Subpart XXa—Standards of Performance for Bulk Gasoline Terminals that Commenced Construction, Modification, or Reconstruction after [THE DATE OF PUBLICATION OF THE PROPOSED RULE IN THE FEDERAL REGISTER]

§60.500a Applicability and designation of affected facility.

(a) The affected facility to which the provisions of this subpart apply is the total of all the loading racks at a bulk gasoline terminal which deliver liquid product into gasoline cargo tanks and all equipment associated with the loading of gasoline including the lines and pumps transferring gasoline from storage vessels, the gasoline loading racks, the vapor collection systems, and the vapor processing system.

(b) Each facility under paragraph (a) of this section for which construction, modification (as defined in § 60.2 and detailed in § 60.14), or reconstruction is commenced after [THE DATE OF PUBLICATION OF THE PROPOSED RULE IN THE **FEDERAL REGISTER**] is subject to the provisions of this subpart.

(c) All standards including emission limitations shall apply at all times, including periods of startup, shutdown and malfunction. As provided in §60.11(f), this provision supersedes the exemptions for periods of startup, shutdown and malfunction in the Part 60 general provisions in Subpart A.

(d) A newly constructed affected facility that was subject to the standards in §60.502a(b) will continue to be subject to the standards in §60.502a(b) for newly constructed affected facilities if they are subsequently modified or reconstructed.

(e) For purposes of this subpart:

(1) The cost of the following frequently replaced components of the affected facility shall not be considered in calculating either the “fixed capital cost of the new components” or the “fixed capital cost that would be required to construct a comparable entirely new facility” under §60.15: pump seals, loading arm gaskets and swivels, coupler gaskets, overfill sensor couplers and cables, flexible vapor hoses, and grounding cables and connectors.

(2) Under §60.15, the “fixed capital cost of the new components” includes the fixed capital cost of all depreciable components (except components specified in paragraph (1) which are or will be replaced pursuant to all continuous programs of component replacement which are commenced within any 2-year period following [THE DATE OF PUBLICATION OF THE PROPOSED RULE IN THE **FEDERAL REGISTER**]. For purposes of this paragraph, “commenced” means that an owner or operator has undertaken a continuous program of component replacement or that an owner or operator has entered into a contractual obligation to undertake and complete, within a reasonable time, a continuous program of component replacement.

§60.501a Definitions.

The terms used in this subpart are defined in the Clean Air Act, in §60.2 of this part, or in this section as follows:

3-hour rolling average means the arithmetic mean of the previous three hours of valid operating data collected. Valid data excludes data collected during periods when the monitoring system is out of control, while conducting repairs associated with periods when the monitoring system is out of control, or while conducting required monitoring system quality assurance or quality control activities. Periods when gasoline loading is not being conducted are not considered valid data, except for the period of time starting at the conclusion of a gasoline loading event and ending once all emissions from the loading event have cleared the control device. The three hours should be consecutive, but not necessarily continuous if operations or the collection of valid data were intermittent.

Bulk gasoline terminal means any gasoline facility which receives gasoline by pipeline, ship, barge, or cargo tank and subsequently loads all or a portion of the gasoline into gasoline cargo tanks for transport to bulk gasoline plants or gasoline dispensing facilities and has a gasoline throughput greater than 20,000 gallons per day (75,700 liters per day). Gasoline throughput shall be the maximum calculated design throughput for the facility as may be limited by compliance with an enforceable condition under Federal, State or local law and discoverable by the Administrator and any other person.

Equipment means each valve, pump, pressure relief device, open-ended valve or line, valve, sampling connection system, and flange or other connector in the gasoline liquid transfer and vapor collection systems. This definition also includes the entire vapor processing system except the exhaust port(s) or stack(s). *Flare* means a thermal combustion device using an open or shrouded flame (without full enclosure) such that the pollutants are not emitted through a conveyance suitable to conduct a performance test.

Flare means a thermal combustion device using an open or shrouded flame (without full enclosure) such that the pollutants are not emitted through a conveyance suitable to conduct a performance test.

Gasoline means any petroleum distillate or petroleum distillate/alcohol blend having a Reid vapor pressure of 4.0 pounds per square inch (27.6 kilopascals) or greater which is used as a fuel for internal combustion engines.

Gasoline cargo tank means a delivery tank truck or railcar which is loading gasoline or which has loaded gasoline on the immediately previous load.

In gasoline service means that a piece of equipment is used in a system that transfers gasoline or gasoline vapors.

Loading rack means the loading arms, pumps, meters, shutoff valves, relief valves, and other piping and valves necessary to fill gasoline cargo tanks.

Submerged filling means, for the purposes of this subpart, the filling of a gasoline cargo tank through a submerged fill pipe whose discharge is no more than the 6 inches from the bottom of the tank. Bottom filling of gasoline cargo tanks is included in this definition.

Thermal oxidation system means an enclosed combustion device used to mix and ignite fuel, air pollutants, and air to provide a flame to heat and oxidize air pollutants. Auxiliary fuel may be used to heat air pollutants to combustion temperatures. *Thermal oxidation systems* emit pollutants through a conveyance suitable to conduct a performance test.

Total organic compounds means those compounds measured according to the procedures in Method 25A or 25B of appendix A-7 of this part.

Vapor collection system means any equipment used for containing total organic compounds vapors displaced during the loading of gasoline cargo tanks.

Vapor processing system means all equipment used for recovering or oxidizing total organic compounds vapors displaced from the affected facility.

Vapor recovery system means processing equipment used to absorb and/or condense collected vapors and return the total organic compounds for blending with gasoline or other petroleum products or return to a petroleum refinery or transmix facility for further processing. Vapor recovery systems include but are not limited to carbon adsorption systems or refrigerated condensers.

Vapor-tight gasoline cargo tank means a gasoline cargo tank which has demonstrated within the 12 preceding months that it meets the annual certification test requirements in § 60.503a(f).

§60.502a Standard for Volatile Organic Compound (VOC) emissions from bulk gasoline terminals.

(a) Each affected facility shall be equipped with a vapor collection system designed and operated to collect the total organic compounds vapors displaced from gasoline cargo tanks during product loading.

(b) For each newly constructed affected facility, the facility owner or operator must meet the applicable emission limitations in paragraph (b)(1) or (2) of this section. A flare cannot be used to comply with the emission limitations in this paragraph.

(1) If a thermal oxidation system is used, maintain the emissions to the atmosphere from the vapor collection system due to the loading of liquid product into gasoline cargo tanks at or below 1.0 milligram of total organic compounds per liter of gasoline loaded (mg/L). Continual compliance with this requirement must be demonstrated as specified in paragraphs (b)(1)(i) and (ii) of this section.

(i) Conduct initial and periodic performance tests as specified in § 60.503a(a) through (c) of this part and meet the emissions limitation in paragraph (b)(1) of this section.

(ii) Maintain combustion zone temperature of the thermal oxidation system at or above the 3-hour rolling average operating limit established during the performance test when loading liquid product into gasoline cargo tanks.

(2) If a vapor recovery system is used:

(i) Maintain the emissions to the atmosphere from the vapor collection system at or below 550 parts per million by volume (ppmv) of total organic compounds (TOC) as propane determined on a 3-hour rolling average when loading liquid product into gasoline cargo tanks; and

(ii) Operate the vapor recovery system to minimize air intrusion except as needed to prevent significant vacuum formation in the system as TOC is removed from the vapor stream. You may use a vacuum breaker valve provided it complies with the pressure-vacuum vent requirements in paragraph (i) of this section. Consistent with § 60.12 of this part, the use of gaseous diluents to achieve compliance with a standard which is based on the concentration of a pollutant in the gases discharged to the atmosphere is prohibited.

(c) For each modified or reconstructed affected facility, the facility owner or operator must meet the applicable emission limitations in paragraphs (c)(1) through (3) of this section.

(1) If a thermal oxidation system is used, maintain the emissions to the atmosphere from the vapor collection system due to the loading of liquid product into gasoline cargo tanks at or below 10 mg/L. Continual compliance with this requirement must be demonstrated as specified in paragraphs (c)(1)(i) and (ii) of this section.

(i) Conduct initial and periodic performance tests as specified in § 60.503a(a) through (c) of this part and meet the emissions limitation in paragraph (c)(1) of this section.

(ii) Maintain combustion zone temperature of the thermal oxidation system at or above the 3-hour rolling average operating limit established during the performance test when loading liquid product into gasoline cargo tanks.

(2) If a vapor recovery system is used:

(i) Maintain the emissions to the atmosphere from the vapor collection system at or below 5500 ppmv of TOC as propane determined on a 3-hour rolling average when loading liquid product into gasoline cargo tanks; and

(ii) Operate the vapor recovery system to minimize air intrusion except as needed to prevent significant vacuum formation in the system as TOC is removed from the vapor stream. You may use a vacuum breaker valve provided it complies with the pressure-vacuum vent requirements in paragraph (i) of this section. Consistent with § 60.12 of this part, the use of gaseous diluents to achieve compliance with a standard which is based on the concentration of a pollutant in the gases discharged to the atmosphere is prohibited.

(3) If a flare is used, meet all applicable requirements specified in § 63.670(b) through (n) of this chapter except as provided in paragraphs (c)(3)(i) through (ix) of this section.

(i) For the purpose of this subpart, “regulated materials” refers to “vapors displaced from gasoline cargo tanks during product loading”.

(ii) The following phrases in § 63.670(c) for visible emissions do not apply:

(A) “Specify the smokeless design capacity of each flare and”; and

(B) “And the flare vent gas flow rate is less than the smokeless design capacity of the flare.”

(C) “The owner or operator shall monitor for visible emissions from the flare as specified in paragraph (h) of this section.”

(iii) The phrase “and the flare vent gas flow rate is less than the smokeless design capacity of the flare” in § 63.670(d) for flare tip velocity requirements does not apply.

(iv) Substitute “pilot flame or flare flame” for each occurrence of “pilot flame.”

(v) Substitute “gasoline distribution facility” for each occurrence of “petroleum refinery” or “refinery.”

(vi) Monitoring of cumulative loading rates of all liquid products loaded into gasoline cargo tanks for which the displaced vapors are managed by the affected facility's vapor collection system and vapor processing system can be used to determine flare waste gas flow rate (vent gas flow rate less supplemental gas flow rate) and is an acceptable alternative to the flow rate monitoring alternatives provided in § 63.670(i).

(vii) If using provision in § 63.670(j)(6) for flare vent gas composition monitoring, a change from winter gasoline to summer gasoline is considered a change in operating conditions. You must submit a separate written application to the Administrator for an exemption from monitoring, as described in § 63.670(j)(6)(i), and determine separate net heating values to use for summer gasoline loading versus winter gasoline loading. You may use the summer net heating value for all subsequent summer gasoline loading operations and the winter net heating value for all subsequent winter gasoline loading operations provided there are no other changes in operations.

(viii) You may elect to establish a minimum flare supplemental gas addition rate and monitor only flare supplemental gas addition rate to demonstrate compliance with the flare combustion zone operating limit in § 63.670(e) as follows.

(A) Use the minimum flare vent gas net heating value prior to addition of flare supplemental gas as established in paragraph (c)(3)(vii) of this section.

(B) Determine the maximum flow rate based on the maximum cumulative loading rate for a 15-minute block period considering all loading racks at the affected facility and considering restrictions on maximum loading rates necessary for compliance with the maximum pressure limits for the vapor collection and liquid loading equipment specified in paragraph (h) of this section.

(C) Determine the supplemental gas addition rate needed to yield net heating value of flare combustion zone gas (NHV_{cz}) of 270 British thermal units per standard cubic feet (Btu/scf) using equation in § 63.670(m)(1).

(D) Maintain the supplemental gas addition rate above the value determined in paragraph (c)(3)(viii)(C) of this section on a 15-minute block period basis when liquid product is loaded into gasoline cargo tanks for at least 15-minutes.

(ix) For flares with perimeter assist air, you may elect to establish a minimum flare supplemental gas addition rate and monitor only flare supplemental gas addition rate to demonstrate compliance with the flare dilution operating limit in § 63.670(f) as follows.

(A) Determine the flare vent gas net heating value prior to addition of flare supplemental gas when loading a single cargo tank of gasoline.

(B) Determine the flow rate as the loading rate for a 15-minute block period when loading a single cargo tank of gasoline.

(C) Determine the supplemental gas addition rate needed to yield net heating value dilution parameter (NHV_{dil}) of 22 British thermal units per square foot (Btu/ft^2) using equation in § 63.670(n)(1).

(D) Determine the supplemental gas addition rate needed to demonstrate compliance with the flare combustion zone operating limit as specified in paragraph (c)(3)(viii) of this section.

(E) Maintain the supplemental gas addition rate above the greater of the values determined in paragraphs (c)(3)(ix)(C) and (D) of this section on a 15-minute block period basis when liquid product is loaded into gasoline cargo tanks for at least 15-minutes.

(d) Each vapor collection system shall be designed to prevent any total organic compounds vapors collected at one loading rack from passing to another loading rack.

(e) Loadings of liquid product into gasoline cargo tanks shall be limited to vapor-tight gasoline cargo tanks using the following procedures:

(1) The owner or operator shall obtain the vapor tightness annual certification test documentation described in §60.505a(a)(4) and (5) or the railcar bubble test certification described in §63.425(i) for each gasoline cargo tank which is to be loaded at the affected facility.

(2) The owner or operator shall obtain and record the cargo tank identification number of each gasoline cargo tank which is to be loaded at the affected facility.

(3) The owner or operator shall cross-check each cargo tank identification number obtained in paragraph (e)(2) of this section with the file of gasoline cargo tank vapor tightness documentation specified in paragraph (e)(1) prior to loading any gasoline into the cargo tank.

(f) Loading of gasoline into cargo tanks shall be conducted using submerged filling, as defined in §60.501a, and only into cargo tanks equipped with vapor collection equipment that is compatible with the terminal's vapor collection system.

(g) Loading of gasoline into cargo tanks shall only be conducted when the terminal's and the cargo tank's vapor collection systems are connected.

(h) The vapor collection and liquid loading equipment shall be designed and operated to prevent gauge pressure in the gasoline cargo tank from exceeding 18 inches of water (450 millimeters (mm) of water) during product loading. This level is not to be exceeded and must be continuously monitored according to the procedures specified in §60.504a(d).

(i) No pressure-vacuum vent in the bulk gasoline terminal's vapor collection system shall begin to open at a system pressure less than 18 inches of water (450 mm of water) or at a vacuum of less than 6.0 inches of water (150 mm of water).

(j) Each owner or operator of an affected facility shall perform leak inspection and repair of all equipment in gasoline service, which includes all equipment in the vapor collection system, the vapor processing system, and each loading rack and loading arm handling gasoline, according to the requirements in paragraphs (j)(1) through (8) of this section. The owner or operator must keep a list, summary description, or diagram(s) showing the location of all equipment in gasoline service at the facility.

(1) Conduct leak detection monitoring of all pumps, valves, and connectors in gasoline service using either of the methods specified in paragraph (j)(1)(i) or (ii) of this section.

(i) Use optical gas imaging to quarterly monitor all pumps, valves, and connectors in gasoline service as specified in §60.503a(e)(2).

(ii) Use Method 21 of appendix A-7 of this part as specified in §60.503a(e)(1) and paragraphs (a)(1)(ii)(A) through (C) of this section.

(A) All pumps must be monitored quarterly, unless the pump meets one of the requirements in §60.482-1a(d) or §60.482-2a(d) through (g). An instrument reading of 10,000 ppm or greater is a leak.

(B) All valves must be monitored quarterly, unless the valve meets one of the requirements in §60.482-1a(d) or §60.482-7a(f) through (h). An instrument reading of 10,000 ppm or greater is a leak.

(C) All connectors must be monitored annually, unless the connector meets one of the requirements in §60.482-1a(d) or §60.482-11a(e) or (f). An instrument reading of 10,000 ppm or greater is a leak.

(2) During normal duties, record leaks identified by audio, visual, or olfactory methods.

(3) If evidence of a potential leak is found at any time by audio, visual, olfactory, or any other detection method for any equipment (as defined in §60.501a), a leak is detected.

(4) For pressure relief devices, comply with the requirements in paragraphs (a)(4)(i) through (ii) of this section.

(i) Conduct instrument monitoring of each pressure relief device quarterly and within 5 days after each pressure release to detect leaks by the methods specified in paragraph (j)(1) of this section, except as provided in §60.482-4a(c).

(ii) If emissions are observed when using optical gas imaging, a leak is detected. If Method 21 is used, an instrument reading of 10,000 ppm or greater indicates a leak is detected.

(5) For sampling connection systems, comply with the requirements in §60.482-5a.

(6) For open-ended valves, or lines comply with the requirements in §60.482-6a.

(7) When a leak is detected for any equipment, comply with the requirements of paragraphs (a)(7)(i) through (iii) of this section.

(i) A weatherproof and readily visible identification, marked with the equipment identification number, must be attached to the leaking equipment. The identification on equipment may be removed after it has been repaired.

(ii) An initial attempt at repair shall be made as soon as practicable, but no later than 5 calendar days after the leak is detected. An initial attempt at repair is not required if the leak is detected using optical gas imaging and the equipment identified as leaking would require elevating the repair personnel more than 2 meters above a support surface.

(iii) Repair or replacement of leaking equipment shall be completed within 15 calendar days after detection of each leak, except as provided in paragraph (j)(8) of this section.

(A) For leaks identified pursuant to instrument monitoring required under paragraph (j)(1) of this section, the leak is repaired when instrument re-monitoring of the equipment does not detect a leak.

(B) For leaks identified pursuant to paragraph (j)(2) of this section, the leak is repaired when the leak can no longer be identified using audio, visual, or olfactory methods.

(8) Delay of repair of leaking equipment will be allowed according to the provisions in paragraphs (j)(8)(i) though (iv) of this section. The owner or operator shall provide in the semiannual report specified in §60.505a(c), the reason(s) why the repair was delayed and the date each repair was completed.

(i) Delay of repair of equipment will be allowed for equipment that is isolated from the affected facility and that does not remain in gasoline service.

(ii) Delay of repair for valves and connectors will be allowed if:

(A) The owner or operator demonstrates that emissions of purged material resulting from immediate repair are greater than the fugitive emissions likely to result from delay of repair, and

(B) When repair procedures are effected, the purged material is collected and destroyed or recovered in a control device complying with § 60.482-10a or the requirements in paragraphs (b) or (c) of this section, as applicable.

(iii) Delay of repair will be allowed for a valve, but not later than 3 months after the leak was detected, if valve assembly replacement is necessary, valve assembly supplies have been depleted, and valve assembly supplies had been sufficiently stocked before the supplies were depleted.

(iv) Delay of repair for pumps will be allowed if:

(A) Repair requires the use of a dual mechanical seal system that includes a barrier fluid system, and

(B) Repair is completed as soon as practicable, but not later than 6 months after the leak was detected.

(k) You must not allow gasoline to be handled in a manner that would result in vapor releases to the atmosphere for extended periods of time. Measures to be taken include, but are not limited to, the following:

(1) Minimize gasoline spills;

(2) Clean up spills as expeditiously as practicable;

(3) Cover all open gasoline containers and all gasoline storage tank fill-pipes with a gasketed seal when not in use;

(4) Minimize gasoline sent to open waste collection systems that collect and transport gasoline to reclamation and recycling devices, such as oil/water separators.

§60.503a Test methods and procedures.

(a) *General Performance Test and Performance Evaluation Requirements*.

(1) In conducting the performance tests or evaluations required by this subpart (or as requested by the Administrator), the owner or operator shall use the test methods and procedures as specified in this section, except as provided in §60.8(b).

(2) Immediately before the performance test, conduct leak detection monitoring following the methods in paragraph (e)(1) of this section to identify leakage of vapor from all potential sources in the terminal's vapor collection system equipment while gasoline is being loaded into a gasoline cargo tank to ensure the terminal's vapor collection system equipment is operated with no detectable emissions. The owner or operator shall repair all leaks identified with readings of 500 ppmv (as methane) or greater above background before conducting the performance test and within the timeframe specified in § 60.502a(j)(7).

(b) *Performance Test or Performance Evaluation Timing.*

(1) For affected facilities subject to the emission limits in § 60.502a(b)(1) or (c)(1), conduct the initial performance test of the vapor collection and processing systems according to the timing specified in § 60.8(a). For affected facilities subject to the emission limits in § 60.502a(b)(2) or (c)(2), conduct the initial performance evaluation of the continuous emissions monitoring system (CEMS) according to the timing specified for performance tests in § 60.8(a).

(2) For affected facilities complying with the mass emission limits in § 60.502a(b)(1) or (c)(1), conduct subsequent performance test of the vapor collection and processing system no later than 60 calendar months after the previous performance test.

(3) For affected facilities complying with the concentration emission limits in § 60.502a(b)(2) or (c)(2), conduct subsequent performance evaluations of CEMS for the vapor collection and processing system no later than 12 calendar months after the previous performance evaluation.

(c) *Performance Test Requirements for Mass Loading Emission Limit.* The owner or operator shall conduct performance tests of the vapor collection and processing system subject to the emission limits in § 60.502a(b)(1) or (c)(1), as specified in paragraphs (c)(1) through (8) of this section.

(1) The performance test shall be 6 hours long during which at least 80,000 gallons (300,000 liters) of gasoline is loaded. If this is not possible, the test may be continued the same day until 80,000 gallons (300,000 liters) of gasoline is loaded. If 80,000 gallons (300,000 liters) cannot be loaded during the first day of testing, the test may be resumed the next day with another 6-hour period. During the second day of testing, the 80,000-gallon (300,000-liter) criterion need not be met. However, as much as possible, testing should be conducted during the 6-hour period in which the highest throughput of gasoline normally occurs.

(2) If the vapor processing system is intermittent in operation and employs an intermediate vapor holder to accumulate total organic compounds vapors collected from gasoline cargo tanks, the performance test shall begin at a reference vapor holder level and shall end at the same reference point. The test shall include at least two startups and shutdowns of the vapor processor. If this does not occur under automatically controlled operations, the system shall be manually controlled.

(3) The emission rate (E) of total organic compounds shall be computed using the following equation:

$$E = K\sum_{i=1}^{n}\left(V_{esi}C_{ei}\right) / \left(L\,10^{6}\right)$$

where:

E = emission rate of total organic compounds, mg/liter of gasoline loaded.

V_{esi} = volume of air-vapor mixture exhausted at each interval “i”, scm.

C_{ei} = concentration of total organic compounds at each interval “i”, ppm.

L = total volume of gasoline loaded, liters.

n = number of testing intervals.

i = emission testing interval of 5 minutes.

K = density of calibration gas, 1.83×10^{6} for propane, mg/scm.

(4) The performance test shall be conducted in intervals of 5 minutes. For each interval “i”, readings from each measurement shall be recorded, and the volume exhausted (V_{esi}) and the corresponding average total organic compounds concentration (C_{ei}) shall be determined. The sampling system response time shall be considered in determining the average total organic compounds concentration corresponding to the volume exhausted.

(5) Method 2B of Appendix A-1 of this part shall be used to determine the volume (V_{esi}) of air-vapor mixture exhausted at each interval.

(6) Method 25A or 25B of Appendix A-7 of this part shall be used for determining the total organic compounds concentration (C_{ei}) at each interval. The calibration gas shall be propane.

(7) To determine the volume (L) of gasoline dispensed during the performance test period at all loading racks whose vapor emissions are controlled by the processing system being tested, terminal records or readings from gasoline dispensing meters at each loading rack shall be used.

(8) Monitor the temperature in the combustion zone using the continuous parameter monitoring system (CPMS) required in § 60.504a(a) and determine the operating limit for the combustion device using the following procedures:

(i) Record the temperature or average temperature for each 5-minute period during the performance test.

(ii) Using only the 5-minute periods in which liquid product is loaded into gasoline cargo tanks, determine the 1-hour average temperature for each hour of the performance test.

(iii) Starting at the end of the third hour of the performance test and at the end of each successive hour, calculate the 3-hour rolling average temperature using the 1-hour average values in paragraph (c)(8)(ii) of this section. For a 6-hour test, this would result in four 3-hour averages (averages for hours 1 through 3, 2 through 4, 3 through 5, and 4 through 6).

(iv) Set the operating limit at the lowest 3-hour average temperature determined in paragraph (c)(8)(iii) of this section. New operating limits become effective on the date that the performance test

report is submitted to the EPA's Compliance and Emissions Data Reporting Interface, per the requirements of § 60.505a(b).

(d) *Performance Evaluation Requirements for Concentration Emission Limit.* The owner or operator shall conduct performance evaluations of the CEMS for vapor collection and processing systems subject to the emission limits in § 60.502a(b)(2) or (c)(2) as specified in paragraphs (d)(1) or (2) of this section, as applicable.

(1) If the CEMS uses a nondispersive infrared analyzer, the CEMS must be installed, evaluated, and operated according to the requirements of Performance Specification 8 of Appendix B of this part. Method 25B in Appendix A-7 of this part must be used as the reference method, and the calibration gas must be propane.

(2) If the CEMS uses a flame ionization detector, the CEMS must be installed, evaluated, and operated according to the requirements of Performance Specification 8A of Appendix B of this part. As part of the performance evaluation, conduct a relative accuracy test audit following the procedures in Performance Specification 2, Section 8.4, of Appendix B of this part; the relative accuracy must meet the criteria of Performance Specification 8, Section 13.2, of Appendix B of this part. Method 25A in Appendix A-7 of this part must be used as the reference method, and the calibration gas must be propane.

(e) *Leak detection monitoring.* Conduct the leak detection monitoring specified in § 60.502a(j)(1) using one of the procedures specified in paragraphs (e)(1) or (e)(2). Conduct the leak detection monitoring specified in § 60.503a(a)(2) using the procedures specified in paragraph (e)(1), except that the instrument reading that defines a leak is specified in § 60.503a(a)(2) and the calibration gas in paragraph (e)(1)(ii) must be at a concentration of 500 ppm methane. The owner or operator shall test each piece of equipment in gasoline service.

(1) Method 21 in Appendix A-7 of this part. The instrument reading that defines a leak is 10,000 ppmv (as methane). The instrument shall be calibrated before use each day of its use by the procedures specified in Method 21 of appendix A-7 of this part. The calibration gases in paragraphs (e)(1)(i) and (ii) must be used. The drift assessment specified in paragraph (e)(1)(iii) must be performed at the end of each monitoring day.

(i) Zero air (less than 10 ppm of hydrocarbon in air); and

(ii) Methane and air at a concentration of 10,000 ppm methane.

(iii) At the end of each monitoring day, check the instrument using the same calibration gas that was used to calibrate the instrument before use. Follow the procedures specified in Method 21 of appendix A-7 of this part, Section 10.1, except do not adjust the meter readout to correspond to the calibration gas value. If multiple scales are used, record the instrument reading for each scale used. Divide the arithmetic difference of the initial and post-test calibration response by the corresponding calibration gas value for each scale and multiply by 100 to express the calibration drift as a percentage. If a calibration drift assessment shows a negative drift of more than 10 percent, then re-monitor all equipment monitored since the last calibration with instrument readings between the leak definition and the leak definition multiplied by (100 minus the percent of negative drift) divided by 100. If any calibration drift assessment shows a positive drift of more than 10 percent from the initial calibration value, then, at the owner/operator's discretion, all equipment with instrument readings above the leak definition and below the leak definition multiplied by (100 plus the percent of positive drift) divided by 100 monitored since the last calibration may be re-monitored.

(2) Optical gas imaging (OGI) according to all the requirements in Appendix K of this part. A leak is defined as any emissions plume imaged by the camera from equipment regulated by this subpart.

(f) *Annual certification test.* The annual certification test for gasoline cargo tanks shall consist of the following test methods and procedures:

(1) Method 27 of Appendix A-8 of this part. Conduct the test using a time period (t) for the pressure and vacuum tests of 5 minutes. The initial pressure (P_i) for the pressure test shall be 460 mm H_2O (18 in. H_2O), gauge. The initial vacuum (V_i) for the vacuum test shall be 150 mm H_2O (6 in. H_2O), gauge. The maximum allowable pressure and vacuum changes (Δp, Δv) are as shown in Table 1 of this paragraph.

TABLE 1—ALLOWABLE GASOLINE CARGO TANK TEST PRESSURE OR VACUUM CHANGE

Gasoline cargo tank or compartment capacity, gallons (liters)	Annual certification-allowable pressure or vacuum change (Δp, Δv) in 5 minutes, mm H_2O (in. H_2O)
2,500 or more (9,464 or more)	12.7 (0.50)
1,500 to 2,499 (5,678 to 9,463)	19.1 (0.75)
1,000 to 1,499 (3,785 to 5,677)	25.4 (1.00)
999 or less (3,784 or less)	31.8 (1.25)

(2) Pressure test of the gasoline cargo tank's internal vapor valve as follows:

(i) After completing the tests under paragraph (e)(1) of this section, use the procedures in Method 27 to repressurize the gasoline cargo tank to 460 mm H_2O (18 in. H_2O), gauge. Close the gasoline cargo tank's internal vapor valve(s), thereby isolating the vapor return line and manifold from the gasoline cargo tank.

(ii) Relieve the pressure in the vapor return line to atmospheric pressure, then reseal the line. After 5 minutes, record the gauge pressure in the vapor return line and manifold. The maximum allowable 5-minute pressure increase is 65 mm H_2O (2.5 in. H_2O).

§60.504a Monitoring Requirements

(a) *Monitoring Requirements for Thermal Oxidation Systems.* Install, operate, and maintain a continuous parameter monitoring system (CPMS) for measuring the combustion zone temperature as specified in paragraphs (a)(1) through (4) of this section.

(1) Install the temperature CPMS in the combustion (flame) zone or in the exhaust gas stream as close as practical to the combustion burners in a position that provides a representative temperature of the combustion zone of the thermal oxidation system.

(2) The temperature CPMS must be capable of measuring temperature with an accuracy of ±1 percent over the normal range of temperatures measured.

(3) The temperature CPMS must be capable of recording the temperature at least once every 5 minutes and calculating hourly block averages that include only those 5-minute periods in which liquid product was loaded into gasoline cargo tanks.

(4) At least quarterly, inspect all components for integrity and all electrical connections for continuity, oxidation, and galvanic corrosion, unless the CPMS has a redundant temperature sensor.

(5) Conduct calibration checks at least annually and conduct calibration checks following any period of more than 24 hours throughout which the temperature exceeded the manufacturer's specified maximum rated temperature or install a new temperature sensor.

(b) *Monitoring Requirements for Vapor Recovery Systems.* Install, calibrate, operate, and maintain a CEMS for measuring the concentration of TOC in the atmospheric vent from the vapor recovery system as specified in paragraphs (b)(1) and (2) of this section. Locate the sampling probe or other interface at a measurement location such that you obtain representative measurements of emissions from the vapor recovery system.

(1) The requirements of Performance Specification 8 of Appendix B of this part, or, if the CEMS uses a flame ionization detector, Performance Specification 8A of Appendix B to this part, the quality assurance requirements in Procedure 1 of Appendix F of this part, and the procedures under § 60.13 must be followed for installation, evaluation, and operation of the CEMS. For CEMS certified using Performance Specification 8A of Appendix B to this part, conduct the relative accuracy test audit required under Procedure 1 according to the requirements in §60.503a(d) of this subpart. As required by §60.503a(b)(3), conduct annual performance evaluations of each TOC CEMS according to the requirements in §60.503a(d) of this subpart. Conduct accuracy determinations quarterly and calibration drift tests daily in accordance with procedure 1 in appendix F of this part.

(2) The span value of the TOC CEMS must be approximately 2 times the applicable emissions limit.

(c) *Monitoring Requirements for Flares.* Install, operate, and maintain CPMS for flares used to comply with the emission limitations in § 60.502a(c)(3) following the requirements specified in § 63.671 of this chapter as specified in paragraphs (c)(1) through (3) of this section and conduct visible emission observations as specified in paragraph (c)(4).

(1) Substitute “pilot flame or flare flame” for each occurrence of “pilot flame.”

(2) You may elect to determine compositional analysis for net heating value with a continuous process mass spectrometer without the use of a gas chromatograph. If you choose to determine compositional analysis for net heating value with a continuous process mass spectrometer, then you must comply with the requirements specified in paragraphs (c)(3)(i) through (vii) of this section.

(i) You must meet the requirements in § 63.671(e)(2). You may augment the minimum list of calibration gas components found in § 63.671(e)(2) with compounds found during a pre-survey or known to be in the gas through process knowledge.

(ii) Calibration gas cylinders must be certified to an accuracy of 2 percent and traceable to National Institute of Standards and Technology (NIST) standards.

(iii) For unknown gas components that have similar analytical mass fragments to calibration compounds, you may report the unknowns as an increase in the overlapped calibration gas

compound. For unknown compounds that produce mass fragments that do not overlap calibration compounds, you may use the response factor for the nearest molecular weight hydrocarbon in the calibration mix to quantify the unknown component's net heating value of flare vent gas (NHV_{vg}).

(iv) You may use the response factor for n-pentane to quantify any unknown components detected with a higher molecular weight than n-pentane.

(v) You must perform an initial calibration to identify mass fragment overlap and response factors for the target compounds.

(vi) You must meet applicable requirements in Performance Specification (PS) 9 of appendix B of this part for continuous monitoring system acceptance including, but not limited to, performing an initial multi-point calibration check at three concentrations following the procedure in Section 10.1 of PS 9 and performing the periodic calibration requirements listed for gas chromatographs in Table 13 of part 63, subpart CC of this chapter, for the process mass spectrometer. You may use the alternative sampling line temperature allowed under Net Heating Value by Gas Chromatograph in Table 13 of part 63, subpart CC of this chapter.

(vii) The average instrument calibration error (CE) for each calibration compound at any calibration concentration must not differ by more than 10 percent from the certified cylinder gas value. The CE for each component in the calibration blend must be calculated using the following equation:

Where:

$$CE = \frac{C_m - C_a}{C_a} \times 100$$

C_m = Average instrument response (ppm)

C_a = Certified cylinder gas value (ppm)

(3) If you use a gas chromatograph or mass spectrometer for compositional analysis for net heating value, then you may choose to use the CE of net heating value (NHV) measured versus the cylinder tag value NHV as the measure of agreement for daily calibration and quarterly audits in lieu of determining the compound-specific CE. The CE for NHV at any calibration level must not differ by more than 10 percent from the certified cylinder gas value. The CE for must be calculated using the following equation:

$$CE = \frac{NHV_{measured} - NHV_a}{NHV_a} \times 100$$

Where:

$NHV_{measured}$ = Average instrument response (Btu/scf)

NHV_a = Certified cylinder gas value (Btu/scf).

(4) If visible emissions are observed for more than one continuous minute during normal duties, visible emissions observation using Method 22 at 40 CFR part 60, appendix A-7 must be conducted for 2 hours or until 5-minutes of visible emissions are observed.

(d) The owner or operator shall install, operate, and maintain a CPMS to measure the pressure of the vapor collection system to determine compliance with the standard in §60.502a(h). as specified in paragraphs (d)(1) through (4) of this section.

(1) Install a pressure CPMS (liquid manometer, magnehelic gauge, or equivalent instrument), capable of measuring up to 500 mm of water gauge pressure with ±2.5 mm of water precision on the terminal's vapor collection system at a pressure tap located as close as possible to the connection with the gasoline cargo tank. If necessary to obtain representative loading pressures, install pressure CPMS for each loading rack.

(2) Check the calibration of the pressure CPMS at least annually. Check the calibration of the pressure CPMS following any period of more than 24 hours throughout which the pressure exceeded the manufacturer’s specified maximum rated pressure or install a new pressure sensor.

(3) At least quarterly, visually inspect components of the pressure CPMS for integrity, oxidation and galvanic corrosion, unless the system has a redundant pressure sensor.

(4) The output of the pressure CPMS must be reviewed each operating day to ensure that the pressure readings fluctuate as expected during loading of gasoline cargo tanks to verify the pressure taps are not plugged. Plugged pressure taps must be unplugged or otherwise repaired within 24 hours or prior to the next gasoline cargo tank loading, whichever time period is longer.

§60.505a Recordkeeping and Reporting.

(a) *Recordkeeping Requirements*. For each affected facility, keep records as specified in paragraphs (a)(1) through (11) for a minimum of five years unless otherwise specified in this section. These recordkeeping requirements supersede the requirements in §60.7(b).

(1) For each thermal oxidation system used to comply with the emission limitations in §60.502a(b)(1) or (c)(1), maintain records of:

(i) The combustion zone temperature operating limit(s) and the applicable date range the limit applies based on when the performance test was conducted.

(ii) Each 3-hour rolling average combustion zone temperature measured by the temperature CPMS.

(iii) The start date and time and duration of each deviation of the combustion zone temperature operating limit.

(iv) The start date and time and duration of each outage or out of control period of the temperature CPMS.

(v) Each inspection or calibration of the temperature CPMS.

(2) For each vapor recovery system used to comply with the emission limitations in §60.502a(b)(2) or (c)(2), maintain records of:

(i) Each 3-hour rolling average TOC concentration (as propane) measured by the TOC CEMS.

(ii) The start date and time, and duration of each deviation of the TOC concentration emissions limit.

(iii) The start date and time, and duration of each outage or out of control period of the TOC CEMS.

(3) For each flare used to comply with the emission limitations in §60.502a(c)(3), maintain records of:

(i) The output of the monitoring device used to detect the presence of a pilot flame as required in §63.670(b) for a minimum of 2 years. Retain records of each 15-minute block during which there was at least one minute that no pilot flame is present when gasoline vapors were routed to the flare for a minimum of 5 years. The record must identify the start and end time and date of each 15-minute block.

(ii) Visible emissions observations as specified in the paragraphs (a)(3)(ii)(A) and (B) of this section, as applicable, for a minimum of 3 years.

(A) If visible emissions observations are performed using Method 22 of Appendix A-7 of this part, the record must identify the date, the start and end time of the visible emissions observation, and the number of minutes for which visible emissions were observed during the observation. If the owner or operator performs visible emissions observations more than one time during a day, include separate records for each visible emissions observation performed.

(B) For each 2-hour period for which visible emissions are observed for more than 5 minutes in 2 consecutive hours but visible emissions observations according to Method 22 of Appendix A-7 of this part were not conducted for the full 2-hour period, the record must include an estimate of the cumulative number of minutes in the 2-hour period for which emissions were visible based on best information available to the owner or operator.

(iii) The 15-minute block average cumulative flows for flare vent gas and, if applicable, total steam, perimeter assist air, and premix assist air specified to be monitored under §63.670(i), along with the date and start and end time for the 15-minute block. If multiple monitoring locations are used to determine cumulative vent gas flow, total steam, perimeter assist air, and premix assist air, retain records of the 15-minute block average flows for each monitoring location for a minimum of 2 years, and retain the 15-minute block average cumulative flows that are used in subsequent calculations for a minimum of 5 years. If pressure and temperature monitoring is used, retain records of the 15-minute block average temperature, pressure and molecular weight of the flare vent gas or assist gas stream for each measurement location used to determine the 15-minute block average cumulative flows for a minimum of 2 years, and retain the 15-minute block average cumulative flows that are used in subsequent calculations for a minimum of 5 years. If you use the supplemental gas flow rate monitoring alternative in §60.502a(c)(3)(viii) or (ix), the target supplemental gas flow rate (winter and summer, if applicable) and the actual monitored supplemental gas flow rate for the 15-minute block. Retain the supplemental gas flow rate records for a minimum of 5 years.

(iv) The flare vent gas compositions specified to be monitored under §63.670(j). Retain records of individual component concentrations from each compositional analyses for a minimum of 2 years. If NHV_{vg} analyzer is used, retain records of the 15-minute block average values for a minimum of 5 years.

(v) Each 15-minute block average operating parameter calculated following the methods specified in §63.670(k) through (n), as applicable.

(vi) All periods during which operating values are outside of the applicable operating limits specified in §63.670(d) through (f) when liquid product is being loaded into gasoline cargo tanks .

(vii) All periods during which the owner or operator does not perform flare monitoring according to the procedures in §63.670(g) through (j) or in §60.502a(c)(3)(viii) or (ix).

(viii) All time periods when liquid product is loaded into gasoline cargo tanks and records of time periods when there was no liquid product loaded into gasoline cargo tanks.

(4) The gasoline cargo tank vapor tightness documentation required under §60.502a(e)(1) shall be kept on file at the terminal in either a hardcopy or electronic form available for inspection for at least five years.

(5) The documentation file for each gasoline cargo tank loading at the facility shall be kept up-to-date. This documentation shall include, as a minimum, the following information:

(i) Test title: Annual Certification Test—EPA Method 27 or Railcar Bubble Leak Test Procedure.

(ii) Cargo tank owner's name and address.

(iii) Cargo tank identification number.

(iv) Test location and date.

(v) Tester name and signature.

(vi) Witnessing inspector, if any: Name, signature, and affiliation.

(vii) Vapor tightness repair: Nature of repair work and when performed in relation to vapor tightness testing.

(viii) Test results: Tank or compartment capacity, test pressure; pressure or vacuum change, mm of water; time period of test; number of leaks found with instrument; and leak definition.

(6) Records of each instance in which gasoline was loaded into a cargo tank for which vapor tightness documentation required under §60.502a(e)(1) was not provided or available in the terminal's records. These records shall include, at a minimum:

(i) Tank owner and address.

(ii) Tank identification number.

(iii) Date gasoline was loaded without proper documentation.

(iv) Date proper documentation was received or statement that proper documentation was never received.

(7) Records of each instance gasoline was loaded into cargo tanks not using submerged filling, as defined in §60.501a and into cargo tanks that were not equipped with vapor collection equipment

that is compatible with the terminal's vapor collection system. These records shall include, at a minimum:

(i) Date and time of gasoline loading into improperly equipped cargo tank.

(ii) The type of deviation (not submerged filling, incompatible equipment, or both).

(iii) The tank identification number.

(8) Records of each instance gasoline was loaded into cargo tanks that were conducted when the terminal's and the cargo tank's vapor collection systems were not connected. These records shall include, at a minimum:

(i) Date and time of gasoline loading into cargo tank not properly connected.

(ii) The tank identification number.

(9) For each pressure CPMS used to comply with the requirements in §60.502a(h), maintain records of:

(i) The 5-minute average pressure readings from the CPMS for a minimum of two years.

(ii) Each 5-minute average pressure reading from the CPMS that exceeded the maximum loading pressure specified in §60.502a(h) and the reason for the exceedance for a minimum of five years.

(iii) The start date and time, duration, and reason of each outage or out of control period of the pressure CPMS.

(iv) Each inspection or calibration of the pressure CPMS.

(10) A record [list, summary description, or diagram(s) showing the location] of all equipment in gasoline service at the facility. A record of each leak inspection required under §60.503a(a)(2) and each leak inspection and leak identified under §60.502a(j) as specified in paragraphs (a)(9)(i) through (v):

(i) For each leak inspection, keep the following records:

(A) An indication if the leak inspection was conducted under §60.502a(j) or §60.503a(a)(2).

(B) Leak determination method used for the leak inspection.

(ii) For leak inspections conducted with Method 21 of Appendix A-7 of this part, keep the following additional records:

(A) Date of inspection.

(B) Inspector name.

(C) Monitoring instrument identification.

(D) Identification of all equipment surveyed and the instrument reading for each piece of equipment.

(E) Date and time of instrument calibration and initials of operator performing the calibration.

(F) Calibration gas cylinder identification, certification date, and certified concentration.

(G) Instrument scale used.

(H) Results of the daily calibration drift assessment.

(iii) For leak inspections conducted with OGI, keep the records specified in Section 12 of Appendix K of this part.

(iv) For each leak detected during a leak inspection or by audio/visual/olfactory methods during normal duties, record the following information:

(A) The equipment type and identification number.

(B) The date the leak was detected, the name of the person who found the leak, the nature of the leak (i.e., vapor or liquid), and the method of detection (i.e, audio/visual/olfactory, Method 21, or OGI).

(C) The dates of each attempt to repair the leak and the repair methods applied in each attempt to repair the leak.

(D) The date of successful repair of the leak, the method of monitoring used to confirm the repair, and if Method 21 of appendix A-7 of this part is used to confirm the repair, the maximum instrument reading measured by Method 21 of appendix A-7 of this part. If OGI is used to confirm the repair, keep video footage of the repair confirmation.

(E) For each repair delayed beyond 15 calendar days after discovery of the leak, record “Repair delayed”, the reason for the delay, and the expected date of successful repair. The owner or operator (or designate) whose decision it was that repair could not be carried out in the 15 calendar day timeframe must sign the record.

(F) For each leak that is not repairable, the maximum instrument reading measured by Method 21 of appendix A-7 of this part at the time the leak is determined to be not repairable, a video captured by the OGI camera showing that emissions are still visible, or a signed record that the leak is still detectable via audio/visual/olfactory methods.

(11) Records of each performance test or performance evaluation conducted on the affected facility and each notification and report submitted to the Administrator.

(b) *Reporting Requirements for Performance Tests and Evaluations*. Within 60 days after the date of completing each performance test and each CEMS performance evaluation required by this subpart, you must submit the results following the procedures specified in paragraph (e) of this section. As required by § 60.8(f)(2)(iv), you must include the value for the combustion zone temperature operating parameter limit set based on your performance test in the performance test

report. Data collected using test methods supported by the EPA's Electronic Reporting Tool (ERT) and performance evaluations of CEMS measuring relative accuracy test audit (RATA) pollutants that are supported by the EPA's ERT as listed on the EPA's ERT website (https://www.epa.gov/electronic-reporting-air-emissions/electronic-reporting-tool-ert) at the time of the test or performance evaluation must be submitted in a file format generated using the EPA's ERT. Alternatively, you may submit an electronic file consistent with the extensible markup language (XML) schema listed on the EPA's ERT website. Data collected using test methods that are not supported by the EPA's ERT and performance evaluations of CEMS measuring RATA pollutants that are not supported by the EPA's ERT as listed on the EPA's ERT website at the time of the test or performance evaluation must be included as an attachment in the ERT or an alternate electronic file

(c) *Reporting Requirements for Semiannual Report.* You must submit to the Administrator semiannual reports with the applicable information in paragraphs (c)(1) through (10) of this section by the dates specified in paragraph (d) of this section following the procedure specified in paragraph (e) of this section. For this subpart, the semiannual reports also serve as the excess emissions report required under § 60.7. Beginning on [DATE OF PUBLICATION OF THE FINAL RULE IN THE **FEDERAL REGISTER**] or once the report template for this subpart has been available on the Compliance and Emissions Data Reporting Interface (CEDRI) website (*https://www.epa.gov/electronic-reporting-air-emissions/cedri*) for one year, whichever date is later, submit all subsequent reports using the appropriate electronic report template on the CEDRI website for this subpart and following the procedure specified in paragraph (e) of this section. The date report templates become available will be listed on the CEDRI website. Unless the Administrator or delegated state agency or other authority has approved a different schedule for submission of reports, the report must be submitted by the deadline specified in this subpart, regardless of the method in which the report is submitted.

(1) Report the following general facility information:

(i) Facility name.

(ii) Facility physical address, including city, county, and state.

(iii) Latitude and longitude of facility's physical location. Coordinates must be in decimal degrees with at least five decimal places.

(iv) The following information for the contact person:

(A) Name.

(B) Mailing address.

(C) Telephone number.

(D) E-mail address.

(v) Date of report and beginning and ending dates of the reporting period. You are no longer required to provide the date of report when the report is submitted via CEDRI.

(vi) Statement by a responsible official, with that official's name, title, and signature, certifying the truth, accuracy, and completeness of the content of the report. If your report is submitted via

CEDRI, the certifier's electronic signature during the submission process replaces the requirement in this paragraph (c)(1)(vi).

(2) For each thermal oxidation system used to comply with the emission limitations in §60.502a(b)(1) or (c)(1), report:

(i) For all instances when the temperature CPMS measured 3-hour rolling averages below the established operating limit when liquid product was being loaded into gasoline cargo tanks:

(A) The date and start time of the deviation.

(B) The duration of the deviation in hours.

(C) Each 3-hour rolling average combustion zone temperature during the deviation.

(D) A unique identifier for the temperature CPMS.

(E) The make, model number, and date of last calibration check of the temperature CPMS.

(ii) For all instances that the temperature CPMS for measuring the combustion zone temperature was not operating or out of control:

(A) The date and start time of the deviation.

(B) The duration of the deviation in hours.

(C) A unique identifier for the temperature CPMS.

(D) The make, model number, and date of last calibration check of the temperature CPMS.

(3) For each vapor recovery system used to comply with the emission limitations in §60.502a(b)(2) or (c)(2), report:

(i) For all instances when the TOC CEMS measured 3-hour rolling average concentrations higher than the applicable emission limitation when liquid product was loaded into gasoline cargo tanks:

(A) The date and start time of the deviation.

(B) The duration of the deviation in hours.

(C) Each 3-hour rolling average TOC concentration during the deviation.

(D) A unique identifier for the TOC CEMS.

(E) The make, model number, and date of last calibration check of the TOC CEMS.

(ii) For all instances that the TOC CEMS was not operating or out of control when liquid product was loaded into gasoline cargo tanks:

(A) The date and start time of the deviation.

(B) The duration of the deviation in hours.

(C) A unique identifier for the TOC CEMS.

(D) The make, model number, and date of last calibration check of the TOC CEMS.

(4) For each flare used to comply with the emission limitations in §60.502a(c)(3), report:

(i) For each 15-minute block during which there was at least one minute when gasoline vapors were routed to the flare and no pilot flame was present, include the start and end time and date of each 15-minute block.

(ii) For each period of 2 consecutive hours during which visible emissions exceeded a total of 5 minutes, the date, the start and end time of the visible emissions observation, and the number of minutes for which visible emissions were observed during the observation or an estimate of the cumulative number of minutes in the 2-hour period for which emissions were visible based on best information available to the owner or operator.

(iii) For each 15-minute block period for which the applicable operating limits specified in §63.670(d) through (f) are not met, report:

(A) The date and start and end time for the period.

(B) The net heating value operating parameter(s) for which there was a deviation (i.e., NHV_{cz}, NHV_{dil}).

(C) If you use the supplemental gas flow rate monitoring alternative in §60.502a(c)(3)(viii) or (ix), the target supplemental gas flow rate and the actual supplemental gas flow rate including units of flow rates for the 15-minute block. Otherwise, the value of the net heating value operating parameter(s) during the deviation determined following the methods in §63.670(k) through (n) as applicable.

(iv) The start date, start time, and duration in minutes for each period when gasoline vapors were routed to the flare and flare monitoring was not performed.

(5) Report any instance in which gasoline was loaded into a cargo tank for which vapor tightness documentation required under §60.502a(e)(1) was not provided or available in the terminal’s records. Report the following information:

(i) Tank owner and address.

(ii) Tank identification number.

(iii) Date gasoline was loaded without proper documentation.

(iv) Date proper documentation was received or statement that proper documentation was never received.

(6) Report each instance gasoline was loaded into cargo tanks not using submerged filling, as defined in §60.501a or into cargo tanks that were not equipped with vapor collection equipment that is compatible with the terminal's vapor collection system. The report shall include:

(i) Date and time of gasoline loading into improperly equipped cargo tank.

(ii) The type of deviation (not submerged filling, incompatible equipment, or both).

(iii) The tank identification number.

(7) Report each instance gasoline was loaded into cargo tanks when the terminal's and the cargo tank's vapor collection systems were not properly connected or indicate no such deviation occurred. The report shall include:

(i) Date and time of gasoline loading into a cargo tank that was not properly connected.

(ii) The tank identification number.

(8) For each pressure CPMS used to comply with the requirements in §60.502a(h), report:

(i) For each instance the vapor collection system pressure exceeded the maximum loading pressure specified in §60.502a(h):

(A) The date and start time of the deviation.

(B) The duration of the deviation in hours.

(C) The average pressure during the deviation.

(D) A unique identifier for the pressure CPMS.

(E) The make, model number, and date of last calibration of the CPMS.

(ii) For all instances that the pressure CPMS was not operating or out of control:

(A) The date and start time of the deviation.

(B) The duration of the deviation in hours.

(C) A unique identifier for the pressure CPMS.

(D) The make, model number, and date of last calibration of the CPMS.

(9) Report the following information for each leak inspection required under §60.502a(j)(1) and §60.503a(a)(2) and each leak identified under §60.502a(j)(2).

(i) For each leak detected during a leak inspection required under §60.502a(j)(1) and §60.503a(a)(2), report:

(A) The date of inspection.

(B) The leak determination method (OGI or Method 21).

(C) The total number and type of equipment for which leaks were detected.

(D) The total number and type of equipment for which leaks were repaired within 15 calendar days.

(E) The total number and type of equipment for which no repair attempt was made within 5 days of the leaks being identified.

(F) The total number and type of equipment placed on the delay of repair, as specified in §60.502a(j)(8).

(ii) For leaks identified under §60.502a(j)(2), report:

(A) The total number and type of equipment for which leaks were identified under §60.502a(j)(2).

(B) The total number and type of equipment for which leaks identified under §60.502a(j)(2) were repaired within 15 calendar days.

(C) The total number and type of equipment for which no repair attempt was made within 5 days of the leaks being identified.

(D) The total number and type of equipment placed on the delay of repair, as specified in §60.502a(j)(8).

(iii) The total number of leaks on the delay of repair list at the start of the reporting period.

(iv) The total number of leaks on the delay of repair list at the end of the reporting period.

(v) For each leak that was on the delay of repair list at any time during the reporting period, report:

(A) Unique equipment identification number.

(B) Type of equipment.

(C) Leak determination method (OGI, Method 21, or AVO).

(D) The reason(s) why the repair was not feasible within 15 days.

(E) If applicable, the date repair was completed.

(10) If there were no deviations from the emission limitations in §60.502a(b)(1), (b)(2), (c)(1), or (c)(2) and there were no deviations from the maximum loading pressure specified in §60.502a(h), then provide a statement that there were no deviations from the emission limitations or loading pressure requirements during the reporting period. If there were no periods during which a continuous monitoring system (including a CEMS or CPMS) was inoperable or out-of-control, then

provide a statement that there were no periods during which a continuous monitoring system was inoperable or out-of-control during the reporting period.

(d) *Timeframe for Semiannual Report Submissions*.

(1) The first semiannual report will cover the date starting with the date the source first becomes an affected facility subject to this subpart and ending with the last day of the month five months later. For example, if the source becomes an affected facility on April 15, the first semiannual report would cover the period from April 15 to September 30. The first semiannual report must be submitted on or before the last day of the month two months after the last date covered by the semiannual report. In this example, the first semiannual report would be due November 30.

(2) Subsequent semiannual reports will cover subsequent 6 calendar month periods with each report due on or before the last day of the month two months after the last date covered by the semiannual report.

(e) *Requirements for Electronically Submitting Reports.* For reports required to be submitted following the procedures specified in this paragraph (f), you must submit reports to the EPA via CEDRI, which can be accessed through the EPA's Central Data Exchange (CDX) (https://cdx.epa.gov/). The EPA will make all the information submitted through CEDRI available to the public without further notice to you. Do not use CEDRI to submit information you claim as confidential business information (CBI). Although we do not expect persons to assert a claim of CBI, if you wish to assert a CBI claim for some of the information in the report, you must submit a complete file in the format specified in this subpart, including information claimed to be CBI, to the EPA following the procedures in paragraphs (e)(1) and (2) of this section. Clearly mark the part or all of the information that you claim to be CBI. Information not marked as CBI may be authorized for public release without prior notice. Information marked as CBI will not be disclosed except in accordance with procedures set forth in 40 CFR part 2. All CBI claims must be asserted at the time of submission. Anything submitted using CEDRI cannot later be claimed CBI. Furthermore, under CAA section 114(c), emissions data is not entitled to confidential treatment, and the EPA is required to make emissions data available to the public. Thus, emissions data will not be protected as CBI and will be made publicly available. You must submit the same file submitted to the CBI office with the CBI omitted to the EPA via the EPA's CDX as described earlier in this paragraph (e).

(1) The preferred method to receive CBI is for it to be transmitted electronically using email attachments, File Transfer Protocol, or other online file sharing services. Electronic submissions must be transmitted directly to the OAQPS CBI Office at the email address oaqpscbi@epa.gov, and as described above, should include clear CBI markings. ERT files should be flagged to the attention of the Group Leader, Measurement Policy Group; all other files should be flagged to the attention of the Gasoline Distribution Sector Lead. If assistance is needed with submitting large electronic files that exceed the file size limit for email attachments, and if you do not have your own file sharing service, please email oaqpscbi@epa.gov to request a file transfer link.

(2) If you cannot transmit the file electronically, you may send CBI information through the postal service to the following address: OAQPS Document Control Officer (C404-02), OAQPS, U.S. Environmental Protection Agency, Research Triangle Park, North Carolina 27711. ERT files should be sent to the attention of the Group Leader, Measurement Policy Group, and all other files should be sent to the attention of the Gasoline Distribution Sector Lead. The mailed CBI material should be double wrapped and clearly marked. Any CBI markings should not show through the outer envelope.

(f) *Claims of EPA System Outage*. If you are required to electronically submit a report through CEDRI in the EPA's CDX, you may assert a claim of EPA system outage for failure to timely comply

with that reporting requirement. To assert a claim of EPA system outage, you must meet the requirements outlined in paragraphs (f)(1) through (7) of this section.

(1) You must have been or will be precluded from accessing CEDRI and submitting a required report within the time prescribed due to an outage of either the EPA's CEDRI or CDX systems.

(2) The outage must have occurred within the period of time beginning five business days prior to the date that the submission is due.

(3) The outage may be planned or unplanned.

(4) You must submit notification to the Administrator in writing as soon as possible following the date you first knew, or through due diligence should have known, that the event may cause or has caused a delay in reporting.

(5) You must provide to the Administrator a written description identifying:

(i) The date(s) and time(s) when CDX or CEDRI was accessed and the system was unavailable;

(ii) A rationale for attributing the delay in reporting beyond the regulatory deadline to EPA system outage;

(iii) A description of measures taken or to be taken to minimize the delay in reporting; and

(iv) The date by which you propose to report, or if you have already met the reporting requirement at the time of the notification, the date you reported.

(6) The decision to accept the claim of EPA system outage and allow an extension to the reporting deadline is solely within the discretion of the Administrator.

(7) In any circumstance, the report must be submitted electronically as soon as possible after the outage is resolved.

(g) *Claims of force majeure.* If you are required to electronically submit a report through CEDRI in the EPA's CDX, you may assert a claim of *force majeure* for failure to timely comply with that reporting requirement. To assert a claim of *force majeure*, you must meet the requirements outlined in paragraphs (g)(1) through (5) of this section.

(1) You may submit a claim if a *force majeure* event is about to occur, occurs, or has occurred or there are lingering effects from such an event within the period of time beginning five business days prior to the date the submission is due. For the purposes of this section, a *force majeure* event is defined as an event that will be or has been caused by circumstances beyond the control of the affected facility, its contractors, or any entity controlled by the affected facility that prevents you from complying with the requirement to submit a report electronically within the time period prescribed. Examples of such events are acts of nature (e.g., hurricanes, earthquakes, or floods), acts of war or terrorism, or equipment failure or safety hazard beyond the control of the affected facility (e.g., large scale power outage).

(2) You must submit notification to the Administrator in writing as soon as possible following the date you first knew, or through due diligence should have known, that the event may cause or has caused a delay in reporting.

(3) You must provide to the Administrator:

(i) A written description of the *force majeure* event;

(ii) A rationale for attributing the delay in reporting beyond the regulatory deadline to the *force majeure* event;

(iii) A description of measures taken or to be taken to minimize the delay in reporting; and

(iv) The date by which you propose to report, or if you have already met the reporting requirement at the time of the notification, the date you reported.

(4) The decision to accept the claim of *force majeure* and allow an extension to the reporting deadline is solely within the discretion of the Administrator.

(5) In any circumstance, the reporting must occur as soon as possible after the *force majeure* event occurs.