a single discharge from a flare triggers a root cause analysis based on more than one of the conditions specified in paragraphs (c)(1)(i) through (iii) of this section, a single root cause analysis and corrective action analysis may be conducted.

(3) If the discharge from a flare is the result of a planned startup or shutdown of a refinery process unit or ancillary equipment connected to the affected flare and the procedures in paragraph (a)(5) of this section were followed, a root cause analysis and corrective action analysis is not required; however, the discharge must be recorded as described in § 60.108a(c)(6) and reported as described in § 60.108a(d)(5).

(4) If both the primary and secondary flare in a cascaded flare system meet

any of the conditions specified in paragraphs (c)(1)(i) through (iii) of this section in the same 24-hour period, a single root cause analysis and corrective action analysis may be conducted.

(5) Except as provided in paragraph (d)(4) of this section, if discharges occur that meet any of the conditions specified in paragraphs (c)(1) through (3) of this section for more than one affected facility in the same 24-hour period, initial root cause analyses shall be conducted for each affected facility. If the initial root cause analyses indicate that the discharges have the same root cause(s), the initial root cause analyses can be recorded as a single root cause analysis and a single corrective action analysis may be conducted.

(e) Except as provided in paragraphs (f) and (g) of this section, each owner or operator of a fuel gas combustion device, flare or sulfur recovery plant subject to this subpart shall implement the corrective action(s) identified in the corrective action analysis conducted pursuant to paragraph (d) of this section in accordance with the applicable requirements in paragraphs (e)(1) through (3) of this section.

(1) All corrective action(s) must be implemented within 45 days of the discharge for which the root cause and corrective action analyses were required or as soon thereafter as practicable. If an owner or operator concludes that corrective action should not be conducted, the owner or operator shall record and explain the basis for that conclusion no later than 45 days following the discharge as specified in § 60.108a(c)(6)(ix).

(2) For corrective actions that cannot be fully implemented within 45 days following the discharge for which the root cause and corrective action analyses were required, the owner or operator shall develop an implementation schedule to complete the corrective action(s) as soon as practicable.

(3) No later than 45 days following the discharge for which a root cause and corrective action analyses were required, the owner or operator shall

record the corrective action(s) completed to date, and, for action(s) not already completed, a schedule for implementation, including proposed commencement and completion dates as specified in § 60.108a(c)(6)(x).

(f) Modified flares shall comply with the requirements of paragraphs (c) through (e) of this section by November 11, 2015 or at startup of the modified flare, whichever is later. Modified flares that were not affected facilities subject to subpart J of this part prior to becoming affected facilities under § 60.100a shall comply with the requirements of paragraph (h) of this section and the requirements of § 60.107a(a)(2) by November 11, 2015 or at startup of the modified flare, whichever is later. Modified flares that were affected facilities subject to subpart J of this part prior to becoming affected facilities under § 60.100a shall comply with the requirements of paragraph (h) of this section and the requirements of § 60.107a(a)(2) by November 13, 2012 or at startup of the modified flare, whichever is later, except that modified flares that have accepted applicability of subpart J under a federal consent decree shall comply with the subpart J requirements as specified in the consent decree, but shall comply with the requirements of paragraph (h) of this section and the requirements of § 60.107a(a)(2) by no later than November 11, 2015.

(g) An affected flare subject to this subpart located in the Bay Area Air Quality Management District (BAAQMD) may elect to comply with both BAAQMD Regulation 12, Rule 11 and BAAQMD Regulation 12, Rule 12 as an alternative to complying with the requirements of paragraphs (a) through (e) of this section. An affected flare subject to this subpart located in the South Coast Air Quality Management District (SCAQMD) may elect to comply with SCAQMD Rule 1118 as an alternative to complying with the requirements of paragraphs (a) through (e) of this section. The owner or operator of an affected flare must notify the Administrator that the flare is in compliance with BAAQMD Regulation 12, Rule 11 and BAAQMD Regulation 12, Rule 12 or SCAQMD Rule 1118. The owner or operator of an affected flare

shall also submit the existing flare management plan to the following address: U.S. Environmental Protection Agency, Office of Air Quality Planning and Standards, Sector Policies and Programs Division, U.S. EPA Mailroom (E143-01), Attention: Refinery Sector Lead, 109 T.W. Alexander Drive, Research Triangle Park, NC 27711. Electronic copies in lieu of hard copies may also be submitted to refinerynsps@epa.gov.

(h) Each owner or operator shall not burn in any affected flare any fuel gas that contains H₂S in excess of 162 ppmv determined hourly on a 3-hour rolling average basis. The combustion in a flare of process upset gases or fuel gas that is released to the flare as a result of relief valve leakage or other emergency malfunctions is exempt from this limit.

(i) Each owner or operator of a delayed coking unit shall depressure each coke drum to 5 lb per square inch gauge (psig) or less prior to discharging the coke drum steam exhaust to the atmosphere. Until the coke drum pressure reaches 5 psig, the coke drum steam exhaust must be managed in an enclosed blowdown system and the uncondensed vapor must either be recovered (e.g., sent to the delayed coking unit fractionators) or vented to the fuel gas system, a fuel gas combustion device or a flare.

(j) *Alternative means of emission limitation.* (1) Each owner or operator subject to the provisions of this section may apply to the Administrator for a determination of equivalence for any means of emission limitation that achieves a reduction in emissions of a specified pollutant at least equivalent to the reduction in emissions of that pollutant achieved by the controls required in this section.

(2) Determination of equivalence to the design, equipment, work practice or operational requirements of this section will be evaluated by the following guidelines:

(i) Each owner or operator applying for a determination of equivalence shall be responsible for collecting and verifying test data to demonstrate the equivalence of the alternative means of emission limitation.

(ii) For each affected facility for which a determination of equivalence is requested, the emission reduction achieved by the design, equipment, work practice or operational requirements shall be demonstrated.

(iii) For each affected facility for which a determination of equivalence is requested, the emission reduction achieved by the alternative means of emission limitation shall be demonstrated.

(iv) Each owner or operator applying for a determination of equivalence to a work practice standard 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.

(v) The Administrator will compare the demonstrated emission reduction for the alternative means of emission limitation to the demonstrated emission reduction for the design, equipment, work practice or operational requirements and, if applicable, will consider the commitment in paragraph (j)(2)(iv) of this section.

(vi) The Administrator may condition the approval of the alternative means of emission limitation on requirements that may be necessary to ensure operation and maintenance to achieve the same emissions reduction as the design, equipment, work practice or operational requirements.

(3) An owner or operator may offer a unique approach to demonstrate the equivalence of any equivalent means of emission limitation.

(4) Approval of the application for equivalence to the design, equipment, work practice or operational requirements of this section will be evaluated by the following guidelines:

(i) 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.

(ii) 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.

(iii) 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 CAA.

(5) Manufacturers of equipment used to control emissions may apply to the Administrator for determination of equivalence for any alternative means of emission limitation that achieves a reduction in emissions achieved by the equipment, design and operational requirements of this section. The Administrator will make an equivalence determination according to the provisions of paragraphs (j)(2) through (4) of this section.

[77 FR 56467, Sep. 12, 2012]

§ 60.104a Performance tests.

(a) The owner or operator shall conduct a performance test for each FCCU, FCU, sulfur recovery plant, flare and fuel gas combustion device to demonstrate initial compliance with each applicable emissions limit in § 60.102a according to the requirements of § 60.8. The notification requirements of § 60.8(d) apply to the initial performance test and to subsequent performance tests required by paragraph (b) of this section (or as required by the Administrator), but does not apply to performance tests conducted for the purpose of obtaining supplemental data because of continuous monitoring system breakdowns, repairs, calibration checks and zero and span adjustments.

(b) The owner or operator of a FCCU or FCU that elects to monitor control device operating parameters according to the requirements in § 60.105a(b), to use bag leak detectors according to the requirements in § 60.105a(c), or to use COMS according to the requirements in § 60.105a(e) shall conduct a PM performance test at least once every 12 months and furnish the Administrator a written report of the results of each test.

(c) In conducting the performance tests required by this subpart (or as requested by the Administrator), the owner or operator shall use the test methods in 40 CFR part 60, Appendices A-1 through A-8 or other methods as specified in this section, except as provided in § 60.8(b).

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(d) The owner or operator shall determine compliance with the PM, NO_x, SO₂, and CO emissions limits in §60.102a(b) for FCCU and FCU using the following methods and procedures:

(1) Method 1 of appendix A-1 to part 60 for sample and velocity traverses.

(2) Method 2 of appendix A-1 to part 60 for velocity and volumetric flow rate.

(3) Method 3, 3A, or 3B of appendix A-2 to part 60 for gas analysis. The method ANSI/ASME PTC 19.10-1981, "Flue and Exhaust Gas Analyses," (incorporated by reference—see §60.17) is an acceptable alternative to EPA Method 3B of appendix A-2 to part 60.

(4) Method 5, 5B, or 5F of appendix A-3 to part 60 for determining PM emissions and associated moisture content from a FCCU or FCU without a wet scrubber subject to the emissions limit in §63.102a(b)(1). Use Method 5 or 5B of appendix A-3 to part 60 for determining PM emissions and associated moisture content from a FCCU or FCU with a wet scrubber subject to the emissions limit in §63.102a(b)(1).

(i) The PM performance test consists of 3 valid test runs; the duration of each test run must be no less than 60 minutes.

(ii) The emissions rate of PM (E_{PM}) is computed for each run using Equation 5 of this section:

$$E = \frac{c_s Q_{sd}}{K R_c} \quad (\text{Eq. 5})$$

Where:

E = Emission rate of PM, g/kg (lb/1,000 lb) of coke burn-off;

c_s = Concentration of total PM, grams per dry standard cubic meter (g/dscm) (gr/dscf);

Q_{sd} = Volumetric flow rate of effluent gas, dry standard cubic meters per hour (dry standard cubic feet per hour);

R_c = Coke burn-off rate, kilograms per hour (kg/hr) [lb per hour (lb/hr)] coke; and

K = Conversion factor, 1.0 grams per gram (7,000 grains per lb).

(iii) The coke burn-off rate (R_c) is computed for each run using Equation 6 of this section:

$$R_c = K_1 Q_r (\%CO_2 + \%CO) + K_2 Q_a - K_3 Q_r (\%CO_2 + \%CO_2 + \%O_2) + K_3 Q_{oxy} (\%O_{oxy})$$

(Eq. 6)

Where:

R_c = Coke burn-off rate, kg/hr (lb/hr);

Q_r = Volumetric flow rate of exhaust gas from FCCU regenerator or fluid coking burner before any emissions control or energy recovery system that burns auxiliary fuel, dry standard cubic meters per minute (dscm/min) [dry standard cubic feet per minute (dscf/min)];

Q_a = Volumetric flow rate of air to FCCU regenerator or fluid coking burner, as determined from the unit's control room instrumentation, dscm/min (dscf/min);

Q_{oxy} = Volumetric flow rate of O₂ enriched air to FCCU regenerator or fluid coking unit, as determined from the unit's con-

trol room instrumentation, dscm/min (dscf/min);

%CO₂ = Carbon dioxide (CO₂) concentration in FCCU regenerator or fluid coking burner exhaust, percent by volume (dry basis);

%CO = CO concentration in FCCU regenerator or fluid coking burner exhaust, percent by volume (dry basis);

%O₂ = O₂ concentration in FCCU regenerator or fluid coking burner exhaust, percent by volume (dry basis);

%O_{oxy} = O₂ concentration in O₂ enriched air stream inlet to the FCCU regenerator or fluid coking burner, percent by volume (dry basis);

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- K₁ = Material balance and conversion factor, 0.2982 (kg-min)/(hr-dscm-%) [0.0186 (lb-min)/(hr-dscf-%)];
- K₂ = Material balance and conversion factor, 2.088 (kg-min)/(hr-dscm) [0.1303 (lb-min)/(hr-dscf)]; and
- K₃ = Material balance and conversion factor, 0.0994 (kg-min)/(hr-dscm-%) [0.00624 (lb-min)/(hr-dscf-%)].

(iv) During the performance test, the volumetric flow rate of exhaust gas from catalyst regenerator (Q_r) before

any emission control or energy recovery system that burns auxiliary fuel is measured using Method 2 of appendix A-1 to part 60.

(v) For subsequent calculations of coke burn-off rates or exhaust gas flow rates, the volumetric flow rate of Q_r is calculated using average exhaust gas concentrations as measured by the monitors required in §60.105a(b)(2), if applicable, using Equation 7 of this section:

$$Q_r = \frac{79 \times Q_a + (100 - \%O_{xy}) \times Q_{oxy}}{100 - \%CO_2 - \%CO - \%O_2} \quad (\text{Eq. 7})$$

Where:

- Q_r = Volumetric flow rate of exhaust gas from FCCU regenerator or fluid coking burner before any emission control or energy recovery system that burns auxiliary fuel, dscm/min (dscf/min);
- Q_a = Volumetric flow rate of air to FCCU regenerator or fluid coking burner, as determined from the unit's control room instrumentation, dscm/min (dscf/min);
- Q_{oxy} = Volumetric flow rate of O₂ enriched air to FCCU regenerator or fluid coking unit, as determined from the unit's control room instrumentation, dscm/min (dscf/min);
- %CO₂ = Carbon dioxide concentration in FCCU regenerator or fluid coking burner exhaust, percent by volume (dry basis);
- %CO = CO concentration FCCU regenerator or fluid coking burner exhaust, percent by volume (dry basis). When no auxiliary fuel is burned and a continuous CO monitor is not required in accordance with §60.105a(h)(3), assume %CO to be zero;
- %O₂ = O₂ concentration in FCCU regenerator or fluid coking burner exhaust, percent by volume (dry basis); and
- %O_{oxy} = O₂ concentration in O₂ enriched air stream inlet to the FCCU regenerator or fluid coking burner, percent by volume (dry basis).

(5) Method 6, 6A, or 6C of appendix A-4 to part 60 for moisture content and

for the concentration of SO₂; the duration of each test run must be no less than 4 hours. The method ANSI/ASME PTC 19.10-1981, "Flue and Exhaust Gas Analyses," (incorporated by reference—see §60.17) is an acceptable alternative to EPA Method 6 or 6A of appendix A-4 to part 60.

(6) Method 7, 7A, 7C, 7D, or 7E of appendix A-4 to part 60 for moisture content and for the concentration of NO_x calculated as nitrogen dioxide (NO₂); the duration of each test run must be no less than 4 hours. The method ANSI/ASME PTC 19.10-1981, "Flue and Exhaust Gas Analyses," (incorporated by reference—see §60.17) is an acceptable alternative to EPA Method 7 or 7C of appendix A-4 to part 60.

(7) Method 10, 10A, or 10B of appendix A-4 to part 60 for moisture content and for the concentration of CO. The sampling time for each run must be 60 minutes.

(8) The owner or operator shall adjust PM, NO_x, SO₂ and CO pollutant concentrations to 0-percent excess air or 0-percent O₂ using Equation 8 of this section:

$$C_{adj} = C_{meas} \left[\frac{20.9}{20.9 - \%O_2} \right] \quad (\text{Eq. 8})$$

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Where:

C_{adj} = pollutant concentration adjusted to 0-percent excess air or O₂, parts per million (ppm) or g/dscm;

C_{meas} = pollutant concentration measured on a dry basis, ppm or g/dscm;

20.9_c = 20.9 percent O₂ - 0.0 percent O₂ (defined O₂ correction basis), percent;

20.9 = O₂ concentration in air, percent; and

%O₂ = O₂ concentration measured on a dry basis, percent.

(e) The owner or operator of a FCCU or FCU that is controlled by an electrostatic precipitator or wet scrubber and that is subject to control device operating parameter limits in §60.102a(c) shall establish the limits based on the performance test results according to the following procedures:

(1) Reduce the parameter monitoring data to hourly averages for each test run;

(2) Determine the hourly average operating limit for each required parameter as the average of the three test runs.

(f) The owner or operator of an FCCU or FCU that uses cyclones to comply with the PM limit in §60.102a(b)(1) and elects to comply with the COMS alternative monitoring option in §60.105a(d) shall establish a site-specific opacity operating limit according to the procedures in paragraphs (f)(1) through (3) of this section.

(1) Collect COMS data every 10 seconds during the entire period of the PM performance test and reduce the data to 6-minute averages.

(2) Determine and record the hourly average opacity from all the 6-minute averages.

(3) Compute the site-specific limit using Equation 9 of this section:

$$Opacity\ Limit = Opacity_{st} \times \left(\frac{11\text{ lb}/1,000\text{ lb coke burn}}{PME_{R_{st}}} \right) \quad (\text{Eq. } 9)$$

Where:

Opacity limit = Maximum permissible 3-hour average opacity, percent, or 10 percent, whichever is greater;

Opacity_{st} = Hourly average opacity measured during the source test, percent; and

PME_{R_{st}} = PM emission rate measured during the source test, lb/1,000 lb coke burn.

(g) The owner or operator of a FCCU or FCU that is exempt from the requirement to install and operate a CO CEMS pursuant to §60.105a(h)(3) and that is subject to control device operating parameter limits in §60.102a(c) shall establish the limits based on the performance test results using the procedures in paragraphs (g)(1) and (2) of this section.

(1) Reduce the temperature and O₂ concentrations from the parameter monitoring systems to hourly averages for each test run.

(2) Determine the operating limit for temperature and O₂ concentrations as the average of the average temperature and O₂ concentration for the three test runs.

(h) The owner or operator shall determine compliance with the SO₂ and H₂S emissions limits for sulfur recovery

plants in §§ 60.102a(f)(1)(i), 60.102a(f)(1)(iii), 60.102a(f)(1)(iii), 60.102a(f)(2)(i), and 60.102a(f)(2)(iii) and the reduced sulfur compounds and H₂S emissions limits for sulfur recovery plants in §60.102a(f)(1)(ii) and §60.102a(f)(2)(ii) using the following methods and procedures:

(1) Method 1 of appendix A-1 to part 60 for sample and velocity traverses.

(2) Method 2 of appendix A-1 to part 60 for velocity and volumetric flow rate.

(3) Method 3, 3A, or 3B of appendix A-2 to part 60 for gas analysis. The method ANSI/ASME PTC 19.10-1981, "Flue and Exhaust Gas Analyses," (incorporated by reference—see §60.17) is an acceptable alternative to EPA Method 3B of appendix A-2 to part 60.

(4) Method 6, 6A, or 6C of appendix A-4 to part 60 to determine the SO₂ concentration. The method ANSI/ASME PTC 19.10-1981, "Flue and Exhaust Gas Analyses," (incorporated by reference—see §60.17) is an acceptable alternative to EPA Method 6 or 6A of appendix A-4 to part 60.

(5) Method 15 or 15A of appendix A-5 to part 60 or Method 16 of appendix A-

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6 to part 60 to determine the reduced sulfur compounds and H₂S concentrations. The method ANSI/ASME PTC 19.10-1981, "Flue and Exhaust Gas Analyses," (incorporated by reference—see § 60.17) is an acceptable alternative to EPA Method 15A of appendix A-5 to part 60.

(i) Each run consists of 16 samples taken over a minimum of 3 hours.

(ii) The owner or operator shall calculate the average H₂S concentration after correcting for moisture and O₂ as the arithmetic average of the H₂S concentration for each sample during the run (ppmv, dry basis, corrected to 0 percent excess air).

(iii) The owner or operator shall calculate the SO₂ equivalent for each run after correcting for moisture and O₂ as the arithmetic average of the SO₂ equivalent of reduced sulfur compounds for each sample during the run (ppmv, dry basis, corrected to 0 percent excess air).

(iv) The owner or operator shall use Equation 8 of this section to adjust pollutant concentrations to 0-percent O₂ or 0-percent excess air.

(i) The owner or operator shall determine compliance with the SO₂ and NO_x emissions limits in § 60.102a(g) for a fuel gas combustion device according to the following test methods and procedures:

(1) Method 1 of appendix A-1 to part 60 for sample and velocity traverses;

(2) Method 2 of appendix A-1 to part 60 for velocity and volumetric flow rate;

(3) Method 3, 3A, or 3B of appendix A-2 to part 60 for gas analysis. The method ANSI/ASME PTC 19.10-1981, "Flue and Exhaust Gas Analyses," (incorporated by reference—see § 60.17) is an acceptable alternative to EPA Method 3B of appendix A-2 to part 60;

(4) Method 6, 6A, or 6C of appendix A-4 to part 60 to determine the SO₂ concentration. The method ANSI/ASME PTC 19.10-1981, "Flue and Exhaust Gas Analyses," (incorporated by reference—see § 60.17) is an acceptable alternative to EPA Method 6 or 6A of appendix A-4 to part 60.

(i) The performance test consists of 3 valid test runs; the duration of each test run must be no less than 1 hour.

(ii) If a single fuel gas combustion device having a common source of fuel

gas is monitored as allowed under § 60.107a(a)(1)(v), only one performance test is required. That is, performance tests are not required when a new affected fuel gas combustion device is added to a common source of fuel gas that previously demonstrated compliance.

(5) Method 7, 7A, 7C, 7D, or 7E of appendix A-4 to part 60 for moisture content and for the concentration of NO_x calculated as NO₂; the duration of each test run must be no less than 4 hours. The method ANSI/ASME PTC 19.10-1981, "Flue and Exhaust Gas Analyses," (incorporated by reference—see § 60.17) is an acceptable alternative to EPA Method 7 or 7C of appendix A-4 to part 60.

(6) For process heaters with a rated heat capacity between 40 and 100 MMBtu/hr that elect to demonstrate continuous compliance with a maximum excess oxygen limit as provided in § 60.107a(c)(6) or (d)(8), the owner or operator shall establish the O₂ operating limit or O₂ operating curve based on the performance test results according to the requirements in paragraph (i)(6)(i) or (ii) of this section, respectively.

(i) If a single O₂ operating limit will be used:

(A) Conduct the performance test following the methods provided in paragraphs (i)(1), (2), (3) and (5) of this section when the process heater is firing at no less than 70 percent of the rated heat capacity. For co-fired process heaters, conduct at least one of the test runs while the process heater is being supplied by both fuel gas and fuel oil and conduct at least one of the test runs while the process heater is being supplied solely by fuel gas.

(B) Each test will consist of three test runs. Calculate the NO_x concentration for the performance test as the average of the NO_x concentrations from each of the three test runs. If the NO_x concentration for the performance test is less than or equal to the numerical value of the applicable NO_x emissions limit (regardless of averaging time), then the test is considered to be a valid test.

(C) Determine the average O₂ concentration for each test run of a valid test.

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(D) Calculate the O₂ operating limit as the average O₂ concentration of the three test runs from a valid test.

(ii) If an O₂ operating curve will be used:

(A) Conduct a performance test following the methods provided in paragraphs (i)(1), (2), (3) and (5) of this section at a representative condition for each operating range for which different O₂ operating limits will be established. Different operating conditions may be defined as different firing rates (e.g., above 50 percent of rated heat capacity and at or below 50 percent of rated heat capacity) and/or, for co-fired process heaters, different fuel mixtures (e.g., primarily gas fired, primarily oil fired, and equally co-fired, *i.e.*, approximately 50 percent of the input heating value is from fuel gas and approximately 50 percent of the input heating value is from fuel oil). Performance tests for different operating ranges may be conducted at different times.

(B) Each test will consist of three test runs. Calculate the NO_x concentration for the performance test as the average of the NO_x concentrations from each of the three test runs. If the NO_x concentration for the performance test is less than or equal to the numerical value of the applicable NO_x emissions limit (regardless of averaging time), then the test is considered to be a valid test.

(C) If an operating curve is developed for different firing rates, conduct at least one test when the process heater is firing at no less than 70 percent of the rated heat capacity and at least one test under turndown conditions (*i.e.*, when the process heater is firing at 50 percent or less of the rated heat capacity). If O₂ operating limits are developed for co-fired process heaters based only on overall firing rates (and not by fuel mixtures), conduct at least one of the test runs for each test while the process heater is being supplied by both fuel gas and fuel oil and conduct at least one of the test runs while the process heater is being supplied solely by fuel gas.

(D) Determine the average O₂ concentration for each test run of a valid test.

(E) Calculate the O₂ operating limit for each operating range as the average O₂ concentration of the three test runs from a valid test conducted at the representative conditions for that given operating range.

(F) Identify the firing rates for which the different operating limits apply. If only two operating limits are established based on firing rates, the O₂ operating limits established when the process heater is firing at no less than 70 percent of the rated heat capacity must apply when the process heater is firing above 50 percent of the rated heat capacity and the O₂ operating limits established for turndown conditions must apply when the process heater is firing at 50 percent or less of the rated heat capacity.

(G) Operating limits associated with each interval will be valid for 2 years or until another operating limit is established for that interval based on a more recent performance test specific for that interval, whichever occurs first. Owners and operators must use the operating limits determined for a given interval based on the most recent performance test conducted for that interval.

(7) The owner or operator of a process heater complying with a NO_x limit in terms of lb/MMBtu as provided in § 60.102a(g)(2)(i)(B), (g)(2)(ii)(B), (g)(2)(iii)(B) or (g)(2)(iv)(B) or a process heater with a rated heat capacity between 40 and 100 MMBtu/hr that elects to demonstrate continuous compliance with a maximum excess O₂ limit, as provided in § 60.107a(c)(6) or (d)(8), shall determine heat input to the process heater in MMBtu/hr during each performance test run by measuring fuel gas flow rate, fuel oil flow rate (as applicable) and heating value content according to the methods provided in § 60.107a(d)(5), (d)(6), and (d)(4) or (d)(7), respectively.

(8) The owner or operator shall use Equation 8 of this section to adjust pollutant concentrations to 0-percent O₂ or 0-percent excess air.

(j) The owner or operator shall determine compliance with the applicable H₂S emissions limit in § 60.102a(g)(1) for a fuel gas combustion device or the concentration requirement in

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§ 60.103a(h) for a flare according to the following test methods and procedures:

(1) Method 1 of appendix A-1 to part 60 for sample and velocity traverses;

(2) Method 2 of appendix A-1 to part 60 for velocity and volumetric flow rate;

(3) Method 3, 3A, or 3B of appendix A-2 to part 60 for gas analysis. The method ANSI/ASME PTC 19.10-1981, "Flue and Exhaust Gas Analyses," (incorporated by reference—see § 60.17) is an acceptable alternative to EPA Method 3B of appendix A-2 to part 60;

(4) EPA Method 11, 15 or 15A of appendix A-5 to part 60 or EPA Method 16 of appendix A-6 to part 60 for determining the H₂S concentration for affected facilities using an H₂S monitor as specified in § 60.107a(a)(2). The method ANSI/ASME PTC 19.10-1981 (incorporated by reference—see § 60.17) is an acceptable alternative to EPA Method 15A of appendix A-5 to part 60. The owner or operator may demonstrate compliance based on the mixture used in the fuel gas combustion device or flare or for each individual fuel gas stream used in the fuel gas combustion device or flare.

(i) For Method 11 of appendix A-5 to part 60, the sampling time and sample volume must be at least 10 minutes and 0.010 dscf (0.35 dscf). Two samples of equal sampling times must be taken at about 1-hour intervals. The arithmetic average of these two samples constitutes a run. For most fuel gases, sampling times exceeding 20 minutes may result in depletion of the collection solution, although fuel gases containing low concentrations of H₂S may necessitate sampling for longer periods of time.

(ii) For Method 15 of appendix A-5 to part 60, at least three injects over a 1-hour period constitutes a run.

(iii) For Method 15A of appendix A-5 to part 60, a 1-hour sample constitutes a run. The method ANSI/ASME PTC 19.10-1981, "Flue and Exhaust Gas Analyses," (incorporated by reference—see § 60.17) is an acceptable alternative to EPA Method 15A of appendix A-5 to part 60.

(iv) If monitoring is conducted at a single point in a common source of fuel gas as allowed under § 60.107a(a)(2)(iv), only one performance test is required.

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That is, performance tests are not required when a new affected fuel gas combustion device or flare is added to a common source of fuel gas that previously demonstrated compliance.

[73 FR 35867, June 24, 2008, as amended at 77 FR 56470, Sep. 12, 2012]

§ 60.105a Monitoring of emissions and operations for fluid catalytic cracking units (FCCU) and fluid coking units (FCU).

(a) *FCCU and FCU subject to PM emissions limit.* Each owner or operator subject to the provisions of this subpart shall monitor each FCCU and FCU subject to the PM emissions limit in § 60.102a(b)(1) according to the requirements in paragraph (b), (c), (d), or (e) of this section.

(b) *Control device operating parameters.* Each owner or operator of a FCCU or FCU subject to the PM per coke burn-off emissions limit in § 60.102a(b)(1) that uses a control device other than fabric filter or cyclone shall comply with the requirements in paragraphs (b)(1) and (2) of this section.

(1) The owner or operator shall install, operate and maintain continuous parameter monitor systems (CPMS) to measure and record operating parameters for each control device according to the applicable requirements in paragraphs (b)(1)(i) through (v) of this section.

(i) For units controlled using an electrostatic precipitator, the owner or operator shall use CPMS to measure and record the hourly average total power input and secondary voltage to the entire system.

(ii) For units controlled using a wet scrubber, the owner or operator shall use CPMS to measure and record the hourly average pressure drop, liquid feed rate, and exhaust gas flow rate. As an alternative to a CPMS, the owner or operator must comply with the requirements in either paragraph (b)(1)(ii)(A) or (B) of this section.

(A) As an alternative to pressure drop, the owner or operator of a jet ejector type wet scrubber or other type of wet scrubber equipped with atomizing spray nozzles must conduct a daily check of the air or water pressure to the spray nozzles and record the results of each check.

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(B) As an alternative to exhaust gas flow rate, the owner or operator shall comply with the approved alternative for monitoring exhaust gas flow rate in 40 CFR 63.1573(a) of the National Emission Standards for Hazardous Air Pollutants for Petroleum Refineries: Catalytic Cracking Units, Catalytic Reforming Units, and Sulfur Recovery Units.

(iii) The owner or operator shall install, operate, and maintain each CPMS according to the manufacturer's specifications and requirements.

(iv) The owner or operator shall determine and record the average coke burn-off rate and hours of operation for each FCCU or FCU using the procedures in §60.104a(d)(4)(iii).

(v) If you use a control device other than an electrostatic precipitator, wet scrubber, fabric filter, or cyclone, you may request approval to monitor parameters other than those required in paragraph (b)(1) of this section by submitting an alternative monitoring plan to the Administrator. The request must include the information in paragraphs (b)(1)(v)(A) through (E) of this section.

(A) A description of each affected facility and the parameter(s) to be monitored to determine whether the affected facility will continuously comply with the emission limitations and an explanation of the criteria used to select the parameter(s).

(B) A description of the methods and procedures that will be used to demonstrate that the parameter(s) can be used to determine whether the affected facility will continuously comply with the emission limitations and the schedule for this demonstration. The owner or operator must certify that an operating limit will be established for the monitored parameter(s) that represents the conditions in existence when the control device is being properly operated and maintained to meet the emission limitation.

(C) The frequency and content of the recordkeeping, recording, and reporting, if monitoring and recording are not continuous. The owner or operator also must include the rationale for the proposed monitoring, recording, and reporting requirements.

(D) Supporting calculations.

(E) Averaging time for the alternative operating parameter.

(2) For use in determining the coke burn-off rate for an FCCU or FCU, the owner or operator shall install, operate, calibrate, and maintain an instrument for continuously monitoring the concentrations of CO₂, O₂ (dry basis), and if needed, CO in the exhaust gases prior to any control or energy recovery system that burns auxiliary fuels.

(i) The owner or operator shall install, operate and maintain each monitor according to Performance Specifications 3 and 4 of appendix B to part 60.

(ii) The owner or operator shall conduct performance evaluations of each CO₂, O₂ and CO monitor according to the requirements in §60.13(c) and Performance Specifications 3 and 4 of appendix B to part 60. The owner or operator shall use EPA Method 3 of appendix A-3 to part 60 and EPA Method 10, 10A or 10B of appendix A-4 to part 60 for conducting the relative accuracy evaluations.

(iii) The owner or operator shall comply with the quality assurance requirements of procedure 1 of appendix F to part 60, including quarterly accuracy determinations for CO₂ and CO monitors, annual accuracy determinations for O₂ monitors, and daily calibration drift tests.

(c) *Bag leak detection systems.* Each owner or operator shall install, operate, and maintain a bag leak detection system for each baghouse or similar fabric filter control device that is used to comply with the PM per coke burn-off emissions limit in §60.102a(b)(1) for an FCCU or FCU according to paragraph (c)(1) of this section; prepare and operate by a site-specific monitoring plan according to paragraph (c)(2) of this section; take action according to paragraph (c)(3) of this section; and record information according to paragraph (c)(4) of this section.

(1) Each bag leak detection system must meet the specifications and requirements in paragraphs (c)(1)(i) through (viii) of this section.

(i) The bag leak detection system must be certified by the manufacturer to be capable of detecting PM emissions at concentrations of 0.00044 grains per actual cubic foot or less.

(ii) The bag leak detection system sensor must provide output of relative PM loadings. The owner or operator shall continuously record the output from the bag leak detection system using electronic or other means (e.g., using a strip chart recorder or a data logger).

(iii) The bag leak detection system must be equipped with an alarm system that will sound when the system detects an increase in relative particulate loading over the alarm set point established according to paragraph (c)(1)(iv) of this section, and the alarm must be located such that it can be heard by the appropriate plant personnel.

(iv) In the initial adjustment of the bag leak detection system, the owner or operator must establish, at a minimum, the baseline output by adjusting the sensitivity (range) and the averaging period of the device, the alarm set points, and the alarm delay time.

(v) Following initial adjustment, the owner or operator shall not adjust the averaging period, alarm set point, or alarm delay time without approval from the Administrator or delegated authority except as provided in paragraph (c)(1)(vi) of this section.

(vi) Once per quarter, the owner or operator may adjust the sensitivity of the bag leak detection system to account for seasonal effects, including temperature and humidity, according to the procedures identified in the site-specific monitoring plan required by paragraph (c)(2) of this section.

(vii) The owner or operator shall install the bag leak detection sensor downstream of the baghouse and upstream of any wet scrubber.

(viii) Where multiple detectors are required, the system's instrumentation and alarm may be shared among detectors.

(2) The owner or operator shall develop and submit to the Administrator for approval a site-specific monitoring plan for each baghouse and bag leak detection system. The owner or operator shall operate and maintain each baghouse and bag leak detection system according to the site-specific monitoring plan at all times. Each monitoring plan must describe the items in

paragraphs (c)(2)(i) through (vii) of this section.

(i) Installation of the bag leak detection system;

(ii) Initial and periodic adjustment of the bag leak detection system, including how the alarm set-point will be established;

(iii) Operation of the bag leak detection system, including quality assurance procedures;

(iv) How the bag leak detection system will be maintained, including a routine maintenance schedule and spare parts inventory list;

(v) How the bag leak detection system output will be recorded and stored;

(vi) Procedures as specified in paragraph (c)(3) of this section. In approving the site-specific monitoring plan, the Administrator or delegated authority may allow owners and operators more than 3 hours to alleviate a specific condition that causes an alarm if the owner or operator identifies in the monitoring plan this specific condition as one that could lead to an alarm, adequately explains why it is not feasible to alleviate this condition within 3 hours of the time the alarm occurs, and demonstrates that the requested time will ensure alleviation of this condition as expeditiously as practicable; and

(vii) How the baghouse system will be operated and maintained, including monitoring of pressure drop across baghouse cells and frequency of visual inspections of the baghouse interior and baghouse components such as fans and dust removal and bag cleaning mechanisms.

(3) For each bag leak detection system, the owner or operator shall initiate procedures to determine the cause of every alarm within 1 hour of the alarm. Except as provided in paragraph (c)(2)(vi) of this section, the owner or operator shall alleviate the cause of the alarm within 3 hours of the alarm by taking whatever action(s) are necessary. Actions may include, but are not limited to the following:

(i) Inspecting the baghouse for air leaks, torn or broken bags or filter media, or any other condition that may cause an increase in particulate emissions;

(ii) Sealing off defective bags or filter media;

(iii) Replacing defective bags or filter media or otherwise repairing the control device;

(iv) Sealing off a defective baghouse compartment;

(v) Cleaning the bag leak detection system probe or otherwise repairing the bag leak detection system; or

(vi) Shutting down the process producing the particulate emissions.

(4) The owner or operator shall maintain records of the information specified in paragraphs (c)(4)(i) through (iii) of this section for each bag leak detection system.

(i) Records of the bag leak detection system output;

(ii) Records of bag leak detection system adjustments, including the date and time of the adjustment, the initial bag leak detection system settings, and the final bag leak detection system settings; and

(iii) The date and time of all bag leak detection system alarms, the time that procedures to determine the cause of the alarm were initiated, the cause of the alarm, an explanation of the actions taken, the date and time the cause of the alarm was alleviated, and whether the alarm was alleviated within 3 hours of the alarm.

(d) *Continuous emissions monitoring systems (CEMS)*. An owner or operator subject to the PM concentration emission limit (in gr/dscf) in §60.102a(b)(1) for an FCCU or FCU shall install, operate, calibrate, and maintain an instrument for continuously monitoring and recording the concentration (0 percent excess air) of PM in the exhaust gases prior to release to the atmosphere. The monitor must include an O₂ monitor for correcting the data for excess air.

(1) The owner or operator shall install, operate, and maintain each PM monitor according to Performance Specification 11 of appendix B to part 60. The span value of this PM monitor is 0.08 gr/dscf PM.

(2) The owner or operator shall conduct performance evaluations of each PM monitor according to the requirements in §60.13(c) and Performance Specification 11 of appendix B to part 60. The owner or operator shall use EPA Methods 5 or 5I of appendix A-3 to

part 60 or Method 17 of appendix A-6 to part 60 for conducting the relative accuracy evaluations.

(3) The owner or operator shall install, operate, and maintain each O₂ monitor according to Performance Specification 3 of appendix B to part 60. The span value of this O₂ monitor must be selected between 10 and 25 percent, inclusive.

(4) The owner or operator shall conduct performance evaluations of each O₂ monitor according to the requirements in §60.13(c) and Performance Specification 3 of appendix B to part 60. Method 3, 3A, or 3B of appendix A-2 to part 60 shall be used for conducting the relative accuracy evaluations. The method ANSI/ASME PTC 19.10-1981, "Flue and Exhaust Gas Analyses," (incorporated by reference—see §60.17) is an acceptable alternative to EPA Method 3B of appendix A-2 to part 60.

(5) The owner or operator shall comply with the quality assurance requirements of Procedure 2 of appendix B to part 60 for each PM CEMS and Procedure 1 of appendix F to part 60 for each O₂ monitor, including quarterly accuracy determinations for each PM monitor, annual accuracy determinations for each O₂ monitor, and daily calibration drift tests.

(e) *Alternative monitoring option for FCCU and FCU—COMS*. Each owner or operator of an FCCU or FCU that uses cyclones to comply with the PM emission limit in §60.102a(b)(1) shall monitor the opacity of emissions according to the requirements in paragraphs (e)(1) through (3) of this section.

(1) The owner or operator shall install, operate, and maintain an instrument for continuously monitoring and recording the opacity of emissions from the FCCU or the FCU exhaust vent.

(2) The owner or operator shall install, operate, and maintain each COMS according to Performance Specification 1 of appendix B to part 60. The instrument shall be spanned at 20 to 60 percent opacity.

(3) The owner or operator shall conduct performance evaluations of each COMS according to §60.13(c) and Performance Specification 1 of appendix B to part 60.

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(f) *FCCU and FCU subject to NO_x limit.* Each owner or operator subject to the NO_x emissions limit in § 60.102a(b)(2) for an FCCU or FCU shall install, operate, calibrate, and maintain an instrument for continuously monitoring and recording the concentration by volume (dry basis, 0 percent excess air) of NO_x emissions into the atmosphere. The monitor must include an O₂ monitor for correcting the data for excess air.

(1) The owner or operator shall install, operate, and maintain each NO_x monitor according to Performance Specification 2 of appendix B to part 60. The span value of this NO_x monitor is 200 ppmv NO_x.

(2) The owner or operator shall conduct performance evaluations of each NO_x monitor according to the requirements in § 60.13(c) and Performance Specification 2 of appendix B to part 60. The owner or operator shall use Methods 7, 7A, 7C, 7D, or 7E of appendix A–4 to part 60 for conducting the relative accuracy evaluations. The method ANSI/ASME PTC 19.10–1981, “Flue and Exhaust Gas Analyses,” (incorporated by reference—see § 60.17) is an acceptable alternative to EPA Method 7 or 7C of appendix A–4 to part 60.

(3) The owner or operator shall install, operate, and maintain each O₂ monitor according to Performance Specification 3 of appendix B to part 60. The span value of this O₂ monitor must be selected between 10 and 25 percent, inclusive.

(4) The owner or operator shall conduct performance evaluations of each O₂ monitor according to the requirements in § 60.13(c) and Performance Specification 3 of appendix B to part 60. Method 3, 3A, or 3B of appendix A–2 to part 60 shall be used for conducting the relative accuracy evaluations. The method ANSI/ASME PTC 19.10–1981, “Flue and Exhaust Gas Analyses,” (incorporated by reference—see § 60.17) is an acceptable alternative to EPA Method 3B of appendix A–2 to part 60.

(5) The owner or operator shall comply with the quality assurance requirements of Procedure 1 of appendix F to part 60 for each NO_x and O₂ monitor, including quarterly accuracy determinations for NO_x monitors, annual accuracy determinations for O₂ monitors, and daily calibration drift tests.

(g) *FCCU and FCU subject to SO₂ limit.* The owner or operator subject to the SO₂ emissions limit in § 60.102a(b)(3) for an FCCU or an FCU shall install, operate, calibrate, and maintain an instrument for continuously monitoring and recording the concentration by volume (dry basis, corrected to 0 percent excess air) of SO₂ emissions into the atmosphere. The monitor shall include an O₂ monitor for correcting the data for excess air.

(1) The owner or operator shall install, operate, and maintain each SO₂ monitor according to Performance Specification 2 of appendix B to part 60. The span value of this SO₂ monitor is 200 ppmv SO₂.

(2) The owner or operator shall conduct performance evaluations of each SO₂ monitor according to the requirements in § 60.13(c) and Performance Specification 2 of appendix B to part 60. The owner or operator shall use Methods 6, 6A, or 6C of appendix A–4 to part 60 for conducting the relative accuracy evaluations. The method ANSI / ASME PTC 19.10–1981, “Flue and Exhaust Gas Analyses,” (incorporated by reference—see § 60.17) is an acceptable alternative to EPA Method 6 or 6A of appendix A–4 to part 60.

(3) The owner or operator shall install, operate, and maintain each O₂ monitor according to Performance Specification 3 of appendix B to part 60. The span value of this O₂ monitor must be selected between 10 and 25 percent, inclusive.

(4) The owner or operator shall conduct performance evaluations of each O₂ monitor according to the requirements in § 60.13(c) and Performance Specification 3 of appendix B to part 60. Method 3, 3A, or 3B of appendix A–2 to part 60 shall be used for conducting the relative accuracy evaluations. The method ANSI/ASME PTC 19.10–1981, “Flue and Exhaust Gas Analyses,” (incorporated by reference—see § 60.17) is an acceptable alternative to EPA Method 3B of appendix A–2 to part 60.

(5) The owner or operator shall comply with the quality assurance requirements in Procedure 1 of appendix F to

part 60 for each SO₂ and O₂ monitor, including quarterly accuracy determinations for SO₂ monitors, annual accuracy determinations for O₂ monitors, and daily calibration drift tests.

(h) *FCCU and fluid coking units subject to CO emissions limit.* Except as specified in paragraph (h)(3) of this section, the owner or operator shall install, operate, calibrate, and maintain an instrument for continuously monitoring and recording the concentration by volume (dry basis) of CO emissions into the atmosphere from each FCCU and FCU subject to the CO emissions limit in §60.102a(b)(4).

(1) The owner or operator shall install, operate, and maintain each CO monitor according to Performance Specification 4 or 4A of appendix B to part 60. The span value for this instrument is 1,000 ppm CO.

(2) The owner or operator shall conduct performance evaluations of each CO monitor according to the requirements in §60.13(c) and Performance Specification 4 or 4A of appendix B to part 60. The owner or operator shall use Methods 10, 10A, or 10B of appendix A-4 to part 60 for conducting the relative accuracy evaluations.

(3) A CO CEMS need not be installed if the owner or operator demonstrates that all hourly average CO emissions are and will remain less than 50 ppmv (dry basis) corrected to 0 percent excess air. The Administrator may revoke this exemption from monitoring upon a determination that CO emissions on an hourly average basis have exceeded 50 ppmv (dry basis) corrected to 0 percent excess air, in which case a CO CEMS shall be installed within 180 days.

(i) The demonstration shall consist of continuously monitoring CO emissions for 30 days using an instrument that meets the requirements of Performance Specification 4 or 4A of appendix B to part 60. The span value shall be 100 ppm CO instead of 1,000 ppm, and the relative accuracy limit shall be 10 percent of the average CO emissions or 5 ppm CO, whichever is greater. For instruments that are identical to Method 10 of appendix A-4 to part 60 and employ the sample conditioning system of Method 10A of appendix A-4 to part 60, the alternative relative accuracy test

procedure in section 10.1 of Performance Specification 2 of appendix B to part 60 may be used in place of the relative accuracy test.

(ii) The owner or operator must submit the following information to the Administrator:

(A) The measurement data specified in paragraph (h)(3)(i) of this section along with all other operating data known to affect CO emissions; and

(B) Descriptions of the CPMS for exhaust gas temperature and O₂ monitor required in paragraph (h)(4) of this section and operating limits for those parameters to ensure combustion conditions remain similar to those that exist during the demonstration period.

(iii) The effective date of the exemption from installation and operation of a CO CEMS is the date of submission of the information and data required in paragraph (h)(3)(ii) of this section.

(4) The owner or operator of a FCCU or FCU that is exempted from the requirement to install and operate a CO CEMS in paragraph (h)(3) of this section shall install, operate, calibrate, and maintain CPMS to measure and record the operating parameters in paragraph (h)(4)(i) or (ii) of this section. The owner or operator shall install, operate, and maintain each CPMS according to the manufacturer's specifications.

(i) For a FCCU or FCU with no post-combustion control device, the temperature and O₂ concentration of the exhaust gas stream exiting the unit.

(ii) For a FCCU or FCU with a post-combustion control device, the temperature and O₂ concentration of the exhaust gas stream exiting the control device.

(i) *Excess emissions.* For the purpose of reports required by §60.7(c), periods of excess emissions for a FCCU or FCU subject to the emissions limitations in §60.102a(b) are defined as specified in paragraphs (i)(1) through (6) of this section. Note: Determine all averages, except for opacity, as the arithmetic average of the applicable 1-hour averages, e.g., determine the rolling 3-hour average as the arithmetic average of three contiguous 1-hour averages.

(1) If a CPMS is used according to §60.105a(b)(1), all 3-hour periods during which the average PM control device

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operating characteristics, as measured by the continuous monitoring systems under § 60.105a(b)(1), fall below the levels established during the performance test.

(2) If a PM CEMS is used according to § 60.105a(d), all 7-day periods during which the average PM emission rate, as measured by the continuous PM monitoring system under § 60.105a(d) exceeds 0.040 gr/dscf corrected to 0 percent excess air for a modified or reconstructed FCCU, 0.020 gr/dscf corrected to 0 percent excess air for a newly constructed FCCU, or 0.040 gr/dscf for an affected fluid coking unit.

(3) If a COMS is used according to § 60.105a(e), all 3-hour periods during which the average opacity, as measured by the COMS under § 60.105a(e), exceeds the site-specific limit established during the most recent performance test.

(4) All rolling 7-day periods during which the average concentration of NO_x as measured by the NO_x CEMS under § 60.105a(f) exceeds 80 ppmv for an affected FCCU or FCU.

(5) All rolling 7-day periods during which the average concentration of SO₂ as measured by the SO₂ CEMS under § 60.105a(g) exceeds 50 ppmv, and all rolling 365-day periods during which the average concentration of SO₂ as measured by the SO₂ CEMS exceeds 25 ppmv.

(6) All 1-hour periods during which the average CO concentration as measured by the CO continuous monitoring system under § 60.105a(h) exceeds 500 ppmv or, if applicable, all 1-hour periods during which the average temperature and O₂ concentration as measured by the continuous monitoring systems under § 60.105a(h)(4) fall below the operating limits established during the performance test.

[73 FR 35867, June 24, 2008, as amended at 77 FR 56473, Sep. 12, 2012]

§ 60.106a Monitoring of emissions and operations for sulfur recovery plants.

(a) The owner or operator of a sulfur recovery plant that is subject to the emissions limits in § 60.102a(f)(1) or § 60.102a(f)(2) shall:

(1) For sulfur recovery plants subject to the SO₂ emission limit in

§ 60.102a(f)(1)(i) or § 60.102a(f)(2)(i), the owner or operator shall install, operate, calibrate, and maintain an instrument for continuously monitoring and recording the concentration (dry basis, zero percent excess air) of any SO₂ emissions into the atmosphere. The monitor shall include an oxygen monitor for correcting the data for excess air.

(i) The span values for this monitor are two times the applicable SO₂ emission limit and between 10 and 25 percent O₂, inclusive.

(ii) The owner or operator shall install, operate, and maintain each SO₂ CEMS according to Performance Specification 2 of appendix B to part 60.

(iii) The owner or operator shall conduct performance evaluations of each SO₂ monitor according to the requirements in § 60.13(c) and Performance Specification 2 of appendix B to part 60. The owner or operator shall use Methods 6 or 6C of appendix A–4 to part 60 and Method 3 or 3A of appendix A–2 of part 60 for conducting the relative accuracy evaluations. The method ANSI/ASME PTC 19.10–1981, “Flue and Exhaust Gas Analyses,” (incorporated by reference—see § 60.17) is an acceptable alternative to EPA Method 6.

(2) For sulfur recovery plants that are subject to the reduced sulfur compound and H₂S emission limit in § 60.102a(f)(1)(ii) or § 60.102a(f)(2)(ii), the owner or operator shall install, operate, calibrate, and maintain an instrument for continuously monitoring and recording the concentration of reduced sulfur, H₂S, and O₂ emissions into the atmosphere. The reduced sulfur emissions shall be calculated as SO₂ (dry basis, zero percent excess air).

(i) The span values for this monitor are two times the applicable reduced sulfur emission limit, two times the H₂S emission limit, and between 10 and 25 percent O₂, inclusive.

(ii) The owner or operator shall install, operate, and maintain each reduced sulfur CEMS according to Performance Specification 5 of appendix B to part 60.

(iii) The owner or operator shall conduct performance evaluations of each reduced sulfur monitor according to the requirements in § 60.13(c) and Performance Specification 5 of appendix B

to part 60. The owner or operator shall use Methods 15 or 15A of appendix A-5 to part 60 for conducting the relative accuracy evaluations. The method ANSI/ASME PTC 19.10-1981, "Flue and Exhaust Gas Analyses," (incorporated by reference—see § 60.17) is an acceptable alternative to EPA Method 15A of appendix A-5 to part 60.

(iv) The owner or operator shall install, operate, and maintain each H₂S CEMS according to Performance Specification 7 of appendix B to part 60.

(v) The owner or operator shall conduct performance evaluations of each reduced sulfur monitor according to the requirements in § 60.13(c) and Performance Specification 5 of appendix B to part 60. The owner or operator shall use Methods 11, 15, or 15A of appendix A-5 to part 60 or Method 16 of appendix A-6 to part 60 for conducting the relative accuracy evaluations. The method ANSI/ASME PTC 19.10-1981, "Flue and Exhaust Gas Analyses," (incorporated by reference—see § 60.17) is an acceptable alternative to EPA Method 15A of appendix A-5 to part 60.

(vi) The owner or operator shall install, operate, and maintain each O₂ monitor according to Performance Specification 3 of appendix B to part 60.

(vii) The span value for the O₂ monitor must be selected between 10 and 25 percent, inclusive.

(viii) The owner or operator shall conduct performance evaluations for the O₂ monitor according to the requirements of § 60.13(c) and Performance Specification 3 of appendix B to part 60. The owner or operator shall use Methods 3, 3A, or 3B of appendix A-2 to part 60 for conducting the relative accuracy evaluations. The method ANSI/ASME PTC 19.10-1981, "Flue and Exhaust Gas Analyses," (incorporated by reference—see § 60.17) is an acceptable alternative to EPA Method 3B of appendix A-2 to part 60.

(ix) The owner or operator shall comply with the applicable quality assurance procedures of appendix F to part 60 for each monitor, including annual accuracy determinations for each O₂ monitor, and daily calibration drift determinations.

(3) In place of the reduced sulfur monitor required in paragraph (a)(2) of this section, the owner or operator

shall install, calibrate, operate, and maintain an instrument using an air or O₂ dilution and oxidation system to convert any reduced sulfur to SO₂ for continuously monitoring and recording the concentration (dry basis, 0 percent excess air) of the total resultant SO₂. The monitor must include an O₂ monitor for correcting the data for excess O₂.

(i) The span value for this monitor is two times the applicable SO₂ emission limit.

(ii) The owner or operator shall conduct performance evaluations of each SO₂ monitor according to the requirements in § 60.13(c) and Performance Specification 5 of appendix B to part 60. The owner or operator shall use Methods 15 or 15A of appendix A-5 to part 60 for conducting the relative accuracy evaluations. The method ANSI/ASME PTC 19.10-1981, "Flue and Exhaust Gas Analyses," (incorporated by reference—see § 60.17) is an acceptable alternative to EPA Method 15A of appendix A-5 to part 60.

(iii) The owner or operator shall install, operate, and maintain each O₂ monitor according to Performance Specification 3 of appendix B to part 60.

(iv) The span value for the O₂ monitor must be selected between 10 and 25 percent, inclusive.

(v) The owner or operator shall conduct performance evaluations for the O₂ monitor according to the requirements of § 60.13(c) and Performance Specification 3 of appendix B to part 60. The owner or operator shall use Methods 3, 3A, or 3B of appendix A-2 to part 60 for conducting the relative accuracy evaluations. The method ANSI/ASME PTC 19.10-1981, "Flue and Exhaust Gas Analyses," (incorporated by reference—see § 60.17) is an acceptable alternative to EPA Method 3B of appendix A-2 to part 60.

(vi) The owner or operator shall comply with the applicable quality assurance procedures of appendix F to part 60 for each monitor, including quarterly accuracy determinations for each SO₂ monitor, annual accuracy determinations for each O₂ monitor, and daily calibration drift determinations.

(b) *Excess emissions.* For the purpose of reports required by § 60.7(c), periods of excess emissions for sulfur recovery

plants subject to the emissions limitations in § 60.102a(f) are defined as specified in paragraphs (b)(1) through (3) of this section.

NOTE: Determine all averages as the arithmetic average of the applicable 1-hour averages, e.g., determine the rolling 12-hour average as the arithmetic average of 12 contiguous 1-hour averages.

(1) All 12-hour periods during which the average concentration of SO₂ as measured by the SO₂ continuous monitoring system required under paragraph (a)(1) of this section exceeds the applicable emission limit (dry basis, zero percent excess air); or

(2) All 12-hour periods during which the average concentration of reduced sulfur (as SO₂) as measured by the reduced sulfur continuous monitoring system required under paragraph (a)(2) of this section exceeds the applicable emission limit; or

(3) All 12-hour periods during which the average concentration of H₂S as measured by the H₂S continuous monitoring system required under paragraph (a)(2) of this section exceeds the applicable emission limit (dry basis, 0 percent excess air).

§ 60.107a Monitoring of emissions and operations for fuel gas combustion devices and flares.

(a) *Fuel gas combustion devices subject to SO₂ or H₂S limit and flares subject to H₂S concentration requirements.* The owner or operator of a fuel gas combustion device that is subject to § 60.102a(g)(1) and elects to comply with the SO₂ emission limits in § 60.102a(g)(1)(i) shall comply with the requirements in paragraph (a)(1) of this section. The owner or operator of a fuel gas combustion device that is subject to § 60.102a(g)(1) and elects to comply with the H₂S concentration limits in § 60.102a(g)(1)(ii) or a flare that is subject to the H₂S concentration requirement in § 60.103a(h) shall comply with paragraph (a)(2) of this section.

(1) The owner or operator of a fuel gas combustion device that elects to comply with the SO₂ emissions limits in § 60.102a(g)(1)(i) shall install, operate, calibrate and maintain an instrument for continuously monitoring and recording the concentration (dry basis, 0-percent excess air) of SO₂ emissions

into the atmosphere. The monitor must include an O₂ monitor for correcting the data for excess air.

(i) The owner or operator shall install, operate, and maintain each SO₂ monitor according to Performance Specification 2 of appendix B to part 60. The span value for the SO₂ monitor is 50 ppm SO₂.

(ii) The owner or operator shall conduct performance evaluations for the SO₂ monitor according to the requirements of § 60.13(c) and Performance Specification 2 of appendix B to part 60. The owner or operator shall use Methods 6, 6A, or 6C of appendix A–4 to part 60 for conducting the relative accuracy evaluations. The method ANSI/ASME PTC 19.10–1981, “Flue and Exhaust Gas Analyses,” (incorporated by reference—see § 60.17) is an acceptable alternative to EPA Method 6 or 6A of appendix A–4 to part 60. Samples taken by Method 6 of appendix A–4 to part 60 shall be taken at a flow rate of approximately 2 liters/min for at least 30 minutes. The relative accuracy limit shall be 20 percent or 4 ppm, whichever is greater, and the calibration drift limit shall be 5 percent of the established span value.

(iii) The owner or operator shall install, operate, and maintain each O₂ monitor according to Performance Specification 3 of appendix B to part 60. The span value for the O₂ monitor must be selected between 10 and 25 percent, inclusive.

(iv) The owner or operator shall conduct performance evaluations for the O₂ monitor according to the requirements of § 60.13(c) and Performance Specification 3 of appendix B to part 60. The owner or operator shall use Methods 3, 3A, or 3B of appendix A–2 to part 60 for conducting the relative accuracy evaluations. The method ANSI/ASME PTC 19.10–1981, “Flue and Exhaust Gas Analyses,” (incorporated by reference—see § 60.17) is an acceptable alternative to EPA Method 3B of appendix A–2 to part 60.

(v) The owner or operator shall comply with the applicable quality assurance procedures in appendix F to part 60, including quarterly accuracy determinations for SO₂ monitors, annual accuracy determinations for O₂ monitors, and daily calibration drift tests.

(vi) Fuel gas combustion devices having a common source of fuel gas may be monitored at only one location (i.e., after one of the combustion devices), if monitoring at this location accurately represents the SO₂ emissions into the atmosphere from each of the combustion devices.

(2) The owner or operator of a fuel gas combustion device that elects to comply with the H₂S concentration limits in § 60.102a(g)(1)(ii) or a flare that is subject to the H₂S concentration requirement in § 60.103a(h) shall install, operate, calibrate and maintain an instrument for continuously monitoring and recording the concentration by volume (dry basis) of H₂S in the fuel gases before being burned in any fuel gas combustion device or flare.

(i) The owner or operator shall install, operate and maintain each H₂S monitor according to Performance Specification 7 of appendix B to part 60. The span value for this instrument is 300 ppmv H₂S.

(ii) The owner or operator shall conduct performance evaluations for each H₂S monitor according to the requirements of § 60.13(c) and Performance Specification 7 of appendix B to part 60. The owner or operator shall use Method 11, 15, or 15A of appendix A-5 to part 60 or Method 16 of appendix A-6 to part 60 for conducting the relative accuracy evaluations. The method ANSI/ASME PTC 19.10-1981, "Flue and Exhaust Gas Analyses," (incorporated by reference—see § 60.17) is an acceptable alternative to EPA Method 15A of appendix A-5 to part 60.

(iii) The owner or operator shall comply with the applicable quality assurance procedures in appendix F to part 60 for each H₂S monitor.

(iv) Fuel gas combustion devices or flares having a common source of fuel gas may be monitored at only one location, if monitoring at this location accurately represents the concentration of H₂S in the fuel gas being burned in the respective fuel gas combustion devices or flares.

(v) The owner or operator of a flare subject to § 60.103a(c) through (e) may use the instrument required in paragraph (e)(1) of this section to demonstrate compliance with the H₂S concentration requirement in § 60.103a(h) if

the owner or operator complies with the requirements of paragraph (e)(1)(i) through (iv) and if the instrument has a span (or dual span, if necessary) capable of accurately measuring concentrations between 20 and 300 ppmv. If the instrument required in paragraph (e)(1) of this section is used to demonstrate compliance with the H₂S concentration requirement, the concentration directly measured by the instrument must meet the numeric concentration in § 60.103a(h).

(vi) The owner or operator of modified flare that meets all three criteria in paragraphs (a)(2)(vi)(A) through (C) of this section shall comply with the requirements of paragraphs (a)(2)(i) through (v) of this section no later than November 11, 2015. The owner or operator shall comply with the approved alternative monitoring plan or plans pursuant to § 60.13(i) until the flare is in compliance with requirements of paragraphs (a)(2)(i) through (v) of this section.

(A) The flare was an affected facility subject to subpart J of this part prior to becoming an affected facility under § 60.100a.

(B) The owner or operator had an approved alternative monitoring plan or plans pursuant to § 60.13(i) for all fuel gases combusted in the flare.

(C) The flare did not have in place on or before September 12, 2012 an instrument for continuously monitoring and recording the concentration by volume (dry basis) of H₂S in the fuel gases that is capable of complying with the requirements of paragraphs (a)(2)(i) through (v) of this section.

(3) The owner or operator of a fuel gas combustion device or flare is not required to comply with paragraph (a)(1) or (2) of this section for fuel gas streams that are exempt under §§ 60.102a(g)(1)(iii) or 60.103a(h) or, for fuel gas streams combusted in a process heater, other fuel gas combustion device or flare that are inherently low in sulfur content. Fuel gas streams meeting one of the requirements in paragraphs (a)(3)(i) through (iv) of this section will be considered inherently low in sulfur content.

(i) Pilot gas for heaters and flares.

(ii) Fuel gas streams that meet a commercial-grade product specification for sulfur content of 30 ppmv or less. In the case of a liquefied petroleum gas (LPG) product specification in the pressurized liquid state, the gas phase sulfur content should be evaluated assuming complete vaporization of the LPG and sulfur containing-compounds at the product specification concentration.

(iii) Fuel gas streams produced in process units that are intolerant to sulfur contamination, such as fuel gas streams produced in the hydrogen plant, catalytic reforming unit, isomerization unit, and HF alkylation process units.

(iv) Other fuel gas streams that an owner or operator demonstrates are low-sulfur according to the procedures in paragraph (b) of this section.

(4) If the composition of an exempt fuel gas stream changes, the owner or operator must follow the procedures in paragraph (b)(3) of this section.

(b) *Exemption from H₂S monitoring requirements for low-sulfur fuel gas streams.* The owner or operator of a fuel gas combustion device or flare may apply for an exemption from the H₂S monitoring requirements in paragraph (a)(2) of this section for a fuel gas stream that is inherently low in sulfur content. A fuel gas stream that is demonstrated to be low-sulfur is exempt from the monitoring requirements of paragraphs (a)(1) and (2) of this section until there are changes in operating conditions or stream composition.

(1) The owner or operator shall submit to the Administrator a written application for an exemption from monitoring. The application must contain the following information:

(i) A description of the fuel gas stream/system to be considered, including submission of a portion of the appropriate piping diagrams indicating the boundaries of the fuel gas stream/system and the affected fuel gas combustion device(s) or flare(s) to be considered;

(ii) A statement that there are no crossover or entry points for sour gas (high H₂S content) to be introduced into the fuel gas stream/system (this should be shown in the piping diagrams);

(iii) An explanation of the conditions that ensure low amounts of sulfur in the fuel gas stream (i.e., control equipment or product specifications) at all times;

(iv) The supporting test results from sampling the requested fuel gas stream/system demonstrating that the sulfur content is less than 5 ppm H₂S. Sampling data must include, at minimum, 2 weeks of daily monitoring (14 grab samples) for frequently operated fuel gas streams/systems; for infrequently operated fuel gas streams/systems, seven grab samples must be collected unless other additional information would support reduced sampling. The owner or operator shall use detector tubes ("length-of-stain tube" type measurement) following the "Gas Processors Association Standard 2377-86, Test for Hydrogen Sulfide and Carbon Dioxide in Natural Gas Using Length of Stain Tubes," 1986 Revision (incorporated by reference—see §60.17), with ranges 0-10/0-100 ppm (N = 10/1) to test the applicant fuel gas stream for H₂S; and

(v) A description of how the 2 weeks (or seven samples for infrequently operated fuel gas streams/systems) of monitoring results compares to the typical range of H₂S concentration (fuel quality) expected for the fuel gas stream/system going to the affected fuel gas combustion device or flare (e.g., the 2 weeks of daily detector tube results for a frequently operated loading rack included the entire range of products loaded out and, therefore, should be representative of typical operating conditions affecting H₂S content in the fuel gas stream going to the loading rack flare).

(2) The effective date of the exemption is the date of submission of the information required in paragraph (b)(1) of this section.

(3) No further action is required unless refinery operating conditions change in such a way that affects the exempt fuel gas stream/system (e.g., the stream composition changes). If such a change occurs, the owner or operator shall follow the procedures in paragraph (b)(3)(i), (b)(3)(ii), or (b)(3)(iii) of this section.

(i) If the operation change results in a sulfur content that is still within the

range of concentrations included in the original application, the owner or operator shall conduct an H₂S test on a grab sample and record the results as proof that the concentration is still within the range.

(ii) If the operation change results in a sulfur content that is outside the range of concentrations included in the original application, the owner or operator may submit new information following the procedures of paragraph (b)(1) of this section within 60 days (or within 30 days after the seventh grab sample is tested for infrequently operated process units).

(iii) If the operation change results in a sulfur content that is outside the range of concentrations included in the original application and the owner or operator chooses not to submit new information to support an exemption, the owner or operator must begin H₂S monitoring using daily stain sampling to demonstrate compliance. The owner or operator must begin monitoring according to the requirements in paragraphs (a)(1) or (a)(2) of this section as soon as practicable, but in no case later than 180 days after the operation change. During daily stain tube sampling, a daily sample exceeding 162 ppmv is an exceedance of the 3-hour H₂S concentration limit. The owner or operator of a fuel gas combustion device must also determine a rolling 365-day average using the stain sampling results; an average H₂S concentration of 5 ppmv must be used for days within the rolling 365-day period prior to the operation change.

(c) *Process heaters complying with the NO_x concentration-based limit.* The owner or operator of a process heater subject to the NO_x emissions limit in § 60.102a(g)(2) and electing to comply with the applicable emissions limit in § 60.102a(g)(2)(i)(A), (g)(2)(ii)(A), (g)(2)(iii)(A) or (g)(2)(iv)(A) shall install, operate, calibrate and maintain an instrument for continuously monitoring and recording the concentration (dry basis, 0-percent excess air) of NO_x emissions into the atmosphere according to the requirements in paragraphs (c)(1) through (5) of this section, except as provided in paragraph (c)(6) of this section. The monitor must include an

O₂ monitor for correcting the data for excess air.

(1) Except as provided in paragraph (c)(6) of this section, the owner or operator shall install, operate and maintain each NO_x monitor according to Performance Specification 2 of appendix B to part 60. The span value of this NO_x monitor must be between 2 and 3 times the applicable emissions limit, inclusive.

(2) The owner or operator shall conduct performance evaluations of each NO_x monitor according to the requirements in § 60.13(c) and Performance Specification 2 of appendix B to part 60. The owner or operator shall use Methods 7, 7A, 7C, 7D, or 7E of appendix A-4 to part 60 for conducting the relative accuracy evaluations. The method ANSI/ASME PTC 19.10-1981, "Flue and Exhaust Gas Analyses," (incorporated by reference—see § 60.17) is an acceptable alternative to EPA Method 7 or 7C of appendix A-4 to part 60.

(3) The owner or operator shall install, operate, and maintain each O₂ monitor according to Performance Specification 3 of appendix B to part 60. The span value of this O₂ monitor must be selected between 10 and 25 percent, inclusive.

(4) The owner or operator shall conduct performance evaluations of each O₂ monitor according to the requirements in § 60.13(c) and Performance Specification 3 of appendix B to part 60. Method 3, 3A, or 3B of appendix A-2 to part 60 shall be used for conducting the relative accuracy evaluations. The method ANSI/ASME PTC 19.10-1981, "Flue and Exhaust Gas Analyses," (incorporated by reference—see § 60.17) is an acceptable alternative to EPA Method 3B of appendix A-2 to part 60.

(5) The owner or operator shall comply with the quality assurance requirements in Procedure 1 of appendix F to part 60 for each NO_x and O₂ monitor, including quarterly accuracy determinations for NO_x monitors, annual accuracy determinations for O₂ monitors, and daily calibration drift tests.

(6) The owner or operator of a process heater that has a rated heating capacity of less than 100 MMBtu and is equipped with combustion modification-based technology to reduce NO_x emissions (*i.e.*, low-NO_x burners, ultra-

low-NO_x burners) may elect to comply with the monitoring requirements in paragraphs (c)(1) through (5) of this section or, alternatively, the owner or operator of such a process heater shall conduct biennial performance tests according to the requirements in § 60.104a(i), establish a maximum excess O₂ operating limit or operating curve according to the requirements in § 60.104a(i)(6) and comply with the O₂ monitoring requirements in paragraphs (c)(3) through (5) of this section to demonstrate compliance. If an O₂ operating curve is used (*i.e.*, if different O₂ operating limits are established for different operating ranges), the owner or operator of the process heater must also monitor fuel gas flow rate, fuel oil flow rate (as applicable) and heating value content according to the methods provided in paragraphs (d)(5), (d)(6), and (d)(4) or (d)(7) of this section, respectively.

(d) *Process heaters complying with the NO_x heating value-based or mass-based limit.* The owner or operator of a process heater subject to the NO_x emissions limit in § 60.102a(g)(2) and electing to comply with the applicable emissions limit in § 60.102a(g)(2)(i)(B) or (g)(2)(ii)(B) shall install, operate, calibrate and maintain an instrument for continuously monitoring and recording the concentration (dry basis, 0-percent excess air) of NO_x emissions into the atmosphere and shall determine the F factor of the fuel gas stream no less frequently than once per day according to the monitoring requirements in paragraphs (d)(1) through (4) of this section. The owner or operator of a co-fired process heater subject to the NO_x emissions limit in § 60.102a(g)(2) and electing to comply with the heating value-based limit in § 60.102a(g)(2)(iii)(B) or (g)(2)(iv)(B) shall install, operate, calibrate and maintain an instrument for continuously monitoring and recording the concentration (dry basis, 0-percent excess air) of NO_x emissions into the atmosphere according to the monitoring requirements in paragraph (d)(1) of this

section; install, operate, calibrate and maintain an instrument for continuously monitoring and recording the flow rate of the fuel gas and fuel oil fed to the process heater according to the monitoring requirements in paragraph (d)(5) and (6) of this section; for fuel gas streams, determine gas composition according to the requirements in paragraph (d)(4) of this section or the higher heating value according to the requirements in paragraph (d)(7) of this section; and for fuel oil streams, determine the heating value according to the monitoring requirements in paragraph (d)(7) of this section.

(1) Except as provided in paragraph (d)(8) of this section, the owner or operator shall install, operate and maintain each NO_x monitor according to the requirements in paragraphs (c)(1) through (5) of this section. The monitor must include an O₂ monitor for correcting the data for excess air.

(2) Except as provided in paragraph (d)(3) of this section, the owner or operator shall sample and analyze each fuel stream fed to the process heater using the methods and equations in section 12.3.2 of EPA Method 19 of appendix A-7 to part 60 to determine the F factor on a dry basis. If a single fuel gas system provides fuel gas to several process heaters, the F factor may be determined at a single location in the fuel gas system provided it is representative of the fuel gas fed to the affected process heater(s).

(3) As an alternative to the requirements in paragraph (d)(2) of this section, the owner or operator of a gas-fired process heater shall install, operate and maintain a gas composition analyzer and determine the average F factor of the fuel gas using the factors in Table 1 of this subpart and Equation 10 of this section. If a single fuel gas system provides fuel gas to several process heaters, the F factor may be determined at a single location in the fuel gas system provided it is representative of the fuel gas fed to the affected process heater(s).

$$F_d = \frac{1,000,000 \times \sum (X_i \times MEV_i)}{\sum (X_i \times MHC_i)} \quad (\text{Eq. 10})$$

Where:

F_d = F factor on dry basis at 0-percent excess air, dscf/MMBtu.

X_i = mole or volume fraction of each component in the fuel gas.

MEV_i = molar exhaust volume, dry standard cubic feet per mole (dscf/mol).

MHC_i = molar heat content, Btu per mole (Btu/mol).

1,000,000 = unit conversion, Btu per MMBtu.

(4) The owner or operator shall conduct performance evaluations of each compositional monitor according to the requirements in Performance Specification 9 of appendix B to part 60. Any of the following methods shall be used for conducting the relative accuracy evaluations:

(i) EPA Method 18 of appendix A-6 to part 60;

(ii) ASTM D1945-03 (Reapproved 2010)(incorporated by reference-see § 60.17);

(iii) ASTM D1946-90 (Reapproved 2006)(incorporated by reference-see § 60.17);

(iv) ASTM D6420-99 (Reapproved 2004)(incorporated by reference-see § 60.17);

(v) GPA 2261-00 (incorporated by reference-see § 60.17); or

(vi) ASTM UOP539-97 (incorporated by reference-see § 60.17).

(5) The owner or operator shall install, operate and maintain fuel gas flow monitors according to the manufacturer's recommendations. For volumetric flow meters, temperature and pressure monitors must be installed in conjunction with the flow meter or in a representative location to correct the measured flow to standard conditions (*i.e.*, 68 °F and 1 atmosphere). For mass flow meters, use gas compositions determined according to paragraph (d)(4) of this section to determine the average molecular weight of the fuel gas and convert the mass flow to a volumetric flow at standard conditions (*i.e.*, 68 °F and 1 atmosphere). The owner or operator shall conduct performance evaluations of each fuel gas flow mon-

itor according to the requirements in § 60.13 and Performance Specification 6 of appendix B to part 60. Any of the following methods shall be used for conducting the relative accuracy evaluations:

(i) EPA Method 2, 2A, 2B, 2C or 2D of Appendix A-2 to part 60;

(ii) ASME MFC-3M-2004 (incorporated by reference-see § 60.17);

(iii) ANSI/ASME MFC-4M-1986 (Reaffirmed 2008) (incorporated by reference-see § 60.17);

(iv) ASME MFC-6M-1998 (Reaffirmed 2005) (incorporated by reference-see § 60.17);

(v) ASME/ANSI MFC-7M-1987 (Reaffirmed 2006) (incorporated by reference-see § 60.17);

(vi) ASME MFC-11M-2006 (incorporated by reference-see § 60.17);

(vii) ASME MFC-14M-2003 (incorporated by reference-see § 60.17);

(viii) ASME MFC-18M-2001 (incorporated by reference-see § 60.17);

(ix) AGA Report No. 3, Part 1 (incorporated by reference-see § 60.17);

(x) AGA Report No. 3, Part 2 (incorporated by reference-see § 60.17);

(xi) AGA Report No. 11 (incorporated by reference-see § 60.17);

(xii) AGA Report No. 7 (incorporated by reference-see § 60.17); and

(xiii) API Manual of Petroleum Measurement Standards, Chapter 22, Section 2 (incorporated by reference-see § 60.17).

(6) The owner or operator shall install, operate and maintain each fuel oil flow monitor according to the manufacturer's recommendations. The owner or operator shall conduct performance evaluations of each fuel oil flow monitor according to the requirements in § 60.13 and Performance Specification 6 of Appendix B to part 60. Any of the following methods shall be used for conducting the relative accuracy evaluations:

(i) Any one of the methods listed in paragraph (d)(5) of this section that are applicable to fuel oil (*i.e.*, "fluids");

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(ii) ANSI/ASME–MFC–5M–1985 (Reaffirmed 2006) (incorporated by reference—see § 60.17);

(iii) ASME/ANSI MFC–9M–1988 (Reaffirmed 2006) (incorporated by reference—see § 60.17);

(iv) ASME MFC–16–2007 (incorporated by reference—see § 60.17);

(v) ASME MFC–22–2007 (incorporated by reference—see § 60.17); or

(vi) ISO 8316 (incorporated by reference—see § 60.17).

(7) The owner or operator shall determine the higher heating value of each fuel fed to the process heater using any of the applicable methods included in paragraphs (d)(7)(i) through (ix) of this section. If a common fuel supply system provides fuel gas or fuel oil to several process heaters, the higher heating value of the fuel in each fuel supply system may be determined at a single location in the fuel supply system provided it is representative of the fuel fed to the affected process heater(s). The higher heating value of each fuel fed to the process heater must be determined no less frequently than once per day except as provided in paragraph (d)(7)(x) of this section.

(i) ASTM D240–02 (Reapproved 2007) (incorporated by reference—see § 60.17).

(ii) ASTM D1826–94 (Reapproved 2003) (incorporated by reference—see § 60.17).

(iii) ASTM D1945–03 (Reapproved 2010) (incorporated by reference—see § 60.17).

(iv) ASTM D1946–90 (Reapproved 2006) (incorporated by reference—see § 60.17).

(v) ASTM D3588–98 (Reapproved 2003) (incorporated by reference—see § 60.17).

(vi) ASTM D4809–06 (incorporated by reference—see § 60.17).

(vii) ASTM D4891–89 (Reapproved 2006) (incorporated by reference—see § 60.17).

(viii) GPA 2172–09 (incorporated by reference—see § 60.17).

(ix) Any of the methods specified in section 2.2.7 of Appendix D to part 75.

(x) If the fuel oil supplied to the affected co-fired process heater originates from a single storage tank, the owner or operator may elect to use the storage tank sampling method in section 2.2.4.2 of Appendix D to part 75 instead of daily sampling, except that the most recent value for heating content must be used.

(8) The owner or operator of a process heater that has a rated heating capacity of less than 100 MMBtu and is equipped with combustion modification based technology to reduce NO_x emissions (*i.e.*, low-NO_x burners or ultra-low NO_x burners) may elect to comply with the monitoring requirements in paragraphs (d)(1) through (7) of this section or, alternatively, the owner or operator of such a process heater shall conduct biennial performance tests according to the requirements in § 60.104a(i), establish a maximum excess O₂ operating limit or operating curve according to the requirements in § 60.104a(i)(6) and comply with the O₂ monitoring requirements in paragraphs (c)(3) through (5) of this section to demonstrate compliance. If an O₂ operating curve is used (*i.e.*, if different O₂ operating limits are established for different operating ranges), the owner or operator of the process heater must also monitor fuel gas flow rate, fuel oil flow rate (as applicable) and heating value content according to the methods provided in paragraphs (d)(5), (d)(6), and (d)(4) or (d)(7) of this section, respectively.

(e) *Sulfur monitoring for assessing root cause analysis threshold for affected flares.* Except as described in paragraphs (e)(4) and (h) of this section, the owner or operator of an affected flare subject to § 60.103a(c) through (e) shall determine the total reduced sulfur concentration for each gas line directed to the affected flare in accordance with either paragraph (e)(1), (e)(2) or (e)(3) of this section. Different options may be elected for different gas lines. If a monitoring system is in place that is capable of complying with the requirements related to either paragraph (e)(1), (e)(2) or (e)(3) of this section, the owner or operator of a modified flare must comply with the requirements related to either paragraph (e)(1), (e)(2) or (e)(3) of this section upon startup of the modified flare. If a monitoring system is not in place that is capable of complying with the requirements related to either paragraph (e)(1), (e)(2) or (e)(3) of this section, the owner or operator of a modified flare must comply with the requirements related to either paragraph (e)(1), (e)(2) or (e)(3) of this section no later than November 11, 2015 or

upon startup of the modified flare, whichever is later.

(1) *Total reduced sulfur monitoring requirements.* The owner or operator shall install, operate, calibrate and maintain an instrument for continuously monitoring and recording the concentration of total reduced sulfur in gas discharged to the flare.

(i) The owner or operator shall install, operate and maintain each total reduced sulfur monitor according to Performance Specification 5 of Appendix B to part 60. The span value should be determined based on the maximum sulfur content of gas that can be discharged to the flare (e.g., roughly 1.1 to 1.3 times the maximum anticipated sulfur concentration), but may be no less than 5,000 ppmv. A single dual range monitor may be used to comply with the requirements of this paragraph and paragraph (a)(2) of this section provided the applicable span specifications are met.

(ii) The owner or operator shall conduct performance evaluations of each total reduced sulfur monitor according to the requirements in §60.13(c) and Performance Specification 5 of Appendix B to part 60. For flares that routinely have flow, the owner or operator of each total reduced sulfur monitor shall use EPA Method 15A of Appendix A-5 to part 60 for conducting the relative accuracy evaluations. The method ANSI/ASME PTC 19.10-1981 (incorporated by reference—see §60.17) is an acceptable alternative to EPA Method 15A of Appendix A-5 to part 60. The alternative relative accuracy procedures described in section 16.0 of Performance Specification 2 of Appendix B to part 60 (cylinder gas audits) may be used for conducting the relative accuracy evaluations. For flares that do not receive routine flow, the alternative relative accuracy procedures described in section 16.0 of Performance Specification 2 of Appendix B to part 60 (cylinder gas audits) may be used for conducting the relative accuracy evaluations, except that it is not necessary to include as much of the sampling probe or sampling line as practical.

(iii) The owner or operator shall comply with the applicable quality assurance procedures in Appendix F to part

60 for each total reduced sulfur monitor.

(2) *H₂S monitoring requirements.* The owner or operator shall install, operate, calibrate, and maintain an instrument for continuously monitoring and recording the concentration of H₂S in gas discharged to the flare according to the requirements in paragraphs (e)(2)(i) through (iii) of this section and shall collect and analyze samples of the gas and calculate total sulfur concentrations as specified in paragraphs (e)(2)(iv) through (ix) of this section.

(i) The owner or operator shall install, operate and maintain each H₂S monitor according to Performance Specification 7 of Appendix B to part 60. The span value should be determined based on the maximum sulfur content of gas that can be discharged to the flare (e.g., roughly 1.1 to 1.3 times the maximum anticipated sulfur concentration), but may be no less than 5,000 ppmv. A single dual range H₂S monitor may be used to comply with the requirements of this paragraph and paragraph (a)(2) of this section provided the applicable span specifications are met.

(ii) The owner or operator shall conduct performance evaluations of each H₂S monitor according to the requirements in §60.13(c) and Performance Specification 7 of Appendix B to part 60. For flares that routinely have flow, the owner or operator shall use EPA Method 11, 15 or 15A of Appendix A-5 to part 60 for conducting the relative accuracy evaluations. The method ANSI/ASME PTC 19.10-1981 (incorporated by reference—see §60.17) is an acceptable alternative to EPA Method 15A of Appendix A-5 to part 60. The alternative relative accuracy procedures described in section 16.0 of Performance Specification 2 of Appendix B to part 60 (cylinder gas audits) may be used for conducting the relative accuracy evaluations. For flares that do not receive routine flow, the alternative relative accuracy procedures described in section 16.0 of Performance Specification 2 of Appendix B to part 60 (cylinder gas audits) may be used for conducting the relative accuracy evaluations, except that it is not necessary to include as much of the sampling probe or sampling line as practical.

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(iii) The owner or operator shall comply with the applicable quality assurance procedures in Appendix F to part 60 for each H₂S monitor.

(iv) In the first 10 operating days after the date the flare must begin to comply with § 60.103a(c)(1), the owner or operator shall collect representative daily samples of the gas discharged to the flare. The samples may be grab samples or integrated samples. The owner or operator shall take subsequent representative daily samples at least once per week or as required in paragraph (e)(2)(ix) of this section.

(v) The owner or operator shall analyze each daily sample for total sulfur using either EPA Method 15A of Appendix A-5 to part 60, EPA Method 16A of Appendix A-6 to part 60, ASTM Method D4468-85 (Reapproved 2006) (incorporated by reference—see § 60.17) or

ASTM Method D5504-08 (incorporated by reference—see § 60.17).

(vi) The owner or operator shall develop a 10-day average total sulfur-to-H₂S ratio and 95-percent confidence interval as follows:

(A) Calculate the ratio of the total sulfur concentration to the H₂S concentration for each day during which samples are collected.

(B) Determine the 10-day average total sulfur-to-H₂S ratio as the arithmetic average of the daily ratios calculated in paragraph (e)(2)(vi)(A) of this section.

(C) Determine the acceptable range for subsequent weekly samples based on the 95-percent confidence interval for the distribution of daily ratios based on the 10 individual daily ratios using Equation 11 of this section.

$$AR = Ratio_{Avg} \pm 2.262 \times SDev \quad (\text{Eq. 11})$$

Where:

AR = Acceptable range of subsequent ratio determinations, unitless.

Ratio_{Avg} = 10-day average total sulfur-to-H₂S concentration ratio, unitless.

2.262 = t-distribution statistic for 95-percent 2-sided confidence interval for 10 samples (9 degrees of freedom).

SDev = Standard deviation of the 10 daily average total sulfur-to-H₂S concentration ratios used to develop the 10-day average total sulfur-to-H₂S concentration ratio, unitless.

(vii) For each day during the period when data are being collected to develop a 10-day average, the owner or operator shall estimate the total sulfur concentration using the measured total sulfur concentration measured for that day.

(viii) For all days other than those during which data are being collected to develop a 10-day average, the owner or operator shall multiply the most recent 10-day average total sulfur-to-H₂S ratio by the daily average H₂S concentrations obtained using the monitor as required by paragraph (e)(2)(i) through (iii) of this section to estimate total sulfur concentrations.

(ix) If the total sulfur-to-H₂S ratio for a subsequent weekly sample is outside the acceptable range for the most recent distribution of daily ratios, the owner or operator shall develop a new 10-day average ratio and acceptable range based on data for the outlying weekly sample plus data collected over the following 9 operating days.

(3) *SO₂ monitoring requirements.* The owner or operator shall install, operate, calibrate and maintain an instrument for continuously monitoring and recording the concentration of SO₂ from a process heater or other fuel gas combustion device that is combusting gas representative of the fuel gas in the flare gas line according to the requirements in paragraph (a)(1) of this section, determine the F factor of the fuel gas at least daily according to the requirements in paragraphs (d)(2) through (4) of this section, determine the higher heating value of the fuel gas at least daily according to the requirements in paragraph (d)(7) of this section and calculate the total sulfur content (as SO₂) in the fuel gas using Equation 12 of this section.

$$TS_{FG} = C_{SO_2} \times F_d \times HHV_{FG} \quad (\text{Eq. 12})$$

Where:

TS_{FG} = Total sulfur concentration, as SO_2 , in the fuel gas, ppmv.

C_{SO_2} = Concentration of SO_2 in the exhaust gas, ppmv (dry basis at 0-percent excess air).

F_d = F factor gas on dry basis at 0-percent excess air, dscf/MMBtu.

HHV_{FG} = Higher heating value of the fuel gas, MMBtu/scf.

(4) *Exemptions from sulfur monitoring requirements.* Flares identified in paragraphs (e)(4)(i) through (iv) of this section are exempt from the requirements in paragraphs (e)(1) through (3) of this section. For each such flare, except as provided in paragraph (e)(4)(iv), engineering calculations shall be used to calculate the SO_2 emissions in the event of a discharge that may trigger a root cause analysis under § 60.103a(c)(1).

(i) Flares that can only receive:

(A) Fuel gas streams that are inherently low in sulfur content as described in paragraph (a)(3)(i) through (iv) of this section; and/or

(B) Fuel gas streams that are inherently low in sulfur content for which the owner or operator has applied for an exemption from the H_2S monitoring requirements as described in paragraph (b) of this section.

(ii) Emergency flares, provided that for each such flare, the owner or operator complies with the monitoring alternative in paragraph (g) of this section.

(iii) Flares equipped with flare gas recovery systems designed, sized and operated to capture all flows except those resulting from startup, shutdown or malfunction, provided that for each such flare, the owner or operator complies with the monitoring alternative in paragraph (g) of this section.

(iv) Secondary flares that receive gas diverted from the primary flare. In the event of a discharge from the secondary flare, the sulfur content measured by the sulfur monitor on the primary flare should be used to calculate SO_2 emissions, regardless of whether or not the monitoring alternative in paragraph (g) of this section is selected for the secondary flare.

(f) *Flow monitoring for flares.* Except as provided in paragraphs (f)(2) and (h) of this section, the owner or operator of an affected flare subject to § 60.103a(c) through (e) shall install, operate, calibrate and maintain, in accordance with the specifications in paragraph (f)(1) of this section, a CPMS to measure and record the flow rate of gas discharged to the flare. If a flow monitor is not already in place, the owner or operator of a modified flare shall comply with the requirements of this paragraph by no later than November 11, 2015 or upon startup of the modified flare, whichever is later.

(1) The owner or operator shall install, calibrate, operate and maintain each flow monitor according to the manufacturer's procedures and specifications and the following requirements.

(i) Locate the monitor in a position that provides a representative measurement of the total gas flow rate.

(ii) Use a flow sensor with a measurement sensitivity of no more than 5 percent of the flow rate or 10 cubic feet per minute, whichever is greater.

(iii) Use a flow monitor that is maintainable online, is able to continuously correct for temperature and pressure and is able to record flow in standard conditions (as defined in § 60.2) over one-minute averages.

(iv) At least quarterly, perform a visual inspection of all components of the monitor for physical and operational integrity and all electrical connections for oxidation and galvanic corrosion if the flow monitor is not equipped with a redundant flow sensor.

(v) Recalibrate the flow monitor in accordance with the manufacturer's procedures and specifications biennially (every two years) or at the frequency specified by the manufacturer.

(2) Emergency flares, secondary flares and flares equipped with flare gas recovery systems designed, sized and operated to capture all flows except those resulting from startup, shutdown or malfunction are not required to install continuous flow monitors; provided, however, that for any

such flare, the owner or operator shall comply with the monitoring alternative in paragraph (g) of this section.

(g) *Alternative monitoring for certain flares equipped with water seals.* The owner or operator of an affected flare subject to § 60.103a(c) through (e) that can be classified as either an emergency flare, a secondary flare or a flare equipped with a flare gas recovery system designed, sized and operated to capture all flows except those resulting from startup, shutdown or malfunction may, as an alternative to the sulfur and flow monitoring requirements of paragraphs (e) and (f) of this section, install, operate, calibrate and maintain, in accordance with the requirements in paragraphs (g)(1) through (7) of this section, a CPMS to measure and record the pressure in the flare gas header between the knock-out pot and water seal and to measure and record the water seal liquid level. If the required monitoring systems are not already in place, the owner or operator of a modified flare shall comply with the requirements of this paragraph by no later than November 11, 2015 or upon startup of the modified flare, whichever is later.

(1) Locate the pressure sensor(s) in a position that provides a representative measurement of the pressure and locate the liquid seal level monitor in a position that provides a representative measurement of the water column height.

(2) Minimize or eliminate pulsating pressure, vibration and internal and external corrosion.

(3) Use a pressure sensor and level monitor with a minimum tolerance of 1.27 centimeters of water.

(4) Using a manometer, check pressure sensor calibration quarterly.

(5) Conduct calibration checks any time the pressure sensor exceeds the manufacturer's specified maximum operating pressure range or install a new pressure sensor.

(6) In a cascaded flare system that employs multiple secondary flares, pressure and liquid level monitoring is required only on the first secondary flare in the system (*i.e.*, the secondary flare with the lowest pressure release set point).

(7) This alternative monitoring option may be elected only for flares with four or fewer pressure exceedances required to be reported under § 60.108a(d)(5) ("reportable pressure exceedances") in any 365 consecutive calendar days. Following the fifth reportable pressure exceedance in a 365-day period, the owner or operator must comply with the sulfur and flow monitoring requirements of paragraphs (e) and (f) of this section as soon as practical, but no later than 180 days after the fifth reportable pressure exceedance in a 365-day period.

(h) *Alternative monitoring for flares located in the BAAQMD or SCAQMD.* An affected flare subject to this subpart located in the BAAQMD may elect to comply with the monitoring requirements in both BAAQMD Regulation 12, Rule 11 and BAAQMD Regulation 12, Rule 12 as an alternative to complying with the requirements of paragraphs (e) and (f) of this section. An affected flare subject to this subpart located in the SCAQMD may elect to comply with the monitoring requirements in SCAQMD Rule 1118 as an alternative to complying with the requirements of paragraphs (e) and (f) of this section.

(i) *Excess emissions.* For the purpose of reports required by § 60.7(c), periods of excess emissions for fuel gas combustion devices subject to the emissions limitations in § 60.102a(g) and flares subject to the concentration requirement in § 60.103a(h) are defined as specified in paragraphs (i)(1) through (5) of this section. Determine a rolling 3-hour or a rolling daily average as the arithmetic average of the applicable 1-hour averages (*e.g.*, a rolling 3-hour average is the arithmetic average of three contiguous 1-hour averages). Determine a rolling 30-day or a rolling 365-day average as the arithmetic average of the applicable daily averages (*e.g.*, a rolling 30-day average is the arithmetic average of 30 contiguous daily averages).

(1) *SO₂ or H₂S limits for fuel gas combustion devices.* (i) If the owner or operator of a fuel gas combustion device elects to comply with the SO₂ emission limits in § 60.102a(g)(1)(i), each rolling 3-hour period during which the average concentration of SO₂ as measured by the SO₂ continuous monitoring system required under paragraph (a)(1) of this

section exceeds 20 ppmv, and each rolling 365-day period during which the average concentration of SO₂ as measured by the SO₂ continuous monitoring system required under paragraph (a)(1) of this section exceeds 8 ppmv.

(ii) If the owner or operator of a fuel gas combustion device elects to comply with the H₂S concentration limits in § 60.102a(g)(1)(ii), each rolling 3-hour period during which the average concentration of H₂S as measured by the H₂S continuous monitoring system required under paragraph (a)(2) of this section exceeds 162 ppmv and each rolling 365-day period during which the average concentration as measured by the H₂S continuous monitoring system under paragraph (a)(2) of this section exceeds 60 ppmv.

(iii) If the owner or operator of a fuel gas combustion device becomes subject to the requirements of daily stain tube sampling in paragraph (b)(3)(iii) of this section, each day during which the daily concentration of H₂S exceeds 162 ppmv and each rolling 365-day period during which the average concentration of H₂S exceeds 60 ppmv.

(2) H₂S concentration limits for flares. (i) Each rolling 3-hour period during which the average concentration of H₂S as measured by the H₂S continuous monitoring system required under paragraph (a)(2) of this section exceeds 162 ppmv.

(ii) If the owner or operator of a flare becomes subject to the requirements of daily stain tube sampling in paragraph (b)(3)(iii) of this section, each day during which the daily concentration of H₂S exceeds 162 ppmv.

(3) *Rolling 30-day average NO_x limits for fuel gas combustion devices.* Each rolling 30-day period during which the average concentration of NO_x as measured by the NO_x continuous monitoring system required under paragraph (c) or (d) of this section exceeds:

(i) For a natural draft process heater, 40 ppmv and, if monitored according to § 60.107a(d), 0.040 lb/MMBtu;

(ii) For a forced draft process heater, 60 ppmv and, if monitored according to § 60.107a(d), 0.060 lb/MMBtu; and

(iii) For a co-fired process heater electing to comply with the NO_x limit in § 60.102a(g)(2)(iii)(A) or (g)(2)(iv)(A), 150 ppmv.

(iv) The site-specific limit determined by the Administrator under § 60.102a(i).

(4) *Daily NO_x limits for fuel gas combustion devices.* Each day during which the concentration of NO_x as measured by the NO_x continuous monitoring system required under paragraph (d) of this section exceeds the daily average emissions limit calculated using Equation 3 in § 60.102a(g)(2)(iii)(B) or Equation 4 in § 60.102a(g)(2)(iv)(B).

(5) *Daily O₂ limits for fuel gas combustion devices.* Each day during which the concentration of O₂ as measured by the O₂ continuous monitoring system required under paragraph (c)(6) of this section exceeds the O₂ operating limit or operating curve determined during the most recent biennial performance test.

[73 FR 35867, June 24, 2008, as amended at 77 FR 56473, Sep. 12, 2012]

§ 60.108a Recordkeeping and reporting requirements.

(a) Each owner or operator subject to the emissions limitations in § 60.102a shall comply with the notification, recordkeeping, and reporting requirements in § 60.7 and other requirements as specified in this section.

(b) Each owner or operator subject to an emissions limitation in § 60.102a shall notify the Administrator of the specific monitoring provisions of §§ 60.105a, 60.106a and 60.107a with which the owner or operator intends to comply. Each owner or operator of a co-fired process heater subject to an emissions limitation in § 60.102a(g)(2)(iii) or (iv) shall submit to the Administrator documentation showing that the process heater meets the definition of a co-fired process heater in § 60.101a. Notifications required by this paragraph shall be submitted with the notification of initial startup required by § 60.7(a)(3).

(c) The owner or operator shall maintain the following records:

(1) A copy of the flare management plan.

(2) Records of information to document conformance with bag leak detection system operation and maintenance requirements in § 60.105a(c).

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(3) Records of bag leak detection system alarms and actions according to § 60.105a(c).

(4) For each FCCU and fluid coking unit subject to the monitoring requirements in § 60.105a(b)(1), records of the average coke burn-off rate and hours of operation.

(5) For each fuel gas stream to which one of the exemptions listed in § 60.107a(a)(3) applies, records of the specific exemption determined to apply for each fuel stream. If the owner or operator applies for the exemption described in § 60.107a(a)(3)(iv), the owner or operator must keep a copy of the application as well as the letter from the Administrator granting approval of the application.

(6) Records of discharges greater than 500 lb SO₂ in any 24-hour period from any affected flare, discharges greater than 500 lb SO₂ in excess of the allowable limits from a fuel gas combustion device or sulfur recovery plant and discharges to an affected flare in excess of 500,000 scf above baseline in any 24-hour period as required by § 60.103a(c). If the monitoring alternative provided in § 60.107a(g) is selected, the owner or operator shall record any instance when the flare gas line pressure exceeds the water seal liquid depth, except for periods attributable to compressor staging that do not exceed the staging time specified in § 60.103a(a)(3)(vii)(C). The following information shall be recorded no later than 45 days following the end of a discharge exceeding the thresholds:

(i) A description of the discharge.

(ii) The date and time the discharge was first identified and the duration of the discharge.

(iii) The measured or calculated cumulative quantity of gas discharged over the discharge duration. If the discharge duration exceeds 24 hours, record the discharge quantity for each 24-hour period. For a flare, record the measured or calculated cumulative quantity of gas discharged to the flare over the discharge duration. If the discharge duration exceeds 24 hours, record the quantity of gas discharged to the flare for each 24-hour period. Engineering calculations are allowed for fuel gas combustion devices, but are not allowed for flares, except for those

complying with the alternative monitoring requirements in § 60.107a(g).

(iv) For each discharge greater than 500 lb SO₂ in any 24-hour period from a flare, the measured total sulfur concentration or both the measured H₂S concentration and the estimated total sulfur concentration in the fuel gas at a representative location in the flare inlet.

(v) For each discharge greater than 500 lb SO₂ in excess of the applicable short-term emissions limit in § 60.102a(g)(1) from a fuel gas combustion device, either the measured concentration of H₂S in the fuel gas or the measured concentration of SO₂ in the stream discharged to the atmosphere. Process knowledge can be used to make these estimates for fuel gas combustion devices, but cannot be used to make these estimates for flares, except as provided in § 60.107a(e)(4).

(vi) For each discharge greater than 500 lb SO₂ in excess of the allowable limits from a sulfur recovery plant, either the measured concentration of reduced sulfur or SO₂ discharged to the atmosphere.

(vii) For each discharge greater than 500 lb SO₂ in any 24-hour period from any affected flare or discharge greater than 500 lb SO₂ in excess of the allowable limits from a fuel gas combustion device or sulfur recovery plant, the cumulative quantity of H₂S and SO₂ released into the atmosphere. For releases controlled by flares, assume 99-percent conversion of reduced sulfur or total sulfur to SO₂. For fuel gas combustion devices, assume 99-percent conversion of H₂S to SO₂.

(viii) The steps that the owner or operator took to limit the emissions during the discharge.

(ix) The root cause analysis and corrective action analysis conducted as required in § 60.103a(d), including an identification of the affected facility, the date and duration of the discharge, a statement noting whether the discharge resulted from the same root cause(s) identified in a previous analysis and either a description of the recommended corrective action(s) or an explanation of why corrective action is not necessary under § 60.103a(e).

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(x) For any corrective action analysis for which corrective actions are required in §60.103a(e), a description of the corrective action(s) completed within the first 45 days following the discharge and, for action(s) not already completed, a schedule for implementation, including proposed commencement and completion dates.

(xi) For each discharge from any affected flare that is the result of a planned startup or shutdown of a refinery process unit or ancillary equipment connected to the affected flare, a statement that a root cause analysis and corrective action analysis are not necessary because the owner or operator followed the flare management plan.

(7) If the owner or operator elects to comply with §60.107a(e)(2) for a flare, records of the H₂S and total sulfur analyses of each grab or integrated sample, the calculated daily total sulfur-to-H₂S ratios, the calculated 10-day average total sulfur-to-H₂S ratios and the 95-percent confidence intervals for each 10-day average total sulfur-to-H₂S ratio.

(d) Each owner or operator subject to this subpart shall submit an excess emissions report for all periods of excess emissions according to the requirements of §60.7(c) except that the report shall contain the information specified in paragraphs (d)(1) through (7) of this section.

(1) The date that the exceedance occurred;

(2) An explanation of the exceedance;

(3) Whether the exceedance was concurrent with a startup, shutdown, or malfunction of an affected facility or control system; and

(4) A description of the action taken, if any.

(5) The information described in paragraph (c)(6) of this section for all discharges listed in paragraph (c)(6) of this section. For a flare complying with the monitoring alternative under §60.107a(g), following the fifth discharge required to be recorded under paragraph (c)(6) of this section and reported under this paragraph, the owner or operator shall include notification that monitoring systems will be installed according to §60.107a(e) and (f) within 180 days following the fifth discharge.

(6) For any periods for which monitoring data are not available, any changes made in operation of the emission control system during the period of data unavailability which could affect the ability of the system to meet the applicable emission limit. Operations of the control system and affected facility during periods of data unavailability are to be compared with operation of the control system and affected facility before and following the period of data unavailability.

(7) A written statement, signed by a responsible official, certifying the accuracy and completeness of the information contained in the report.

[73 FR 35867, June 24, 2008, as amended at 77 FR 56479, Sep. 12, 2012]

§ 60.109a Delegation of authority.

(a) This subpart can be implemented and enforced by the U.S. EPA or a delegated authority such as a State, local, or tribal agency. You should contact your U.S. EPA Regional Office to find out if this subpart is delegated to a State, local, or tribal agency within your State.

(b) In delegating implementation and enforcement authority of this subpart to a state, local or tribal agency, the approval authorities contained in paragraphs (b)(1) through (4) of this section are retained by the Administrator of the U.S. EPA and are not transferred to the state, local or tribal agency.

(1) Approval of a major change to test methods under §60.8(b). A “major change to test method” is defined in 40 CFR 63.90.

(2) Approval of a major change to monitoring under §60.13(i). A “major change to monitoring” is defined in 40 CFR 63.90.

(3) Approval of a major change to recordkeeping/reporting under §60.7(b) through (f). A “major change to recordkeeping/reporting” is defined in 40 CFR 63.90.

(4) Approval of an application for an alternative means of emission limitation under §60.103a(j) of this subpart.

[73 FR 35867, June 24, 2008, as amended at 77 FR 56480, Sep. 12, 2012]

TABLE 1 TO SUBPART JA OF PART 60—
MOLAR EXHAUST VOLUMES AND
MOLAR HEAT CONTENT OF FUEL GAS
CONSTITUENTS

Constituent	MEV ^a dscf/mol	MHC ^b Btu/mol
Methane (CH ₄)	7.29	842
Ethane (C ₂ H ₆)	12.96	1,475
Hydrogen (H ₂)	1.61	269
Ethene (C ₂ H ₄)	11.34	1,335
Propane (C ₃ H ₈)	18.62	2,100
Propene (C ₃ H ₆)	17.02	1,947
Butane (C ₄ H ₁₀)	24.30	2,717
Butene (C ₄ H ₈)	22.69	2,558
Inerts	0.85	0

^aMEV = molar exhaust volume, dry standard cubic feet per gram-mole (dscf/g-mol) at standard conditions of 68 °F and 1 atmosphere.

^bMHC = molar heat content (higher heating value basis), Btu per gram-mole (Btu/g-mol).

[77 FR 56480, Sep. 12, 2012]

Subpart K—Standards of Performance for Storage Vessels for Petroleum Liquids for Which Construction, Reconstruction, or Modification Commenced After June 11, 1973, and Prior to May 19, 1978

§ 60.110 Applicability and designation of affected facility.

(a) Except as provided in § 60.110(b), the affected facility to which this subpart applies is each storage vessel for petroleum liquids which has a storage capacity greater than 151,412 liters (40,000 gallons).

(b) This subpart does not apply to storage vessels for petroleum or condensate stored, processed, and/or treated at a drilling and production facility prior to custody transfer.

(c) Subject to the requirements of this subpart is any facility under paragraph (a) of this section which:

(1) Has a capacity greater than 151,416 liters (40,000 gallons), but not exceeding 246,052 liters (65,000 gallons), and commences construction or modification after March 8, 1974, and prior to May 19, 1978.

(2) Has a capacity greater than 246,052 liters (65,000 gallons) and commences construction or modification after June 11, 1973, and prior to May 19, 1978.

[42 FR 37937, July 25, 1977, as amended at 45 FR 23379, Apr. 4, 1980]

§ 60.111 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) *Storage vessel* means any tank, reservoir, or container used for the storage of petroleum liquids, but does not include:

(1) Pressure vessels which are designed to operate in excess of 15 pounds per square inch gauge without emissions to the atmosphere except under emergency conditions,

(2) Subsurface caverns or porous rock reservoirs, or

(3) Underground tanks if the total volume of petroleum liquids added to and taken from a tank annually does not exceed twice the volume of the tank.

(b) *Petroleum liquids* means petroleum, condensate, and any finished or intermediate products manufactured in a petroleum refinery but does not mean Nos. 2 through 6 fuel oils as specified in ASTM D396-78, 89, 90, 92, 96, or 98, gas turbine fuel oils Nos. 2-GT through 4-GT as specified in ASTM D2880-78 or 96, or diesel fuel oils Nos. 2-D and 4-D as specified in ASTM D975-78, 96, or 98a. (These three methods are incorporated by reference—see § 60.17.)

(c) *Petroleum refinery* means each facility engaged in producing gasoline, kerosene, distillate fuel oils, residual fuel oils, lubricants, or other products through distillation of petroleum or through redistillation, cracking, extracting, or reforming of unfinished petroleum derivatives.

(d) *Petroleum* means the crude oil removed from the earth and the oils derived from tar sands, shale, and coal.

(e) *Hydrocarbon* means any organic compound consisting predominantly of carbon and hydrogen.

(f) *Condensate* means hydrocarbon liquid separated from natural gas which condenses due to changes in the temperature and/or pressure and remains liquid at standard conditions.

(g) *Custody transfer* means the transfer of produced petroleum and/or condensate, after processing and/or treating in the producing operations, from storage tanks or automatic transfer facilities to pipelines or any other forms of transportation.