EASTMAN CHEMICAL COMPANY CONSOLIDATED PERMIT

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ARKANSAS DEPARTMENT OF POLLUTION CONTROL AND ECOLOGY
DIVISION OF AIR POLLUTION CONTROL

Summary Report Relative to Permit Application

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CSN: 32-0036 **Permit No.:** 1085-AR-10 **Date Issued:**

Submittals: August 26, 1996; October 21, 1996

SUMMARY

Eastman Chemical Company, Arkansas Eastman Division, operates a chemical processing plant (Organic Chemical Intermediates) (SIC Code 2869) which is located at 2800 Gap Road, Highway 394, in Batesville. This permit (1085-AR-10) allows the construction and operation of a new building to house a continuous dust collection system and central vacuum cleaning system. Five additional atmospheric emission points (5M16-01, 5M11-15, 5M18-01, 5M18-02, 5M18-03) discharging from venturi scrubbers and fabric filters, and an emission point 5M01-TSP designating fugitive emissions from maintenance activities, will be created with the startup of this dust collection and vacuum cleaning system.

This permit (1085-AR-10) also allows the organic sulfonation facility to produce alternative products. These alternative products will require minor changes in the process chemistry to meet customer expectations or new markets. Eight new emission points are created with this modification: 5M04-11, 5M04-12, 5M11-08, 5M11-09, 5M11-10, 5M11-12, 5M11-13, and 5M11-14. The description of these emission points can be found in the table of allowable emission rates in this permit.

The total allowable emissions increases associated with the above two projects are 3.5 tons per year of sulfur dioxide, 7.7 tons per year of particulate matter, 3.8 tons per year of VOCs, 0.2 tons per year of nitrogen oxides, and a 0.3 tons per year decrease of inorganic emissions.

Reviewed By: Shane Byrum **Approved By:** Keith A. Michaels
Applicable Regulation: Air Code SIP NSPS NESHAP PSD

SUMMARY OF PREVIOUS PERMIT MODIFICATIONS

1. The purpose of consolidated permit # 1085-A was to modernize some of the older permits and to put all of the Eastman Chemical Company permits into one package. This permit also required Eastman to install and operate a Regenerative Thermal Oxidizer (RTO) on the batch organic chemicals production facilities in buildings 5N01 and 5N03 for the control of VOC emissions by July, 1992. This was in response to the discovery that the existing scrubbers were unable to capture VOC as efficiently as applied for in previous permits. Permit 1085-A was issued on January 11, 1991.

2. The permittee submitted a PSD permit application. The modification involved the installation of a 221 million BTU per hour natural gas fired boiler (6M-07-01), which required a PSD permit due to significant nitrogen oxide (NO_x) emissions (98 tons per year). Permit # 1085-AR-1 was issued on May 14, 1992.

3. Permit # 1085-AR-2 was issued to document the burning of wastewater sludge in all three of the coal fired boilers at the facility. Eastman proposed to dewater wastewater treatment plant sludge before atomizing it using compressed air, into the high temperature combustion zone of the boilers. Permit # 1085-AR-2 was issued on February 9, 1994.

4. The permittee submitted their first minor permit modification October 11, 1993. The modification involved the addition of a packed-bed water scrubber to source 5N01-45, a 24,000 gallon above-ground storage tank which stores crotonaldehyde. This was an uncontrolled source prior to this minor permit modification. Potential emissions from this source will be 5.7 tons per year after control. Permit # 1085-AR-3 was issued on April 18, 1994.

5. The permittee submitted a minor modification on April 15, 1995, which proposed to vent several temporary storage tanks to the RTOs (regenerative thermal oxidizers). The main purpose of this modification is to control the odor generated from the use of ethyl mercaptan. Ethyl mercaptan is mainly used to odorize natural gas. When the storage tanks used in this process vent to the atmosphere, small amounts of ethyl mercaptan are released. The odor threshold of ethyl mercaptan is 0.4 ppb (parts per billion). Permit # 1085-AR-4 was issued on October 20, 1994. The following tanks were deleted from the Table I since they no longer vent to the atmosphere.

PES #	Description	PES #	Description
5N01-11	Tank	5N01-12	Tank
5N01-13	Tank	5N01-14	Tank
5N01-16	Tank	5N01-19	Tank
5N01-20	Tank	5N01-21	Tank
5N01-29	Tank	5N01-30	Tank
5N01-34	Tank	5N01-35	Tank
5N01-36	Tank	5N01-37	Tank
5N01-50	Tank	5N01-51	Tank
5N01-52	Tank	5N01-53	Tank
5N01-60	Tank	5N01-62	Tank
5N03-09	Tank	5N03-10	Tank
5N03-61	Tank		

6. The permittee submitted a minor modification on July 18, 1994, which proposed to produce a new polymer in the Polymer Production Facility. Emissions from this modification are controlled by the RTOs (regenerative thermal oxidizers), scrubbers, and conservation vents on tanks. Permit # 1085-AR-5 was issued on October 18, 1994.

7. The permittee submitted a permit modification on October 18, 1994, which proposed to modify existing solvent recovery equipment used to recover additional solvent and to remove potential odor producing compounds by destroying them in the existing RTOs (regenerative thermal oxidizers). The main purpose of this modification is to control the odor generated from the use of ethyl mercaptan. Ethyl mercaptan is mainly used to odorize natural gas. The odor threshold of ethyl mercaptan is 0.4 ppb (parts per billion). To eliminate this odor, the facility has proposed that the scrubber atmospheric vents be connected to the RTOs. Additionally, the permittee proposed to modify the existing wastewater treatment system by closing the existing equalization basin, discontinuing the use of the existing diversion basin for processing wastewater, and constructing aboveground tanks for equalization/neutralization and diversion of the wastewater. The system modifications included the addition of two 30,000 gallon pump station clearwells, two 750,000 gallon equalization tanks, and one 1,000,000 gallon diversion tank. Also a new lift station, neutralization system, and a floating organic skimmer and decant system was to be provided. The existing diversion basin was to be used to capture noncontact cooling water and stormwater runoff should it become contaminated. Permit # 1085-AR-6 was issued on June 6, 1995.

8. The permittee submitted a permit modification on May 30, 1995, which proposed to modify the particulate emission limit for the existing Regenerative Thermal Oxidizers (RTOs) to reflect the higher emission rate discovered during stack testing. Permit # 1085-AR-7 was issued on November 27, 1995.

9. The permittee submitted a permit modification on November 6, 1995, which proposed (1) to route emissions from eleven waste storage tanks to its coal-fired boilers to abate odors within the utilities area of the plant, (2) to burn waste solvent fuel in the boilers at the rates certified under the Boiler and Industrial Furnace regulation (BIF), (3) to increase the rate of rubber and paper pellet fuel burning to 100% of the total heat input of the coal-fired boilers, and (4) to construct one 20,000 gallon capacity storage tank containing a final polymer product . The following tanks were deleted from the Table I since they no longer vent to the atmosphere. Permit #1085-AR-8 was issued on May 8, 1996.

PES #	Description	PES #	Description
6M03-02	Tank	6M03-09	Tank
6M03-03	Tank	6M03-10	Tank
6M03-04	Tank	6M03-11	Tank
6M03-06	Tank	6M03-12	Dumpster Storage
6M03-07	Tank	6M03-13	Dumpster Storage
6M03-08	Tank		

10. The permittee submitted a permit modification on April 4, 1996, to (1) increase potential VOC emissions from the Waste Chemical Destructor (6M03-5) from 0.5 tpy to 8.8 tpy due to an anticipated future increase in business and a corresponding increase in the amount of wastes that could potentially be generated; and (2) to increase potential inorganic emissions from 16.3 tpy to 43.8 tpy from the two RTOs due to an anticipated increase in chlorinated compounds production. Permit #1085-AR-9 was issued on 11/12/96.

FACILITY WIDE - SPECIFIC CONDITIONS

1. Emissions sources of VOC are, under most operating conditions, expected to be operated without visible emissions. Visible emissions from VOC sources may, in certain circumstances, indicate equipment problems or upset conditions. Eastman Chemical Company shall report any visible emissions from VOC equipment to Arkansas Department of Pollution Control and Ecology, Air Division, as required by General Condition 7 of this permit, governing the reporting of upset conditions.

SOLVENT RECOVERY OPERATIONS FOR BUILDINGS 5N01, 5N03, AND 4P01

These facilities support the Buildings 5N01 and 5N03 manufacturing complex by recovering a portion of the spent solvents for reuse in the process. Solvent recovery equipment is used for distillation of solvents for reclamation and recycling. These reclamation and recycling units reduce raw material usage and the volume of spent solvent waste that would otherwise be thermally treated; thus, reducing emissions to the atmosphere. Eastman's solvent recovery facilities are used in common by many processes. The solvent recovery operation has the capability of recovering solvents from streams containing odor producing compounds.

Process Waste containing mixed solvents are stored in storage vessels and sent through a decanter to separate the recoverable materials. The separated streams are sent to solvent recovery distillation columns. The residual waste from the recovery operation will enter another distillation column for further reclamation. When the solvent waste stream can no longer be distilled/refined for production use, the residual waste stream is routed to an incinerator or industrial boiler where heat is recovered for the generation of process steam. Residual wastewater will be sent to an NPDES permitted wastewater treatment plant. Organic vapors vented from the storage vessels and distillation columns are presently routed to scrubbers to control these emissions before they reach the atmosphere.

None of this equipment is currently subject to NSPS Subpart NNN for the SOCMI distillation operations, which has an effective date of 12/30/83.

SOLVENT RECOVERY OPERATIONS
FOR BUILDINGS 5N01, 5N03, AND 4P01- SPECIFIC CONDITIONS

1A. All distillation equipment, scrubbers, and condensers shall be kept in good working condition at all times.

2A. Modification or reconstruction of any of the distillation operations may be subject to NSPS Subpart NNN.

ORGANIC SULFONATE PRODUCTION

The Organic Sulfonation facility can produce several different products to be used in household products. Oleum is used to sulfonate phenol thus forming a product that is neutralized to form a sodium salt of the sulfonate. The product is crystallized and separated from the solution by centrifuging. The other intermediate is generated as an amido acid by reacting caprolactam with pelargonic acid. The organic sulfonate product is formed by reacting the amido acid and salt of sulfonation with acetic anhydride and sulfolane. Acetic acid is generated as a byproduct of the reaction and is ultimately refined and sold. The solvent is recovered and reused in the existing solvent recovery equipment. The resulting organic salt is isolated by centrifugation and is dried. The dry organic sulfonate is stabilized in a mildly acidic environment, agglomerated into particles, and stored for shipment. The final product is shipped by truck or rail throughout the world.

This process was originally permitted under permit #794-A. Eastman has recently developed a method to use water as a process solvent, thus reducing VOC emissions from the process. Scrubbers are used to control VOC emissions from various stages of the process, and are estimated to be 99% efficient.

This permit (1085-AR-10) allows the construction and operation of a new building to house a continuous dust collection system and central vacuum cleaning system. Five additional atmospheric emission points (5M16-01, 5M11-15, 5M18-01, 5M18-02, 5M18-03) discharging from venturi scrubbers and fabric filters, and an emission point 5M01-TSP designating fugitive emissions from maintenance activities, will be created with the startup of this dust collection and vacuum cleaning system. The Central Vacuum Cleaning System (5M18-02) particulate emissions were calculated using 2190 hours per year maximum operations.

This permit (1085-AR-10) also allows the organic sulfonation facility to produce alternative products. These alternative products will require minor changes in the process chemistry to meet customer expectations or new markets. Eight new emission points are created with this modification: 5M04-11, 5M04-12, 5M11-08, 5M11-09, 5M11-10, 5M11-12, 5M11-13, and 5M11-14. The description of these emission points can be found in the table of allowable emission rates in this permit.

ORGANIC SULFONATE PRODUCTION - SPECIFIC CONDITIONS

1B. All scrubbers shall be kept in good working condition at all times.

2B. Certain affected equipment in this process shall be subject to NSPS Subpart VV (VOC equipment leaks) and Subpart NNN (distillation processes). All testing and reporting requirements shall be the responsibility of Eastman Chemical Company.

3B. Filter change maintenance on PES#5M01-TSP shall not exceed 120 hours during any 12 month consecutive period. Eastman shall keep records on the times and durations of filter changes sufficient to verify compliance with this condition. These records shall be kept on site and updated within 15 days after the reported 12 month period.

4B. Hours of operation of the Central Vacuum Cleaning System (5M18-02) shall not exceed 2190 hours during any 12 month consecutive period. Eastman shall keep records on the hours of operation of this source sufficient to verify compliance with this condition. These records shall be kept on site and updated within 15 days after the reported 12 month period.

ORGANIC SULFONATE PLANT II

Eastman Chemical Company has constructed a second organic sulfonate production facility, similar to its existing organic sulfonate facility, at its Batesville plant.

The associated process equipment includes reactors, centrifuges, and storage tanks. Seven scrubbers are used to control VOC emissions from various stages of the process, and are estimated to be 98-99% efficient. Total VOC emissions from the entire process, including fugitives, are estimated to be approximately 17 tons per year. Testing has been done on two of these scrubbers to confirm their efficiency.

ORGANIC SULFONATE PLANT II - SPECIFIC CONDITIONS

1C. All scrubbers shall be kept in good working condition at all times.

2C. Certain affected equipment used in this process shall be subject to NSPS Subpart VV.

BUILDINGS 5N01, 5N03, AND 5N07 BATCH PRODUCTION FACILITIES AND NEW REGENERATIVE THERMAL OXIDATION SYSTEM

Eastman Chemical Company has installed a thermal oxidation control system (commonly referred to as the RTO or regenerative thermal oxidizer) on its batch organic chemicals production facilities in buildings 5N01, 5N03 and 5N07 for the control of VOC emissions. This is in response to the discovery that the existing scrubbers were unable to capture VOCs as efficiently as applied for in previous air permits.

Reactors, filters, dryers, and batch stills, and other processing equipment are used in the batch production facilities. Most of the solvents used in the batch processes are recovered by distillation and reused in the chemical processes. The exhaust streams from these processes contain some VOCs, sulfur dioxide, particulates, hydrogen chloride, and chlorine.

These pollutants are currently controlled with eductor water scrubbers, caustic scrubbers, and spray tower scrubbers. The exhaust streams are configured and ducted to the two new thermal oxidizers in order to destroy the VOCs remaining in the exhaust streams. The thermal oxidizers are of the regenerative type, which takes advantage of the combustion energy content of the destroyed VOCs by capturing the heat in ceramic packing. The destruction efficiency of the thermal oxidizers is guaranteed by the manufacturer to be 95% (based on a minimum inlet concentration of 1000 ppm), with a maximum concentration of 50 ppm at the exit. VOC emissions will be reduced by 1,000 tons per year.

Permit 1085-AR-9 is being issued to reflect an anticipated increase in production of certain specialty chemicals by 250%. The permitted emissions of Inorganics has been increased from 3.7 lb/hr to 10 lb/hr.

Permits PSD-AR-153 and 262-A are now obsolete because of the installation of the thermal oxidizing system and this permit shall replace them.

BUILDINGS 5N01, 5N03, AND 5N07 BATCH PRODUCTION FACILITIES AND NEW REGENERATIVE THERMAL OXIDATION SYSTEM - SPECIFIC CONDITIONS

1D. All scrubbers shall be kept in good working order at all times.

2D. The thermal oxidizers shall be kept in good working order, and shall be used whenever VOCs are being emitted from the batch processes from buildings 5N01, 5N03, and 5N07 (upset conditions are covered under General Condition #7). Sensors, controls, and alarms shall be present on the thermal oxidizer system to ensure proper operation.

DIPB PROCESS

This process was originally permitted under 744-A. Propylene is reacted with benzene in the presence of a catalyst to form a mixture of Isopropylbenzenes. The desired products are refined by distillation. The propylene storage tanks are maintained under pressure. The catalyst storage and transfer system is equipped with a fabric filter followed by a water scrubber. The reaction and refining operations are vented to the flare. In the event of a powerhouse malfunction, and during process upsets, start-up, or shut-down, the off gases are vented to a flare. Because the off-gases are similar to liquified petroleum gases, combustion efficiency should be high. As the vapor pressures are low, the product storage tanks are equipped only with conservation vents. The main emissions from this process are VOCs, estimated to be approximately 1.6 pounds per hour.

Since benzene is used in this process, NESHAPS Subparts J and V apply.

DIPB PROCESS - SPECIFIC CONDITIONS

1E. The equipment used in this process is subject to NESHAPS standards, 40 CFR Part 61, Subparts J and V, and NSPS standards, 40 CFR Part 60, Subpart VV.

STORAGE TANKS AND MISCELLANEOUS SOURCES

This permit section deals with the tank farms and the other miscellaneous sources not specifically associated with any of the other major permit sections of this consolidated document. Most of the sources in this section deal with tank farms used for bulk storage of VOCs. Many of these tanks have conservation vents to reduce losses. Several scrubbers are also included in this section which control VOC emissions. Fabric filters at the lime storage and cement plant are also covered. Lab hoods are covered under this section, but are not listed on the overall Air Emissions Inventory.

STORAGE TANKS AND MISCELLANEOUS SOURCES - SPECIFIC CONDITIONS

1F. Eastman shall keep an inventory of tanks used for storage of VOCs, including tank capacity, liquid stored, date of installation, and vapor pressure of the stored liquid to determine compliance with NSPS regulations for VOC storage vessels (40 CFR Part 60, Subpart Kb).

2F. Hours of operation of source 7N02-01 (fabric filter), during bulk cement supply deliveries, shall not exceed 300 hours during any consecutive 12 month period. Eastman shall keep records sufficient to verify compliance with this condition. These records shall be updated monthly within 30 days after each 12 month period.

WASTE CHEMICAL DESTRUCTOR

The waste chemical destructors were originally permitted under air permit 262-A.

The #2 destructor is now under Resource Conservation and Recovery Act (RCRA) permit 11-HR-1. Air emissions from the destructor are controlled with a venturi scrubber.

Permit 1085-AR-8 (November, 1995 Modification) is being issued to route the vents of the eleven waste chemical storage tanks through a header to the coal-fired boilers. During normal operation (tank filling and withdrawal) small amounts of organic chemicals are released through the relief devices. Some of these materials have a low odor threshold. The primary relief device consists of a Pressure Safety Valve (PSV) and a detonation flame arrestor. These safety vapor devices will be connected through a stainless steel header to the boilers. A fan will force the vapors collected in the header to pass through a flow meter, double block-and-bleed valve arrangement, a manual valve, and a detonation flame arrestor. The vapors will enter the boiler(s) through a burner ring.

Permit 1085-AR-9 is being issued to increase permitted emissions of VOC from the waste chemical destructor (6M03-5) due to anticipated increases in business and a corresponding increase in the amount of wastes that could be potentially generated. This change in permit limits is also based on the design capacity of the destructor which is also permitted under a RCRA Part B permit.

Highlights of Resource Conservation and Recovery Act (RCRA) Permit:

RCRA permit 11-HR-1 indirectly affects the air emissions from the #2 destructor. Destruction efficiency of principal organic hazardous constituents is required to be 99.99%. The HCl emissions are limited to 4 lb/hr or 99% removal. Particulate emissions are limited to 0.08 grains/dscf. CO concentrations in the exhaust gas are limited to 100 ppm (one hour rolling average). These limits shall govern the allowable emissions from the unit.

WASTE CHEMICAL DESTRUCTOR - SPECIFIC CONDITIONS

1G. The scrubbers on the destructor units shall be kept in good working order at all times.

2G. For compliance purposes of this air permit, Eastman shall comply with all conditions and limits pertaining to air emissions in RCRA permit 11-HR-1 for destructor #2.

COAL AND NATURAL GAS FIRED BOILERS

Eastman operates three coal fired boilers and two natural gas fired boilers to produce process steam for the facility.

The coal boilers were originally permitted under 262-A. Each boiler is rated at 70 million BTU/hr, and the maximum sulfur content of the coal is limited to 4%. An electrostatic precipitator controls particulate emissions. Under RCRA interim status, up to 28 gpm of waste solvents may be burned as a fuel in the coal fired boilers. These boilers are identical Keeler Type MKB boilers, each rated at 50,000 lbs steam per hour continuous service at an operating steam pressure of 610 psia, and equipped with a 2,300 cubic feet furnace volume. Each boiler system is designed as a 70 million Btu/hr unit and is equipped with its own electrostatic precipitator to control particulate emissions to less than 0.08 gr/dscf. Each boiler is designed to fire approximately 3.5 tons of coal in addition to waste fuels. Approximately 4,000 tons per year of fuel-quality liquid waste chemicals are burned as fuels in three coal-fired boilers. Each of the three boilers are designed to combust a maximum of 25 pounds of wastes per minute. Only boilers 1 and 2 are proposed for treatment of VOC emission from the waste tanks.

In 1987, Eastman received PSD permit 829-A for the installation of a 78 million BTU/hr natural gas fired boiler (#4 boiler). BACT at that time was considered to be a standard register burner.

Permit 1085-AR-2 was issued to document the burning of wastewater sludge in all three of the coal fired boilers at the facility (see Wastewater Treatment System section for description of sludge generation). Eastman proposes to dewater wastewater treatment plant sludge before atomizing it, using compressed air, into the high temperature combustion zone of the boilers. In addition to the air permit, the burning of wastewater sludge in the coal fired boilers may subject Eastman to the Boiler and Industrial Furnace regulations (BIF). Compliance with the air permit does not connote compliance with the BIF regulations or other RCRA regulations which may be applicable.

Permit 1085-AR-8 (November, 1995 Modification) is being issued to increase the rate of rubber and paper pellet fuel burning to 100% of the heat input of the coal-fired boilers. Paper pellet material handling assessments and emission testing have proven the fuel may be burned at the same rates as coal, resulting in a significant reduction of emissions. Certification for compliance with BIF emission requirements was completed on August 21,1995. The fuel is derived from off-quality feminine care products. The manufacturing process results in the creation of waste materials consisting of polypropylene, polyethylene, cellulose fiber, food-grade adhesives, and sodium polyacrylate super absorbents. Rather than landfill this waste, the waste is shredded, blended, and pelletized for subsequent use as a supplemental fuel. The ash (Paper/Rubber fuel) content in the paper pellets is significantly lower than coal. Only small amounts of rubber will be burned (approximately 9 tons per week). The process rubber has a higher ash content, but the feed rate of the rubber will be lower than the paper pellets. Therefore, the particulate emissions will not exceed those established in the BIF certification of compliance test.

COAL AND NATURAL GAS FIRED BOILERS - SPECIFIC CONDITIONS

1H. Eastman shall not burn coal with sulfur content of greater than 4% in the coal fired boilers.

2H. Up to 28 gpm total of those hazardous wastes authorized by applicable RCRA regulations may be burned in the coal fired boilers.

3H. The electrostatic precipatator (ESP) shall be kept in good working condition at all times.

4H. The maximum opacity of the ESP exhaust shall not be greater than 20% (EPA Method 9).

5H. Eastman shall maintain a monthly record of the total coal fed to the three coal-fired boilers. These records shall be kept on site and shall be provided to Department personnel upon request.

6H. Eastman shall maintain a daily log of the times when the wastewater sludge and the hazardous wastes are being fed to the boilers. These records shall be kept on site and shall be provided to Department personnel upon request.

7H. Eastman shall maintain monthly records of the wastewater sludge fed to the boilers. These records shall be kept on site and shall be provided to Department personnel upon request.

8H. Each boiler shall be limited to a maximum steam production rate of 40,000 pounds per hour, based upon an hourly rolling average, while burning wastewater sludge.

9H. Each boiler shall be limited to a feed rate of 778 pounds per hour of wastewater treatment dry solids per boiler. The total for all three boilers shall be 2334 pounds per hour. This shall be monitored by measuring the flow rate of the sludge and determining the percentage of dry solids each day that sludge is burned, unless a similar compliance test is required under the BIF (Boiler and Industrial Furnace) rules.

10H. The permittee may burn scrap rubber and paper in the coal fired boilers as long as the sulfur content of the rubber does not exceed 4% by weight. Additionally, paper and rubber scrap may be burned at 100% of the total heat input to the boilers, providing that hazardous waste is not burned simultaneously with the rubber and paper scrap.

11H. Paper and rubber scrap shall not exceed 50% of the total heat input to the boilers while burning hazardous waste authorized by applicable Resource Conservation and Recovery Act (RCRA) regulations.

Eastman Chemical Company has installed a 221 million BTU/hr natural gas fired boiler, which required a PSD permit due to significant NO_x emissions (98 tons/year). No other pollutant will be emitted in PSD significant amounts. NSPS regulations are also in effect for this source.

BACT

BACT for this application was determined to be low-NO_x burners, which will emit a maximum of 0.1 lb No_x/MMBTU. Selective catalytic reduction was not chosen because of high costs and adverse environmental impacts. Thermal $DeNO_x$ was not chosen because it was not technically feasible to use this technology on this size package boiler.

AIR Quality Analysis

Eastman Chemical Company operates an ambient air monitoring station on its plant property. Annual NO_x concentrations prior to the installation of the new boiler have been measured to be 9.3 ug/m^3. Dispersion modeling of the new boiler predicts less than 1 ug/m^3 of additional NO_x ambient impact beyond the plant property. No further air quality or increment analysis is required.

NSPS Requirements

This boiler is subject to NSPS Subpart Db, except that the emission standard for NO_x is 0.1 lb/MMBTU due to PSD BACT limitations. Eastman has exercised its right under 40 CFR 60.49b(c) to submit and follow an operating plan for the boiler in lieu of using a NO_x continuous emissions monitor.

SPECIFIC CONDITIONS

1I. PSD REQUIREMENTS: The boiler shall not fire any fuel other than pipeline quality natural gas. The boiler shall not exceed the following emissions rates at full firing capacity (221 MMBTU/hr natural gas):

NO_x - 21.96 lb/hr and 0.1 lb/MMBTU (to meet BACT)

CO - 18.01 lb/hr (testing to confirm CO emissions below 100 TPY)

2I. NSPS REQUIREMENTS: The boiler is subject to the applicable provisions of NSPS Subpart Db (see appendix of consolidated permit 1085-A), including the NO_x compliance test. The test shall be done within the 60/180 day time frame defined in NSPS regulations, and shall be done using EPA Method 7E.

3I. Currently, Eastman operates a software CEM for predicting NO_x emissions from the boiler based on the operating parameters. Eastman shall operate the CEM system in accordance with all applicable requirements in the Department's Continuous Emission Monitoring System Standards.

Since the boiler is less than 250 MMBTU/hr input, the monitoring of boiler operation parameters may be done in lieu of CEM requirements. Eastman shall be responsible for monitoring all parameters and keeping all records required in 40 CFR 60.49b(c).

OXIDIZED CELLULOSE PLANT

This process was originally permitted in 1986 under permit 262-AR-6. The process basically consists of the oxidation of cotton gauze with nitrogen oxides. The oxidized cellulose is washed with demineralized water and dried. Nitric oxide and nitrogen tetroxide are condensed, evaporated, and recycled to the oxidizer. In a separate process, oxidized cellulose powder is produced from purified wood cellulose in carbon tetrachloride and nitrogen tetroxide. Gases that are not condensed and recycled in the process will be scrubbed by an aqueous solution of sodium hydroxide in a packed column. A packed column scrubber controls the emissions of NO_x to approximately 2.5 lb/hr.

OXIDIZED CELLULOSE PLANT - SPECIFIC CONDITIONS

1J. The scrubber shall be kept in good working condition at all times, and shall be used whenever the oxidized cellulose process is in operation. Operation under upset conditions shall be according to General Condition #7.

POLYMER PRODUCTION FACILITY

Eastman Chemical Company added a new polymer production facility to their organic chemical manufacturing plant in February, 1991. This facility was originally permitted under 981-A in February, 1990. The polymer production processes include polymer formation in reactors, centrifuging, drying, and solvent recovery. The facility was completed and placed into operation in February, 1991, under consolidated permit 1085-A. The polymer production facility was shut down in August, 1993, due to the loss of the initial polymer product business. ADPC&E was notified of the facility shut down.

A spray polymer product is produced in the polymer production facility and was permitted under 1085-AR-4 in October, 1994. The spray polymer process produces a solid product from a variety of solid and liquid reactants that react in solution with one major solvent. Acetone is the major solvent. Acrylic acid, t-butyl acrylate and silicone macromonomer react in acetone to form one polymer. A second polymer is produced using the same reactants but with ethanol as the solvent. The two polymers are combined to form one final product. Washing and purification of the material is done with water. Solid-liquid separation occurs in centrifuges and decanters for each reaction step. The solid polymer is dried and packaged for shipment. Acetone is sent to solvent recovery for reuse.

Permit 1085-AR-8 (November, 1995 Modification) is being issued to add a new 20,000 gallon storage tank (PES 4P94-11) containing a final polymer product. The new tank will accumulate batches of final polymer product for truck loading. This source is subject to *New Source Performance Standards* (NSPS), 40 CFR Part 60, Subpart Kb, 60.116b(a) and 60.116b(b), Standards of Performance for Volatile Organic Liquid Storage Vessels. Additionally, Eastman Chemical Company proposes to increase the emission rate from PES 5N03-17 (storage tank) to reflect a change in the operation of the source. The emission rate increase is required due to nitrogen sparging. Nitrogen is sparged into the tank to remove dissolved oxygen from the raw material. Dissolved oxygen interferes with the reaction of the polymer material in the polymerization process.

POLYMER PRODUCTION FACILITY - SPECIFIC CONDITIONS

1K. All scrubbers shall be kept in good working order and shall be used whenever the associated processes are in operation. Operation under upset conditions shall be done according to General Condition #7.

2K. The baghouses located in this production area are not currently in service. The permittee shall notify the Department if these baghouses are to be removed of placed back in operation.

3K. The new 20,000 gallon storage tank (PES 4P94-11) is subject to *New Source Performance Standards* (NSPS), 40 CFR Part 60, Subpart Kb, 60.116b(a) and 60.116b(b), Standards of Performance for Volatile Organic Liquid Storage Vessels.

WASTEWATER TREATMENT SYSTEM

Wastewater containing small amounts of organic materials from the production facilities flows through the sewer system into the 30,000 gallon pump station clearwells. The wastewater is pumped to the equalization tanks for variability reduction and equalization. After equalization, the treated wastewater is sent to the activated sludge treatment basins. The treated wastewater is sent to the White River from NPDES permitted outfall 002. The aboveground diversion tank is to be used to handle off quality wastewater streams and accidental discharges within the production facilities. The wastewater treatment system employs an activated sludge process to decompose the dilute concentrations of organics in the water. Dissolved oxygen necessary for the biological treatment is supplied to the system by subsurface aeration.

A portion of the VOCs in the wastewater is released to the atmosphere as it is collected and treated. It is estimated that approximately 203 tons per year of VOCs are released from the system including tanks and chemical dumpster.

This wastewater treatment system was installed in early 1996.

WASTEWATER TREATMENT SYSTEM - SPECIFIC CONDITIONS

1L. Eastman shall estimate yearly VOC emissions from the wastewater treatment system based on yearly wastewater throughput and wastewater VOC concentrations. This yearly estimate shall be reported on the yearly emissions inventory forms completed by the facility, and shall be used in future PSD offsetting calculations. Emissions from the wastewater treatment system shall not exceed the limits specified in Table I of this permit.

TABLE I

ALLOWABLE EMISSION RATES Eastman Chemical Company, Arkansas Eastman Division							
PES #	Description	Hours of Operation (hr/yr)	Emission Rate		Pollutant	Regulation	Opacity (%)
			lb/hr	ton/yr			
Solvent Recovery Operations for Buildings 5N01, 5N03, & 4P01							
4P02-01	Scrubber	8760	0.1	0.2	VOC	SIP	N/A
4P02-02	Condenser	8760	3.0	13.2	VOC	SIP	N/A
4P02-03	Dumpster	8760	1.0	4.4	VOC	SIP	N/A
4P02-04	Dumpster	8760	1.0	4.4	VOC	SIP	N/A
4P94-01	Scrubber	8760	1.0	4.4	VOC	SIP	N/A
4P94-02	Scrubber	8760	1.0	4.4	VOC	SIP	N/A
4P94-03	Tank	8760	0.1	0.4	Inorganic[2]	SIP	20%
4P94-04	Tank	8760	0.1	0.4	Inorganic[2]	SIP	20%
4P94-05	Tank	8760	0.1	0.2	VOC	SIP	N/A
5N01-12	Column	Routed to RTO as of April 15, 1994 Minor Modification					
5N01-14	Column	Routed to RTO as of April 15, 1994 Minor Modification					
5N01-15	Column	8760	0.1	0.4	VOC	SIP	N/A
5N01-17	Column	8760	0.8	3.2	VOC	SIP	N/A
5N01-18	Column	8760	1.0	4.4	VOC	SIP	N/A

ALLOWABLE EMISSION RATES Eastman Chemical Company, Arkansas Eastman Division							
PES #	Description	Hours of Operation (hr/yr)	Emission Rate		Pollutant	Regulation	Opacity (%)
			lb/hr	ton/yr			
5N01-46	Dumpster	8760	1.0	4.4	VOC	SIP	N/A
5N01-47	Dumpster	8760	1.0	4.4	VOC	SIP	N/A
5N01-60	Tank	Routed to RTO as of April 15, 1994 Minor Modification					
5N01-61	Tank	8760	0.1	0.2	VOC	SIP	N/A
5N03-19	Dumpster	8760	1.0	4.4	VOC	SIP	N/A
5N03-20	Dumpster	8760	1.0	4.4	VOC	SIP	N/A
Organic Sulfonate Production Area - Buildings 5M01, 5M03, 5M04, & 5M05							
5M01-01	Scrubber	8760	0.2	0.6	VOC	SIP	N/A
5M01-02	Tank	8760	0.1	0.4	VOC	SIP NSPS - VV	N/A
5M01-03	Vacuum System	8760	0.1	0.4	VOC	SIP NSPS- NNN	N/A
5M01-05	Scrubber	8760	0.1	0.4	VOC	SIP	N/A
5M01-06	Scrubber	8760	0.2	0.9	VOC	SIP	N/A
5M01-07	Scrubber	8760	0.1	0.4	VOC	SIP	N/A
5M01-08	Scrubber	8760	0.1	0.4	VOC	SIP	N/A

ALLOWABLE EMISSION RATES
Eastman Chemical Company, Arkansas Eastman Division

PES #	Description	Hours of Operation (hr/yr)	Emission Rate		Pollutant	Regulation	Opacity (%)
			lb/hr	ton/yr			
5M01-TSP	Maintenance Activity Fugitives - Filter Changes	120	3.1	0.2	TSP	SIP	20%
5M03-01	Scrubber	8760	0.3	1.3	VOC	SIP NSPS-NNN	N/A
5M03-02	Scrubber	8760	0.1	0.4	VOC	SIP	N/A
5M03-06	Vacuum System	8760	0.1	0.4	VOC	SIP NSPS-NNN	N/A
5M04-01	Scrubber	8760	0.1	0.4	VOC	SIP NSPS-Kb	N/A
5M04-02	Scrubber	8760	0.1	0.4	VOC	SIP NSPS-Kb	N/A
5M04-03	Tank	8760	0.1	0.4	VOC	SIP NSPS-VV	N/A
5M04-06	Tank	8760	0.1	0.4	VOC	SIP NSPS-VV NSPS-Kb	N/A
5M04-07	Tank	8760	0.1	0.4	VOC	SIP NSPS-VV	N/A

ALLOWABLE EMISSION RATES Eastman Chemical Company, Arkansas Eastman Division							
PES #	Description	Hours of Operation (hr/yr)	Emission Rate		Pollutant	Regulation	Opacity (%)
			lb/hr	ton/yr			
5M04-08	Tank	8760	0.1	0.4	VOC	SIP NSPS-VV NSPS-Kb	N/A
5M04-09	Tank	8760	0.1	0.4	VOC	SIP NSPS-VV	N/A
5M04-10	Scrubber	8760	0.1	0.4	VOC	SIP	N/A
5M04-11	Tank	8760	0.1	0.4	None	SIP	N/A
5M04-12	Tank	8760	0.1	0.4	VOC	SIP	N/A
5M05-01	Scrubber	8760	0.1	0.4	VOC	SIP	N/A
Fugitive	VOC Fugitives	8760	2.4	10.5	VOC	SIP	N/A
Organic Sulfonate II Production Area							
5M11-01	Scrubber	8760	0.2	0.6	VOC	SIP	N/A
5M11-02	Tank	8760	0.1	0.4	VOC	SIP NSPS-VV	N/A
5M11-03	Vacuum System	8760	0.1	0.4	VOC	SIP	N/A
5M11-04	Scrubber	8760	0.2	0.9	VOC	SIP	N/A

ALLOWABLE EMISSION RATES
Eastman Chemical Company, Arkansas Eastman Division

PES #	Description	Hours of Operation (hr/yr)	Emission Rate lb/hr	Emission Rate ton/yr	Pollutant	Regulation	Opacity (%)
5M11-05	Scrubber	8760	0.2	0.9	VOC	SIP NSPS-NNN	N/A
5M11-06	Scrubber	8760	0.1 0.8	0.4 3.5	VOC SO_2	SIP	N/A
5M11-07	Scrubber	8760	0.1	0.4	VOC	SIP	N/A
5M11-08	Scrubber	8760	0.1	0.4	VOC	SIP	N/A
5M11-09	Analysis Bins	8760	0.1	0.2	PM/PM_{10}	SIP	20%
5M11-10	Agglomeration Bins	8760	0.1	0.1	PM/PM_{10}	SIP	20%
5M11-12	Binder Vessel	8760	0.1	0.1	VOC	SIP	N/A
5M11-13	Truck Loading	8760	0.1	0.4	PM/PM_{10}	SIP	20%
5M11-14	Citric Acid Storage	8760	0.1	0.1	PM/PM_{10}	SIP	20%
5M11-15	Supersack Load Hopper Dust Control System	8760	0.1	0.3	TSP	SIP	20%
5M13-01	Scrubber	8760	0.3	1.3	VOC	SIP NSPS-NNN	N/A
5M13-02	Scrubber	8760	0.1	0.4	VOC	SIP	N/A
5M13-03	Vacuum System	8760	0.1	0.4	VOC	SIP	N/A

ALLOWABLE EMISSION RATES
Eastman Chemical Company, Arkansas Eastman Division

PES #	Description	Hours of Operation (hr/yr)	Emission Rate		Pollutant	Regulation	Opacity (%)
			lb/hr	ton/yr			
5M14-01	Tank/Scrubber	8760	0.1	0.4	VOC	SIP NSPS-VV	N/A
5M14-02	Tank/Scrubber	8760	0.1	0.4	VOC	SIP NSPS-VV	N/A
5M14-03	Tank	8760	0.1	0.4	VOC	SIP NSPS-VV	N/A
5M14-04	Tank	8760	0.1	0.4	VOC	SIP NSPS -VV	N/A
5M14-05	Tank	8760	0.1	0.4	VOC	SIP NSPS-VV	N/A
5M14-06	Tank	8760	0.1	0.4	VOC	SIP NSPS-VV NSPS-Kb	N/A
5M14-07	Tank	8760	0.1	0.4	TSP	SIP	20%
5M14-08	Tank/Scrubber	8760	0.1	0.4	TSP	SIP	20%
5M14-09	Tank/Scrubber	8760	0.1	0.4	VOC	SIP NSPS-VV	N/A
Fugitives	VOC Fugitives	8760	2.0	8.8	VOC	SIP	N/A
5M16-01	Supersack Loadout Dust Control System	8760	0.1	0.1	TSP	SIP	20%

ALLOWABLE EMISSION RATES Eastman Chemical Company, Arkansas Eastman Division							
PES #	Description	Hours of Operation (hr/yr)	Emission Rate		Pollutant	Regulation	Opacity (%)
			lb/hr	ton/yr			
5M18-01	Continuous Dust Control System	8760	0.9	2.0	TSP	SIP	20%
5M18-02	Central Vacuum Cleaning System	2190	3.4	3.8	TSP	SIP	20%
5M18-03	Bin Vacuum Cleaning System	8760	0.2	0.9	TSP	SIP	20%
Building 5N01 - Batch Production of Organic Chemicals							
5N01-01	Scrubber	Routed to RTO as of January 11, 1991 Modification					
5N01-02	Scrubber	Routed to RTO as of January 11, 1991 Modification					
5N01-04	Scrubber	Routed to RTO as of January 11, 1991 Modification					
5N01-05	Scrubber	Routed to RTO as of January 11, 1991 Modification					
5N01-06	Scrubber	Routed to RTO as of January 11, 1991 Modification					
5N01-07	Scrubber	Routed to RTO as of January 11, 1991 Modification					
5N01-08	Scrubber	Removed from Service					
5N01-09	Scrubber	Routed to RTO as of January 11, 1991 Modification					
5N01-10	Scrubber	Routed to RTO as of January 11, 1991 Modification					

ALLOWABLE EMISSION RATES Eastman Chemical Company, Arkansas Eastman Division							
PES #	Description	Hours of Operation (hr/yr)	Emission Rate		Pollutant	Regulation	Opacity (%)
			lb/hr	ton/yr			
5N01-11	Scrubber	Routed to RTO as of April 15, 1994 Minor Modification					
5N01-54	Scrubber	Routed to RTO as of January 11, 1991 Modification					
5N01-55	Scrubber(s)	Routed to RTO as of January 11, 1991 Modification					
5N01-56	Scrubber	Routed to RTO as of January 11, 1991 Modification					
5N01-57	Scrubber	Routed to RTO as of January 11, 1991 Modification					
5N01-58	Extractor	8760	1.0	4.4	VOC	SIP	N/A
5N01-59	Scrubber	Routed to RTO as of January 11, 1991 Modification					
5N01-62	Sump/Tank	Routed to RTO as of April 15, 1994 Minor Modification					
5N01-63	Tank	8760	0.8	3.5	VOC	SIP	N/A
5N01-64	Tank	8760	0.1	0.4	VOC	SIP	N/A
Building 5N03 - Batch Production of Organic Chemicals							
5N03-01	Scrubber	Routed to RTO as of January 11, 1991 Modification					
5N03-02	Scrubber	Routed to RTO as of January 11, 1991 Modification					
5N03-03	Scrubber	Routed to RTO as of January 11, 1991 Modification					
5N03-04	Scrubber	Routed to RTO as of January 11, 1991 Modification					

ALLOWABLE EMISSION RATES
Eastman Chemical Company, Arkansas Eastman Division

PES #	Description	Hours of Operation (hr/yr)	Emission Rate lb/hr	Emission Rate ton/yr	Pollutant	Regulation	Opacity (%)
5N03-05	Scrubber	Routed to RTO as of January 11, 1991 Modification					
5N03-06	Scrubber	Routed to RTO as of January 11, 1991 Modification					
5N03-07	Scrubber	Routed to RTO as of January 11, 1991 Modification					
5N03-08	Scrubber	Routed to RTO as of January 11, 1991 Modification					
5N03-21	Scrubber	Routed to RTO as of January 11, 1991 Modification					
5N03-22	Scrubber	Routed to RTO as of January 11, 1991 Modification					
5N03-23	Scrubber	Routed to RTO as of January 11, 1991 Modification					
5N03-24	Scrubber	Routed to RTO as of January 11, 1991 Modification					
5N03-26	Scrubber	Routed to RTO as of January 11, 1991 Modification					
5N03-28	Scrubber	Routed to RTO as of January 11, 1991 Modification					
5N03-30	Scrubber	Routed to RTO as of January 11, 1991 Modification					
5N03-31	Tank	8760	0.3	1.3	VOC	SIP	N/A
5N03-58	Tank	8760	0.1 0.1	0.1 0.4	VOC Inorganic[2]	SIP	20%
5N03-59	Tank	8760	0.1 0.1	0.1 0.1	VOC Inorganic[2]	SIP	20%
5N03-60	Tank	8760	0.1	0.1	VOC	SIP	N/A

ALLOWABLE EMISSION RATES Eastman Chemical Company, Arkansas Eastman Division							
PES #	Description	Hours of Operation (hr/yr)	Emission Rate		Pollutant	Regulation	Opacity (%)
			lb/hr	ton/yr			
5N03-61	Tank	Routed to RTO as of April 15, 1994 Minor Modification					
5N03-62	Tank	8760	0.1	0.4	VOC	SIP	N/A
DIPB Process - Building 5N03							
5N03-11	Tank	8760	0.1	0.4	VOC	SIP NSPS -VV	N/A
5N03-15	Tank	8760	0.1	0.4	VOC	SIP NSPS-VV	N/A
5N03-16	Tank	8760	0.1	0.4	VOC	SIP NSPS-VV	N/A
5N03-41	Tank	8760	0.1	0.4	VOC	PSD NSPS-VV	N/A
5N03-42	Tank	8760	0.1	0.4	VOC	PSD NSPS-VV	N/A
5N03-48	Filter	8760	0.1	0.4	TSP	SIP	20%
	Scrubber	8760	0.1	0.4	Inorganic[2]	SIP	20%
5N03-49	Tank	8760	0.1	0.4	VOC	SIP NSPS-VV	N/A

ALLOWABLE EMISSION RATES
Eastman Chemical Company, Arkansas Eastman Division

PES #	Description	Hours of Operation (hr/yr)	Emission Rate		Pollutant	Regulation	Opacity (%)
			lb/hr	ton/yr			
5N03-50	Tank	8760	0.1	0.4	VOC	SIP NSPS-VV	N/A
5N03-51	Tank	8760	0.1	0.4	VOC	SIP NSPS-VV	N/A
5N03-52	Tank	8760	0.1	0.4	VOC	SIP NSPS-VV	N/A
5N03-53	Tank	8760	0.1	0.4	VOC	SIP NSPS-Kb NSPS-VV	N/A
5N03-54	Flare	8760	0.1 0.1 0.9 0.4 1.4	0.2 0.1 3.8 1.5 5.9	TSP SO_2 VOC CO NO_X	NESHAP-J NESHAP-V	20%
5N03-55	Tank	8760	0.1 0.1	0.4 0.4	VOC Inorganic[2]	SIP NSPS-Kb NSPS-VV	20%
5N03-56	Baghouse/Scrubber	Removed from service and emissions routed to RTO as of July 18, 1994					
5Q94-01	Tank	8760	0.3	1.4	VOC	SIP NSPS-Kb NSPS-VV	N/A

ALLOWABLE EMISSION RATES Eastman Chemical Company, Arkansas Eastman Division							
PES #	Description	Hours of Operation (hr/yr)	Emission Rate		Pollutant	Regulation	Opacity (%)
			lb/hr	ton/yr			
5N03-57	Dumpster	8760	0.1	0.4	VOC	SIP	N/A
Storage Tanks and Miscellaneous Sources							
5N01-13	Scrubber	Routed to RTO as of April 15, 1994 Minor Modification					
5N01-16	Tank	Routed to RTO as of April 15, 1994 Minor Modification					
5N01-19	Tank	Routed to RTO as of April 15, 1994 Minor Modification					
5N01-20	Tank	Routed to RTO as of April 15, 1994 Minor Modification					
5N01-21	Tank	Routed to RTO as of April 15, 1994 Minor Modification					
5N01-22	Tank	8760	0.1	0.4	VOC	SIP	N/A
5N01-23	Tank	8760	0.1	0.4	VOC	SIP	N/A
5N01-24	Tank	8760	1.0	4.4	VOC	SIP	N/A
5N01-25	Tank	8760	0.1	0.4	VOC	SIP	N/A
5N01-26	Tank	8760	0.1	0.4	VOC	SIP	N/A
5N01-27	Tank	8760	0.1	0.1	VOC	SIP	N/A
5N01-28	Tank	8760	1.0	4.4	VOC	SIP	N/A
5N01-29	Tank	Routed to RTO as of April 15, 1994 Minor Modification					

ALLOWABLE EMISSION RATES Eastman Chemical Company, Arkansas Eastman Division							
PES #	Description	Hours of Operation (hr/yr)	Emission Rate		Pollutant	Regulation	Opacity (%)
			lb/hr	ton/yr			
5N01-30	Tank	Routed to RTO as of April 15, 1994 Minor Modification					
5N01-31	Tank	8760	0.1	0.4	VOC	SIP	N/A
5N01-32	Tank	8760	0.1	0.1	VOC	SIP	N/A
5N01-33	Tank	8760	5.0	21.9	VOC	SIP	N/A
5N01-34	Tank	Routed to RTO as of April 15, 1994 Minor Modification					
5N01-35	Tank	Routed to RTO as of April 15, 1994 Minor Modification					
5N01-36	Tank	Routed to RTO as of April 15, 1994 Minor Modification					
5N01-37	Tank	Routed to RTO as of April 15, 1994 Minor Modification					
5N01-38	Tank	8760	1.0	4.4	VOC	SIP	N/A
5N01-39	Tank	8760	1.0	4.4	VOC	SIP	N/A
5N01-40	Tank	8760	0.1	0.1	Inorganic[2]	SIP	20%
5N01-41	Tank	8760	0.1	0.1	Inorganic[2]	SIP	20%
5N01-42	Tank	8760	0.1	0.4	Inorganic[2]	SIP	20%
5N01-43	Tank	8760	0.1	0.1	VOC	SIP	N/A
5N01-44	Tank	8760	1.0	4.4	VOC	SIP	N/A
5N01-45	Tank	8760	1.0	4.4	VOC	SIP	N/A

ALLOWABLE EMISSION RATES Eastman Chemical Company, Arkansas Eastman Division							
PES #	Description	Hours of Operation (hr/yr)	Emission Rate		Pollutant	Regulation	Opacity (%)
			lb/hr	ton/yr			
5N01-48	Tank	8760	0.1	0.1	VOC	SIP	N/A
5N01-49	Tank	8760	0.1	0.1	VOC	SIP	N/A
5N01-50	Tank	Routed to RTO as of April 15, 1994 Minor Modification					
5N01-51	Tank	Routed to RTO as of April 15, 1994 Minor Modification					
5N01-52	Tank	Routed to RTO as of April 15, 1994 Minor Modification					
5N01-53	Tank	Routed to RTO as of April 15, 1994 Minor Modification					
5N03-09	Tank	Routed to RTO as of April 15, 1994 Minor Modification					
5N03-10	Tank	Routed to RTO as of April 15, 1994 Minor Modification					
5N03-12	Tank	8760	0.1	0.4	VOC	SIP	N/A
5N03-13	Tank	8760	0.1	0.4	VOC	SIP	N/A
5N03-14	Tank	8760	0.1	0.4	VOC	SIP	N/A
5N03-34	Tank	8760	0.1	0.1	VOC	SIP	N/A
5N03-35	Tank	8760	0.1	0.4	VOC	SIP	N/A
5N03-36	Tank	8760	0.1	0.4	VOC	SIP	N/A
5N03-37	Tank	8760	0.1	0.4	VOC	SIP	N/A
5N03-38	Scrubber	8760	0.1	0.4	Inorganic[2]	SIP	20%

ALLOWABLE EMISSION RATES
Eastman Chemical Company, Arkansas Eastman Division

PES #	Description	Hours of Operation (hr/yr)	Emission Rate		Pollutant	Regulation	Opacity (%)
			lb/hr	ton/yr			
5N03-39	Tank	8760	0.1	0.4	VOC	SIP	N/A
5N03-40	Tank	8760	0.1	0.4	VOC	SIP	N/A
5N03-45	Scrubber	8760	0.1	0.1	Inorganic[2]	SIP	20%
5N03-46	Unload Station	300	0.2	0.1	Inorganic[2]	SIP	20%
5N03-47	Unload Station	500	0.1	0.1	Inorganic[2]	SIP	20%
6N01-01	Tank	8760	0.1	0.1	VOC	SIP	N/A
6N01-02	Tank	8760	0.5	2.2	VOC	SIP	N/A
6N01-03	Tank	8760	0.5	2.2	VOC	SIP	N/A
7P01-01	Tank	8760	0.1	0.1	VOC	SIP	N/A
7P01-02	Tank	8760	0.1	0.1	VOC	SIP	N/A
7P01-03	Tank	8760	0.1	0.1	VOC	SIP	N/A
7P01-04	Tank	8760	0.1	0.1	VOC	SIP	N/A
5N02-01	Scrubber	8760	0.1	0.4	VOC	SIP	N/A
5N02-02	Scrubber	8760	0.1	0.4	VOC	SIP	N/A
6N02-01	Tank	8760	0.1	0.1	Inorganic[2]	SIP	20%
6N02-02	Tank	8760	0.1	0.1	Inorganic[2]	SIP	20%

ALLOWABLE EMISSION RATES Eastman Chemical Company, Arkansas Eastman Division							
PES #	Description	Hours of Operation (hr/yr)	Emission Rate		Pollutant	Regulation	Opacity (%)
			lb/hr	ton/yr			
7M01-01	Fabric Filter (Lime Storage)	500	REMOVED FROM SERVICE				
7M01-02	Fabric Filter (Lime Storage)	500	REMOVED FROM SERVICE				
7N02-01	Fabric Filter (Cement Plant)	300	4.0	0.6	TSP	SIP	20%
9P01-01	Tank	8760	0.1	0.1	VOC	SIP	N/A
9P01-02	Tank	8760	0.1	0.1	VOC	SIP	N/A
Waste Chemical Destructor Area - Buildings 6M03 & 6M05							
6M03-01	#1 Destructor (Scrubber) Non-RCRA Waste Only	Removed from Service					
6M03-02	Tank	Routed to Powerhouse (EPS) as of November 6, 1995 Modification					
6M03-03	Tank	Routed to Powerhouse (EPS) as of November 6, 1995 Modification					
6M03-04	Tank	Routed to Powerhouse (EPS) as of November 6, 1995 Modification					

ALLOWABLE EMISSION RATES
Eastman Chemical Company, Arkansas Eastman Division

PES #	Description	Hours of Operation (hr/yr)	Emission Rate lb/hr	Emission Rate ton/yr	Pollutant	Regulation	Opacity (%)
6M03-05	#2 Destructor	8760	20.1 1.4 2.0 7.7	88.1 6.2 8.8 33.7	TSP SO_2 VOC Inorganic[2]	PSD	20%
6M03-06	Tank	Routed to Powerhouse (EPS) as of November 6, 1995 Modification					
6M03-07	Tank	Routed to Powerhouse (EPS) as of November 6, 1995 Modification					
6M03-08	Tank	Routed to Powerhouse (EPS) as of November 6, 1995 Modification					
6M03-09	Tank	Routed to Powerhouse (EPS) as of November 6, 1995 Modification					
6M03-10	Tank	Routed to Powerhouse (EPS) as of November 6, 1995 Modification					
6M03-11	Tank	Routed to Powerhouse (EPS) as of November 6, 1995 Modification					
6M03-12	Dumpster Storage	Routed to Powerhouse (EPS) as of November 6, 1995 Modification					
6M03-13	Dumpster Storage	Routed to Powerhouse (EPS) as of November 6, 1995 Modification					
6M03-15	Tank	8760	0.1	0.1	Inorganic[2]	SIP	20%
Coal & Gas Fired Boiler Operations - Buildings 6M01, 6M06							
6M01	Coal Pile	8760	0.1	0.1	TSP	SIP	20%

ALLOWABLE EMISSION RATES Eastman Chemical Company, Arkansas Eastman Division							
PES #	Description	Hours of Operation (hr/yr)	Emission Rate		Pollutant	Regulation	Opacity (%)
			lb/hr	ton/yr			
6M01-01	Powerhouse (EPS) Coal-Fired Boilers (1,2 and 3) 70 MM Btu/hr (Each)	8760	39.3 1450.0 0.2 990.0 858.0	172.1 6351.0 0.5 4336.2 3758.1	TSP SO_2 VOC CO NO_X	SIP	20%
6M01-01A	Fabric Filter (Coal Bunker)	8760	0.1	0.4	TSP	SIP	20%
6M06-01	#4 Boiler	8760	0.4 1.2 0.3 2.8 13.3	1.8 5.3 1.3 12.3 58.3	TSP SO_2 VOC CO NO_X	SIP	20%
6M07-01	#5 Boiler 221 MMBTU/Hr Natural Gas Fired	8760	1.1 0.1 2.9 18.0 22.0	4.8 0.4 12.7 78.8 96.4	TSP SO_2 VOC CO NO_X	PSD NSPS-Db	20%
Oxidized Cellulose Plant - Building 4P03							
4P03-09	Scrubber	8760	2.5	11.0	NO_X	SIP	N/A

ALLOWABLE EMISSION RATES Eastman Chemical Company, Arkansas Eastman Division							
PES #	Description	Hours of Operation (hr/yr)	Emission Rate		Pollutant	Regulation	Opacity (%)
			lb/hr	ton/yr			
Polymer Production							
5N07-01	Baghouse/Scrubber	Removed from service and emissions routed to RTO as of July 18, 1994					
5N07-02	2-Stage Scrubber	Removed from service and emissions routed to RTO as of July 18, 1994					
5N07-03	Tank Vent	8760	0.1	0.2	TSP	SIP	20%
5N07-04	Scrubber	8760	0.1	0.4	TSP	SIP	20%
4P04-01	2-Stage Scrubber	Routed to RTO as of October 18, 1994 Minor Modification					
4P04-02	Scrubber	Routed to RTO as of October 18, 1994 Minor Modification					
4P04-03	Tank	Routed to RTO as of July 18, 1994 Minor Modification					
4P94-08	Tank	8760	0.1	0.1	Inorganic[2]	SIP	20%
4P94-09	Tank	8760	0.1	0.1	Inorganic[2]	SIP	20%
4P94-10	Tank	8760	0.1	0.1	Inorganic[2]	SIP	20%
4P94-11	Tank	8760	0.1	0.4	VOC	SIP NSPS-Kb	N/A
5N03-17	Tank	8760	0.8	3.5	VOC	SIP	N/A
5N03-18	Tank	8760	0.1	0.4	VOC	SIP	N/A
5N03-50	Tank	8760	0.3	1.1	VOC	SIP	N/A

ALLOWABLE EMISSION RATES Eastman Chemical Company, Arkansas Eastman Division							
PES #	Description	Hours of Operation (hr/yr)	Emission Rate lb/hr	Emission Rate ton/yr	Pollutant	Regulation	Opacity (%)
Fugitives	Fugitives	8760	5.9	25.8	VOC	SIP	N/A
Wastewater Treatment System							
7K01-01	WWTS[1]	8760	46.0	201.5	VOC	SIP	N/A
7M01-02	WW Decant Tank	8760	0.1	0.4	VOC	SIP	N/A
7M01-03	Caustic Tank	8760	0.1	0.4	Inorganic[2]	SIP	20%
7M01-04	Dumpster	8760	0.3	1.3	VOC	SIP	N/A
Regenerative Thermal Oxidizer							
5N09-01	RTO Regenerative Thermal Oxidizer	8760	3.5 8.4 42.0 5.3 8.7 10.0	15.4 36.8 184.0 23.2 38.1 43.8	TSP SO_2 VOC CO NO_x Inorganic[2]	PSD	20%

ALLOWABLE EMISSION RATES Eastman Chemical Company, Arkansas Eastman Division							
PES #	Description	Hours of Operation (hr/yr)	Emission Rate		Pollutant	Regulation	Opacity (%)
			lb/hr	ton/yr			
EMISSIONS SUMMARY TABLE							
TOTAL EMISSIONS			**77.4** **1462** **143.3** **1016** **905.9** **20**	**293** **6403.3** **617.7** **4452** **3968** **81.6**	**TSP** **SO_2** **VOC** **CO** **NO_X** **Inorganics[2]**		

[1] See Specific Condition #2L on page 16 of this permit.

[2] Inorganic Compounds - H_2SO_4. HCl, HBr, Cl, $ClSO_2OH$, $SOCl_2$, $AlCl_3$, NaOH, SO_3, H_2

ALLOWABLE EMISSIONS													
PES #	TSP		SO2		VOC		CO		NOX		Inorganics	
	pph	tpy	pph	tpy	pph	tpy	pph	tpy	pph	tpy	pph	tpy
4P02-01					0.1	0.2						
4P02-02					3.0	13.2						
4P02-03					1.0	4.4						
4P02-04					1.0	4.4						
4P94-01					1.0	4.4						
4P94-02					1.0	4.4						
4P94-03											0.1	0.4
4P94-04											0.1	0.4
4P94-05					0.1	0.2						
5N01-12	ROUTED TO RTO											
5N01-14	ROUTED TO RTO											
5N01-15					0.1	0.4						
5N01-17					0.8	3.2						
5N01-18					1.0	4.4						
5N01-46					1.0	4.4						
5N01-47					1.0	4.4						
5N01-60	ROUTED TO RTO											
5N01-61					0.1	0.2						
5N03-19					1.0	4.4						
5N03-20					1.0	4.4						
5M01-01					0.2	0.6						
5M01-02					0.1	0.4						
5M01-03					0.1	0.4						
5M01-05					0.1	0.4						
5M01-06					0.2	0.9						
5M01-07					0.1	0.4						
5M01-08					0.1	0.4						
5M01-TSP	3.1	0.2										
5M03-01					0.3	1.3						
5M03-02					0.1	0.4						

ALLOWABLE EMISSIONS													
PES #	TSP		SO2		VOC		CO		NOX		Inorganics	
	pph	tpy	pph	tpy	pph	tpy	pph	tpy	pph	tpy	pph	tpy
5M03-06					0.1	0.4						
5M04-01					0.1	0.4						
5M04-02					0.1	0.4						
5M04-03					0.1	0.4						
5M04-06					0.1	0.4						
5M04-07					0.1	0.4						
5M04-08					0.1	0.4						
5M04-09					0.1	0.4						
5M04-10					0.1	0.4						
5M04-11					0.1	0.4						
5M04-12					0.1	0.4						
5M05-01					0.1	0.4						
FUGITIVE					2.4	10.5						
5M11-01					0.2	0.6						
5M11-02					0.1	0.4						
5M11-03					0.1	0.4						
5M11-04					0.2	0.9						
5M11-05					0.2	0.9						
5M11-06			0.8	3.5	0.1	0.4						
5M11-07					0.1	0.4						
5M11-08					0.1	0.4						
5M11-09	0.1	0.2										
5M11-10	0.1	0.1										
5M11-12					0.1	0.1						
5M11-13	0.1	0.4										
5M11-14	0.1	0.1										
5M11-15	0.1	0.3										
5M13-01					0.3	1.3						
5M13-02					0.1	0.4						
5M13-03					0.1	0.4						

ALLOWABLE EMISSIONS													
PES #	TSP		SO2		VOC		CO		NOX		Inorganics	
	pph	tpy	pph	tpy	pph	tpy	pph	tpy	pph	tpy	pph	tpy
5M14-01					0.1	0.4						
5M15-02					0.1	0.4						
5M14-03					0.1	0.4						
5M14-04					0.1	0.4						
5M14-05					0.1	0.4						
5M14-06					0.1	0.4						
5M14-07	0.1	0.4										
5M14-08	0.1	0.4										
5M14-09					0.1	0.4						
FUGITIVE					2.0	8.8						
5M16-01	0.1	0.1										
5M18-01	0.9	2.0										
5M18-02	3.4	3.8										
5M18-03	0.2	0.9										
5N01-01	ROUTED TO RTO											
5N01-02												
5N01-04												
5N01-05												
5N01-06												
5N01-07												
5N01-08	REMOVED FROM SERVICE											
5N01-09	ROUTED TO RTO											
5N01-10												
5N01-11												
5N01-54												
5N01-55												
5N01-56												
5N01-57												
5N01-58					1.0	4.4						
5N01-59	ROUTED TO RTO											

ALLOWABLE EMISSIONS												
PES #	TSP		SO2		VOC		CO		NOX		Inorganics	
	pph	tpy	pph	tpy	pph	tpy	pph	tpy	pph	tpy	pph	tpy
5N01-62												
5N01-63					0.8	3.5						
5N01-64					0.1	0.4						
5N03-01												
5N03-02												
5N03-03	ROUTED TO RTO											
5N03-04												
5N03-05												
5N03-06												
5N03-07												
5N03-08												
5N03-21												
5N03-22	ROUTED TO RTO											
5N03-23												
5N03-24												
5N03-26												
5N03-28												
5N03-30												
5N03-31					0.3	1.3						
5N03-58					0.1	0.1					0.1	0.1
5N03-59					0.1	0.1					0.1	0.1
5N03-60					0.1	0.1						
5N03-61	ROUTED TO RTO											
5N03-62					0.1	0.4						
5N03-11					0.1	0.4						
5N03-15					0.1	0.4						
5N03-16					0.1	0.4						
5N03-41					0.1	0.4						
5N03-42					0.1	0.4						
5N03-48	0.1	0.4									0.1	0.4
5N03-49					0.1	0.4						

ALLOWABLE EMISSIONS

PES #	TSP		SO2		VOC		CO		NOX		Inorganics	
	pph	tpy	pph	tpy	pph	tpy	pph	tpy	pph	tpy	pph	tpy
5N03-50					0.1	0.4						
5N03-51					0.1	0.4						
5N03-52					0.1	0.4						
5N03-53					0.1	0.4						
5N03-54	0.1	0.2	0.1	0.1	0.9	3.8	0.4	1.5	1.4	5.9		
5N03-55					0.1	0.4					0.1	0.4
5N03-56	ROUTED TO RTO											
5Q94-01					0.3	1.4						
5N03-57					0.1	0.4						
5N01-13	ROUTED TO RTO											
5N01-16												
5N01-19	ROUTED TO RTO											
5N01-20												
5N01-21												
5N01-22					0.1	0.4						
5N01-23					0.1	0.4						
5N01-24					1.0	4.4						
5N01-25					0.1	0.4						
5N01-26					0.1	0.4						
5N01-27					0.1	0.1						
5N01-28					1.0	4.4						
5N01-29	ROUTED TO RTO											
5N01-30												
5N01-31					0.1	0.4						
5N01-32					0.1	0.1						
5N01-33					5.0	21.9						
5N01-34	ROUTED TO RTO											
5N01-35												
5N01-36												
5N01-37												
5N01-38					1.0	4.4						

ALLOWABLE EMISSIONS													
PES #	TSP		SO2		VOC		CO		NOX		Inorganics	
	pph	tpy	pph	tpy	pph	tpy	pph	tpy	pph	tpy	pph	tpy
5N01-39					1.0	4.4						
5N01-40											0.1	0.1
5N01-41											0.1	0.1
5N01-42											0.1	0.4
5N01-43					0.1	0.1						
5N01-44					1.0	4.4						
5N01-45					1.0	4.4						
5N01-48					0.1	0.1						
5N01-49					0.1	0.1						
5N01-50	ROUTED TO RTO											
5N01-51												
5N01-52												
5N01-53												
5N03-09	ROUTED TO RTO											
5N03-10												
5N03-12					0.1	0.4						
5N03-13					0.1	0.4						
5N03-14					0.1	0.4						
5N03-34					0.1	0.1						
5N03-35					0.1	0.4						
5N03-36					0.1	0.4						
5N03-37					0.1	0.4						
5N03-38											0.1	0.4
5N03-39					0.1	0.4						
5N03-40					0.1	0.4						
5N03-45											0.1	0.1
5N03-46											0.2	0.1
5N03-47											0.1	0.1
6N01-01					0.1	0.1						
6N01-02					0.5	2.2						
6N01-03					0.5	2.2						

ALLOWABLE EMISSIONS												
PES #	TSP		SO2		VOC		CO		NOX		Inorganics	
	pph	tpy	pph	tpy	pph	tpy	pph	tpy	pph	tpy	pph	tpy
7P01-01					0.1	0.1						
7P01-02					0.1	0.1						
7P01-03					0.1	0.1						
7P01-04					0.1	0.1						
5N02-01					0.1	0.4						
5N02-02					0.1	0.4						
6N02-01											0.1	0.1
6N02-02											0.1	0.1
7N02-01	4.0	0.6										
9P01-01					0.1	0.1						
9P01-02					0.1	0.1						
6M03-01	REMOVED FROM SERVICE											
6M03-02	ROUTED TO POWERHOUSE											
6M03-03	ROUTED TO POWERHOUSE											
6M03-04												
6M03-05	20.1	88.1	1.4	6.2	2.0	8.8					7.7	33.7
6M03-06	ROUTED TO POWERHOUSE											
6M03-07												
6M03-08												
6M03-09												
6M03-10												
6M03-11												
6M03-12												
6M03-13												
6M03-15											0.1	0.1
6M01	0.1	0.1										
6M01-01	39.3	172.1	1450.0	6351.0	0.2	0.5	990.0	4336.2	858.0	3758.1		
6M01-01A	0.1	0.4										
6M06-01	0.4	1.8	1.2	5.3	0.3	1.3	2.8	12.3	13.3	58.3		
6M07-01	1.1	4.8	0.1	0.4	2.9	12.7	18.0	78.8	22.0	96.4		

ALLOWABLE EMISSIONS												
PES #	TSP		SO2		VOC		CO		NOX		Inorganics	
	pph	tpy	pph	tpy	pph	tpy	pph	tpy	pph	tpy	pph	tpy
4P03-09									2.5	11.0		
5N07-01	ROUTED TO RTO											
5N07-02												
5N07-03	0.1	0.2										
5N07-04	0.1	0.4										
4P04-01	ROUTED TO RTO											
4P04-02												
4P04-03												
4P94-08											0.1	0.1
4P94-09											0.1	0.1
4P04-10											0.1	0.1
4P94-11					0.1	0.4						
5N03-17					0.8	3.5						
5N03-18					0.1	0.4						
5N03-50					0.3	1.1						
FUGITIVE					5.9	25.8						
7K01-01					46.0	201.5						
7M01-02					0.1	0.4						
7M01-03											0.1	0.4
7M01-04					0.3	1.3						
5N09-01	3.5	15.4	8.4	36.8	42.0	184.0	5.3	23.2	8.7	38.1	10.0	43.8
TOTALS												

Subpart Db-Standards of Performance for Industrial-Commercial-Institutional Steam Generating Units

Source: 52 FR 47842, Dec. 16, 1987, unless otherwise noted.

§60.40b Applicability and delegation of authority.

(a) The affected facility to which this subpart applies is each steam generating unit that commences construction, modification, or reconstruction after June 19, 1984, and that has a heat input capacity from fuels combusted in the steam generating unit of greater than 29 MW (100 million Btu/hour).

(b) Any affected facility meeting the applicability requirements under paragraph (a) of this section and commencing construction, modification, or reconstruction after June 19, 1984, but on or before June 19, 1986, is subject to the following standards:

(1) Coal-fired affected facilities having a heat input capacity between 29 and 73 MW (100 and 250 million Btu/hour), inclusive, are subject to the particulate matter and nitrogen oxides standards under this subpart.

(2) Coal-fired affected facilities having a heat input capacity greater than 73 MW (250 million Btu/hour) and meeting the applicability requirements under subpart D (Standards of performance for fossil-fuel- fired steam generators; §60.40) are subject to the particulate matter and nitrogen oxides standards under this subpart and to the sulfur dioxide standards under subpart D (§60.43).

(3) Oil-fired affected facilities having a heat input capacity between 29 and 73 MW (100 and 250 million Btu/hour), inclusive, are subject to the nitrogen oxides standards under this subpart.

(4) Oil-fired affected facilities having a heat input capacity greater than 73 MW (250 million Btu/hour) and meeting the applicability requirements under subpart D (Standards of performance for fossil-fuel- fired steam generators; §60.40) are also subject to the nitrogen oxides standards under this subpart and the particulate matter and sulfur dioxide standards under subpart D (§60.42 and §60.43).

(c) Affected facilities which also meet the applicability requirements under subpart J (Standards of performance for petroleum refineries; §60.104) are subject to the particulate matter and nitrogen oxides standards under this subpart and the sulfur dioxide standards under subpart J (§60.104).

(d) Affected facilities which also meet the applicability requirements under subpart E (Standards of performance for incinerators; §60.50) are subject to the nitrogen oxides and particulate matter standards under this subpart.

(e) Steam generating units meeting the applicability requirements under subpart Da (Standards of performance for electric utility steam generating units; §60.40a) are not subject to this subpart.

(f) Any change to an existing steam generating unit for the sole purpose of combusting gases containing TRS as defined under §60.281 is not considered a modification under §60.14 and the steam generating unit is not subject to this subpart.

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

(1) Section 60.44b(f).

(2) Section 60.44b(g).

(3) Section 60.49b(a)(4).

§60.41b 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.

Annual capacity factor means the ratio between the actual heat input to a steam generating unit from the fuels listed in §60.42b(a), §60.43b(a), or §60.44b(a), as applicable, during a calendar year and the potential heat input to the steam generating unit had it been operated for 8,760 hours during a calendar year at the maximum steady state design heat input capacity. In the case of steam generating units that are rented or leased, the actual heat input shall be determined based on the combined heat input from all operations of the affected facility in a calendar year.

Byproduct/waste means any liquid or gaseous substance produced at chemical manufacturing plants or petroleum refineries (except natural gas, distillate oil, or residual oil) and combusted in a steam generating unit for heat recovery or for disposal. Gaseous substances with carbon dioxide levels greater than 50 percent or carbon monoxide levels greater than 10 percent are not byproduct/waste for the purposes of this subpart.

Chemical manufacturing plants means industrial plants which are classified by the Department of Commerce under Standard Industrial Classification (SIC) Code 28.

Coal means all solid fuels classified as anthracite, bituminous, subbituminous, or lignite by the American Society of Testing and Materials in ASTM D388-77, Standard Specification for Classification of Coals by Rank (IBR-see §60.17), coal refuse, and petroleum coke. Coal-derived synthetic fuels, including but not limited to solvent refined coal, gasified coal, coal-oil mixtures, and coal-water mixtures, are also included in this definition for the purposes of this subpart.

Coal refuse means any byproduct of coal mining or coal cleaning operations with an ash content greater than 50 percent, by weight, and a heating value less than 13,900 kJ/kg (6,000 Btu/lb) on a dry basis.

Combined cycle system means a system in which a separate source, such as a gas turbine, internal combustion engine, kiln, etc., provides exhaust gas to a heat recovery steam generating unit.

Conventional technology means wet flue gas desulfurization (FGD) technology, dry FGD technology, atmospheric fluidized bed combustion technology, and oil hydrodesulfurization technology.

Distillate oil means fuel oils that contain 0.05 weight percent nitrogen or less and comply with the specifications for fuel oil numbers 1 and 2, as defined by the American Society of Testing and Materials in ASTM D396-78, Standard Specifications for Fuel Oils (incorporated by reference-see §60.17).

Dry flue gas desulfurization technology means a sulfur dioxide control system that is located downstream of the steam generating unit and removes sulfur oxides from the combustion gases of the steam generating unit by contacting the combustion gases with an alkaline slurry or solution and forming a dry powder material. This definition includes devices where the dry powder material is subsequently converted to another form. Alkaline slurries or solutions used in dry flue gas desulfurization technology include but are not limited to lime and sodium.

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

Emerging technology means any sulfur dioxide control system that is not defined as a conventional technology under this section, and for which the owner or operator of the facility has applied to the Administrator and received approval to operate as an emerging technology under §60.49b(a)(4).

Federally enforceable means all limitations and conditions that are enforceable by the Administrator, including the requirements of 40 CFR parts 60 and 61, requirements within any applicable State Implementation Plan, and any permit requirements established under 40 CFR 52.21 or under 40 CFR 51.18 and 40 CFR 51.24.

Fluidized bed combustion technology means combustion of fuel in a bed or series of beds (including but not limited to bubbling bed units and circulating bed units) of limestone aggregate (or other sorbent materials) in which these materials are forced upward by the flow of combustion air and the gaseous products of combustion.

Fuel pretreatment means a process that removes a portion of the sulfur in a fuel before combustion of the fuel in a steam generating unit.

Full capacity means operation of the steam generating unit at 90 percent or more of the maximum steady-state design heat input capacity.

Heat input means heat derived from combustion of fuel in a steam generating unit and does not include the heat input from preheated combustion air, recirculated flue gases, or exhaust gases from other sources, such as gas turbines, internal combustion engines, kilns, etc.

Heat release rate means the steam generating unit design heat input capacity (in MW or Btu/hour) divided by the furnace volume (in cubic meters or cubic feet); the furnace volume is that volume bounded by the front furnace wall where the burner is located, the furnace side waterwall, and extending to the level just below or in front of the first row of convection pass tubes.

Heat transfer medium means any material that is used to transfer heat from one point to another point.

High heat release rate means a heat release rate greater than 730,000 J/sec-m83 (70,000 Btu/hour-ft83).

Lignite means a type of coal classified as lignite A or lignite B by the American Society of Testing and Materials in ASTM D388-77, Standard Specification for Classification of Coals by Rank (IBR-see §60.17).

Low heat release rate means a heat release rate of 730,000 J/sec-m83 (70,000 Btu/hour-ft83) or less.

Mass-feed stoker steam generating unit means a steam generating unit where solid fuel is introduced directly into a retort or is fed directly onto a grate where it is combusted.

Maximum heat input capacity means the ability of a steam generating unit to combust a stated maximum amount of fuel on a steady state basis, as determined by the physical design and characteristics of the steam generating unit.

Municipal-type solid waste means refuse, more than 50 percent of which is waste consisting of a mixture of paper, wood, yard wastes, food wastes, plastics, leather, rubber, and other combustible materials, and noncombustible materials such as glass and rock.

Natural gas means (1) a naturally occurring mixture of hydrocarbon and nonhydrocarbon gases found in geologic formations beneath the earth's surface, of which the principal constituent is methane; or (2) liquid petroleum gas, as defined by the American Society for Testing and Materials in ASTM D1835-82, ``Standard Specification for Liquid Petroleum Gases'' (IBR-see §60.17).

Noncontinental area means the State of Hawaii, the Virgin Islands, Guam, American Samoa, the Commonwealth of Puerto Rico, or the Northern Mariana Islands.

Oil means crude oil or petroleum or a liquid fuel derived from crude oil or petroleum, including distillate and residual oil.

Petroleum refinery means industrial plants as classified by the Department of Commerce under Standard Industrial Classification (SIC) Code 29.

Potential sulfur dioxide emission rate means the theoretical sulfur dioxide emissions (ng/J, lb/million Btu heat input) that would result from combusting fuel in an uncleaned state and without using emission control systems.

Process heater means a device that is primarily used to heat a material to initiate or promote a chemical reaction in which the material participates as a reactant or catalyst.

Pulverized coal-fired steam generating unit means a steam generating unit in which pulverized coal is introduced into an air stream that carries the coal to the combustion chamber of the steam generating unit where it is fired in suspension. This includes both conventional pulverized coal-fired and micropulverized coal-fired steam generating units.

Residual oil means crude oil, fuel oil numbers 1 and 2 that have a nitrogen content greater than 0.05 weight percent, and all fuel oil numbers 4, 5 and 6, as defined by the American Society of Testing and Materials in ASTM D396-78, Standard Specifications for Fuel Oils (IBR-see §60.17).

Spreader stoker steam generating unit means a steam generating unit in which solid fuel is introduced to the combustion zone by a mechanism that throws the fuel onto a grate from above. Combustion takes place both in suspension and on the grate.

Steam generating unit means a device that combusts any fuel or byproduct/waste to produce steam or to heat water or any other heat transfer medium. This term includes any municipal-type solid waste incinerator with a heat recovery steam generating unit or any steam generating unit that combusts fuel and is part of a cogeneration system or a combined cycle system. This term does not include process heaters as they are defined in this subpart.

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

Very low sulfur oil means an oil that contains no more than 0.5 weight percent sulfur or that, when combusted without sulfur dioxide emission control, has a sulfur dioxide emission rate equal to or less than 215 ng/J (0.5 lb/million Btu) heat input.

Wet flue gas desulfurization technology means a sulfur dioxide control system that is located downstream of the steam generating unit and removes sulfur oxides from the combustion gases of the steam generating unit by contacting the combustion gas with an alkaline slurry or solution and forming a liquid material. This definition applies to devices where the aqueous liquid material product of this contact is subsequently converted to other forms. Alkaline reagents used in wet flue gas desulfurization technology include, but are not limited to, lime, limestone, and sodium.

Wet scrubber system means any emission control device that mixes an aqueous stream or slurry with the exhaust gases from a steam generating unit to control emissions of particulate matter or sulfur dioxide.

Wood means wood, wood residue, bark, or any derivative fuel or residue thereof, in any form, including, but not limited to, sawdust, sanderdust, wood chips, scraps, slabs, millings, shavings, and processed pellets made from wood or other forest residues.

[52 FR 47842, Dec. 16, 1987, as amended at 54 FR 51819, Dec. 18, 1989]

§60.42b Standard for sulfur dioxide.

(a) Except as provided in paragraphs (b), (c), (d), or (j) of this section, on and after the date on which the performance test is completed or required to be completed under §60.8 of this part, whichever date comes first, no owner or operator of an affected facility that combusts coal or oil shall cause to be discharged into the atmosphere any gases that contain sulfur dioxide in excess of 10 percent (0.10) of the potential sulfur dioxide emission rate (90 percent reduction) and that contain sulfur dioxide in excess of the emission limit determined according to the following formula:

$$E_s=(K_aH_a+K_bH_b)/(H_a+H_b)$$

where:
E_s is the sulfur dioxide emission limit, in ng/J or lb/million Btu heat input,
K_a is 520 ng/J (or 1.2 lb/million Btu),
K_b is 340 ng/J (or 0.80 lb/million Btu),
H_a is the heat input from the combustion of coal, in J (million Btu),
H_b is the heat input from the combustion of oil, in J (million Btu).

Only the heat input supplied to the affected facility from the combustion of coal and oil is counted under this section. No credit is provided for the heat input to the affected facility from the combustion of natural gas, wood, municipal-type solid waste, or other fuels or heat input to the affected facility from exhaust gases from another source, such as gas turbines, internal combustion engines, kilns, etc.

(b) On and after the date on which the performance test is completed or required to be completed under §60.8 of this part, whichever comes first, no owner or operator of an affected facility that combusts coal refuse alone in a fluidized bed combustion steam generating unit shall cause to be discharged into the atmosphere any gases that contain sulfur dioxide in excess of 20 percent of the potential sulfur dioxide emission rate (80 percent reduction) and that contain sulfur dioxide in excess of 520 ng/J (1.2 lb/million Btu) heat input. If coal or oil is fired with coal refuse, the affected facility is subject to paragraph (a) or (d) of this section, as applicable.

(c) On and after the date on which the performance test is completed or is required to be completed under §60.8 of this part, whichever comes first, no owner or operator of an affected facility that combusts coal or oil, either alone or in combination with any other fuel, and that uses an emerging technology for the control of sulfur dioxide emissions, shall cause to be discharged into the atmosphere any gases that contain sulfur dioxide in excess of 50 percent of the potential sulfur dioxide emission rate (50 percent reduction) and that contain sulfur dioxide in excess of the emission limit determined according to the following formula:

$$E_s=(K_cH_c+K_dH_d)/H_c+H_d)$$

where:
E_s is the sulfur dioxide emission limit, expressed in ng/J (lb/million Btu) heat input,
K_c is 260 ng/J (0.60 lb/million Btu),
K_d is 170 ng/J (0.40 lb/million Btu),
H_c is the heat input from the combustion of coal, J (million Btu),
H_d is the heat input from the combustion of oil, J (million Btu).

Only the heat input supplied to the affected facility from the combustion of coal and oil is counted under this section. No credit is provided for the heat input to the affected facility from the combustion of natural gas, wood, municipal-type solid waste, or other fuels, or from the heat input to the affected facility from exhaust gases from another source, such as gas turbines, internal combustion engines, kilns, etc.

(d) On and after the date on which the performance test is completed or required to be completed under §60.8 of this part, whichever comes first, no owner or operator of an affected facility listed in paragraphs (d) (1), (2), or (3) of this section shall cause to be discharged into the atmosphere any gases that contain sulfur dioxide in excess of 520 ng/J (1.2 lb/million Btu) heat input if the affected facility combusts coal, or 215 ng/J (0.5 lb/million Btu) heat input if the affected facility combusts oil other than very low sulfur oil. Percent reduction requirements are not applicable to affected facilities under this paragraph.

(1) Affected facilities that have an annual capacity factor for coal and oil of 30 percent (0.30) or less and are subject to a Federally enforceable permit limiting the operation of the affected facility to an annual capacity factor for coal and oil of 30 percent (0.30) or less;

(2) Affected facilities located in a noncontinental area; or

(3) Affected facilities combusting coal or oil, alone or in combination with any other fuel, in a duct burner as part of a combined cycle system where 30 percent (0.30) or less of the heat input to the steam generating unit is from combustion of coal and oil in the duct burner and 70 percent (0.70) or more of the heat input to the steam generating unit is from the exhaust gases entering the duct burner.

(e) Except as provided in paragraph (f) of this section, compliance with the emission limits, fuel oil sulfur limits, and/or percent reduction requirements under this section are determined on a 30-day rolling average basis.

(f) Except as provided in paragraph (j)(2) of this section, compliance with the emission limits or fuel oil sulfur limits under this section is determined on a 24-hour average basis for affected facilities that (1) have a Federally enforceable permit limiting the annual capacity factor for oil to 10 percent or less, (2) combust only very low sulfur oil, and (3) do not combust any other fuel.

(g) Except as provided in paragraph (i) of this section, the sulfur dioxide emission limits and percent reduction requirements under this section apply at all times, including periods of startup, shutdown, and malfunction.

(h) Reductions in the potential sulfur dioxide emission rate through fuel pretreatment are not credited toward the percent reduction requirement under paragraph (c) of this section unless:

(1) Fuel pretreatment results in a 50 percent or greater reduction in potential sulfur dioxide emissions and

(2) Emissions from the pretreated fuel (without combustion or post combustion sulfur dioxide control) are equal to or less than the emission limits specified in paragraph (c) of this section.

(i) An affected facility subject to paragraph (a), (b), or (c) of this section may combust very low sulfur oil or natural gas when the sulfur dioxide control system is not being operated because of malfunction or maintenance of the sulfur dioxide control system.

(j) Percent reduction requirements are not applicable to affected facilities combusting only very low sulfur oil. The owner or operator of an affected facility combusting very low sulfur oil shall demonstrate that the oil meets the definition of very low sulfur oil by: (1) Following the performance testing procedures as described in §60.45b(c) or §60.45b(d), and following the monitoring procedures as described in §60.47b(a) or §60.47b(b) to determine sulfur dioxide emission rate or fuel oil sulfur content; or (2) maintaining fuel receipts as described in §60.49b(r).

[52 FR 47842, Dec. 16, 1987, as amended at 54 FR 51819, Dec. 18, 1989]

§60.43b Standard for particulate matter.

(a) On and after the date on which the initial performance test is completed or is required to be completed under §60.8 of this part, whichever comes first, no owner or operator of an affected facility which combusts coal or combusts mixtures of coal with other fuels, shall cause to be discharged into the atmosphere from that affected facility any gases that contain particulate matter in excess of the following emission limits:

(1) 22 ng/J (0.05 lb/million Btu) heat input,

(i) If the affected facility combusts only coal, or

(ii) If the affected facility combusts coal and other fuels and has an annual capacity factor for the other fuels of 10 percent (0.10) or less.

(2) 43 ng/J (0.10 lb/million Btu) heat input if the affected facility combusts coal and other fuels and has an annual

capacity factor for the other fuels greater than 10 percent (0.10) and is subject to a federally enforceable requirement limiting operation of the affected facility to an annual capacity factor greater than 10 percent (0.10) for fuels other than coal.

(3) 86 ng/J (0.20 lb/million Btu) heat input if the affected facility combusts coal or coal and other fuels and

(i) Has an annual capacity factor for coal or coal and other fuels of 30 percent (0.30) or less,

(ii) Has a maximum heat input capacity of 73 MW (250 million Btu/hour) or less,

(iii) Has a federally enforceable requirement limiting operation of the affected facility to an annual capacity factor of 30 percent (0.30) or less for coal or coal and other solid fuels, and

(iv) Construction of the affected facility commenced after June 19, 1984, and before November 25, 1986.

(b) On and after the date on which the performance test is completed or required to be completed under 60.8 of this part, whichever date comes first, no owner or operator of an affected facility that combusts oil (or mixtures of oil with other fuels) and uses a conventional or emerging technology to reduce sulfur dioxide emissions shall cause to be discharged into the atmosphere from that affected facility any gases that contain particulate matter in excess of 43 ng/J (0.10 lb/million Btu) heat input.

(c) On and after the date on which the initial performance test is completed or is required to be completed under §60.8 of this part, whichever date comes first, no owner or operator of an affected facility that combusts wood, or wood with other fuels, except coal, shall cause to be discharged from that affected facility any gases that contain particulate matter in excess of the following emission limits:

(1) 43 ng/J (0.10 lb/million Btu) heat input if the affected facility has an annual capacity factor greater than 30 percent (0.30) for wood.

(2) 86 ng/J (0.20 lb/million Btu) heat input if

(i) The affected facility has an annual capacity factor of 30 percent (0.30) or less for wood,

(ii) Is subject to a federally enforceable requirement limiting operation of the affected facility to an annual capacity factor of 30 percent (0.30) or less for wood, and

(iii) Has a maximum heat input capacity of 73 MW (250 million Btu/hour) or less.

(d) On and after the date on which the initial performance test is completed or is required to be completed under §60.8 of this part, whichever date comes first, no owner or operator of an affected facility that combusts municipal-type solid waste or mixtures of municipal-type solid waste with other fuels, shall cause to be discharged into the atmosphere from that affected facility any gases that contain particulate matter in excess of the following emission limits:

(1) 43 ng/J (0.10 lb/million Btu) heat input,

(i) If the affected facility combusts only municipal-type solid waste, or

(ii) If the affected facility combusts municipal-type solid waste and other fuels and has an annual capacity factor for the other fuels of 10 percent (0.10) or less.

(2) 86 ng/J (0.20 lb/million Btu) heat input if the affected facility combusts municipal- type solid waste or municipal-type solid waste and other fuels; and

(i) Has an annual capacity factor for municipal-type solid waste and other fuels of 30 percent (0.30) or less,

(ii) Has a maximum heat input capacity of 73 MW (250 million Btu/hour) or less,

(iii) Has a federally enforceable requirement limiting operation of the affected facility to an annual capacity factor of 30 percent (0.30) for municipal-type solid waste, or municipal-type solid waste and other fuels, and

(iv) Construction of the affected facility commenced after June 19, 1984, but before November 25, 1986.

(e) For the purposes of this section, the annual capacity factor is determined by dividing the actual heat input to the steam generating unit during the calendar year from the combustion of coal, wood, or municipal-type solid waste, and other fuels, as applicable, by the potential heat input to the steam generating unit if the steam generating unit had been operated for 8,760 hours at the maximum design heat input capacity.

(f) On and after the date on which the initial performance test is completed or is required to be completed under 60.8 of this part, whichever date comes first, no owner or operator of an affected facility that combusts coal, oil, wood, or mixtures of these fuels with any other fuels shall cause to be discharged into the atmosphere any gases that exhibit greater than 20 percent opacity (6-minute average), except for one 6-minute period per hour of not more than 27 percent opacity.

(g) The particulate matter and opacity standards apply at all times, except during periods of startup, shutdown or malfunction.

[52 FR 47842, Dec. 16, 1987, as amended at 54 FR 51819, Dec. 18, 1989]

§60.44b Standard for nitrogen oxides.

(a) Except as provided under paragraph (k) of this section, on and after the date on which the initial performance test is completed or is required to be completed under §60.8 of this part, whichever date comes first, no owner or operator of an affected facility that is subject to the provisions of this section and that combusts only coal, oil, or natural gas shall cause to be discharged into the atmosphere from that affected facility any gases that contain nitrogen oxides (expressed as NO2) in excess of the following emission limits:

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Fuel/Steam generating unit type	Nitrogen Oxide emission limits ng/J (lb million BTU) (expressed as NO_2) heat input
(1) Natural gas and distillate oil, except (4):	
(i) Low heat release rate	43 (0.10)
(ii) High heat release rate	86 (0.20)
(2) Residual oil:	
(i) Low heat release rate	130 (0.30)
(ii) High heat release rate	170 (0.40)
(3) Coal:	
(i) Mass-feed stoker	210 (0.50)
(ii) Spreader stoker and fluidized bed combustion	260 (0.60)
(iii) Pulverized coal	300 (0.70)
(iv) Lignite, except (v)	260 (0.60)
(v) Lignite mined in North Dakota, South Dakota, or Montana and combusted in a slag tap furnace.	340 (0.80)
(vi) Coal-derived synthetic fuels	210 (0.50)
(4) Duct burner used in a combined cycle system:	
(i) Natural gas and distillate oil	86 (0.20)
(ii) Residual oil	170 (0.40)

(b) Except as provided under paragraph (k) of this section, on and after the date on which the initial performance test is completed or is required to be completed under §60.8 of this part, whichever date comes first, no owner or operator of an affected facility that simultaneously combusts mixtures of coal, oil, or natural gas shall cause to be discharged into the atmosphere from that affected facility any gases that contain nitrogen oxides in excess of a limit determined by use of the following formula:

En=[(ELgo Hgo)+(ELro Hro)+(ELc Hc)]
/(Hgo+Hro+Hc)

where:
En is the nitrogen oxides emission limit (expressed as NO2), ng/J (lb/million Btu) ELgo is the appropriate emission limit from paragraph (a)(1) for combustion of natural gas or distillate oil, ng/J (lb/million Btu)
Hgo is the heat input from combustion of natural gas or distillate oil, ELro is the appropriate emission limit from paragraph (a)(2) for combustion of residual oil,
Hro is the heat input from combustion of residual oil, ELc is the appropriate emission limit from paragraph (a)(3) for combustion of coal, and Hc is the heat input from combustion of coal.

(c) On and after the date on which the initial performance test is completed or is required to be completed under §60.8 of this part, whichever comes first, no owner or operator of an affected facility that simultaneously combusts coal or oil, or a mixture of these fuels with natural gas, and wood, municipal-type solid waste, or any other fuel shall cause to be discharged into the atmosphere any gases that contain nitrogen oxides in excess of the emission limit for the coal or oil, or mixture of these fuels with natural gas combusted in the affected facility, as determined pursuant to paragraph (a) or (b) of this section, unless the affected facility has an annual capacity factor for coal or oil, or mixture of these fuels with natural gas of 10 percent (0.10) or less and is subject to a federally enforceable requirement that limits operation of the facility to an annual capacity factor of 10 percent (0.10) or less for coal, oil, or a mixture of these fuels with natural gas.

(d) On and after the date on which the initial performance test is completed or is required to be completed under §60.8 of this part, whichever date comes first, no owner or operator of an affected facility that simultaneously combusts natural gas with wood, municipal-type solid waste, or other solid fuel, except coal, shall cause to be discharged into the atmosphere from that affected facility any gases that contain nitrogen oxides in excess of 130 ng/J (0.30 lb/million Btu) heat input unless the affected facility has an annual capacity factor for natural gas of 10 percent (0.10) or less and is subject to a federally enforceable requirement that limits operation of the affected facility to an annual capacity factor of 10 percent (0.10) or less for natural gas.

(e) On and after the date on which the initial performance test is completed or is required to be completed under §60.8 of this part, whichever date comes first, no owner or operator of an affected facility that simultaneously combusts coal, oil, or natural gas with byproduct/waste shall cause to be discharged into the atmosphere from that affected facility any gases that contain nitrogen oxides in excess of an emission limit determined by the following formula unless the affected facility has an annual capacity factor for coal, oil, and natural gas of 10 percent (0.10) or less and is subject to a federally enforceable requirement which limits operation of the affected facility to an annual capacity factor of 10 percent (0.10) or less:

$$E_n=[(EL_{go}\ H_{go})+(EL_{ro}\ H_{ro})+(EL_cH_c)]/(H_{go}+H_{ro}+H_c)$$

where:

E_n is the nitrogen oxides emission limit (expressed as NO_2), ng/J (lb/million Btu)

EL_{go} is the appropriate emission limit from paragraph (a)(1) for combustion of natural gas or distillate oil, ng/J (lb/million Btu).

H_{go} is the heat input from combustion of natural gas, distillate oil and gaseous byproduct/waste, ng/J (lb/million Btu).

EL_{ro} is the appropriate emission limit from paragraph (a)(2) for combustion of residual oil, ng/J (lb/million Btu)

H_{ro} is the heat input from combustion of residual oil and/or liquid byproduct/waste.

EL_c is the appropriate emission limit from paragraph (a)(3) for combustion of coal, and

H_c is the heat input from combustion of coal.

(f) Any owner or operator of an affected facility that combusts byproduct/waste with either natural gas or oil may petition the Administrator within 180 days of the initial startup of the affected facility to establish a nitrogen oxides emission limit which shall apply specifically to that affected facility when the byproduct/waste is combusted. The petition shall include sufficient and appropriate data, as determined by the Administrator, such as nitrogen oxides emissions from the affected facility, waste composition (including nitrogen content), and combustion conditions to allow the Administrator to confirm that the affected facility is unable to comply with the emission limits in paragraph (e) of this section and to determine the appropriate emission limit for the affected facility.

(1) Any owner or operator of an affected facility petitioning for a facility-specific nitrogen oxides emission limit under this section shall:

(i) Demonstrate compliance with the emission limits for natural gas and distillate oil in paragraph (a)(1) of this section or for residual oil in paragraph (a)(2) of this section, as appropriate, by conducting a 30-day performance test as provided in §60.46b(e). During the performance test only natural gas, distillate oil, or residual oil shall be combusted in the affected facility; and

(ii) Demonstrate that the affected facility is unable to comply with the emission limits for natural gas and distillate oil in paragraph (a)(1) of this section or for residual oil in paragraph (a)(2) of this section, as appropriate, when gaseous or liquid byproduct/waste is combusted in the affected facility under the same conditions and using the same technological system of emission reduction applied when demonstrating compliance under paragraph (f)(1)(i) of this section.

(2) The nitrogen oxides emission limits for natural gas or distillate oil in paragraph (a)(1) of this section or for residual oil in paragraph (a)(2) of this section, as appropriate, shall be applicable to the affected facility until and unless the petition is approved by the Administrator. If the petition is approved by the Administrator, a facility-specific nitrogen oxides emission limit will be established at the nitrogen oxides emission level achievable when the affected facility is combusting oil or natural gas and byproduct/waste in a manner that the Administrator determines to be consistent with minimizing nitrogen oxides emissions.

(g) Any owner or operator of an affected facility that combusts hazardous waste (as defined by 40 CFR part 261 or 40 CFR part 761) with natural gas or oil may petition the Administrator within 180 days of the initial startup of the affected facility for a waiver from compliance with the nitrogen oxides emission limit which applies specifically to that affected facility. The petition must include sufficient and appropriate data, as determined by the Administrator, on nitrogen oxides emissions from the affected facility, waste destruction efficiencies, waste composition (including nitrogen content), the quantity of specific wastes to be combusted and combustion conditions to allow the Administrator to determine if the affected facility is able to comply with the nitrogen oxides emission limits required by this section. The owner or operator of the affected facility shall demonstrate that when hazardous waste is combusted in the affected facility, thermal destruction efficiency requirements for hazardous waste specified in an applicable federally enforceable requirement preclude compliance with the nitrogen oxides emission limits of this section. The nitrogen oxides emission limits for natural gas or distillate oil in paragraph (a)(1) of this section or for residual oil in paragraph (a)(2) of this section, as appropriate, are applicable to the affected facility until and unless the petition is approved by the Administrator. (See 40 CFR 761.70 for regulations applicable to the incineration of materials containing polychlorinated biphenyls (PCB's).)

(h) For purposes of paragraph (i) of this section, the nitrogen oxide standards under this section apply at all times including periods of startup, shutdown, or malfunction.

(i) Except as provided under paragraph (j) of this section, compliance with the emission limits under this section is determined on a 30-day rolling average basis.

(j) Compliance with the emission limits under this section is determined on a 24-hour average basis for the initial performance test and on a 3-hour average basis for subsequent performance tests for any affected facilities that:

(1) Combust, alone or in combination, only natural gas, distillate oil, or residual oil with a nitrogen content of 0.30 weight percent or less;

(2) Have a combined annual capacity factor of 10 percent or less for natural gas, distillate oil, and residual oil with a nitrogen content of 0.30 weight percent or less; and

(3) Are subject to a Federally enforceable requirement limiting operation of the affected facility to the firing of natural gas, distillate oil, and/or residual oil with a nitrogen content of 0.30 weight percent or less and limiting operation of the affected facility to a combined annual capacity factor of 10 percent or less for natural gas, distillate oil, and residual oil and a nitrogen content of 0.30 weight percent or less.

(k) Affected facilities that meet the criteria described in paragraphs (j) (1), (2), and (3) of this section, and that have a heat input capacity of 73 MW (250 million Btu/hour) or less, are not subject to the nitrogen oxides emission limits under this section.

[52 FR 47842, Dec. 16, 1987, as amended at 54 FR 51825, Dec. 18, 1989]

§60.45b Compliance and performance test methods and procedures for sulfur dioxide.

(a) The sulfur dioxide emission standards under §60.42b apply at all times.

(b) In conducting the performance tests required under §60.8, the owner or operator shall use the methods and procedures in appendix A of this part or the methods and procedures as specified in this section, except as provided in §60.8(b). Section 60.8(f) does not apply to this section. The 30-day notice required in §60.8(d) applies only to the initial performance test unless otherwise specified by the Administrator.

(c) The owner or operator of an affected facility shall conduct performance tests to determine compliance with the percent of potential sulfur dioxide emission rate (% Ps) and the sulfur dioxide emission rate (Es) pursuant to §60.42b following the procedures listed below, except as provided under paragraph (d) of this section.

(1) The initial performance test shall be conducted over the first 30 consecutive operating days of the steam generating unit. Compliance with the sulfur dioxide standards shall be determined using a 30-day average. The first operating day included in the initial performance test shall be scheduled within 30 days after achieving the maximum production rate at which the affected facility will be operated, but not later than 180 days after initial startup of the facility.

(2) If only coal or only oil is combusted, the following procedures are used:

(i) The procedures in Method 19 are used to determine the hourly sulfur dioxide emission rate (Eho) and the 30-day average emission rate (Eao). The hourly averages used to compute the 30-day averages are obtained from the continuous emission monitoring system of §60.47b (a) or (b).

(ii) The percent of potential sulfur dioxide emission rate (% Ps) emitted to the atmosphere is computed using the following formula:

$$\% P_s = 100 (1 - \% R_g/100)(1 - \% R_f/100)$$

where:

% Rg is the sulfur dioxide removal efficiency of the control device as determined by Method 19, in percent.

% Rf is the sulfur dioxide removal efficiency of fuel pretreatment as determined by Method 19, in percent.

(3) If coal or oil is combusted with other fuels, the same procedures required in paragraph (c)(2) of this section are used, except as provided in the following:

(i) An adjusted hourly sulfur dioxide emission rate (Ehoo) is used in Equation 19-19 of Method 19 to compute an adjusted 30-day average emission rate (Eaoo). The Eho is computed using the following formula:

$$E_{hoo} = [E_{ho} - E_w(1 - X_k)]/X_k$$

where:

Ehoo is the adjusted hourly sulfur dioxide emission rate, ng/J (lb/million Btu).

Eho is the hourly sulfur dioxide emission rate, ng/J (lb/million Btu).

Ew is the sulfur dioxide concentration in fuels other than coal and oil combusted in the affected facility, as determined by the fuel sampling and analysis procedures in Method 19, ng/J (lb/million Btu). The value Ew for each fuel lot is used for each hourly average during the time that the lot is being combusted.

Xk is the fraction of total heat input from fuel combustion derived from coal, oil, or coal and oil, as determined by applicable procedures in Method 19.

(ii) To compute the percent of potential sulfur dioxide emission rate (% Ps), an adjusted % Rg (% Rgo) is computed from the adjusted Eaoo from paragraph (b)(3)(i) of this section and an adjusted average sulfur dioxide inlet rate (Eaio) using the following formula:

% Rgo=100 (1.0-Eaoo/Eaio)

To compute Eaio, an adjusted hourly sulfur dioxide inlet rate (Ehio) is used. The Ehio is computed using the following formula:

Ehio=[Ehi-Ew(1-Xk)]/Xk
where:
Ehio is the adjusted hourly sulfur dioxide inlet rate, ng/J (lb/million Btu).
Ehi is the hourly sulfur dioxide inlet rate, ng/J (lb/million Btu).

(4) The owner or operator of an affected facility subject to paragraph (b)(3) of this section does not have to measure parameters Ew or Xk if the owner or operator elects to assume that Xk=1.0. Owners or operators of affected facilities who assume Xk=1.0 shall

(i) Determine % Ps following the procedures in paragraph (c)(2) of this section, and

(ii) Sulfur dioxide emissions (Es) are considered to be in compliance with sulfur dioxide emission limits under §60.42b.

(5) The owner or operator of an affected facility that qualifies under the provisions of §60.42b(d) does not have to measure parameters Ew or Xk under paragraph (b)(3) of this section if the owner or operator of the affected facility elects to measure sulfur dioxide emission rates of the coal or oil following the fuel sampling and analysis procedures under Method 19.

(d) Except as provided in paragraph (j), the owner or operator of an affected facility that combusts only very low sulfur oil, has an annual capacity factor for oil of 10 percent (0.10) or less, and is subject to a Federally enforceable requirement limiting operation of the affected facility to an annual capacity factor for oil of 10 percent (0.10) or less shall:

(1) Conduct the initial performance test over 24 consecutive steam generating unit operating hours at full load;

(2) Determine compliance with the standards after the initial performance test based on the arithmetic average of the hourly emissions data during each steam generating unit operating day if a continuous emission measurement system (CEMS) is used, or based on a daily average if Method 6B or fuel sampling and analysis procedures under Method 19 are used.

(e) The owner or operator of an affected facility subject to §60.42b(d)(1) shall demonstrate the maximum design capacity of the steam generating unit by operating the facility at maximum capacity for 24 hours. This demonstration will be made during the initial performance test and a subsequent demonstration may be requested at any other time. If the 24-hour average firing rate for the affected facility is less than the maximum design capacity provided by the manufacturer of the affected facility, the 24-hour average firing rate shall be used to determine the capacity utilization rate for the affected facility, otherwise the maximum design capacity provided by the manufacturer is used.

(f) For the initial performance test required under §60.8, compliance with the sulfur dioxide emission limits and percent reduction requirements under §60.42b is based on the average emission rates and the average percent reduction for sulfur dioxide for the first 30 consecutive steam generating unit operating days, except as provided under paragraph (d) of this section. The initial performance test is the only test for which at least 30 days prior notice is required unless otherwise specified by the Administrator. The initial performance test is to be scheduled so that the first steam generating unit operating day of the 30 successive steam generating unit operating days is completed within 30 days after achieving the maximum production rate at which the affected facility will be operated, but not later than 180 days after initial startup of the facility. The boiler load during the 30-day period does not have to be the maximum design load, but must be representative of future operating conditions and include at least one 24-hour period at full load.

(g) After the initial performance test required under §60.8, compliance with the sulfur dioxide emission limits and percent reduction requirements under §60.42b is based on the average emission rates and the average percent reduction for sulfur dioxide for 30 successive steam generating unit operating days, except as provided under paragraph (d). A separate performance test is completed at the end of each steam generating unit operating day after the initial performance test, and a new 30-day average emission rate and percent reduction for sulfur dioxide are calculated to show compliance with the standard.

(h) Except as provided under paragraph (i) of this section, the owner or operator of an affected facility shall use all valid sulfur dioxide emissions data in calculating % Ps and Eho under paragraph (c), of this section whether or not the minimum emissions data requirements under §60.46b are achieved. All valid emissions data, including valid sulfur dioxides emission data collected during periods of startup, shutdown and malfunction, shall be used in calculating % Ps and Eho pursuant to paragraph (c) of this section.

(i) During periods of malfunction or maintenance of the sulfur dioxide control systems when oil is combusted as provided under §60.42b(i), emission data are not used to calculate % Ps or Es under §60.42b (a), (b) or (c), however, the emissions data are used to determine compliance with the emission limit under §60.42b(i).

(j) The owner or operator of an affected facility that combusts very low sulfur oil is not subject to the compliance and performance testing requirements of this section if the owner or operator obtains fuel receipts as described in §60.49b(r).

[52 FR 47842, Dec. 16, 1987, as amended at 54 FR 51820, 51825, Dec. 18, 1989]

§60.46b Compliance and performance test methods and procedures for particulate matter and nitrogen oxides.

(a) The particulate matter emission standards and opacity limits under §60.43b apply at all times except during periods of startup, shutdown, or malfunction. The nitrogen oxides emission standards under §60.44b apply at all times.

(b) Compliance with the particulate matter emission standards under §60.43b shall be determined through performance testing as described in paragraph (d) of this section.

(c) Compliance with the nitrogen oxides emission standards under §60.44b shall be determined through performance testing under paragraph (e) or (f), or under paragraphs (g) and (h) of this section, as applicable.

(d) To determine compliance with the particulate matter emission limits and opacity limits under §60.43b, the owner or operator of an affected facility shall conduct an initial performance test as required under §60.8 using the following procedures and reference methods:

(1) Method 3B is used for gas analysis when applying Method 5 or Method 17.

(2) Method 5, Method 5B, or Method 17 shall be used to measure the concentration of particulate matter as follows:

(i) Method 5 shall be used at affected facilities without wet flue gas desulfurization (FGD) systems; and

(ii) Method 17 may be used at facilities with or without wet scrubber systems provided the stack gas temperature does not exceed a temperature of 160 EC (320 EF). The procedures of sections 2.1 and 2.3 of Method 5B may be used in Method 17 only if it is used after a wet FGD system. Do not use Method 17 after wet FGD systems if the effluent is saturated or laden with water droplets.

(iii) Method 5B is to be used only after wet FGD systems.

(3) Method 1 is used to select the sampling site and the number of traverse sampling points. The sampling time for each run is at least 120 minutes and the minimum sampling volume is 1.7 dscm (60 dscf) except that smaller sampling times or volumes may be approved by the Administrator when necessitated by process variables or other factors.

(4) For Method 5, the temperature of the sample gas in the probe and filter holder is monitored and is maintained at 160EC (320EF).

(5) For determination of particulate matter emissions, the oxygen or carbon dioxide sample is obtained simultaneously with each run of Method 5, Method 5B or Method 17 by traversing the duct at the same sampling location.

(6) For each run using Method 5, Method 5B or Method 17, the emission rate expressed in nanograms per joule heat input is determined using:

(i) The oxygen or carbon dioxide measurements and particulate matter measurements obtained under this section,

(ii) The dry basis F factor, and

(iii) The dry basis emission rate calculation procedure contained in Method 19 (appendix A).

(7) Method 9 is used for determining the opacity of stack emissions.

(e) To determine compliance with the emission limits for nitrogen oxides required under §60.44b, the owner or operator of an affected facility shall conduct the performance test as required under §60.8 using the continuous system for monitoring nitrogen oxides under §60.48(b).

(1) For the initial compliance test, nitrogen oxides from the steam generating unit are monitored for 30 successive steam generating unit operating days and the 30-day average emission rate is used to determine compliance with the nitrogen oxides emission standards under §60.44b. The 30-day average emission rate is calculated as the average of all hourly emissions data recorded by the monitoring system during the 30-day test period.

(2) Following the date on which the initial performance test is completed or is required to be completed under §60.8 of this part, whichever date comes first, the owner or operator of an affected facility which combusts coal or which combusts residual oil having a nitrogen content greater than 0.30 weight percent shall determine compliance with the nitrogen oxides emission standards under §60.44b on a continuous basis through the use of a 30-day rolling average emission rate. A new 30-day rolling average emission rate is calculated each steam generating unit operating day as the average of all of the hourly nitrogen oxides emission data for the preceding 30 steam generating unit operating days.

(3) Following the date on which the initial performance test is completed or is required to be completed under §60.8 of this part, whichever date comes first, the owner or operator of an affected facility which has a heat input capacity greater than 73 MW (250 million Btu/hour) and which combusts natural gas, distillate oil, or residual oil having a nitrogen content of 0.30 weight percent or less shall determine compliance with the nitrogen oxides standards under §60.44b on a continuous basis through the use of a 30-day rolling average emission rate. A new 30-day rolling average emission rate is calculated each steam generating unit operating day as the average of all of the hourly nitrogen oxides emission data for the preceding 30 steam generating unit operating days.

(4) Following the date on which the initial performance test is completed or required to be completed under §60.8 of this part, whichever date comes first, the owner

or operator of an affected facility which has a heat input capacity of 73 MW (250 million Btu/hour) or less and which combusts natural gas, distillate oil, or residual oil having a nitrogen content of 0.30 weight percent or less shall upon request determine compliance with the nitrogen oxides standards under §60.44b through the use of a 30-day performance test. During periods when performance tests are not requested, nitrogen oxides emissions data collected pursuant to §60.48b(g)(1) or §60.48b(g)(2) are used to calculate a 30-day rolling average emission rate on a daily basis and used to prepare excess emission reports, but will not be used to determine compliance with the nitrogen oxides emission standards. A new 30-day rolling average emission rate is calculated each steam generating unit operating day as the average of all of the hourly nitrogen oxides emission data for the preceding 30 steam generating unit operating days.

(5) If the owner or operator of an affected facility which combusts residual oil does not sample and analyze the residual oil for nitrogen content, as specified in §60.49b(e), the requirements of paragraph (iii) of this section apply and the provisions of paragraph (iv) of this section are inapplicable.

(f) To determine compliance with the emission limit for nitrogen oxides required by §60.44b(a)(4) for duct burners used in combined cycle systems, the owner or operator of an affected facility shall conduct the performance test required under §60.8 using the nitrogen oxides and oxygen measurement procedures in 40 CFR part 60 appendix A, Method 20. During the performance test, one sampling site shall be located as close as practicable to the exhaust of the turbine, as provided by section 6.1.1 of Method 20. A second sampling site shall be located at the outlet to the steam generating unit. Measurements of nitrogen oxides and oxygen shall be taken at both sampling sites during the performance test. The nitrogen oxides emission rate from the combined cycle system shall be calculated by subtracting the nitrogen oxides emission rate measured at the sampling site at the outlet from the turbine from the nitrogen oxides emission rate measured at the sampling site at the outlet from the steam generating unit.

(g) The owner or operator of an affected facility described in §60.44b(j) or §60.44b(k) shall demonstrate the maximum heat input capacity of the steam generating unit by operating the facility at maximum capacity for 24 hours. The owner or operator of an affected facility shall determine the maximum heat input capacity using the heat loss method described in sections 5 and 7.3 of the ASME Power Test Codes 4.1 (see IBR §60.17(h)). This demonstration of maximum heat input capacity shall be made during the initial performance test for affected facilities that meet the criteria of §60.44b(j). It shall be made within 60 days after achieving the maximum production rate at which the affected facility will be operated, but not later than 180 days after initial start-up of each facility, for affected facilities meeting the criteria of §60.44b(k). Subsequent demonstrations may be required by the Administrator at any other time. If this demonstration indicates that the maximum heat input capacity of the affected facility is less than that stated by the manufacturer of the affected facility, the maximum heat input capacity determined during this demonstration shall be used to determine the capacity utilization rate for the affected facility. Otherwise, the maximum heat input capacity provided by the manufacturer is used.

(h) The owner or operator of an affected facility described in §60.44b(j) that has a heat input capacity greater than 73 MW (250 million Btu/hour) shall:

(1) Conduct an initial performance test as required under §60.8 over a minimum of 24 consecutive steam generating unit operating hours at maximum heat input capacity to demonstrate compliance with the nitrogen oxides emission standards under §60.44b using Method 7, 7A, 7E, or other approved reference methods; and

(2) Conduct subsequent performance tests once per calendar year or every 400 hours of operation (whichever comes first) to demonstrate compliance with the nitrogen oxides emission standards under §60.44b over a minimum of 3 consecutive steam generating unit operating hours at maximum heat input capacity using Method 7, 7A, 7E, or other approved reference methods.

[52 FR 47842, Dec. 16, 1987, as amended at 54 FR 51820, 51825, Dec. 18, 1989; 55 FR 18876, May 7, 1990]

§60.47b Emission monitoring for sulfur dioxide.

(a) Except as provided in paragraphs (b) and (f) of this section, the owner or operator of an affected facility subject to the sulfur dioxide standards under §60.42b shall install, calibrate, maintain, and operate continuous emission monitoring systems (CEMS) for measuring sulfur dioxide concentrations and either oxygen (O2) or carbon dioxide (CO2) concentrations and shall record the output of the systems. The sulfur dioxide and either oxygen or carbon dioxide concentrations shall both be monitored at the inlet and outlet of the sulfur dioxide control device.

(b) As an alternative to operating CEMS as required under paragraph (a) of this section, an owner or operator may elect to determine the average sulfur dioxide emissions and percent reduction by:

(1) Collecting coal or oil samples in an as-fired condition at the inlet to the steam generating unit and analyzing them for sulfur and heat content according to Method 19. Method 19 provides procedures for converting these measurements into the format to be used in calculating the average sulfur dioxide input rate, or

(2) Measuring sulfur dioxide according to Method 6B at the inlet or outlet to the sulfur dioxide control system. An initial stratification test is required to verify the

adequacy of the Method 6B sampling location. The stratification test shall consist of three paired runs of a suitable sulfur dioxide and carbon dioxide measurement train operated at the candidate location and a second similar train operated according to the procedures in section 3.2 and the applicable procedures in section 7 of Performance Specification 2. Method 6B, Method 6A, or a combination of Methods 6 and 3 or 3B or Methods 6C and 3A are suitable measurement techniques. If Method 6B is used for the second train, sampling time and timer operation may be adjusted for the stratification test as long as an adequate sample volume is collected; however, both sampling trains are to be operated similarly. For the location to be adequate for Method 6B 24-hour tests, the mean of the absolute difference between the three paired runs must be less than 10 percent.

(3) A daily sulfur dioxide emission rate, ED, shall be determined using the procedure described in Method 6A, section 7.6.2 (Equation 6A-8) and stated in ng/J (lb/million Btu) heat input.

(4) The mean 30-day emission rate is calculated using the daily measured values in ng/J (lb/million Btu) for 30 successive steam generating unit operating days using equation 19-20 of Method 19.

(c) The owner or operator of an affected facility shall obtain emission data for at least 75 percent of the operating hours in at least 22 out of 30 successive boiler operating days. If this minimum data requirement is not met with a single monitoring system, the owner or operator of the affected facility shall supplement the emission data with data collected with other monitoring systems as approved by the Administrator or the reference methods and procedures as described in paragraph (b) of this section.

(d) The 1-hour average sulfur dioxide emission rates measured by the CEMS required by paragraph (a) of this section and required under §60.13(h) is expressed in ng/J or lb/million Btu heat input and is used to calculate the average emission rates under §60.42b. Each 1-hour average sulfur dioxide emission rate must be based on more than 30 minutes of steam generating unit operation and include at least 2 data points with each representing a 15-minute period. Hourly sulfur dioxide emission rates are not calculated if the affected facility is operated less than 30 minutes in a 1-hour period and are not counted toward determination of a steam generating unit operating day.

(e) The procedures under §60.13 shall be followed for installation, evaluation, and operation of the CEMS.

(1) All CEMS shall be operated in accordance with the applicable procedures under Performance Specifications 1, 2, and 3 (appendix B).

(2) Quarterly accuracy determinations and daily calibration drift tests shall be performed in accordance with Procedure 1 (appendix F).

(3) For affected facilities combusting coal or oil, alone or in combination with other fuels, the span value of the sulfur dioxide CEMS at the inlet to the sulfur dioxide control device is 125 percent of the maximum estimated hourly potential sulfur dioxide emissions of the fuel combusted, and the span value of the CEMS at the outlet to the sulfur dioxide control device is 50 percent of the maximum estimated hourly potential sulfur dioxide emissions of the fuel combusted.

(f) The owner or operator of an affected facility that combusts very low sulfur oil is not subject to the emission monitoring requirements of this section if the owner or operator obtains fuel receipts as described in §60.49b(r).

[52 FR 47842, Dec. 16, 1987, as amended at 54 FR 51820, Dec. 18, 1989; 55 FR 5212, Feb. 14, 1990; 55 FR 18876, May 7, 1990]

§60.48b Emission monitoring for particulate matter and nitrogen oxides.

(a) The owner or operator of an affected facility subject to the opacity standard under §60.43b shall install, calibrate, maintain, and operate a continuous monitoring system for measuring the opacity of emissions discharged to the atmosphere and record the output of the system.

(b) Except as provided under paragraphs (g), (h), and (i) of this section, the owner or operator of an affected facility subject to the nitrogen oxides standards under §60.44b shall install, calibrate, maintain, and operate a continuous monitoring system for measuring nitrogen oxides emissions discharged to the atmosphere and record the output of the system.

(c) The continuous monitoring systems required under paragraph (b) of this section shall be operated and data recorded during all periods of operation of the affected facility except for continuous monitoring system breakdowns and repairs. Data is recorded during calibration checks, and zero and span adjustments.

(d) The 1-hour average nitrogen oxides emission rates measured by the continuous nitrogen oxides monitor required by paragraph (b) of this section and required under §60.13(h) shall be expressed in ng/J or lb/million Btu heat input and shall be used to calculate the average emission rates under §60.44b. The 1-hour averages shall be calculated using the data points required under §60.13(b). At least 2 data points must be used to calculate each 1-hour average.

(e) The procedures under §60.13 shall be followed for installation, evaluation, and operation of the continuous monitoring systems.

(1) For affected facilities combusting coal, wood or municipal-type solid waste, the span value for a continuous monitoring system for measuring opacity shall be between 60 and 80 percent.

(2) For affected facilities combusting coal, oil, or natural gas, the span value for nitrogen oxides is determined as follows:

Fuel	Span values for nitrogen oxides (PPM)
Natural gas	500
Oil	500
Coal	1,000
Mixtures	500(x+y)+1,000z

where:
x is the fraction of total heat input derived from natural gas,
y is the fraction of total heat input derived from oil, and
z is the fraction of total heat input derived from coal.

(3) All span values computed under paragraph (e)(2) of this section for combusting mixtures of regulated fuels are rounded to the nearest 500 ppm.

(f) When nitrogen oxides emission data are not obtained because of continuous monitoring system breakdowns, repairs, calibration checks and zero and span adjustments, emission data will be obtained by using standby monitoring systems, Method 7, Method 7A, or other approved reference methods to provide emission data for a minimum of 75 percent of the operating hours in each steam generating unit operating day, in at least 22 out of 30 successive steam generating unit operating days.

(g) The owner or operator of an affected facility that has a heat input capacity of 73 MW (250 million Btu/hour) or less, and which has an annual capacity factor for residual oil having a nitrogen content of 0.30 weight percent or less, natural gas, distillate oil, or any mixture of these fuels, greater than 10 percent (0.10) shall:

(1) Comply with the provisions of paragraphs (b), (c), (d), (e)(2), (e)(3), and (f) of this section, or

(2) Monitor steam generating unit operating conditions and predict nitrogen oxides emission rates as specified in a plan submitted pursuant to §60.49b(c).

(h) The owner or operator of an affected facility which is subject to the nitrogen oxides standards of §60.44b(a)(4) is not required to install or operate a continuous monitoring system to measure nitrogen oxides emissions.

(i) The owner or operator of an affected facility described in §60.44b(j) or §60.44b(k) is not required to install or operate a continuous monitoring system for measuring nitrogen oxides emissions.

[52 FR 47842, Dec. 16, 1987, as amended at 54 FR 51825, Dec. 18, 1989]

§60.49b Reporting and recordkeeping requirements.

(a) The owner or operator of each affected facility shall submit notification of the date of initial startup, as provided by §60.7. This notification shall include:

(1) The design heat input capacity of the affected facility and identification of the fuels to be combusted in the affected facility,

(2) If applicable, a copy of any Federally enforceable requirement that limits the annual capacity factor for any fuel or mixture of fuels under §§60.42b(d)(1), 60.43b(a)(2), (a)(3)(iii), (c)(2)(ii), (d)(2)(iii), 60.44b(c), (d), (e), (i), (j), (k), 60.45b(d), (g), 60.46b(h), or 60.48b(i),

(3) The annual capacity factor at which the owner or operator anticipates operating the facility based on all fuels fired and based on each individual fuel fired, and,

(4) Notification that an emerging technology will be used for controlling emissions of sulfur dioxide. The Administrator will examine the description of the emerging technology and will determine whether the technology qualifies as an emerging technology. In making this determination, the Administrator may require the owner or operator of the affected facility to submit additional information concerning the control device. The affected facility is subject to the provisions of §60.42b(a) unless and until this determination is made by the Administrator.

(b) The owner or operator of each affected facility subject to the sulfur dioxide, particulate matter, and/or nitrogen oxides emission limits under §§60.42b, 60.43b, and 60.44b shall submit to the Administrator the performance test data from the initial performance test and the performance evaluation of the CEMS using the applicable performance specifications in appendix B. The owner or operator of each affected facility described in §60.44b(j) or §60.44b(k) shall submit to the Administrator the maximum heat input capacity data from the demonstration of the maximum heat input capacity of the affected facility.

(c) The owner or operator of each affected facility subject to the nitrogen oxides standard of §60.44b who seeks to demonstrate compliance with those standards through the monitoring of steam generating unit operating conditions under the provisions of §60.48b(g)(2) shall submit to the Administrator for approval a plan that identifies the operating conditions to be monitored under §60.48b(g)(2) and the records to be maintained under §60.49b(j). This plan shall be submitted to the Administrator for approval within 360 days of the initial startup of the affected facility. The plan shall:

(1) Identify the specific operating conditions to be monitored and the relationship between these operating conditions and nitrogen oxides emission rates (i.e., ng/J or lbs/million Btu heat input). Steam generating unit operating conditions include, but are not limited to, the degree of staged combustion (i.e., the ratio of primary air to secondary and/or tertiary air) and the level of excess air (i.e., flue gas oxygen level);

(2) Include the data and information that the owner or operator used to identify the relationship between

nitrogen oxides emission rates and these operating conditions;

(3) Identify how these operating conditions, including steam generating unit load, will be monitored under §60.48b(g) on an hourly basis by the owner or operator during the period of operation of the affected facility; the quality assurance procedures or practices that will be employed to ensure that the data generated by monitoring these operating conditions will be representative and accurate; and the type and format of the records of these operating conditions, including steam generating unit load, that will be maintained by the owner or operator under §60.49b(j).

If the plan is approved, the owner or operator shall maintain records of predicted nitrogen oxide emission rates and the monitored operating conditions, including steam generating unit load, identified in the plan.

(d) The owner or operator of an affected facility shall record and maintain records of the amounts of each fuel combusted during each day and calculate the annual capacity factor individually for coal, distillate oil, residual oil, natural gas, wood, and municipal-type solid waste for each calendar quarter. The annual capacity factor is determined on a 12-month rolling average basis with a new annual capacity factor calculated at the end of each calendar month.

(e) For an affected facility that combusts residual oil and meets the criteria under §§60.46b(e)(4), 60.44b(j), or (k), the owner or operator shall maintain records of the nitrogen content of the residual oil combusted in the affected facility and calculate the average fuel nitrogen content on a per calendar quarter basis. The nitrogen content shall be determined using ASTM Method D3431-80, Test Method for Trace Nitrogen in Liquid Petroleum Hydrocarbons (IBR-see §60.17), or fuel suppliers. If residual oil blends are being combusted, fuel nitrogen specifications may be prorated based on the ratio of residual oils of different nitrogen content in the fuel blend.

(f) For facilities subject to the opacity standard under §60.43b, the owner or operator shall maintain records of opacity.

(g) Except as provided under paragraph (p) of this section, the owner or operator of an affected facility subject to the nitrogen oxides standards under §60.44b shall maintain records of the following information for each steam generating unit operating day:

(1) Calendar date.

(2) The average hourly nitrogen oxides emission rates (expressed as $NO2$) (ng/J or lb/million Btu heat input) measured or predicted.

(3) The 30-day average nitrogen oxides emission rates (ng/J or lb/million Btu heat input) calculated at the end of each steam generating unit operating day from the measured or predicted hourly nitrogen oxide emission rates for the preceding 30 steam generating unit operating days.

(4) Identification of the steam generating unit operating days when the calculated 30-day average nitrogen oxides emission rates are in excess of the nitrogen oxides emissions standards under §60.44b, with the reasons for such excess emissions as well as a description of corrective actions taken.

(5) Identification of the steam generating unit operating days for which pollutant data have not been obtained, including reasons for not obtaining sufficient data and a description of corrective actions taken.

(6) Identification of the times when emission data have been excluded from the calculation of average emission rates and the reasons for excluding data.

(7) Identification of ``F'' factor used for calculations, method of determination, and type of fuel combusted.

(8) Identification of the times when the pollutant concentration exceeded full span of the continuous monitoring system.

(9) Description of any modifications to the continuous monitoring system that could affect the ability of the continuous monitoring system to comply with Performance Specification 2 or 3.

(10) Results of daily CEMS drift tests and quarterly accuracy assessments as required under appendix F, Procedure 1.

(h) The owner or operator of any affected facility in any category listed in paragraphs (h)(1) or (2) of this section is required to submit excess emission reports for any calendar quarter during which there are excess emissions from the affected facility. If there are no excess emissions during the calendar quarter, the owner or operator shall submit a report semiannually stating that no excess emissions occurred during the semiannual reporting period.

(1) Any affected facility subject to the opacity standards under §60.43b(e) or to the operating parameter monitoring requirements under §60.13(i)(1).

(2) Any affected facility that is subject to the nitrogen oxides standard of §60.44b, and that

(i) Combusts natural gas, distillate oil, or residual oil with a nitrogen content of 0.3 weight percent or less, or

(ii) Has a heat input capacity of 73 MW (250 million Btu/hour) or less and is required to monitor nitrogen oxides emissions on a continuous basis under §60.48b(g)(1) or steam generating unit operating conditions under §60.48b(g)(2).

(3) For the purpose of §60.43b, excess emissions are defined as all 6-minute periods during which the average opacity exceeds the opacity standards under §60.43b(f).

(4) For purposes of §60.48b(g)(1), excess emissions are defined as any calculated 30-day rolling average nitrogen oxides emission rate, as determined under §60.46b(e), which exceeds the applicable emission limits in §60.44b.

(i) The owner or operator of any affected facility subject to the continuous monitoring requirements for nitrogen oxides under §60.48(b) shall submit a quarterly report containing the information recorded under paragraph (g) of this section. All quarterly reports shall be postmarked by the 30th day following the end of each calendar quarter.

(j) The owner or operator of any affected facility subject to the sulfur dioxide standards under §60.42b shall submit written reports to the Administrator for every calendar quarter. All quarterly reports shall be postmarked by the 30th day following the end of each calendar quarter.

(k) For each affected facility subject to the compliance and performance testing requirements of §60.45b and the reporting requirement in paragraph (j) of this section, the following information shall be reported to the Administrator:

(1) Calendar dates covered in the reporting period.

(2) Each 30-day average sulfur dioxide emission rate (ng/J or lb/million Btu heat input) measured during the reporting period, ending with the last 30-day period in the quarter; reasons for noncompliance with the emission standards; and a description of corrective actions taken.

(3) Each 30-day average percent reduction in sulfur dioxide emissions calculated during the reporting period, ending with the last 30-day period in the quarter; reasons for noncompliance with the emission standards; and a description of corrective actions taken.

(4) Identification of the steam generating unit operating days that coal or oil was combusted and for which sulfur dioxide or diluent (oxygen or carbon dioxide) data have not been obtained by an approved method for at least 75 percent of the operating hours in the steam generating unit operating day; justification for not obtaining sufficient data; and description of corrective action taken.

(5) Identification of the times when emissions data have been excluded from the calculation of average emission rates; justification for excluding data; and description of corrective action taken if data have been excluded for periods other than those during which coal or oil were not combusted in the steam generating unit.

(6) Identification of ``F'' factor used for calculations, method of determination, and type of fuel combusted.

(7) Identification of times when hourly averages have been obtained based on manual sampling methods.

(8) Identification of the times when the pollutant concentration exceeded full span of the CEMS.

(9) Description of any modifications to the CEMS that could affect the ability of the CEMS to comply with Performance Specification 2 or 3.

(10) Results of daily CEMS drift tests and quarterly accuracy assessments as required under appendix F, Procedure 1.

(11) The annual capacity factor of each fired as provided under paragraph (d) of this section.

(l) For each affected facility subject to the compliance and performance testing requirements of §60.45b(d) and the reporting requirements of paragraph (j) of this section, the following information shall be reported to the Administrator:

(1) Calendar dates when the facility was in operation during the reporting period;

(2) The 24-hour average sulfur dioxide emission rate measured for each steam generating unit operating day during the reporting period that coal or oil was combusted, ending in the last 24-hour period in the quarter; reasons for noncompliance with the emission standards; and a description of corrective actions taken;

(3) Identification of the steam generating unit operating days that coal or oil was combusted for which sulfur dioxide or diluent (oxygen or carbon dioxide) data have not been obtained by an approved method for at least 75 percent of the operating hours; justification for not obtaining sufficient data; and description of corrective action taken.

(4) Identification of the times when emissions data have been excluded from the calculation of average emission rates; justification for excluding data; and description of corrective action taken if data have been excluded for periods other than those during which coal or oil were not combusted in the steam generating unit.

(5) Identification of ``F'' factor used for calculations, method of determination, and type of fuel combusted.

(6) Identification of times when hourly averages have been obtained based on manual sampling methods.

(7) Identification of the times when the pollutant concentration exceeded full span of the CEMS.

(8) Description of any modifications to the CEMS which could affect the ability of the CEMS to comply with Performance Specification 2 or 3.

(9) Results of daily CEMS drift tests and quarterly accuracy assessments as required under appendix F, Procedure 1.

(m) For each affected facility subject to the sulfur dioxide standards under §60.42b for which the minimum amount of data required under §60.47b(f) were not obtained during a calendar quarter, the following information is reported to the Administrator in addition to that required under paragraph (k) of this section:

(1) The number of hourly averages available for outlet emission rates and inlet emission rates.

(2) The standard deviation of hourly averages for outlet emission rates and inlet emission rates, as determined in Method 19, section 7.

(3) The lower confidence limit for the mean outlet emission rate and the upper confidence limit for the mean inlet emission rate, as calculated in Method 19, section 7.

(4) The ratio of the lower confidence limit for the mean outlet emission rate and the allowable emission rate, as determined in Method 19, section 7.

(n) If a percent removal efficiency by fuel pretreatment (i.e., % Rf) is used to determine the overall percent reduction (i.e., % Ro) under §60.45b, the owner or operator of the affected facility shall submit a signed statement with the quarterly report:

(1) Indicating what removal efficiency by fuel pretreatment (i.e., % Rf) was credited for the calendar quarter;

(2) Listing the quantity, heat content, and date each pretreated fuel shipment was received during the previous calendar quarter; the name and location of the fuel pretreatment facility; and the total quantity and total heat content of all fuels received at the affected facility during the previous calendar quarter;

(3) Documenting the transport of the fuel from the fuel pretreatment facility to the steam generating unit.

(4) Including a signed statement from the owner or operator of the fuel pretreatment facility certifying that the percent removal efficiency achieved by fuel pretreatment was determined in accordance with the provisions of Method 19 (appendix A) and listing the heat content and sulfur content of each fuel before and after fuel pretreatment.

(o) All records required under this section shall be maintained by the owner or operator of the affected facility for a period of 2 years following the date of such record.

(p) The owner or operator of an affected facility described in §§60.44b(j) or (k) shall maintain records of the following information for each steam generating unit operating day:

(1) Calendar date,

(2) The number of hours of operation, and

(3) A record of the hourly steam load.

(q) The owner or operator of an affected facility described in §60.44b(j) or §60.44b(k) shall submit to the Administrator on a quarterly basis:

(1) The annual capacity factor over the previous 12 months,

(2) The average fuel nitrogen content during the quarter, if residual oil was fired; and

(3) If the affected facility meets the criteria described in §60.44b(j), the results of any nitrogen oxides emission tests required during the quarter, the hours of operation during the quarter, and the hours of operation since the last nitrogen oxides emission test.

(r) The owner or operator of an affected facility who elects to demonstrate that the affected facility combusts only very low sulfur oil under §60.42b(j)(2) shall obtain and maintain at the affected facility fuel receipts from the fuel supplier which certify that the oil meets the definition of distillate oil as defined in §60.41b. For the purposes of this section, the oil need not meet the fuel nitrogen content specification in the definition of distillate oil. Quarterly reports shall be submitted to the Administrator certifying that only very low sulfur oil meeting this definition was combusted in the affected facility during the preceding quarter.

[52 FR 47842, Dec. 16, 1987, as amended at 54 FR 51820, 51825, Dec. 18, 1989]

Appendix:
NSPS Subpart Kb

Subpart Kb-Standards of Performance for Volatile Organic Liquid Storage Vessels (Including Petroleum Liquid Storage Vessels) for Which Construction, Reconstruction, or Modification Commenced after July 23, 1984

Source: 52 FR 11429, Apr. 8, 1987, unless otherwise noted.

§60.110b Applicability and designation of affected facility.

(a) Except as provided in paragraphs (b), (c), and (d) of this section, the affected facility to which this subpart applies is each storage vessel with a capacity greater than or equal to 40 cubic meters (m3) that is used to store volatile organic liquids (VOL's) for which construction, reconstruction, or modification is commenced after July 23, 1984.

(b) Except as specified in paragraphs (a) and (b) of §60.116b, storage vessels with design capacity less than 75 m3 are exempt from the General Provisions (part 60, subpart A) and from the provisions of this subpart.

(c) Except as specified in paragraphs (a) and (b) of §60.116b, vessels either with a capacity greater than or equal to 151 m83 storing a liquid with a maximum true vapor pressure less than 3.5 kPa or with a capacity greater than or equal to 75 m83 but less than 151 m83 storing a liquid with a maximum true vapor pressure less than 15.0 kPa are exempt from the General Provisions (part 60, subpart A) and from the provisions of this subpart.

(d) This subpart does not apply to the following:

(1) Vessels at coke oven by-product plants.

(2) Pressure vessels designed to operate in excess of 204.9 kPa and without emissions to the atmosphere.

(3) Vessels permanently attached to mobile vehicles such as trucks, railcars, barges, or ships.

(4) Vessels with a design capacity less than or equal to 1,589.874 m3 used for petroleum or condensate stored, processed, or treated prior to custody transfer.

(5) Vessels located at bulk gasoline plants.

(6) Storage vessels located at gasoline service stations.

(7) Vessels used to store beverage alcohol.

[52 FR 11429, Apr. 8, 1987, as amended at 54 FR 32973, Aug. 11, 1989]

§60.111b Definitions.

Terms used in this subpart are defined in the Act, in subpart A of this part, or in this subpart as follows:

(a) Bulk gasoline plant means any gasoline distribution facility that has a gasoline throughput less than or equal to 75,700 liters per day. Gasoline throughput shall be the maximum calculated design throughput as may be limited by compliance with an enforceable condition under Federal requirement or Federal, State or local law, and discoverable by the Administrator and any other person.

(b) Condensate means hydrocarbon liquid separated from natural gas that condenses due to changes in the temperature or pressure, or both, and remains liquid at standard conditions.

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

(d) Fill means the introduction of VOL into a storage vessel but not necessarily to complete capacity.

(e) Gasoline service station means any site where gasoline is dispensed to motor vehicle fuel tanks from stationary storage tanks.

(f) Maximum true vapor pressure means the equilibrium partial pressure exerted by the stored VOL at the temperature equal to the highest calendar-month average of the VOL storage temperature for VOL's stored above or below the ambient temperature or at the local maximum monthly average temperature as reported by the National Weather Service for VOL's stored at the ambient temperature, as determined:

(1) In accordance with methods described in American Petroleum institute Bulletin 2517, Evaporation Loss From External Floating Roof Tanks, (incorporated by reference-see §60.17); or

(2) As obtained from standard reference texts; or

(3) As determined by ASTM Method D2879-83 (incorporated by reference-see §60.17);

(4) Any other method approved by the Administrator.

(g) Reid vapor pressure means the absolute vapor pressure of volatile crude oil and volatile nonviscous petroleum liquids except liquified petroleum gases, as determined by ASTM D323-82 (incorporated by reference-see §60.17).

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

(i) Petroleum liquids means petroleum, condensate, and any finished or intermediate products manufactured in a petroleum refinery.

(j) Storage vessel means each tank, reservoir, or container used for the storage of volatile organic liquids but does not include:

(1) Frames, housing, auxiliary supports, or other components that are not directly involved in the containment of liquids or vapors; or

(2) Subsurface caverns or porous rock reservoirs.

(k) Volatile organic liquid (VOL) means any organic liquid which can emit volatile organic compounds into the atmosphere except those VOL's that emit only those compounds which the Administrator has determined do not contribute appreciably to the formation of ozone. These compounds are identified in EPA statements on ozone abatement policy for SIP revisions (42 FR 35314, 44 FR 32042, 45 FR 32424, and 45

FR 48941).

(l) Waste means any liquid resulting from industrial, commercial, mining or agricultural operations, or from community activities that is discarded or is being accumulated, stored, or physically, chemically, or biologically treated prior to being discarded or recycled.

[52 FR 11429, Apr. 8, 1987, as amended at 54 FR 32973, Aug. 11, 1989]

§60.112b Standard for volatile organic compounds (VOC).

(a) The owner or operator of each storage vessel either with a design capacity greater than or equal to 151 m83 containing a VOL that, as stored, has a maximum true vapor pressure equal to or greater than 5.2 kPa but less than 76.6 kPa or with a design capacity greater than or equal to 75 m83 but less than 151 m83 containing a VOL that, as stored, has a maximum true vapor pressure equal to or greater than 27.6 kPa but less than 76.6 kPa, shall equip each storage vessel with one of the following:

(l) A fixed roof in combination with an internal floating roof meeting the following specifications:

(i) The internal floating roof shall rest or float on the liquid surface (but not necessarily in complete contact with it) inside a storage vessel that has a fixed roof. The internal floating roof shall be floating on the liquid surface at all times, except during initial fill and during those intervals when the storage vessel is completely emptied or subsequently emptied and refilled. When the roof is resting on the leg supports, the process of filling, emptying, or refilling shall be continuous and shall be accomplished as rapidly as possible.

(ii) Each internal floating roof shall be equipped with one of the following closure devices between the wall of the storage vessel and the edge of the internal floating roof:

(A) A foam-or liquid-filled seal mounted in contact with the liquid (liquid-mounted seal). A liquid-mounted seal means a foam-or liquid-filled seal mounted in contact with the liquid between the wall of the storage vessel and the floating roof continuously around the circumference of the tank.

(B) Two seals mounted one above the other so that each forms a continuous closure that completely covers the space between the wall of the storage vessel and the edge of the internal floating roof. The lower seal may be vapor-mounted, but both must be continuous.

(C) A mechanical shoe seal. A mechanical shoe seal is a metal sheet held vertically against the wall of the storage vessel by springs or weighted levers and is connected by braces to the floating roof. A flexible coated fabric (envelope) spans the annular space between the metal sheet and the floating roof.

(iii) Each opening in a noncontact internal floating roof except for automatic bleeder vents (vacuum breaker vents) and the rim space vents is to provide a projection below the liquid surface.

(iv) Each opening in the internal floating roof except for leg sleeves, automatic bleeder vents, rim space vents, column wells, ladder wells, sample wells, and stub drains is to be equipped with a cover or lid which is to be maintained in a closed position at all times (i.e., no visible gap) except when the device is in actual use. The cover or lid shall be equipped with a gasket. Covers on each access hatch and automatic gauge float well shall be bolted except when they are in use.

(v) Automatic bleeder vents shall be equipped with a gasket and are to be closed at all times when the roof is floating except when the roof is being floated off or is being landed on the roof leg supports.

(vi) Rim space vents shall be equipped with a gasket and are to be set to open only when the internal floating roof is not floating or at the manufacturer's recommended setting.

(vii) Each penetration of the internal floating roof for the purpose of sampling shall be a sample well. The sample well shall have a slit fabric cover that covers at least 90 percent of the opening.

(viii) Each penetration of the internal floating roof that allows for passage of a column supporting the fixed roof shall have a flexible fabric sleeve seal or a gasketed sliding cover.

(ix) Each penetration of the internal floating roof that allows for passage of a ladder shall have a gasketed sliding cover.

(2) An external floating roof. An external floating roof means a pontoon-type or double-deck type cover that rests on the liquid surface in a vessel with no fixed roof. Each external floating roof must meet the following specifications:

(i) Each external floating roof shall be equipped with a closure device between the wall of the storage vessel and the roof edge.
The closure device is to consist of two seals, one above the other. The lower seal is referred to as the primary seal, and the upper seal is referred to as the secondary seal.

(A) The primary seal shall be either a mechanical shoe seal or a liquid-mounted seal. Except as provided in §60.113b(b)(4), the seal shall completely cover the annular space between the edge of the floating roof and tank wall.

(B) The secondary seal shall completely cover the annular space between the external floating roof and the wall of the storage vessel in a continuous fashion except as allowed in §60.113b(b)(4).

(ii) Except for automatic bleeder vents and rim space vents, each opening in a noncontact external floating roof shall provide a projection below the liquid surface. Except for automatic bleeder vents, rim space vents, roof drains, and leg sleeves, each opening in the roof is to be equipped with a gasketed cover, seal, or lid that is to be maintained in a closed position at all times (i.e., no visible gap) except when the device is in actual use. Automatic bleeder vents are to be closed at all times when the roof is floating except when the roof is being floated off or is being landed on the roof leg supports. Rim vents are to be set to open when the roof is being floated off the roof legs supports or at the manufacturer's recommended setting. Automatic bleeder vents and rim space vents are to be gasketed. Each emergency roof drain is to be provided with a slotted membrane fabric cover that covers at least 90 percent of the area of the opening.

(iii) The roof shall be floating on the liquid at all times (i.e., off the roof leg supports) except during initial fill until the roof is lifted off leg supports and when the tank is completely emptied and subsequently refilled. The process of filling, emptying, or refilling when the roof is resting on the leg supports shall be continuous and shall be accomplished as rapidly as possible.

(3) A closed vent system and control device meeting the following specifications:

(i) The closed vent system shall be designed to collect all VOC vapors and gases discharged from the storage vessel and operated with no detectable emissions as indicated by an instrument reading of less than 500 ppm above background and visual inspections, as determined in part 60, subpart VV, §60.485(b).

(ii) The control device shall be designed and operated to reduce inlet VOC emissions by 95 percent or greater. If a flare is used as the control device, it shall meet the specifications described in the general control device requirements (§60.18) of the General Provisions.

(4) A system equivalent to those described in paragraphs (a)(1), (a)(2), or (a)(3) of this section as provided in §60.114b of this subpart.

(b) The owner or operator of each storage vessel with a design capacity greater than or equal to 75 m3 which contains a VOL that, as stored, has a maximum true vapor pressure greater than or equal to 76.6 kPa shall equip each storage vessel with one of the following:

(1) A closed vent system and control device as specified in §60.112b(a)(3).

(2) A system equivalent to that described in paragraph (b)(1) as provided in §60.114b of this subpart.

§60.113b Testing and procedures.

The owner or operator of each storage vessel as specified in §60.112b(a) shall meet the requirements of paragraph (a), (b), or (c) of this section. The applicable paragraph for a particular storage vessel depends on the control equipment installed to meet the requirements of §60.112b.

(a) After installing the control equipment required to meet §60.112b(a)(1) (permanently affixed roof and internal floating roof), each owner or operator shall:

(1) Visually inspect the internal floating roof, the primary seal, and the secondary seal (if one is in service), prior to filling the storage vessel with VOL. If there are holes, tears, or other openings in the primary seal, the secondary seal, or the seal fabric or defects in the internal floating roof, or both, the owner or operator shall repair the items before filling the storage vessel.

(2) For Vessels equipped with a liquid-mounted or mechanical shoe primary seal, visually inspect the internal floating roof and the primary seal or the secondary seal (if one is in service) through manholes and roof hatches on the fixed roof at least once every 12 months after initial fill. If the internal floating roof is not resting on the surface of the VOL inside the storage vessel, or there is liquid accumulated on the roof, or the seal is detached, or there are holes or tears in the seal fabric, the owner or operator shall repair the items or empty and remove the storage vessel from service within 45 days. If a failure that is detected during inspections required in this paragraph cannot be repaired within 45 days and if the vessel cannot be emptied within 45 days, a 30-day extension may be requested from the Administrator in the inspection report required in §60.115b(a)(3). Such a request for an extension must document that alternate storage capacity is unavailable and specify a schedule of actions the company will take that will assure that the control equipment will be repaired or the vessel will be emptied as soon as possible.

(3) For vessels equipped with a double-seal system as specified in §60.112b(a)(1)(ii)(B):

(i) Visually inspect the vessel as specified in paragraph (a)(4) of this section at least every 5 years; or

(ii) Visually inspect the vessel as specified in paragraph (a)(2) of this section.

(4) Visually inspect the internal floating roof, the primary seal, the secondary seal (if one is in service), gaskets, slotted membranes and sleeve seals (if any) each time the storage vessel is emptied and degassed. If the internal floating roof has defects, the primary seal has holes, tears, or other openings in the seal or the seal fabric, or the secondary seal has holes, tears, or other openings in the seal or the seal fabric, or the gaskets no longer close off the liquid surfaces from the atmosphere, or the slotted membrane has more than 10 percent open area, the owner or operator shall repair the items as necessary so that none of the conditions specified in this paragraph exist before refilling the storage vessel with VOL. In no event shall inspections conducted in accordance with this provision occur at intervals greater than 10 years in the case of vessels conducting the annual visual inspection as specified in paragraphs (a)(2) and (a)(3(ii) of this section and at intervals no greater than 5 years in the case of vessels specified in paragraph (a)(3)(i) of this section.

(5) Notify the Administrator in writing at least 30 days prior to the filling or refilling of each storage vessel for which an inspection is required by paragraphs (a)(1) and (a)(4) of this section to afford the Administrator the opportunity to have an observer present. If the

inspection required by paragraph (a)(4) of this section is not planned and the owner or operator could not have known about the inspection 30 days in advance or refilling the tank, the owner or operator shall notify the Administrator at least 7 days prior to the refilling of the storage vessel. Notification shall be made by telephone immediately followed by written documentation demonstrating why the inspection was unplanned. Alternatively, this notification including the written documentation may be made in writing and sent by express mail so that it is received by the Administrator at least 7 days prior to the refilling.

(b) After installing the control equipment required to meet §60.112b(a)(2) (external floating roof), the owner or operator shall:

(1) Determine the gap areas and maximum gap widths, between the primary seal and the wall of the storage vessel and between the secondary seal and the wall of the storage vessel according to the following frequency.

(i) Measurements of gaps between the tank wall and the primary seal (seal gaps) shall be performed during the hydrostatic testing of the vessel or within 60 days of the initial fill with VOL and at least once every 5 years thereafter.

(ii) Measurements of gaps between the tank wall and the secondary seal shall be performed within 60 days of the initial fill with VOL and at least once per year thereafter.

(iii) If any source ceases to store VOL for a period of 1 year or more, subsequent introduction of VOL into the vessel shall be considered an initial fill for the purposes of paragraphs (b)(1)(i) and (b)(1)(ii) of this section.

(2) Determine gap widths and areas in the primary and secondary seals individually by the following procedures:

(i) Measure seal gaps, if any, at one or more floating roof levels when the roof is floating off the roof leg supports.

(ii) Measure seal gaps around the entire circumference of the tank in each place where a 0.32-cm diameter uniform probe
passes freely (without forcing or binding against seal) between the seal and the wall of the storage vessel and measure the circumferential distance of each such location.

(iii) The total surface area of each gap described in paragraph (b)(2)(ii) of this section shall be determined by using probes of various widths to measure accurately the actual distance from the tank wall to the seal and multiplying each such width by its respective circumferential distance.

(3) Add the gap surface area of each gap location for the primary seal and the secondary seal individually and divide the sum for each seal by the nominal diameter of the tank and compare each ratio to the respective standards in paragraph (b)(4) of this section.

(4) Make necessary repairs or empty the storage vessel within 45 days of identification in any inspection for seals not meeting the requirements listed in (b)(4)(i) and (ii) of this section:

(i) The accumulated area of gaps between the tank wall and the mechanical shoe or liquid-mounted primary seal shall not exceed 212 Cm82 per meter of tank diameter, and the width of any portion of any gap shall not exceed 3.81 cm.

(A) One end of the mechanical shoe is to extend into the stored liquid, and the other end is to extend a minimum vertical distance of 61 cm above the stored liquid surface.

(B) There are to be no holes, tears, or other openings in the shoe, seal fabric, or seal envelope.

(ii) The secondary seal is to meet the following requirements:

(A) The secondary seal is to be installed above the primary seal so that it completely covers the space between the roof edge and the tank wall except as provided in paragraph (b)(2)(iii) of this section.

(B) The accumulated area of gaps between the tank wall and the secondary seal shall not exceed 21.2 cm2 per meter of tank diameter, and the width of any portion of any gap shall not exceed 1.27 cm.

(C) There are to be no holes, tears, or other openings in the seal or seal fabric.

(iii) If a failure that is detected during inspections required in paragraph (b)(1) of §60.113b(b) cannot be repaired within 45 days and if the vessel cannot be emptied within 45 days, a 30-day extension may be requested from the Administrator in the inspection report required in §60.115b(b)(4). Such extension request must include a demonstration of unavailability of alternate storage capacity and a specification of a schedule that will assure that the control equipment will be repaired or the vessel will be emptied as soon as possible.

(5) Notify the Administrator 30 days in advance of any gap measurements required by paragraph (b)(1) of this section to afford the Administrator the opportunity to have an observer present.

(6) Visually inspect the external floating roof, the primary seal, secondary seal, and fittings each time the vessel is emptied and degassed.

(i) If the external floating roof has defects, the primary seal has holes, tears, or other openings in the seal or the seal fabric, or the secondary seal has holes, tears, or other openings in the seal or the seal fabric, the owner or operator shall repair the items as necessary so that none of the conditions specified in this paragraph exist before filling or refilling the storage vessel with VOL.

(ii) For all the inspections required by paragraph (b)(6) of this section, the owner or operator shall notify the Administrator in writing at least 30 days prior to the filling or refilling of each storage vessel to afford the Administrator the opportunity to inspect the storage vessel prior to refilling. If the inspection required by paragraph (b)(6) of this section is not planned and the owner or operator could not have known about the inspection 30 days in advance of refilling the tank, the owner or operator shall notify the Administrator at least 7 days prior to the refilling of the storage vessel. Notification shall be made by telephone immediately followed by written documentation demonstrating why the inspection was unplanned. Alternatively, this notification including the written documentation may be made in writing and sent by express mail so that it is received by the Administrator at least 7 days prior to the refilling.

(c) The owner or operator of each source that is equipped with a closed vent system and control device as required in §60.112b (a)(3) or (b)(2) (other than a flare) is exempt from §60.8 of the General Provisions and shall meet the following requirements.

(1) Submit for approval by the Administrator as an attachment to the notification required by §60.7(a)(1) or, if the facility is exempt from §60.7(a)(1), as an attachment to the notification required by §60.7(a)(2), an operating plan containing the information listed below.

(i) Documentation demonstrating that the control device will achieve the required control efficiency during maximum loading conditions. This documentation is to include a description of the gas stream which enters the control device, including flow and VOC content under varying liquid level conditions (dynamic and static) and manufacturer's design specifications for the control device. If the control device or the closed vent capture system receives vapors, gases, or liquids other than fuels from sources that are not designated sources under this subpart, the efficiency demonstration is to include consideration of all vapors, gases, and liquids received by the closed vent capture system and control device. If an enclosed combustion device with a minimum residence time of 0.75 seconds and a minimum temperature of 816 EC is used to meet the 95 percent requirement, documentation that those conditions will exist is sufficient to meet the requirements of this paragraph.

(ii) A description of the parameter or parameters to be monitored to ensure that the control device will be operated in conformance with its design and an explanation of the criteria used for selection of that parameter (or parameters).

(2) Operate the closed vent system and control device and monitor the parameters of the closed vent system and control device in accordance with the operating plan submitted to the Administrator in accordance with paragraph (c)(1) of this section, unless the plan was modified by the Administrator during the review process. In this case, the modified plan applies.

(d) The owner or operator of each source that is equipped with a closed vent system and a flare to meet the requirements in §60.112b (a)(3) or (b)(2) shall meet the requirements as specified in the general control device requirements, §60.18 (e) and (f).

[52 FR 11429, Apr. 8, 1987, as amended at 54 FR 32973, Aug. 11, 1989]

§60.114b Alternative means of emission limitation.

(a) If, in the Administrator's judgment, an alternative means of emission limitation will achieve a reduction in emissions at least equivalent to the reduction in emissions achieved by any requirement in §60.112b, the Administrator will publish in the Federal Register a notice permitting the use of the alternative means for purposes of compliance with that requirement.

(b) Any notice under paragraph (a) of this section will be published only after notice and an opportunity for a hearing.

(c) Any person seeking permission under this section shall submit to the Administrator a written application including:

(1) An actual emissions test that uses a full-sized or scale-model storage vessel that accurately collects and measures all VOC emissions from a given control device and that accurately simulates wind and accounts for other emission variables such as temperature and barometric pressure.

(2) An engineering evaluation that the Administrator determines is an accurate method of determining equivalence.

(d) The Administrator may condition the permission on requirements that may be necessary to ensure operation and maintenance to achieve the same emissions reduction as specified in §60.112b.

§60.115b Reporting and recordkeeping requirements.

The owner or operator of each storage vessel as specified in §60.112b(a) shall keep records and furnish reports as required by paragraphs (a), (b), or (c) of this section depending upon the control equipment installed to meet the requirements of §60.112b. The owner or operator shall keep copies of all reports and records required by this section, except for the record required by (c)(1), for at least 2 years. The record required by (c)(1) will be kept for the life of the control equipment.

(a) After installing control equipment in accordance with §60.112b(a)(1) (fixed roof and internal floating roof), the owner or operator shall meet the following requirements.

(1) Furnish the Administrator with a report that describes the control equipment and certifies that the control equipment meets the specifications of §60.112b(a)(1) and §60.113b(a)(1). This report shall be an attachment to the notification required by §60.7(a)(3).

(2) Keep a record of each inspection performed as required by §60.113b (a)(1), (a)(2), (a)(3), and (a)(4). Each record shall identify the storage vessel on which the inspection was performed and shall contain the date the vessel was inspected and the observed condition of

each component of the control equipment (seals, internal floating roof, and fittings).

(3) If any of the conditions described in §60.113b(a)(2) are detected during the annual visual inspection required by §60.113b(a)(2), a report shall be furnished to the Administrator within 30 days of the inspection. Each report shall identify the storage vessel, the nature of the defects, and the date the storage vessel was emptied or the nature of and date the repair was made.

(4) After each inspection required by §60.113b(a)(3) that finds holes or tears in the seal or seal fabric, or defects in the internal floating roof, or other control equipment defects listed in §60.113b(a)(3)(ii), a report shall be furnished to the Administrator within 30 days of the inspection. The report shall identify the storage vessel and the reason it did not meet the specifications of §61.112b(a)(1) or §60.113b(a)(3) and list each repair made.

(b) After installing control equipment in accordance with §61.112b(a)(2) (external floating roof), the owner or operator shall meet the following requirements.

(1) Furnish the Administrator with a report that describes the control equipment and certifies that the control equipment meets the specifications of §60.112b(a)(2) and §60.113b(b)(2), (b)(3), and (b)(4). This report shall be an attachment to the notification required by §60.7(a)(3).

(2) Within 60 days of performing the seal gap measurements required by §60.113b(b)(1), furnish the Administrator with a report that contains:

(i) The date of measurement.

(ii) The raw data obtained in the measurement.

(iii) The calculations described in §60.113b (b)(2) and (b)(3).

(3) Keep a record of each gap measurement performed as required by §60.113b(b). Each record shall identify the storage vessel in which the measurement was performed and shall contain:

(i) The date of measurement.

(ii) The raw data obtained in the measurement.

(iii) The calculations described in §60.113b (b)(2) and (b)(3).

(4) After each seal gap measurement that detects gaps exceeding the limitations specified by §60.113b(b)(4), submit a report to the Administrator within 30 days of the inspection. The report will identify the vessel and contain the information specified in paragraph (b)(2) of this section and the date the vessel was emptied or the repairs made and date of repair.

(c) After installing control equipment in accordance with §60.112b (a)(3) or (b)(1) (closed vent system and control device other than a flare), the owner or operator shall keep the following records.

(1) A copy of the operating plan.

(2) A record of the measured values of the parameters monitored in accordance with §60.113b(c)(2).

(d) After installing a closed vent system and flare to comply with §60.112b, the owner or operator shall meet the following requirements.

(1) A report containing the measurements required by §60.18(f) (1), (2), (3), (4), (5), and (6) shall be furnished to the Administrator as required by §60.8 of the General Provisions. This report shall be submitted within 6 months of the initial start-up date.

(2) Records shall be kept of all periods of operation during which the flare pilot flame is absent.

(3) Semiannual reports of all periods recorded under §60.115b(d)(2) in which the pilot flame was absent shall be furnished to the Administrator.

§60.116b Monitoring of operations.

(a) The owner or operator shall keep copies of all records required by this section, except for the record required by paragraph (b) of this section, for at least 2 years. The record required by paragraph (b) of this section will be kept for the life of the source.

(b) The owner or operator of each storage vessel as specified in §60.110b(a) shall keep readily accessible records showing the dimension of the storage vessel and an analysis showing the capacity of the storage vessel. Each storage vessel with a design capacity less than 75 m3 is subject to no provision of this subpart other than those required by this paragraph.

(c) Except as provided in paragraphs (f) and (g) of this section, the owner or operator of each storage vessel either with a design capacity greater than or equal to 151 m3 storing a liquid with a maximum true vapor pressure greater than or equal to 3.5 kPa or with a design capacity greater than or equal to 75 m3 but less than 151 m3 storing a liquid with a maximum true vapor pressure greater than or equal to 15.0 kPa shall maintain a record of the VOL stored, the period of storage, and the maximum true vapor pressure of that VOL during the respective storage period.

(d) Except as provided in paragraph (g) of this section, the owner or operator of each storage vessel either with a design capacity greater than or equal to 151 m3 storing a liquid with a maximum true vapor pressure that is normally less than 5.2 kPa or with a design capacity greater than or equal to 75 m3 but less than 151 m3 storing a liquid with a maximum true vapor pressure that is normally less than 27.6 kPa shall notify the Administrator within 30 days when the maximum true vapor pressure of the liquid exceeds the respective maximum true vapor pressure values for each volume range.

(e) Available data on the storage temperature may be used to determine the maximum true vapor pressure as determined below.

(1) For vessels operated above or below ambient temperatures, the maximum true vapor pressure is calculated based upon the highest expected calendar-month average of the storage temperature. For vessels operated at ambient temperatures, the maximum

true vapor pressure is calculated based upon the maximum local monthly average ambient temperature as reported by the National Weather Service.

(2) For crude oil or refined petroleum products the vapor pressure may be obtained by the following:

(i) Available data on the Reid vapor pressure and the maximum expected storage temperature based on the highest expected calendar-month average temperature of the stored product may be used to determine the maximum true vapor pressure from nomographs contained in API Bulletin 2517 (incorporated by reference-see §60.17), unless the Administrator specifically requests that the liquid be sampled, the actual storage temperature determined, and the Reid vapor pressure determined from the sample(s).

(ii) The true vapor pressure of each type of crude oil with a Reid vapor pressure less than 13.8 kPa or with physical properties that preclude determination by the recommended method is to be determined from available data and recorded if the estimated maximum true vapor pressure is greater than 3.5 kPa.

(3) For other liquids, the vapor pressure:

(i) May be obtained from standard reference texts, or

(ii) Determined by ASTM Method D2879-83 (incorporated by reference-see §60.17); or

(iii) Measured by an appropriate method approved by the Administrator; or

(iv) Calculated by an appropriate method approved by the Administrator.

(f) The owner or operator of each vessel storing a waste mixture of indeterminate or variable composition shall be subject to the following requirements.

(1) Prior to the initial filling of the vessel, the highest maximum true vapor pressure for the range of anticipated liquid compositions to be stored will be determined using the methods described in paragraph (e) of this section.

(2) For vessels in which the vapor pressure of the anticipated liquid composition is above the cutoff for monitoring but below the cutoff for controls as defined in §60.112b(a), an initial physical test of the vapor pressure is required; and a physical test at least once every 6 months thereafter is required as determined by the following methods:

(i) ASTM Method D2879-83 (incorporated by reference-see §60.17); or

(ii) ASTM Method D323-82 (incorporated by reference-see §60.17); or

(iii) As measured by an appropriate method as approved by the Administrator.

(g) The owner or operator of each vessel equipped with a closed vent system and control device meeting the specifications of §60.112b is exempt from the requirements of paragraphs (c) and (d) of this section.

§60.117b 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 will not be delegated to States: §§60.111b(f)(4), 60.114b, 60.116b(e)(3)(iii), 60.116b(e)(3)(iv), and 60.116b(f)(2)(iii).

[52 FR 11429, Apr. 8, 1987, as amended at 52 FR 22780, June 16, 1987]

Subpart VV-Standards of Performance for Equipment Leaks of VOC in the Synthetic Organic Chemicals Manufacturing Industry

Source: 48 FR 48335, Oct. 18, 1983, unless otherwise noted.

§60.480 Applicability and designation of affected facility.

(a)(1) The provisions of this subpart apply to affected facilities in the synthetic organic chemicals manufacturing industry.
(2) The group of all equipment (defined in §60.481) within a process unit is an affected facility.
(b) Any affected facility under paragraph (a) of this section that commences construction or modification after January 5, 1981, shall be subject to the requirements of this subpart.
(c) Addition or replacement of equipment for the purpose of process improvement which is accomplished without a capital expenditure shall not by itself be considered a modification under this subpart.
(d)(1) If an owner or operator applies for one or more of the exemptions in this paragraph, then the owner or operator shall maintain records as required in §60.486(i).
(2) Any affected facility that has the design capacity to produce less than 1,000 Mg/yr is exempt from §60.482.
(3) If an affected facility produces heavy liquid chemicals only from heavy liquid feed or raw materials, then it is exempt from §60.482.
(4) Any affected facility that produces beverage alcohol is exempt from §60.482.
(5) Any affected facility that has no equipment in VOC service is exempt from §60.482.

[48 FR 48335, Oct. 18, 1983, as amended at 49 FR 22607, May 30, 1984]

§60.481 Definitions.

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

Capital expenditure means, in addition to the definition in 40 CFR 60.2, an expenditure for a physical or operational change to an existing facility that:
(a) Exceeds P, the product of the facility's replacement cost, R, and an adjusted annual asset guideline repair allowance, A, as reflected by the following equation: P = R X A, where
(1) The adjusted annual asset guideline repair allowance, A, is the product of the percent of the replacement cost, Y, and the applicable basic annual asset guideline repair allowance, B, as reflected by the following equation:

$$A = Y \times (B \div 100);$$

(2) The percent Y is determined from the following equation:

$Y = 1.0 - 0.575 \log X$, where X is 1982 minus the year of construction; and
(3) The applicable basic annual asset guideline repair allowance, B, is selected from the following table consistent with the applicable subpart:

Table for Determining Applicable for B	
Subpart applicable to facility	Value of B to be used in equation
VV	12.5
DDD	12.5
GGG	7.0
KKK	4.5

Closed vent system means a system that is not open to the atmosphere and that is composed of piping, connections, and, if necessary, flow inducing devices that transport gas or vapor from a piece or pieces of equipment to a control device.
Connector means flanged, screwed, welded, or other joined fittings used to connect two pipe lines or a pipe line and a piece of process equipment.
Control device means an enclosed combustion device, vapor recovery system, or flare.
Distance piece means an open or enclosed casing through which the piston rod travels, separating the compressor cylinder from the crankcase.
Double block and bleed system means two block valves connected in series with a bleed valve or line that can vent the line between the two block valves.
Equipment means each pump, compressor, pressure relief device, sampling connection system, open-ended valve or line, valve, and flange or other connector in VOC service and any devices or systems required by

this subpart.

First attempt at repair means to take rapid action for the purpose of stopping or reducing leakage of organic material to atmosphere using best practices.

In gas/vapor service means that the piece of equipment contains process fluid that is in the gaseous state at operating conditions.

In heavy liquid service means that the piece of equipment is not in gas/vapor service or in light liquid service.

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

In-situ sampling systems means nonextractive samplers or in-line samplers.

In vacuum service means that equipment is operating at an internal pressure which is at least 5 kilopascals (kPa) below ambient pressure.

In VOC service means that the piece of equipment contains or contacts a process fluid that is at least 10 percent VOC by weight. (The provisions of §60.485(d) specify how to determine that a piece of equipment is not in VOC service.)

Liquids dripping means any visible leakage from the seal including spraying, misting, clouding, and ice formation.

Open-ended valve or line means any valve, except safety relief valves, having one side of the valve seat in contact with process fluid and one side open to the atmosphere, either directly or through open piping.

Pressure release means the emission of materials resulting from system pressure being greater than set pressure of the pressure relief device.

Process improvement means routine changes made for safety and occupational health requirements, for energy savings, for better utility, for ease of maintenance and operation, for correction of design deficiencies, for bottleneck removal, for changing product requirements, or for environmental control.

Process unit means components assembled to produce, as intermediate or final products, one or more of the chemicals listed in §60.489 of this part. A process unit can operate independently if supplied with sufficient feed or raw materials and sufficient storage facilities for the product.

Process unit shutdown means a work practice or operational procedure that stops production from a process unit or part of a process unit. An unscheduled work practice or operational procedure that stops production from a process unit or part of a process unit for less than 24 hours is not a process unit shutdown. The use of spare equipment and technically feasible bypassing of equipment without stopping production are not process unit shutdowns.

Quarter means a 3-month period; the first quarter concludes on the last day of the last full month during the 180 days following initial startup.

Repaired means that equipment is adjusted, or otherwise altered, in order to eliminate a leak as indicated by one of the following: an instrument reading or 10,000 ppm or greater, indication of liquids dripping, or indication by a sensor that a seal or barrier fluid system has failed.

Replacement cost means the capital needed to purchase all the depreciable components in a facility.

Sensor means a device that measures a physical quantity or the change in a physical quantity such as temperature, pressure, flow rate, pH, or liquid level.

Synthetic organic chemicals manufacturing industry means the industry that produces, as intermediates or final products, one or more of the chemicals listed in §60.489.

Volatile organic compounds or VOC means, for the purposes of this subpart, any reactive organic compounds as defined in §60.2 Definitions.

[48 FR 48335, Oct. 18, 1983, as amended at 49 FR 22607, May 30, 1984; 49 FR 26738, June 29, 1984]

§60.482-1 Standards: General.

(a) Each owner or operator subject to the provisions of this subpart shall demonstrate compliance with the requirements of §§60.482-1 to 60.482-10 for all equipment within 180 days of initial startup.

(b) Compliance with §§60.482-1 to 60.482-10 will be determined by review of records and reports, review of performance test results, and inspection using the methods and procedures specified in §60.485.

(c)(1) An owner or operator may request a determination of equivalence of a means of emission limitation to the requirements of §§60.482-2, 60.482-3, 60.482-5, 60.482-6, 60.482-7, 60.482-8, and 60.482-10 as provided in §60.484.

(2) If the Administrator makes a determination that a means of emission limitation is at least equivalent to the requirements of §§60.482-2, 60.482-3, 60.482-5, 60.482-6, 60.482-7, 60.482-8, or 60.482-10, an owner or operator shall comply with the requirements of that determination.

(d) Equipment that is in vacuum service is excluded from the requirements of §§60.482-2 to 60.482-10 if it is identified as required in §60.486(e)(5).

[48 FR 48335, Oct. 18, 1983, as amended at 49 FR 22608, May 30, 1984]

§60.482-2 Standards: Pumps in light liquid service.

(a)(1) Each pump in light liquid service shall be monitored monthly to detect leaks by the methods specified in §60.485(b), except as provided in §60.482-1(c) and paragraphs (d), (e), and (f) of this section.

(2) Each pump in light liquid service shall be checked by visual inspection each calendar week for indications

of liquids dripping from the pump seal.

(b)(1) If an instrument reading of 10,000 ppm or greater is measured, a leak is detected.

(2) If there are indications of liquids dripping from the pump seal, a leak is detected.

(c)(1) When a leak is detected, it shall be repaired as soon as practicable, but not later than 15 calendar days after it is detected, except as provided in §60.482-9.

(2) A first attempt at repair shall be made no later than 5 calendar days after each leak is detected.

(d) Each pump equipped with a dual mechanical seal system that includes a barrier fluid system is exempt from the requirements of paragraph (a), Provided the following requirements are met:

(1) Each dual mechanical seal system is-

(i) Operated with the barrier fluid at a pressure that is at all times greater than the pump stuffing box pressure; or

(ii) Equipment with a barrier fluid degassing reservoir that is connected by a closed vent system to a control device that complies with the requirements of §60.482-10; or

(iii) Equipped with a system that purges the barrier fluid into a process stream with zero VOC emissions to the atmosphere.

(2) The barrier fluid system is in heavy liquid service or is not in VOC service.

(3) Each barrier fluid system is equipped with a sensor that will detect failure of the seal system, the barrier fluid system, or both.

(4) Each pump is checked by visual inspection, each calendar week, for indications of liquids dripping from the pump seals.

(5)(i) Each sensor as described in paragraph (d)(3) is checked daily or is equipped with an audible alarm, and

(ii) The owner or operator determines, based on design considerations and operating experience, a criterion that indicates failure of the seal system, the barrier fluid system, or both.

(6)(i) If there are indications of liquids dripping from the pump seal or the sensor indicates failure of the seal system, the barrier fluid system, or both based on the criterion determined in paragraph (d)(5)(ii), a leak is detected.

(ii) When a leak is detected, it shall be repaired as soon as practicable, but not later than 15 calendar days after it is detected, except as provided in §60.482-9.

(iii) A first attempt at repair shall be made no later than 5 calendar days after each leak is detected.

(e) Any pump that is designated, as described in §60.486(e)(1) and (2), for no detectable emission, as indicated by an instrument reading of less than 500 ppm above background, is exempt from the requirements of paragraphs (a), (c), and (d) if the pump:

(1) Has no externally actuated shaft penetrating the pump housing,

(2) Is demonstrated to be operating with no detectable emissions as indicated by an instrument reading of less than 500 ppm above background as measured by the methods specified in §60.485(c), and

(3) Is tested for compliance with paragraph (e)(2) initially upon designation, annually, and at other times requested by the Administrator.

(f) If any pump is equipped with a closed vent system capable of capturing and transporting any leakage from the seal or seals to a control device that complies with the requirements of §60.482-10, it is exempt from the paragraphs (a) through (e).

§60.482-3 Compressors.

(a) Each compressor shall be equipped with a seal system that includes a barrier fluid system and that prevents leakage of VOC to the atmosphere, except as provided in §60.482-1(c) and paragraph (h) and (i) of this section.

(b) Each compressor seal system as required in paragraph (a) shall be:

(1) Operated with the barrier fluid at a pressure that is greater than the compressor stuffing box pressure; or

(2) Equipped with a barrier fluid system that is connected by a closed vent system to a control device that complies with the requirements of §60.482-10; or

(3) Equipped with a system that purges the barrier fluid into a process stream with zero VOC emissions to the atmosphere.

(c) The barrier fluid system shall be in heavy liquid service or shall not be in VOC service.

(d) Each barrier fluid system as described in paragraph (a) shall be equipped with a sensor that will detect failure of the seal system, barrier fluid system, or both.

(e)(1) Each sensor as required in paragraph (d) shall be checked daily or shall be equipped with an audible alarm.

(2) The owner or operator shall determine, based on design considerations and operating experience, a criterion that indicates failure of the seal system, the barrier fluid system, or both.

(f) If the sensor indicates failure of the seal system, the barrier system, or both based on the criterion determined under paragraph (e)(2), a leak is detected.

(g)(1) When a leak is detected, it shall be repaired as soon as practicable, but not later than 15 calendar days after it is detected, except as provided in §60.482-9.

(2) A first attempt at repair shall be made no later than 5 calendar days after each leak is detected.

(h) A compressor is exempt from the requirements of paragraphs (a) and (b), if it is equipped with a closed vent system capable of capturing and transporting any leakage from the seal to a control device that complies with the requirements of §60.482-10, except as provided in paragraph (i) of this section.

(i) Any compressor that is designated, as described in

§60.486(e) (1) and (2), for no detectable emissions, as indicated by an instrument reading of less than 500 ppm above background, is exempt from the requirements of paragraphs (a)-(h) if the compressor:
(1) Is demonstrated to be operating with no detectable emissions, as indicated by an instrument reading of less than 500 ppm above background, as measured by the methods specified in §60.485(c); and
(2) Is tested for compliance with paragraph (i)(1) initially upon designation, annually, and at other times requested by the Administrator.
(j) Any existing reciprocating compressor in a process unit which becomes an affected facility under provisions of §60.14 or §60.15 is exempt from §60.482(a), (b), (c), (d), (e), and (h), provided the owner or operator demonstrates that recasting the distance piece or replacing the compressor are the only options available to bring the compressor into compliance with the provisions of paragraphs (a) through (e) and (h) of this section.

§60.482-4 Standards: Pressure relief devices in gas/vapor service.

(a) Except during pressure releases, each pressure relief device in gas/vapor service shall be operated with no detectable emissions, as indicated by an instrument reading of less than 500 ppm above background, as determined by the methods specified in §60.485(c).
(b)(1) After each pressure release, the pressure relief device shall be returned to a condition of no detectable emissions, as indicated by an instrument reading of less than 500 ppm above background, as soon as practicable, but no later than 5 calendar days after the pressure release, except as provided in §60.482-9.
(2) No later than 5 calendar days after the pressure release, the pressure relief device shall be monitored to confirm the conditions of no detectable emissions, as indicated by an instrument reading of less than 500 ppm above background, by the methods specified in §60.485(c).
(c) Any pressure relief device that is equipped with a closed vent system capable of capturing and transporting leakage through the pressure relief device to a control device as described in §60.482-10 is exempted from the requirements of paragraphs (a) and (b).

§60.482-5 Standards: Sampling connection systems.

(a) Each sampling connection system shall be equipped with a closed purge system or closed vent system, except as provided in §60.482-1(c).
(b) Each closed purge system or closed vent system as required in paragraph (a) shall:
(1) Return the purged process fluid directly to the process line with zero VOC emissions to the atmosphere; or
(2) Collect and recycle the purged process fluid with zero VOC emissions to the atmosphere; or
(3) Be designed and operated to capture and transport all the purged process fluid to a control device that complies with the requirements of §60.482-10.
(c) In-situ sampling systems are exempt from paragraphs (a) and (b).

§60.482-6 Standards: Open-ended valves or lines.

(a)(1) Each open-ended valve or line shall be equipped with a cap, blind flange, plug, or a second valve, except as provided in §60.482-1(c).
(2) The cap, blind flange, plug, or second valve shall seal the open end at all times except during operations requiring process fluid flow through the open-ended valve or line.
(b) Each open-ended valve or line equipped with a second valve shall be operated in a manner such that the valve on the process fluid end is closed before the second valve is closed.
(c) When a double block-and-bleed system is being used, the bleed valve or line may remain open during operations that require venting the line between the block valves but shall comply with paragraph (a) at all other times.

[48 FR 48335, Oct. 18, 1983, as amended at 49 FR 22607, May 30, 1984]

§60.482-7 Standards: Valves in gas/vapor service in light liquid service.

(a) Each valve shall be monitored monthly to detect leaks by the methods specified in §60.485(b) and shall comply with paragraphs (b) through (e), except as provided in paragraphs (f), (g), and (h), §60.483-1, 2, and §60.482-1(c).
(b) If an instrument reading of 10,000 ppm or greater is measured, a leak is detected.
(c)(1) Any valve for which a leak is not detected for 2 successive months may be monitored the first month of every quarter, beginning with the next quarter, until a leak is detected.
(2) If a leak is detected, the valve shall be monitored monthly until a leak is not detected for 2 successive months.
(d)(1) When a leak is detected, it shall be repaired as soon as practicable, but no later than 15 calendar days after the leak is detected, except as provided in §60.482-9.
(2) A first attempt at repair shall be made no later than 5 calendar days after each leak is detected.
(e) First attempts at repair include, but are not limited to, the following best practices where practicable:
(1) Tightening of bonnet bolts;
(2) Replacement of bonnet bolts;

(3) Tightening of packing gland nuts;
(4) Injection of lubricant into lubricated packing.
(f) Any valve that is designated, as described in §60.486(e)(2), for no detectable emissions, as indicated by an instrument reading of less than 500 ppm above background, is exempt from the requirements of paragraph (a) if the valve:
(1) Has no external actuating mechanism in contact with the process fluid,
(2) Is operated with emissions less than 500 ppm above background as determined by the method specified in §60.485(c), and
(3) Is tested for compliance with paragraph (f)(2) initially upon designation, annually, and at other times requested by the Administrator.
(g) Any valve that is designated, as described in §60.486(f)(1), as an unsafe-to-monitor valve is exempt from the requirements of paragraph (a) if:
(1) The owner or operator of the valve demonstrates that the valve is unsafe to monitor because monitoring personnel would be exposed to an immediate danger as a consequence of complying with paragraph (a), and
(2) The owner or operator of the valve adheres to a written plan that requires monitoring of the valve as frequently as practicable during safe-to-monitor times.
(h) Any valve that is designated, as described in §60.486(f)(2), as a difficult-to-monitor valve is exempt from the requirements of paragraph (a) if:
(1) The owner or operator of the valve demonstrates that the valve cannot be monitored without elevating the monitoring personnel more than 2 meters above a support surface.
(2) The process unit within which the valve is located either becomes an affected facility through §60.14 or §60.15 or the owner or operator designates less than 3.0 percent of the total number of valves as difficult- to-monitor, and
(3) The owner or operator of the valve follows a written plan that requires monitoring of the valve at least once per calendar year.

[48 FR 48335, Oct. 18, 1983, as amended at 49 FR 22608, May 30, 1984]

§60.482-8 Standards: Pumps and valves in heavy liquid service, pressure relief devices in light liquid or heavy liquid service, and flanges and other connectors.

(a) Pumps and valves in heavy liquid service, pressure relief devices in light liquid or heavy liquid service, and flanges and other connectors shall be monitored within 5 days by the method specified in §60.485(b) if evidence of a potential leak is found by visual, audible, olfactory, or any other detection method.
(b) If an instrument reading of 10,000 ppm or greater is measured, a leak is detected.
(c)(1) When a leak is detected, it shall be repaired as soon as practicable, but not later than 15 calendar days after it is detected, except as provided in §60.482-9.
(2) The first attempt at repair shall be made no later than 5 calendar days after each leak is detected.
(d) First attempts at repair include, but are not limited to, the best practices described under §60.482-7(e).

§60.482-9 Standards: Delay of repair.

(a) Delay of repair of equipment for which leaks have been detected will be allowed if the repair is technically infeasible without a process unit shutdown. Repair of this equipment shall occur before the end of the next process unit shutdown.
(b) Delay of repair of equipment will be allowed for equipment which is isolated from the process and which does not remain in VOC service.
(c) Delay of repair for valves will be allowed if:
(1) The owner or operator demonstrates that emissions of purged material resulting from immediate repair are greater than the fugitive emissions likely to result from delay of repair, and
(2) When repair procedures are effected, the purged material is collected and destroyed or recovered in a control device complying with §60.482-10.
(d) Delay of repair for pumps will be allowed if:
(1) Repair requires the use of a dual mechanical seal system that includes a barrier fluid system, and
(2) Repair is completed as soon as practicable, but not later than 6 months after the leak was detected.
(e) Delay of repair beyond a process unit shutdown will be allowed for a valve, if valve assembly replacement is necessary during the process unit shutdown, valve assembly supplies have been depleted, and valve assembly supplies had been sufficiently stocked before the supplies were depleted. Delay of repair beyond the next process unit shutdown will not be allowed unless the next process unit shutdown occurs sooner than 6 months after the first process unit shutdown.

§60.482-10 Standards: Closed vent systems and control devices.

(a) Owners or operators of closed vent systems and control devices used to comply with provisions of this subpart shall comply with the provisions of this section.
(b) Vapor recovery systems (for example, condensers and adsorbers) shall be designed and operated to recover the VOC emissions vented to them with an efficiency of 95 percent or greater.
(c) Enclosed combustion devices shall be designed and operated to reduce the VOC emissions vented to them with an efficiency of 95 percent or greater, or to provide a minimum residence time of 0.75 seconds at a minimum temperature of 816EC.
(d) Flares used to comply with this subpart shall

comply with the requirements of §60.18.

(e) Owners or operators of control devices used to comply with the provisions of this subpart shall monitor these control devices to ensure that they are operated and maintained in conformance with their designs.

(f)(1) Closed vent systems shall be designed and operated with no detectable emissions, as indicated by an instrument reading of less than 500 ppm above background and visual inspections, as determined by the methods specified in §60.485(c).

(2) Closed vent systems shall be monitored to determine compliance with this section initially in accordance with §60.8, annually and at other times requested by the Administrator.

(g) Closed vent systems and control devices used to comply with provisions of this subpart shall be operated at all times when emissions may be vented to them.

[48 FR 48335, Oct. 18, 1983, as amended at 51 FR 2702, Jan. 21, 1986]

§60.483-1 Alternative standards for valves-allowable percentage of valves leaking.

(a) An owner or operator may elect to comply with an allowable percentage of valves leaking of equal to or less than 2.0 percent.

(b) The following requirements shall be met if an owner or operator wishes to comply with an allowable percentage of valves leaking:

(1) An owner or operator must notify the Administrator that the owner or operator has elected to comply with the allowable percentage of valves leaking before implementing this alternative standard, as specified in §60.487(b).

(2) A performance test as specified in paragraph (c) of this section shall be conducted initially upon designation, annually, and at other times requested by the Administrator.

(3) If a valve leak is detected, it shall be repaired in accordance with §60.482-7(d) and (e).

(c) Performance tests shall be conducted in the following manner:

(1) All valves in gas/vapor and light liquid service within the affected facility shall be monitored within 1 week by the methods specified in §60.485(b).

(2) If an instrument reading of 10,000 ppm or greater is measured, a leak is detected.

(3) The leak percentage shall be determined by dividing the number of valves for which leaks are detected by the number of valves in gas/vapor and light liquid service within the affected facility.

(d) Owners and operators who elect to comply with this alternative standard shall not have an affected facility with a leak percentage greater than 2.0 percent.

§60.483-2 Alternative standards for valves-skip period leak detection and repair.

(a)(1) An owner or operator may elect to comply with one of the alternative work practices specified in paragraphs (b)(2) and (3) of this section.

(2) An owner or operator must notify the Administrator before implementing one of the alternative work practices, as specified in §60.487(b).

(b)(1) An owner or operator shall comply initially with the requirements for valves in gas/vapor service and valves in light liquid service, as described in §60.482-7.

(2) After 2 consecutive quarterly leak detection periods with the percent of valves leaking equal to or less than 2.0, an owner or operator may begin to skip 1 of the quarterly leak detection periods for the valves in gas/vapor and light liquid service.

(3) After 5 consecutive quarterly leak detection periods with the percent of valves leaking equal to or less than 2.0, an owner or operator may begin to skip 3 of the quarterly leak detection periods for the valves in gas/vapor and light liquid service.

(4) If the percent of valves leaking is greater than 2.0, the owner or operator shall comply with the requirements as described in §60.482-7 but can again elect to use this section.

(5) The percent of valves leaking shall be determined by dividing the sum of valves found leaking during current monitoring and valves for which repair has been delayed by the total number of valves subject to the requirements of this section.

(6) An owner or operator must keep a record of the percent of valves found leaking during each leak detection period.

§60.484 Equivalence of means of emission limitation.

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

(b) Determination of equivalence to the equipment, design, and operational requirements of this subpart will be evaluated by the following guidelines:

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

(2) The Administrator will compare test data for the means of emission limitation to test data for the equipment, design, and operational requirements.

(3) The Administrator may condition the approval of equivalence on requirements that may be necessary to assure operation and maintenance to achieve the same emission reduction as the equipment, design, and operational requirements.

(c) Determination of equivalence to the required work practices in this subpart will be evaluated by the following guidelines:

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

(2) For each affected facility for which a determination of equivalence is requested, the emission reduction achieved by the required work practice shall be demonstrated.

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

(4) Each owner or operator applying for a determination of equivalence shall commit in writing to work practice(s) that provide for emission reductions equal to or greater than the emission reductions achieved by the required work practice.

(5) The Administrator will compare the demonstrated emission reduction for the equivalent means of emission limitation to the demonstrated emission reduction for the required work practices and will consider the commitment in paragraph (c)(4).

(6) The Administrator may condition the approval of equivalence on requirements that may be necessary to assure operation and maintenance to achieve the same emission reduction as the required work practice.

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

(e)(1) After a request for determination of equivalence is received, the Administrator will publish a notice in the Federal Register and provide the opportunity for public hearing if the Administrator judges that the request may be approved.

(2) After notice and opportunity for public hearing, the Administrator will determine the equivalence of a means of emission limitation and will publish the determination in the Federal Register.

(3) Any equivalent means of emission limitations approved under this section shall constitute a required work practice, equipment, design, or operational standard within the meaning of section 111(h)(1) of the Clean Air Act.

(f)(1) Manufacturers of equipment used to control equipment leaks of VOC may apply to the Administrator for determination of equivalence for any equivalent means of emission limitation that achieves a reduction in emissions of VOC achieved by the equipment, design, and operational requirements of this subpart.

(2) The Administrator will make an equivalence determination according to the provisions of paragraphs (b), (c), (d), and (e).

§60.485 Test methods and procedures.

(a) In conducting the performance tests required in §60.8, the owner or operator shall use as reference methods and procedures the test methods in appendix A of this part or other methods and procedures as specified in this section, except as provided in §60.8(b).

(b) The owner or operator shall determine compliance with the standards in §§60.482, 60.483, and 60.484 as follows:

(1) Method 21 shall be used to determine the presence of leaking sources. The instrument shall be calibrated before use each day of its use by the procedures specified in Method 21. The following calibration gases shall be used:

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

(ii) A mixture of methane or n-hexane and air at a concentration of about, but less than, 10,000 ppm methane or n-hexane.

(c) The owner or operator shall determine compliance with the no detectable emission standards in §§60.482-2(e), 60.482-3(i), 60.482-4, 60.482-7(f), and 60.482-10(e) as follows:

(1) The requirements of paragraph (b) shall apply.

(2) Method 21 shall be used to determine the background level. All potential leak interfaces shall be traversed as close to the interface as possible. The arithmetic difference between the maximum concentration indicates by the instrument and the background level is compared with 500 ppm for determining compliance.

(d) The owner or operator shall test each piece of equipment unless he demonstrates that a process unit is not in VOC series, i.e., that the VOC content would never be reasonably expected to exceed 10 percent by weight. For purposes of this demonstration, the following methods and procedures shall be used:

(1) Procedures that conform to the general methods in ASTM E-260, E-168, E-169 (incorporated by reference-see §60.17) shall be used to determine the percent VOC content in the process fluid that is contained in or contacts a piece of equipment.

(2) Organic compounds that are considered by the Administrator to have negligible photochemical reactivity may be excluded from the total quantity of organic compounds in determining the VOC content of the process fluid.

(3) Engineering judgment may be used to estimate the VOC content, if a piece of equipment had not been shown previously to be in service. If the Administrator disagrees with the judgment, paragraphs (d) (1) and (2) of this section shall be used to resolve the disagreement.

(e) The owner or operator shall demonstrate that an equipment is in light liquid service by showing that all the following conditions apply:

(1) The vapor pressure of one or more of the components is greater than 0.3 kPa at 20 EC. Standard

reference texts or ASTM D-2879 (incorporated by reference-see §60.17) shall be used to determine the vapor pressures.

(2) The total concentration of the pure components having a vapor pressure greater than 0.3 kPa at 20 °C is equal to or greater than 20 percent by weight.

(3) The fluid is a liquid at operating conditions.

(f) Samples used in conjunction with paragraphs (d), (e), and (g) shall be representative of the process fluid that is contained in or contacts the equipment or the gas being combusted in the flare.

(g) The owner or operator shall determine compliance with the standards of flares as follows:

(1) Method 22 shall be used to determine visible emissions.

(2) A thermocouple or any other equivalent device shall be used to monitor the presence of a pilot flame in the flare.

(3) The maximum permitted velocity (Vmax) for air-assisted flares shall be computed using the following equation:

$$V_{max}=8.706+0.7084\ H_T$$

where:

Vmax=maximum permitted velocity, m/sec.

HT=net heating value of the gas being combusted, MJ/scm.

(4) The net heating value (HT) of the gas being combusted in a flare shall be computed as follows:

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

where:

K=conversion constant, 1.740×10^{-7} [(g-mole)(MJ)]/[(ppm)(scm)(kcal).

Ci=concentration of sample component ``i'', ppm.

Hi=net heat of combustion of sample component ``i'' at 25 °C and 760 mm Hg, kcal/g-mole.

(5) Method 18 and ASTM D 2504-67 (incorporated by reference-see §60.17) shall be used to determine the concentration of sample component ``i.''

(6) ASTM D 2382-76 (incorporated by reference-see §60.17) shall be used to determine the net heat of combustion of component ``i'' if published values are not available or cannot be calculated.

(7) Method 2, 2A, 2C, or 2D, as appropriate, shall be used to determine the actual exit velocity of a flare. If needed, the unobstructed (free) cross-sectional area of the flare tip shall be used.

[54 FR 6678, Feb. 14, 1989, as amended at 54 FR 27016, June 27, 1989]

§60.486 Recordkeeping requirements.

(a)(1) Each owner or operator subject to the provisions of this subpart shall comply with the recordkeeping requirements of this section.

(2) An owner or operator of more than one affected facility subject to the provisions of this subpart may comply with the recordkeeping requirements for these facilities in one recordkeeping system if the system identifies each record by each facility.

(b) When each leak is detected as specified in §§60.482-2, 60.482-3, 60.482-7, 60.482-8, and 60.483-2, the following requirements apply:

(1) A weatherproof and readily visible identification, marked with the equipment identification number, shall be attached to the leaking equipment.

(2) The identification on a valve may be removed after it has been monitored for 2 successive months as specified in §60.482-7(c) and no leak has been detected during those 2 months.

(3) The identification on equipment except on a valve, may be removed after it has been repaired.

(c) When each leak is detected as specified in §§60.482-2, 60.482-3, 60.482-7, 60.482-8, and 60.483-2, the following information shall be recorded in a log and shall be kept for 2 years in a readily accessible location:

(1) The instrument and operator identification numbers and the equipment identification number.

(2) The date the leak was detected and the dates of each attempt to repair the leak.

(3) Repair methods applied in each attempt to repair the leak.

(4) ``Above 10,000'' if the maximum instrument reading measured by the methods specified in §60.485(a) after each repair attempt is equal to or greater than 10,000 ppm.

(5) ``Repair delayed'' and the reason for the delay if a leak is not repaired within 15 calendar days after discovery of the leak.

(6) The signature of the owner or operator (or designate) whose decision it was that repair could not be effected without a process shutdown.

(7) The expected date of successful repair of the leak if a leak is not repaired within 15 days.

(8) Dates of process unit shutdown that occur while the equipment is unrepaired.

(9) The date of successful repair of the leak.

(d) The following information pertaining to the design requirements for closed vent systems and control devices described in §60.482-10 shall be recorded and kept in a readily accessible location:

(1) Detailed schematics, design specifications, and piping and instrumentation diagrams.

(2) The dates and descriptions of any changes in the design specifications.

(3) A description of the parameter or parameters monitored, as required in §60.482-10(e), to ensure that control devices are operated and maintained in conformance with their design and an explanation of

why that parameter (or parameters) was selected for the monitoring.

(4) Periods when the closed vent systems and control devices required in §§60.482-2, 60.482-3, 60.482-4, and 60.482-5 are not operated as designed, including periods when a flare pilot light does not have a flame.

(5) Dates of startups and shutdowns of the closed vent systems and control devices required in §§60.482-2, 60.482-3, 60.482-4, and 60.482-5.

(e) The following information pertaining to all equipment subject to the requirements in §§60.482-1 to 60.482-10 shall be recorded in a log that is kept in a readily accessible location:

(1) A list of identification numbers for equipment subject to the requirements of this subpart.

(2)(i) A list of identification numbers for equipment that are designated for no detectable emissions under the provisions of §§60.482-2(e), 60.482-3(i) and 60.482-7(f).

(ii) The designation of equipment as subject to the requirements of §60.482-2(e), §60.482-3(i), or §60.482-7(f) shall be signed by the owner or operator.

(3) A list of equipment identification numbers for pressure relief devices required to comply with §60.482-4.

(4)(i) The dates of each compliance test as required in §§60.482-2(e), 60.482-3(i), 60.482-4, and 60.482-7(f).

(ii) The background level measured during each compliance test.

(iii) The maximum instrument reading measured at the equipment during each compliance test.

(5) A list of identification numbers for equipment in vacuum service.

(f) The following information pertaining to all valves subject to the requirements of §60.482-7(g) and (h) shall be recorded in a log that is kept in a readily accessible location:

(1) A list of identification numbers for valves that are designated as unsafe- to-monitor, an explanation for each valve stating why the valve is unsafe-to-monitor, and the plan for monitoring each valve.

(2) A list of identification numbers for valves that are designated as difficult- to-monitor, an explanation for each valve stating why the valve is difficult-to-monitor, and the schedule for monitoring each value.

(g) The following information shall be recorded for valves complying with §60.483-2:

(1) A schedule of monitoring.

(2) The percent of valves found leaking during each monitoring period.

(h) The following information shall be recorded in a log that is kept in a readily accessible location:

(1) Design criterion required in §§60.482-2(d)(5) and 60.482-3(e)(2) and explanation of the design criterion; and

(2) Any changes to this criterion and the reasons for the changes.

(i) The following information shall be recorded in a log that is kept in a readily accessible location for use in determining
exemptions as provided in §60.480(d):

(1) An analysis demonstrating the design capacity of the affected facility,

(2) A statement listing the feed or raw materials and products from the affected facilities and an analysis demonstrating whether these chemicals are heavy liquids or beverage alcohol, and

(3) An analysis demonstrating that equipment is not in VOC service.

(j) Information and data used to demonstrate that a piece of equipment is not in VOC service shall be recorded in a log that is kept in a readily accessible location.

(k) The provisions of §60.7 (b) and (d) do not apply to affected facilities subject to this subpart.

§60.487 Reporting requirements.

(a) Each owner or operator subject to the provisions of this subpart shall submit semiannual reports to the Administrator beginning six months after the initial start up date.

(b) The initial semiannual report to the Administrator shall include the following information:

(1) Process unit identification.

(2) Number of valves subject to the requirements of §60.482-7, excluding those valves designated for no detectable emissions under the provisions of §60.482-7(f).

(3) Number of pumps subject to the requirements of §60.482-2, excluding those pumps designated for no detectable emissions under the provisions of §60.482-2(e) and those pumps complying with §60.482-2(f).

(4) Number of compressors subject to the requirements of §60.482-3, excluding those compressors designated for no detectable emissions under the provisions of §60.482-3(i) and those compressors complying with §60.482-3(h).

(c) All semiannual reports to the Administrator shall include the following information, summarized from the information in §60.486:

(1) Process unit identification.

(2) For each month during the semiannual reporting period,

(i) Number of valves for which leaks were detected as described in §60.482(7)(b) or §60.483-2,

(ii) Number of valves for which leaks were not repaired as required in §60.482-7(d)(1),

(iii) Number of pumps for which leaks were detected as described in §60.482-2(b) and (d)(6)(i),

(iv) Number of pumps for which leaks were not repaired as required in §60.482-2(c)(1) and (d)(6)(ii),

(v) Number of compressors for which leaks were detected as described in §60.482-3(f),

(vi) Number of compressors for which leaks were not repaired as required in §60.482-3(g)(1), and

(vii) The facts that explain each delay of repair and, where appropriate, why a process unit shutdown was technically infeasible.

(3) Dates of process unit shutdowns which occurred within the semiannual reporting period.

(4) Revisions to items reported according to paragraph (b) if changes have occurred since the initial report or subsequent revisions to the initial report.

(d) An owner or operator electing to comply with the provisions of §§60.483-1 and 60.483-2 shall notify the Administrator of the alternative standard selected 90 days before implementing either of the provisions.

(e) An owner or operator shall report the results of all performance tests in accordance with §60.8 of the General Provisions. The provisions of §60.8(d) do not apply to affected facilities subject to the provisions of this subpart except that an owner or operator must notify the Administrator of the schedule for the initial performance tests at least 30 days before the initial performance tests.

(f) The requirements of paragraphs (a) through (c) of this section remain in force until and unless EPA, in delegating enforcement authority to a State under section 111(c) of the Act, approves reporting requirements or an alternative means of compliance surveillance adopted by such State. In that event, affected sources within the State will be relieved of the obligation to comply with the requirements of paragraphs (a) through (c) of this section, provided that they comply with the requirements established by the State.

[48 FR 48335, Oct. 18, 1983, as amended at 49 FR 22608, May 30, 1984]

§60.488 Reconstruction.

For the purposes of this subpart:

(a) The cost of the following frequently replaced components of the facility shall not be considered in calculating either the ``fixed capital cost of the new components'' or the ``fixed capital costs that would be required to construct a comparable new facility'' under §60.15: pump seals, nuts and bolts, rupture disks, and packings.

(b) Under §60.15, the ``fixed capital cost of new components'' includes the fixed capital cost of all depreciable components (except components specified in §60.488 (a)) which are or will be replaced pursuant to all continuous programs of component replacement which are commenced within any 2-year period following the applicability date for the appropriate subpart. (See the ``Applicability and designation of affected facility'' section of the appropriate subpart.) For purposes of this paragraph, ``commenced'' means that an owner or operator has undertaken a continuous program of component replacement or that an owner or operator has entered into a contractual obligation to undertake and complete, within a reasonable time, a continuous program of component replacement.

[49 FR 22608, May 30, 1984]

§60.489 List of chemicals produced by affected facilities.

(a) The following chemicals are produced, as intermediates or final products, by process units covered under this subpart. The applicability date for process units producing one or more of these chemicals is January 5, 1981.

CAS No.	Chemical
105-57-7	Acetal
75-07-0	Acetaldehyde
107-89-1	Acetaldol
60-35-5	Acetamide
103-84-4	Acetanilide
64-19-7	Acetic acid
108-24-7	Acetic anhydride
67-64-1	Acetone
75-86-5	Acetone cyanohydrin
75-05-8	Acetonitrile

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CAS No.	Chemical
98-86-2	Acetophenone
75-36-5	Acetyl chloride
74-86-2	Acetylene
107-02-8	Acrolein
79-06-1	Acrylamide
79-10-7	Acrylic acid
107-13-1	Acrylonitrile
124-04-9	Adipic acid
111-69-3	Adiponitrile
(b)	Alkyl naphthalenes
107-18-6	Allyl alcohol
107-05-1	Allyl chloride
1321-11-5	Aminobenzoic acid
111-41-1	Aminoethylethanolamine
123-30-8	p-Aminophenol
628-63-7, 123-92-2	Amyl acetates
71-41-0 c	Amyl alcohols
110-58-7	Amyl amine
543-59-9	Amyl chloride
110-66-7 c	Amyl mercaptans
1322-06-1	Amyl phenol
62-53-3	Aniline
142-04-1	Aniline hydrochloride
29191-52-4	Anisidine
100-66-3	Anisole
118-92-3	Anthranilic acid
84-65-1	Anthraquinone
100-52-7	Benzaldehyde
55-21-0	Benzamide
71-43-2	Benzene
98-48-6	Benzenedisulfonic acid
98-11-3	Benzenesulfonic acid

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CAS No.	Chemical
134-81-6	Benzil
76-93-7	Benzilic acid
65-85-0	Benzoic acid
119-53-9	Benzoin
98-87-3	Benzyl dichloride
119-61-9	Benzophenone
98-07-7	Benzotrichloride
98-88-4	Benzoyl chloride
100-51-6	Benzyl alcohol
100-46-9	Benzylamine
120-51-4	Benzyl benzoate
100-44-7	Benzyl chloride
100-47-0	Benzonitrile
92-52-4	Biphenyl
80-05-7	Bisphenol A
10-86-1	Bromobenzene
27497-51-4	Bromonaphthalene
106-99-0	Butadiene
106-98-9	1-butene
123-86-4	n-butyl acetate
141-32-2	n-butyl acrylate
71-36-3	n-butyl alcohol
78-92-2	s-butyl alcohol
75-65-0	t-butyl alcohol
109-73-9	n-butylamine
13952-84-6	s-butylamine
75-64-9	t-butylamine
98-73-7	p-tert-butyl benzoic acid
107-88-0	1,3-butylene glycol
123-72-8	n-butyraldehyde
107-92-6	Butyric acid
106-31-0	Butyric anhydride

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CAS No.	Chemical
109-74-0	Butyronitrile
105-60-2	Caprolactam
75-1-50	Carbon disulfide
558-13-4	Carbon tetrabromide
56-23-5	Carbon tetrachloride
9004-35-7	Cellulose acetate
79-11-8	Chloroacetic acid
108-42-9	m-chloroaniline
95-51-2	o-chloroaniline
106-47-8	p-chloroaniline
35913-09-8	Chlorobenzaldehyde
108-90-7	Chlorobenzene
118-91-2, 535-80-8, 74-11-3 c	Chlorobenzoic acid
2136-81-4, 2136-89-2, 5216-25-1c	Chlorobenzotrichloride
1321-03-5	Chlorbenzoyl chloride
25497-29-4	Chlorodifluoromethane
75-45-6	Chlorodifluoroethane
67-66-3	Chloroform
25586-43-0	Chloronapthalene
88-73-3	o-chloronitrobenzene
100-00-5	p-chloronitrobenzene
25167-80-0	Chlorophenols
126-99-8	Chloroprene
7790-94-5	Chlorosulfonic acid
108-41-8	m-chlorotoluene
95-49-8	o-chlorotoluene
106-43-4	p-chlorotoluene
75-72-9	Chlorotrifluoromethane
108-39-4	m-cresol
95-48-7	o-cresol
106-44-5	p-cresol
1319-77-3	Mixed cresols

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CAS No.	Chemical
1319-77-3	Cresylic acid
4170-30-0	Crotonaldehyde
3724-65-0	Crotonic acid
98-82-8	Cumene
80-15-9	Cumene hydroperoxide
372-09-8	Cyanoacetic acid
506-77-4	Cyanogen chloride
108-80-5	Cyanuric acid
108-77-0	Cyanuric chloride
110-82-7	Cyclohexane
108-93-0	Cyclohexanol
108-94-1	Cyclohexanone
110-83-8	Cyclohexene
108-91-8	Cyclohexylamine
111-78-4	Cyclooctadiene
112-30-1	Decanol
123-42-2	Diacetone alcohol
27576-04-1	Diaminobenzoic acid
95-76-1, 95-82-9, 554-00-7, 608-27-5, 608-31-1, 626-43-7, 27134-27-6, 57311-92-9 c	Dichloroaniline
541-73-1	m-dichlorobenzene
95-50-1	o-dichlorobenzene
106-46-7	p-dichlorobenzene
75-71-8	Dichlorodifluoromethane
111-44-4	Dichloroethyl ether
107-06-2	1,2-dichloroethane (EDC)
96-23-1	Dichlorohydrin
26952-23-8	Dichloropropene
101-83-7	Dicyclohexylamine
109-89-7	Diethylamine
111-46-6	Diethylene glycol
112-36-7	Diethylene glycol diethyl ether
111-96-6	Diethylene glycol dimethyl ether

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CAS No.	Chemical
112-34-5	Diethylene glycol monobutyl ether
124-17-7	Diethylene glycol monobutyl ether acetate
111-90-0	Diethylene glycol monoethyl ether
112-15-2	Diethylene glycol monoethyl ether acetate
111-77-3	Diethylene glycol monomethyl ether
64-67-5	Diethyl sulfate
75-37-6	Difluoroethane
25167-70-8	Diisobutylene
26761-40-0	Diisodecyl phthalate
27554-26-3	Diisooctyl phthalate
674-82-8	Diketene
124-40-3	Dimethylamine
121-69-7	N,N-dimethylaniline
115-10-6	N,N-dimethyl ether
68-12-2	N,N-dimethylformamide
57-14-7	Dimethylhydrazine
77-78-1	Dimethyl sulfate
75-18-3	Dimethyl sulfide
67-68-5	Dimethyl sulfoxide
120-61-6	Dimethyl terephthalate
99-34-3	3,5-dinitrobenzoic acid
51-28-5	Dinitrophenol
25321-14-6	Dinitrotoluene
123-91-1	Dioxane
646-06-0	Dioxilane
122-39-4	Diphenylamine
101-84-8	Diphenyl oxide
102-08-9	Diphenyl thiourea
25265-71-8	Dipropylene glycol
25378-22-7	Dodecene
28675-17-4	Dodecylaniline
27193-86-8	Dodecylphenol

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CAS No.	Chemical
106-89-8	Epichlorohydrin
64-17-5	Ethanol
141-43-5 c	Ethanolamines
141-78-6	Ethyl acetate
141-97-9	Ethyl acetoacetate
140-88-5	Ethyl acrylate
75-04-7	Ethylamine
100-41-4	Ethylbenzene
74-96-4	Ethyl bromide
9004-57-3	Ethylcellulose
75-00-3	Ethyl chloride
105-39-5	Ethyl chloroacetate
105-56-6	Ethylcyanoacetate
74-85-1	Ethylene
96-49-1	Ethylne carbonate
107-07-3	Ethylene chlorohydrin
107-15-3	Ethylenediamine
106-93-4	Ethylene dibromide
107-21-1	Ethylene glycol
111-55-7	Ethylene glycol diacetate
110-71-4	Ethylene glycol dimethyl ether
111-76-2	Ethylene glycol monobutyl ether
112-07-2	Ethylene glycol monobutyl ether acetate
110-80-5	Ethylene glycol monoethy ether
111-15-9	Ethylene glycol monethyl ether acetate
109-86-4	Ethylene glycol monomethyl ether
110-49-6	Ethylene glycol monomethyl ether acetate
122-99-6	Ethylene glycol monophenyl ether
2807-30-9	Ethylene glycol monopropyl ether
75-21-8	Ethylene oxide
60-29-7	Ethyl ether
104-76-7	2-ethylhexanol

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CAS No.	Chemical
122-51-0	Ethyl orthoformate
95-92-1	Ethyl oxalate
41892-71-1	Ethyl sodium oxalacetate
50-00-0	Formaldehyde
75-12-7	Formamide
64-18-6	Formic acid
110-17-8	Fumaric acid
98-01-1	Furfural
56-81-5	Glycerol
26545-73-7	Glycerol dichlorohydrin
25791-96-2	Glycerol triether
56-40-6	Glycine
107-22-2	Glyoxal
118-74-1	Hexachlorobenzene
67-72-1	Hexachloroethane
36653-82-4	Hexadecyl alcohol
124-09-4	Hexamethylenediamine
629-11-8	Hexamethylene glycol
100-97-0	Hexamethylenetetramine
74-90-8	Hydrogen cyanide
123-31-9	Hydroquinone
99-96-7	p-hydroxybenzoic acid
26760-64-5	Isoamylene
78-83-1	Isobutanol
110-19-0	Isobutyl acetate
115-11-7	Isobutylene
78-84-2	Isobutyraldehyde
79-31-2	Isobutyric acid
25339-17-7	Isodecanol
26952-21-6	Isooctyl alcohol
78-78-4	Isopentane
78-59-1	Isophorone

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CAS No.	Chemical
121-91-5	Isophthalic acid
78-79-5	Isoprene
67-63-0	Isopropanol
108-21-4	Isopropyl acetate
75-31-0	Isopropylamine
75-29-6	Isopropyl chloride
25168-06-3	Isopropylphenol
463-51-4	Ketene
(b)	Linear alkyl sulfonate
123-01-3	Linear alkylbenzene (linear dodecylbenzene)
110-16-7	Maleic acid
108-31-6	Maleic anhydride
6915-15-7	Malic acid
141-79-7	Mesityl oxide
121-47-1	Metanilic acid
79-41-4	Methacrylic acid
563-47-3	Methallyl chloride
67-56-1	Methanol
79-20-9	Methyl acetate
105-45-3	Methyl acetoacetate
74-89-5	Methylamine
100-61-8	n-methylaniline
74-83-9	Methyl bromide
37365-71-2	Methyl butynol
74-87-3	Methyl chloride
108-87-2	Methylcyclohexane
1331-22-2	Methylcyclohexanone
75-09-2	Methylene chloride
101-77-9	Methylene dianiline
101-68-8	Methylene diphenyl diisocyanate
78-93-3	Methyl ethyl ketone
107-31-3	Methyl formate

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CAS No.	Chemical
108-11-2	Methyl isobutyl carbinol
108-10-1	Methyl isobutyl ketone
80-62-6	Methyl methacrylate
77-75-8	Methylpentynol
98-83-9	a-methylstyrene
110-91-8	Morpholine
85-47-2	a-naphthalene sulfonic acid
120-18-3	b-naphthalene sulfonic acid
90-15-3	a-naphthol
135-19-3	b-naphthol
75-98-9	Neopentanoic acid
88-74-4	o-nitroaniline
100-01-6	p-nitroaniline
91-23-6	o-nitroanisole
100-17-4	p-nitroanisole
98-95-3	Nitrobenzene
27178-83-2c	Nitrobenzoic acid (o,m, and p)
79-24-3	Nitroethane
75-52-5	Nitromethane
88-75-5	2-Nitrophenol
25322-01-4	Nitropropane
1321-12-6	Nitrotoluene
27215-95-8	Nonene
25154-52-3	Nonylphenol
27193-28-8	Octylphenol
123-63-7	Paraldehyde
115-77-5	Pentaerythritol
109-66-0	n-pentane
109-67-1	1-pentene
127-18-4	Perchloroethylene
594-42-3	Perchloromethyl mercaptan
94-70-2	o-phenetidine

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CAS No.	Chemical
156-43-4	p-phenetidine
108-95-2	Phenol
98-67-9, 585-38-6, 609-46-1, 1333-39-7 c	Phenolsulfonic acids
Phenyl anthranilic acid	Phenyl anthranilic acid
(b)	Phenylenediamine
75-44-5	Phosgene
85-44-9	Phthalic anhydride
85-41-6	Phthalimide
108-99-6	b-picoline
110-85-0	Piperazine
9003-29-6, 25036-29-7c	Polybutenes
25322-68-3	Polyethylene glycol
25322-69-4	Polypropylene glycol
123-38-6	Propional dehyde
79-09-4	Propionic acid
71-23-8	n-propyl alcohol
107-10-8	Propylamine
540-54-5	Propyl chloride
115-07-1	Propylene
127-00-4	Propylene chlorohydrin
78-87-5	Propylene dichloride
57-55-6	Propylene glycol
75-56-9	Propylene oxide
110-86-1	Pyridine
106-51-4	Quinone
108-46-3	Resorcinol
27138-57-4	Resorcylic acid
69-72-7	Salicylic acid
127-09-3	Sodium acetate
532-32-1	Sodium benzoate
9004-32-4	Sodium carboxymethyl cellulose
3926-62-3	Sodium chloroacetate

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CAS No.	Chemical
141-53-7	Sodium formate
139-02-6	Sodium phenate
110-44-1	Sorbic acid
100-42-5	Styrene
110-15-6	Succinic acid
110-61-2	Succinonitrile
121-57-3	Sulfanilic acid
126-33-0	Sulfolane
1401-55-4	Tannic acid
100-21-0	Terephthalic acid
79-34-5 c	Tetrachloroethanes
117-08-8	Tetrachlorophthalic anhydride
78-00-2	Tetraethyl lead
119-64-2	Tetrahydronapthalene
85-43-8	Tetrahydrophthalic anhydride
75-74-1	Tetramethyl lead
110-60-1	Tetramethylenediamine
110-18-9	Tetramethylethylenediamine
108-88-3	Toluene
95-80-7	Toluene-2,4-diamine
584-84-9	Toluene-2,4-diisocyanate
26471-62-5	Toluene diisocyanates (mixture)
1333-07-9	Toluenesulfonamide
104-15-4 c	Toluenesulfonic acids
98-59-9	Toluenesulfonyl chloride
26915-12-8	Toluidines
87-61-6, 108-70-3, 120-82-1 c	Trichlorobenzenes
71-55-6	1,1,1-trichloroethane
79-00-5	1,1,2-trichloroethane
79-01-6	Trichloroethylene
75-69-4	Trichlorofluoromethane
96-18-4	1,2,3-trichloropropane

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CAS No.	Chemical
76-13-1	1,1,2-trichloro-1,2,2-trifluoroethane
121-44-8	Triethylamine
112-27-6	Triethylene glycol
112-49-2	Triethylene glycol dimethyl ether
7756-94-7	Triisobutylene
75-50-3	Trimethylamine
57-13-6	Urea
108-05-4	Vinyl acetate
75-01-4	Vinyl chloride
75-35-4	Vinylidene chloride
25013-15-4	Vinyl toluene
1330-20-7	Xylenes (mixed)
95-47-6	o-xylene
106-42-3	p-xylene
1300-71-6	Xylenol
1300-73-8	Xylidine

a CAS numbers refer to the Chemical Abstracts Registry numbers assigned to specific chemicals, isomers, or mixtures of chemicals. Some isomers or mixtures that are covered by the standards do not have CAS numbers assigned to them. The standards apply to all of the chemicals listed, whether CAS numbers have been assigned or not.

b No CAS number(s) have been assigned to this chemical, its isomers, or mixtures containing these chemicals.

c CAS numbers for some of the isomers are listed; the standards apply to all of the isomers and mixtures, even if CAS numbers have not been assigned.

Subpart NNN-Standards of Performance for Volatile Organic Compound (VOC) Emissions From Synthetic Organic Chemical Manufacturing Industry (SOCMI) Distillation Operations

Source: 55 FR 26942, June 29, 1990, unless otherwise noted.

§60.660 Applicability and designation of affected facility.

(a) The provisions of this subpart apply to each affected facility designated in paragraph (b) of this section that is part of a process unit that produces any of the chemicals listed in §60.667 as a product, co-product, by-product, or intermediate, except as provided in paragraph (c).

(b) The affected facility is any of the following for which construction, modification, or reconstruction commenced after December 30, 1983:

(1) Each distillation unit not discharging its vent stream into a recovery system.

(2) Each combination of a distillation unit and the recovery system into which its vent stream is discharged.

(3) Each combination of two or more distillation units and the common recovery system into which their vent streams are discharged.

(c) Exemptions from the provisions of paragraph (a) of this section are as follows:

(1) Any distillation unit operating as part of a process unit which produces coal tar or beverage alcohols, or which uses, contains, and produces no VOC is not an affected facility.

(2) Any distillation unit that is subject to the provisions of Subpart DDD is not an affected facility.

(3) Any distillation unit that is designed and operated as a batch operation is not an affected facility.

(4) Each affected facility that has a total resource effectiveness (TRE) index value greater than 8.0 is exempt from all provisions of this subpart except for §§60.662; 60.664 (d), (e), and (f); and 60.665 (h) and (l).

(5) Each affected facility in a process unit with a total design capacity for all chemicals produced within that unit of less than one gigagram per year is exempt from all provisions of this subpart except for the recordkeeping and reporting requirements in paragraphs (j), (l)(6), and (n) of §60.665.

(6) Each affected facility operated with a vent stream flow rate less than 0.008 scm/min is exempt from all provisions of this subpart except for the test method and procedure and the recordkeeping and reporting requirements in §60.664(g) and paragraphs (i), (l)(5), and (o) of §60.665.

[Note: The intent of these standards is to minimize the emissions of VOC through the application of best demonstrated technology (BDT). The numerical emission limits in these standards are expressed in terms of total organic compounds (TOC), measured as TOC less methane and ethane. This emission limit reflects the performance of BDT.]

§60.661 Definitions.

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

Batch distillation operation means a noncontinuous distillation operation in which a discrete quantity or batch of liquid feed is charged into a distillation unit and distilled at one time. After the initial charging of the liquid feed, no additional liquid is added during the distillation operation.

Boiler means any enclosed combustion device that extracts useful energy in the form of steam.

By compound means by individual stream components, not carbon equivalents.

Continuous recorder means a data recording device recording an instantaneous data value at least once every 15 minutes. Distillation operation means an operation separating one or more feed stream(s) into two or more exit stream(s), each exit stream having component concentrations different from those in the feed stream(s). The separation is achieved by the redistribution of the components between the liquid and vapor-phase as they approach equilibrium within the distillation unit.

Distillation unit means a device or vessel in which distillation operations occur, including all associated internals (such as trays or packing) and accessories (such as reboiler, condenser, vacuum pump, steam jet, etc.), plus any associated recovery system.

Flame zone means the portion of the combustion chamber in a boiler occupied by the flame envelope.

Flow indicator means a device which indicates whether gas flow is present in a vent stream.

Halogenated vent stream means any vent stream determined to have a total concentration (by volume) of compounds containing halogens of 20 ppmv (by compound) or greater.

Incinerator means any enclosed combustion device that is used for destroying organic compounds and does not extract energy in the form of steam or process heat.

Process heater means a device that transfers heat liberated by burning fuel to fluids contained in tubes, including all fluids except water that is heated to produce steam.

Process unit means equipment assembled and connected by pipes or ducts to produce, as intermediates or final products, one or more of the chemicals in §60.667. A process unit can operate independently if supplied with sufficient fuel or raw materials and sufficient product storage facilities.

Product means any compound or chemical listed in §60.667 that is produced for sale as a final product as that chemical, or for use in the production of other chemicals or compounds. By-products, co-products, and intermediates are considered to be products.

Recovery device means an individual unit of equipment, such as an absorber, carbon adsorber, or condenser, capable of and used for the purpose of recovering chemicals for use, reuse, or sale.

Recovery system means an individual recovery device or series of such devices applied to the same vent stream.

Total organic compounds (TOC) means those compounds measured according to the procedures in §60.664(b)(4). For the purposes of measuring molar composition as required in §60.664(d)(2)(i); hourly emissions rate as required in §60.664(d)(5) and §60.664(e); and TOC concentration as required in §60.665(b)(4) and §60.665(g)(4), those compounds which the Administrator has determined do not contribute appreciably to the formation of ozone are to be excluded. The compounds to be excluded are identified in Environmental Protection Agency's statements on ozone abatement policy for State Implementation Plans (SIP) revisions (42 FR 35314; 44 FR 32042; 45 FR 32424; 45 FR 48942).

TRE index value means a measure of the supplemental total resource requirement per unit reduction of TOC associated with an individual distillation vent stream, based on vent stream flow rate, emission rate of TOC net heating value, and corrosion properties (whether or not the vent stream is halogenated), as quantified by the equation given under §60.664(e).

Vent stream means any gas stream discharged directly from a distillation facility to the atmosphere or indirectly to the atmosphere after diversion through other process equipment. The vent stream excludes relief valve discharges and equipment leaks including, but not limited to, pumps, compressors, and valves.

§60.662 Standards.

Each owner or operator of any affected facility shall comply with paragraph (a), (b), or (c) of this section for each vent stream on and after the date on which the initial performance test required by §60.8 and §60.664 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 the initial start-up, whichever date comes first. Each owner or operator shall either:

(a) Reduce emissions of TOC (less methane and ethane) by 98 weight-percent, or to a TOC (less methane and ethane) concentration of 20 ppmv, on a dry basis corrected to 3 percent oxygen, whichever is less stringent. If a boiler or process heater is used to comply with this paragraph, then the vent stream shall be introduced into the flame zone of the boiler or process heater; or

(b) Combust the emissions in a flare that meets the requirements of §60.18; or

(c) Maintain a TRE index value greater than 1.0 without use of VOC emission control devices.

§60.663 Monitoring of emissions and operations.

(a) The owner or operator of an affected facility that uses an incinerator to seek to comply with the TOC emission limit specified under §60.662(a) shall install, calibrate, maintain, and operate according to manufacturer's specifications the following equipment:

(1) A temperature monitoring device equipped with a continuous recorder and having an accuracy of ±1 percent of the temperature being monitored expressed in degrees Celsius or ±0.5 EC, whichever is greater.

(i) Where an incinerator other than a catalytic incinerator is used, a temperature monitoring device shall be installed in the firebox.

(ii) Where a catalytic incinerator is used, temperature monitoring devices shall be installed in the gas stream immediately before and after the catalyst bed.

(2) A flow indicator that provides a record of vent stream flow to the incinerator at least once every hour for each affected facility. The flow indicator shall be installed in the vent stream from each affected facility at a point closest to the inlet of each incinerator and before being joined with any other vent stream.

(b) The owner or operator of an affected facility that uses a flare to seek to comply with §60.662(b) shall install, calibrate, maintain and operate according to manufacturer's specifications the following equipment:

(1) A heat sensing device, such as a ultra-violet beam sensor or thermocouple, at the pilot light to indicate the continuous presence of a flame.

(2) A flow indicator that provides a record of vent stream flow to the flare at least once every hour for each affected facility. The flow indicator shall be installed in the vent stream from each affected facility at a point closest to the flare and before being joined with any other vent stream.

(c) The owner or operator of an affected facility that uses a boiler or process heater to seek to comply with §60.662(a) shall install, calibrate, maintain and operate according to the manufacturer's specifications in the following equipment:

(1) A flow indicator that provides a record of vent stream flow to the boiler or process heater at least once every hour for each affected facility. The flow indicator shall be installed in the vent stream from each distillation unit within an affected facility at a point closest to the inlet of each boiler or process heater and before being joined with any other vent stream.

(2) A temperature monitoring device in the firebox equipped with a continuous recorder and having an accuracy of ±1 percent of the temperature being measured expressed in degrees Celsius or ±0.5 EC,

whichever is greater, for boilers or process heaters of less than 44 MW (150 million Btu/hr) heat input design capacity.

(3) Monitor and record the periods of operation of the boiler or process heater if the design heat input capacity of the boiler or process heater is 44 MW (150 million Btu/hr) or greater. The records must be readily available for inspection.

(d) The owner or operator of an affected facility that seeks to comply with the TRE index value limit specified under §60.662(c) shall install, calibrate, maintain, and operate according to manufacturer's specifications the following equipment, unless alternative monitoring procedures or requirements are approved for that facility by the Administrator:

(1) Where an absorber is the final recovery device in the recovery system:

(i) A scrubbing liquid temperature monitoring device having an accuracy of ±1 percent of the temperature being monitored expressed in degrees Celsius or ±0.5 EC, whichever is greater, and a specific gravity monitoring device having an accuracy of ±0.02 specific gravity units, each equipped with a continuous recorder, or

(ii) An organic monitoring device used to indicate the concentration level of organic compounds exiting the recovery device based on a detection principle such as infrared, photoionization, or thermal conductivity, each equipped with a continuous recorder.

(2) Where a condenser is the final recovery device in the recovery system:

(i) A condenser exit (product side) temperature monitoring device equipped with a continuous recorder and having an accuracy of ±1 percent of the temperature being monitored expressed in degrees Celsius or ±0.5 EC, whichever is greater, or

(ii) An organic monitoring device used to monitor organic compounds exiting the recovery device based on a detection principle such as infra-red, photoionization, or thermal conductivity, each equipped with a continuous recorder.

(3) Where a carbon adsorber is the final recovery device unit in the recovery system:

(i) An integrating steam flow monitoring device having an accuracy of ±10 percent, and a carbon bed temperature monitoring device having an accuracy of ±1 percent of the temperature being monitored expressed in degrees Celsius or ±0.5 EC, whichever is greater, both equipped with a continuous recorder, or

(ii) An organic monitoring device used to indicate the concentration level of organic compounds exiting the recovery device based on a detection principle such as infra-red, photoionization, or thermal conductivity, each equipped with a continuous recorder.

(e) An owner or operator of an affected facility seeking to demonstrate compliance with the standards specified under §60.662 with control devices other than incinerator, boiler, process heater, or flare; or recovery device other than an absorber, condenser, or carbon absorber shall provide to the Administrator information describing the operation of the control device or recovery device and the process parameter(s) which would indicate proper operation and maintenance of the device. The Administrator may request further information and will specify appropriate monitoring procedures or requirements.

§60.664 Test methods and procedures.

(a) For the purpose of demonstrating compliance with §60.662, all affected facilities shall be run at full operating conditions and flow rates during any performance test.

(b) The following methods in appendix A to this part, except as provided under §60.8(b), shall be used as reference methods to determine compliance with the emission limit or percent reduction efficiency specified under §60.662(a).

(1) Method 1 or 1A, as appropriate, for selection of the sampling sites. The control device inlet sampling site for determination of vent stream molar composition or TOC (less methane and ethane) reduction efficiency shall be prior to the inlet of the control device and after the recovery system.

(2) Method 2, 2A, 2C, or 2D, as appropriate, for determination of the gas volumetric flow rates.

(3) The emission rate correction factor, integrated sampling and analysis procedure of Method 3 shall be used to determine the oxygen concentration (%O_{2d}) for the purposes of determining compliance with the 20 ppmv limit. The sampling site shall be the same as that of the TOC samples, and the samples shall be taken during the same time that the TOC samples are taken. The TOC concentration corrected to 3 percent 02 (Cc) shall be computed using the following equation:

$$C_c = C_{TOC} \frac{17.9}{20.9 - \%O_{2d}}$$

where:

Cc=Concentration of TOC corrected to 3 percent O_2, dry basis, ppm by volume.

CTOC=Concentration of TOC (minus methane and ethane), dry basis, ppm by volume.

%O_{2d}=Concentration of O_2, dry basis, percent by volume.

(4) Method 18 to determine the concentration of TOC in the control device outlet and the concentration of TOC in the inlet when the reduction efficiency of the control device is to be determined.

(i) The sampling time for each run shall be 1 hour in which either an integrated sample or four grab samples shall be taken. If grab sampling is used then the samples shall be taken at 15-minute intervals.

(ii) The emission reduction (R) of TOC (minus methane and ethane) shall be determined using the following equation:

$$R = \frac{E_i - E_o}{E_i} \times 100$$

where:
R=Emission reduction, percent by weight.
Ei=Mass rate of TOC entering the control device, kg TOC/hr. Eo=Mass rate of TOC discharged to the atmosphere, kg TOC/hr.

(iii) The mass rates of TOC (Ei, Eo) shall be computed using the following equations:

$$E_i = K_2 \left(\sum_{j=1}^{n} C_{ij} M_{ij} \right) Q_i$$

$$E_o = K_2 \left(\sum_{j=1}^{n} C_{oj} M_{oj} \right) Q_o$$

where:
Cij, Coj=Concentration of sample component ``j'' of the gas stream at the inlet and outlet of the control device, respectively dry basis, ppm by volume.
Mij, Moj=Molecular weight of sample component ``j'' of the gas stream at the inlet and outlet of the control device, respectively, g/g-mole (lb/lb-mole).
Qi, Qo=Flow rate of gas stream at the inlet and outlet of the control device, respectively, dscm/min (dscf/hr).
K2=Constant, 2.494×10^{-6} (1/ppm) (g-mole/scm) (kg/g) (min/hr), where standard temperature for (g-mole/scm) is 20 °C.

(iv) The TOC concentration (CTOC) is the sum of the individual components and shall be computed for each run using the following equation:

$$C_{TOC} = \sum_{j=1}^{n} C_j$$

where:
CTOC=Concentration of TOC (minus methane and ethane), dry basis, ppm by volume.
Cj=Concentration of sample components ``j'', dry basis, ppm by volume.
n=Number of components in the sample.

(5) When a boiler or process heater with a design heat input capacity of 44 MW (150 million Btu/hour) or greater is used to seek to comply with §60.662(a), the requirement for an initial performance test is waived, in accordance with §60.8(b). However, the Administrator reserves the option to require testing at such other times as may be required, as provided for in section 114 of the Act.

(c) When a flare is used to seek to comply with §60.662(b), the flare shall comply with the requirements of §60.18.

(d) The following test methods in appendix A to this part, except as provided under §60.8(b), shall be used for determining the net heating value of the gas combusted to determine compliance under §60.662(b) and for determining the process vent stream TRE index value to determine compliance under §60.662(c).

(1)(i) Method 1 or 1A, as appropriate, for selection of the sampling site. The sampling site for the vent stream flow rate and molar composition determination prescribed in §60.664(d) (2) and (3) shall be, except for the situations outlined in paragraph (d)(1)(ii) of this section, prior to the inlet of any control device, prior to any post-distillation dilution of the stream with air, and prior to any post-distillation introduction of halogenated compounds into the process vent stream. No transverse site selection method is needed for vents smaller than 4 inches in diameter.

(ii) If any gas stream other than the distillation vent stream from the affected facility is normally conducted through the final recovery device.

(A) The sampling site for vent stream flow rate and molar composition shall be prior to the final recovery device and prior to the point at which the nondistillation stream is introduced.

(B) The efficiency of the final recovery device is determined by measuring the TOC concentration using Method 18 at the inlet to the final recovery device after the introduction of any nondistillation vent stream and at the outlet of the final recovery device.

(C) This efficiency is applied to the TOC concentration measured prior to the final recovery device and prior to the introduction of the nondistillation stream to determine the concentration of TOC in the distillation vent stream from the final recovery device. This concentration of TOC is then used to perform the calculations outlined in §60.664(d) (4) and (5).

(2) The molar composition of the process vent stream shall be determined as follows:

(i) Method 18 to measure the concentration of TOC including those containing halogens.

(ii) ASTM D1946-77 (incorporation by reference as specified in §60.17 of this part) to measure the concentration of carbon monoxide and hydrogen.

(iii) Method 4 to measure the content of water vapor.

(3) The volumetric flow rate shall be determined using Method 2, 2A, 2C, or 2D, as appropriate.

(4) The net heating value of the vent stream shall be calculated using the following equation:

$$H_T = K_1 \left(\sum_{j=1}^{n} C_j H_j \right)$$

where:
HT=Net heating value of the sample, MJ/scm, where the net enthalpy per mole of vent stream is based on combustion at 25 EC and 760 mm Hg, but the standard temperature for determining the volume corresponding to one mole is 20EC, as in the definition of Qs (vent stream flow rate).
K1=Constant, 1.740 x 10^{-7}

$$\left(\frac{1}{ppm}\right)\left(\frac{g\text{-mole}}{scm}\right)\left(\frac{MJ}{kcal}\right),$$

where standard temperature for

$$\left(\frac{g\text{-mole}}{scm}\right)$$

is 20 EC.

Cj=Concentration on a wet basis of compound j in ppm, as measured for organics by Method 18 and measured for hydrogen and carbon monoxide by ASTM D1946-77 (incorporation by reference as specified in §60.17 of this part) as indicated in §60.664(d)(2).
Hj=Net heat of combustion of compound j, kcal/g-mole, based on combustion at 25 EC and 760 mm Hg.
The heats of combustion of vent stream components would be required to be determined using ASTM D2382-76 (incorporation by reference as specified in §60.17 of this part) if published values are not available or cannot be calculated.
(5) The emission rate of TOC in the vent stream shall be calculated using the following equation:

$$E_{TOC} = K_2 \left[\sum_{j=1}^{n} C_j M_j \right] Q_s$$

where:
ETOC=Emission rate of TOC in the sample, kg/hr.
K2=Constant, 2.494x10^{-6} (l/ppm) (g-mole/scm) (kg/g) (min/hr), where standard temperature for (g-mole/scm) is 20 EC.
Cj=Concentration on a basis of compound j in ppm as measured by Method 18 as indicated in §60.664(d)(2).
Mj=Molecular weight of sample j, g/g-mole.
Qs=Vent stream flow rate (scm/min) at a temperature of 20 EC.
(6) The total process vent stream concentration (by volume) of compounds containing halogens (ppmv, by compound) shall be summed from the individual concentrations of compounds containing halogens which were measured by Method 18.
(e) For purposes of complying with §60.662(c) the owner or operator of a facility affected by this subpart shall calculate the TRE index value of the vent stream using the equation for incineration in paragraph (e)(1) of this section for halogenated vent streams. The owner or operator of an affected facility with a nonhalogenated vent stream shall determine the TRE index value by calculating values using both the incinerator equation in (e)(1) and the flare equation in (e)(2) of this section and selecting the lower of the two values.
(1) The equation for calculating the TRE index value of a vent stream controlled by an incinerator is as follows:

$$TRE = \frac{1}{E_{TOC}} \left[a + b(Q_s) + d(Q_s)^{0.88} + d(Q_s)(H_T) + e(Q_s)^{0.88}(H_T)^{0.88} + f(Y_s)^{0.5} \right]$$

(i) where for a vent stream flow rate (scm/min) at a standard temperature of 20 EC that is greater than or equal to 14.2 scm/min:
TRE=TRE index value.
Qs=Vent stream flow rate (scm/min) at a standard temperature of 20 EC.
HT=Vent stream net heating value (MJ/scm), where the net enthalpy per mole of vent stream is based on combustion at 25 EC and 760 mm Hg, but the standard temperature for determining the volume corresponding to one mole is 20 EC as in the definition of Qs.
Ys=Qs for all vent stream categories listed in Table 1 except for Category E vent streams where Ys=(Qs)(HT)/3.6.
ETOC=Hourly emissions of TOC reported in kg/hr.
a, b, c, d, e, and f are coefficients.

The set of coefficients that apply to a vent stream can be obtained from Table 1.

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Table 1. Distillation NSPS TRE coefficients for Vent Streams Controlled by an Incinerator

Design Category A1. For Halogenated Process Vent Streams, if 0#Net Heating Value (MJ/scm)#3.5:

Q_s=Vent Steam Flow Rate (scm/min)	a	b	c	d	e	f
14.2#Q_s#18.8	19.18370	0.27580	0.75762	-0.13064	0	0.01025
18.8#Q_s#699	20.00563	0.27580	0.30387	-0.13064	0	0.01025
699#Q_s#1400	39.87022	0.29973	0.30387	-0.13064	0	0.01449
1400#Q_s#2100	59.73481	0.31467	0.30387	-0.13064	0	0.01775
2100#Q_s#2800	79.59941	0.32572	0.30387	-0.13064	0	0.02049
2800#Q_s#3500	99.46400	0.33456	0.30387	-0.13064	0	0.02291

Design Category A2. For Halogenated Process Vent Streams, if Net Heating Value (MJ/scm)>3.5:

Q_s=Vent Steam Flow Rate (scm/min)	a	b	c	d	e	f
14.2#Q_s#18.8	18.84466	0.26742	-0.20044	0	0	0.01025
18.8#Q_s#699	19.66658	0.26742	-0.25332	0	0	0.01025
699#Q_s#1400	39.19213	0.29062	-0.25332	0	0	0.01449
1400#Q_s#2100	58.71768	0.30511	-0.25332	0	0	0.01775
2800#Q_s#3500	78.24323	0.31582	-0.25332	0	0	0.02049
	97.76879	0.32439	-0.25332	0	0	0.02291

Design Category B. For Nonhalogenated Process Vent Streams, if 0#Net Heating Value (MJ/scm)#0.48:

Q_s=Vent Steam Flow Rate (scm/min)	a	b	c	d	e	f
14.2#Q_s#1340	8.54245	0.10555	0.09030	-0.17109	0	0.01025
1340#Q_s#2690	16.94386	0.11470	0.09030	-0.17109	0	0.01449
2690#Q_s#4040	25.34528	0.12042	0.09030	-0.17109	0	0.01775

Design Category C. For Nonhalogenated Process Vent Streams, if 0.48<Net Heating Value (MJ/scm)#1.9:

Q_s=Vent Steam Flow Rate (scm/min)	a	b	c	d	e	f
14.2#Q_s#1340	9.25233	0.06105	0.31937	-0.16181	0	0.01025
1340#Q_s#2690	18.36363	0.06635	0.31937	-0.16181	0	0.01449
2690#Q_s#4040	27.47492	0.06965	0.31937	-0.16181	0	0.01775

Design Category D. For Nonhalogenated Process Vent Streams, if 1.9<Net Heating Value (MJ/scm)#3.6:

Q_s=Vent Steam Flow Rate (scm/min)	a	b	c	d	e	f
14.2#Q_s#1180	6.67868	0.06943	0.02582	0	0	0.01025
1180#Q_s#2370	13.21633	0.07546	0.02582	0	0	0.01449
2370#Q_s#3550	19.75398	0.07922	0.02582	0	0	0.01775

Design Category E. For Nonhalogenated Process Vent Streams, if Net Heating Value (MJ/scm)>3.6:

Y_s=Dilution Flow Rate (scm/min)=(Q_s) (H_T)/3.6	a	b	c	d	e	f

14.2#Y_s#1180	6.67868	0	0	-0.00707	0.02220	0.01025
1180#Y_s#2370	13.21633	0	0	-0.00707	0.02412	0.01449
2370#Y_s#3550	19.75398	0	0	-0.00707	0.02533	0.01775

(ii) where for a vent stream flow rate (scm/min) at a standard temperature of 20 EC that is less than 14.2 scm/min:

TRE=TRE index value.
Qs=14.2 scm/min.
HT=(FLOW)(HVAL)/14.2.

where by the following inputs are used:

FLOW=Vent stream flow rate (scm/min), at a standard temperature of 20 EC.
HVAL=Vent stream net heating value (MJ/scm), where the net enthalpy per mole of vent stream is based on combustion at 25 EC and 760 mm Hg, but the standard temperature for determining the volume corresponding to one mole is 20 EC as in definition of Qs.
Ys=14.2 scm/min for all vent stream categories listed in Table 1 except for Category E vent streams, where Ys=(14.2)(HT)/3.6. ETOC=Hourly emissions of TOC reported in kg/hr.
a, b, c, d, e, and f are coefficients.

The set of coefficients that apply to a vent stream can be obtained from Table 1.

(2) The equation for calculating the TRE index value of a vent stream controlled by a flare is as follows:

$$TRE = \frac{1}{ETOC}[a(Qs)+b(Qs)^{0.8}+c(Qs)(HT)+d(ETOC)+e]$$

where:
TRE=TRE index value.
ETOC=Hourly emission rate of TOC reported in kg/hr.
Qs=Vent stream flow rate (scm/min) at a standard temperature of 20 EC.
HT=Vent stream net heating value (MJ/scm) where the net enthalpy per mole of offgas is based on combustion at 25 EC and 760 mm Hg, but the standard temperature for determining the volume corresponding to one mole is 20 EC as in the definition of Qs.
a, b, c, d, and e are coefficients.

The set of coefficients that apply to a vent stream shall be obtained from Table 2.

Table 2. Distillation NSPS TRE Coefficients for Vent Streams Controlled by a Flare

	a	b	c	d	e
H_T<11.2 MJ/scm	2.25	0.288	-0.193	-0.0051	2.08
$H_T$$11.2 MJ/scm	0.309	0.0619	-0.0043	-0.0034	2.08

(f) Each owner or operator of an affected facility seeking to comply with §60.660(c)(4) or §60.662(c) shall recalculate the TRE index value for that affected facility whenever process changes are made. Examples of process changes include changes in production capacity, feedstock type, or catalyst type, or whenever there is replacement, removal, or addition of recovery equipment. The TRE index value shall be recalculated based on test data, or on best engineering estimates of the effects of the change to the recovery system.

(1) Where the recalculated TRE index value is less than or equal to 1.0, the owner or operator shall notify the Administrator within 1 week of the recalculation and shall conduct a performance test according to the methods and procedures required by §60.664 in order to determine compliance with §60.662(a). Performance tests must be conducted as soon as possible after the process change but no later than 180 days from the time of the process change.

(2) Where the initial TRE index value is greater than 8.0 and the recalculated TRE index value is less than or equal to 8.0 but greater than 1.0, the owner or operator shall conduct a performance test in accordance with §§60.8 and 60.664 and shall comply with §§60.663, 60.664 and 60.665. Performance tests must be conducted as soon as possible after the process change but no later than 180 days from the time of the process change.

(g) Any owner or operator subject to the provisions of this subpart seeking to demonstrate compliance with

§60.660(c)(6) shall use Method 2, 2A, 2C, or 2D as appropriate, for determination of volumetric flow rate.

§60.665 Reporting and recordkeeping requirements.

(a) Each owner or operator subject to §60.662 shall notify the Administrator of the specific provisions of §60.662 (§60.662 (a), (b), or (c)) with which the owner or operator has elected to comply. Notification shall be submitted with the notification of initial start-up required by §60.7(a)(3). If an owner or operator elects at a later date to use an alternative provision of §60.662 with which he or she will comply, then the Administrator shall be notified by the owner or operator 90 days before implementing a change and, upon implementing the change, a performance test shall be performed as specified by §60.664 within 180 days.

(b) Each owner or operator subject to the provisions of this subpart shall keep an up-to-date, readily accessible record of the following data measured during each performance test, and also include the following data in the report of the initial performance test required under §60.8. Where a boiler or process heater with a design heat input capacity of 44 MW (150 million Btu/hour) or greater is used to comply with §60.662(a), a report containing performance test data need not be submitted, but a report containing the information in §60.665(b)(2)(i) is required. The same data specified in this section shall be submitted in the reports of all subsequently required performance tests where either the emission control efficiency of a control device, outlet concentration of TOC, or the TRE index value of a vent stream from a recovery system is determined.

(1) Where an owner or operator subject to the provisions of this subpart seeks to demonstrate compliance with §60.662(a) through use of either a thermal or catalytic incinerator:

(i) The average firebox temperature of the incinerator (or the average temperature upstream and downstream of the catalyst bed for a catalytic incinerator), measured at least every 15 minutes and averaged over the same time period of the performance testing, and

(ii) The percent reduction of TOC determined as specified in §60.664(b) achieved by the incinerator, or the concentration of TOC (ppmv, by compound) determined as specified in §60.664(b) at the outlet of the control device on a dry basis corrected to 3 percent oxygen.

(2) Where an owner or operator subject to the provisions of this subpart seeks to demonstrate compliance with §60.662(a) through use of a boiler or process heater:

(i) A description of the location at which the vent stream is introduced into the boiler or process heater, and

(ii) The average combustion temperature of the boiler or process heater with a design heat input capacity of less than 44 MW (150 million Btu/hr) measured at least every 15 minutes and averaged over the same time period of the performance testing.

(3) Where an owner or operator subject to the provisions of this subpart seeks to demonstrate compliance with §60.662(b) through use of a smokeless flare, flare design (i.e., steam- assisted, air-assisted or nonassisted), all visible emission readings, heat content determinations, flow rate measurements, and exit velocity determinations made during the performance test, continuous records of the flare pilot flame monitoring, and records of all periods of operations during which the pilot flame is absent.

(4) Where an owner or operator subject to the provisions of this subpart seeks to demonstrate compliance with §60.662(c):

(i) Where an absorber is the final recovery device in the recovery system, the exit specific gravity (or alternative parameter which is a measure of the degree of absorbing liquid saturation, if approved by the Administrator), and average exit temperature, of the adsorbing liquid measured at least every 15 minutes and averaged over the same time period of the performance testing (both measured while the vent stream is normally routed and constituted), or

(ii) Where a condenser is the final recovery device in the recovery system, the average exit (product side) temperature measured at least every 15 minutes and averaged over the same time period of the performance testing while the vent stream is routed and constituted normally, or

(iii) Where a carbon adsorber is the final recovery device in the recovery system, the total steam mass flow measured at least every 15 minutes and averaged over the same time period of the performance test (full carbon bed cycle), temperature of the carbon bed after regeneration (and within 15 minutes of completion of any cooling cycle(s)), and duration of the carbon bed steaming cycle (all measured while the vent stream is routed and constituted normally), or

(iv) As an alternative to §60.665(b)(4) ((i), (ii) or (iii), the concentration level or reading indicated by the organics monitoring device at the outlet of the absorber, condenser, or carbon adsorber, measured at least every 15 minutes and averaged over the same time period of the performance testing while the vent stream is normally routed and constituted.

(v) All measurements and calculations performed to determine the TRE index value of the vent stream.

(c) Each owner or operator subject to the provisions of this subpart shall keep up-to-date, readily accessible continuous records of the equipment operating parameters specified to be monitored under §60.663 (a) and (c) as well as up-to-date, readily accessible records of periods of operation during which the parameter boundaries established during the most recent performance test are exceeded. The Administrator may at any time require a report of these data. Where a combustion device is used to comply with §60.662(a), periods of operation during which the parameter boundaries established during the most recent performance tests are exceeded are defined as follows:

(1) For thermal incinerators, all 3-hour periods of operation during which the average combustion temperature was more than 28 EC (50 EF) below the average combustion temperature during the most recent performance test at which compliance with §60.662(a) was determined.

(2) For catalytic incinerators, all 3-hour periods of operation during which the average temperature of the vent stream immediately before the catalyst bed is more than 28 EC (50 EF) below the average temperature of the vent stream during the most recent performance test at which compliance with §60.662(a) was determined. The owner or operator also shall record all 3-hour periods of operation during which the average temperature difference across the catalyst bed is less than 80 percent of the average temperature difference of the device during the most recent performance test at which compliance with §60.662(a) was determined.

(3) All 3-hour periods of operation during which the average combustion temperature was more than 28 EC (50 EF) below the average combustion temperature during the most recent performance test at which compliance with §60.662(a) was determined for boilers or process heaters with a design heat input capacity of less than 44 MW (150 million Btu/hr).

(4) For boilers or process heaters, whenever there is a change in the location at which the vent stream is introduced into the flame zone as required under §60.662(a).

(d) Each owner or operator subject to the provisions of this subpart shall keep up to date, readily accessible continuous records of the flow indication specified under §60.663(a)(2), §60.663(b)(2) and §60.663(c)(1), as well as up-to-date, readily accessible records of all periods when the vent stream is diverted from the control device or has no flow rate.

(e) Each owner or operator subject to the provisions of this subpart who uses a boiler or process heater with a design heat input capacity of 44 MW or greater to comply with §60.662(a) shall keep an up-to-date, readily accessible record of all periods of operation of the boiler or process heater. (Examples of such records could include records of steam use, fuel use, or monitoring data collected pursuant to other State or Federal regulatory requirements.)

(f) Each owner or operator subject to the provisions of this subpart shall keep up-to-date, readily accessible continuous records of the flare pilot flame monitoring specified under §60.663(b), as well as up-to-date, readily accessible records of all periods of operations in which the pilot flame is absent.

(g) Each owner or operator subject to the provisions of this subpart shall keep up-to-date, readily accessible continuous records of the equipment operating parameters specified to be monitored under §60.663(d), as well as up-to-date, readily accessible records of periods of operation during which the parameter boundaries established during the most recent performance test are exceeded. The Administrator may at any time require a report of these data. Where an owner or operator seeks to comply with §60.662(c), periods of operation during which the parameter boundaries established during the most recent performance tests are exceeded are defined as follows:

(1) Where an absorber is the final recovery device in a recovery system, and where an organic compound monitoring device is not used:

(i) All 3-hour periods of operation during which the average absorbing liquid temperature was more than 11 EC (20 EF) above the average absorbing liquid temperature during the most recent performance test, or

(ii) All 3-hour periods of operation during which the average absorbing liquid specific gravity was more than 0.1 unit above, or more than 0.1 unit below, the average absorbing liquid specific gravity during the most recent performance test (unless monitoring of an alternative parameter, which is a measure of the degree of absorbing liquid saturation, is approved by the Administrator, in which case he will define appropriate parameter boundaries and periods of operation during which they are exceeded).

(2) Where a condenser is the final recovery device in a system, and where an organic compound monitoring device is not used, all 3-hour periods of operation during which the average exit (product side) condenser operating temperature was more than 6 EC (1 1EF) above the average exit (product side) operating temperature during the most recent performance test.

(3) Where a carbon adsorber is the final recovery device in a system, and where an organic compound monitoring device is not used:

(i) All carbon bed regeneration cycles during which the total mass steam flow was more than 10 percent below the total mass steam flow during the most recent performance test, or

(ii) All carbon bed regeneration cycles during which the temperature of the carbon bed after regeneration (and after completion of any cooling cycle(s)) was more than 10 percent greater than the carbon bed temperature (in degrees Celsius) during the most recent performance test.

(4) Where an absorber, condenser, or carbon adsorber is the final recovery device in the recovery system and where an organic compound monitoring device is used, all 3-hour periods of operation during which the average organic compound concentration level or reading of organic compounds in the exhaust gases is more than 20 percent greater than the exhaust gas organic compound concentration level or reading measured by the monitoring device during the most recent performance test.

(h) Each owner or operator of an affected facility subject to the provisions of this subpart and seeking to demonstrate compliance with §60.662(c) shall keep up-to-date, readily accessible records of:

(1) Any changes in production capacity, feedstock type, or catalyst type, or of any replacement, removal or addition of recovery equipment or a distillation unit;

(2) Any recalculation of the TRE index value performed pursuant to §60.664(f); and

(3) The results of any performance test performed pursuant to the methods and procedures required by §60.664(d).

(i) Each owner or operator of an affected facility that seeks to comply with the requirements of this subpart by complying with the flow rate cutoff in §60.660(c)(6) shall keep up-to- date, readily accessible records to indicate that the vent stream flow rate is less than 0.008 m83 /min and of any change in equipment or process operation that increases the operating vent stream flow rate, including a measurement of the new vent stream flow rate.

(j) Each owner or operator of an affected facility that seeks to comply with the requirements of this subpart by complying with the design production capacity provision in §60.660(c)(5) shall keep up-to-date, readily accessible records of any change in equipment or process operation that increases the design production capacity of the process unit in which the affected facility is located.

(k) Each owner and operator subject to the provisions of this subpart is exempt from the quarterly reporting requirements contained in §60.7(c) of the General Provisions.

(l) Each owner or operator that seeks to comply with the requirements of this subpart by complying with the requirements of §60.660 (c)(4), (c)(5), or (c)(6) or §60.662 shall submit to the Administrator semiannual reports of the following recorded information. The initial report shall be submitted within 6 months after the initial start-up date.

(1) Exceedances of monitored parameters recorded under §60.665 (c) and (g).

(2) All periods recorded under §60.665(d) when the vent stream is diverted from the control device or has no flow rate.

(3) All periods recorded under §60.665(e) when the boiler or process heater was not operating.

(4) All periods recorded under §60.665(f) in which the pilot flame of the flare was absent.

(5) Any change in equipment or process operation that increases the operating vent stream flow rate above the low flow exemption level in §60.660(c)(6), including a measurement of the new vent stream flow rate, as recorded under §60.665(i). These must be reported as soon as possible after the change and no later than 180 days after the change. A performance test must be completed with the same time period to verify the recalculated flow value and to obtain the vent stream characteristics of heating value and ETOC. The performance test is subject to the requirements of §60.8 of the General Provisions. Unless the facility qualifies for an exemption under the low capacity exemption status in §60.660(c)(5), the facility must begin compliance with the requirements set forth in §60.662.

(6) Any change in equipment or process operation, as recorded under §60.665(j), that increases the design production capacity above the low capacity exemption level in §60.660(c)(5) and the new capacity resulting from the change for the distillation process unit containing the affected facility. These must be reported as soon as possible after the change and no later than 180 days after the change. A performance test must be completed within the same time period to obtain the vent stream flow rate, heating value, ETOC. The performance test is subject to the requirements of §60.8 of the General Provisions. Unless the facility qualifies for an exemption under the low flow exemption in §60.660(c)(6), the facility must begin compliance with the requirements set forth in §60.662.

(7) Any recalculation of the TRE index value, as recorded under §60.665(h).

(m) The requirements of §60.665(l) remain in force until and unless EPA, in delegating enforcement authority to a State under section 111(c) of the Act, approves reporting requirements or an alternative means of compliance surveillance adopted by such State. In that event, affected sources within the State will be relieved of the obligation to comply with §60.665(l), provided that they comply with the requirements established by the State.

(n) Each owner or operator that seeks to demonstrate compliance with §60.660(c)(5) must submit to the Administrator an initial report detailing the design production capacity of the process unit.

(o) Each owner or operator that seeks to demonstrate compliance with §60.660(c)(6) must submit to the Administrator an initial report including a flow rate measurement using the test methods specified in §60.664.

(p) The Administrator will specify appropriate reporting and recordkeeping requirements where the owner or operator of an affected facility complies with the standards specified under §60.662 other than as provided under §60.663(a), (b), (c) and (d).

[55 FR 26922, June 29, 1990; 55 FR 36932, Sept. 7, 1990]

§60.666 Reconstruction.

For purposes of this subpart ``fixed capital cost of the new components," as used in §60.15, 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 December 30, 1983. 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.

§60.667 Chemicals affected by subpart NNN.

Chemical Name	CAS No.[i]
Acetaldehyde	75-07-0
Acetaldol	107-89-1
Acetic acid	64-19-7
Acetic anhydride	108-24-7
Acetone	67-64-1
Acetone cyanohydrin	75-86-5
Acetylene	74-86-2
Acrylic acid	79-10-7
Acrylonitrile	107-13-1
Adipic acid	124-04-9
Adiponitrile	111-69-3
Alcohols, C-11 or lower, mixtures	
Alcohols, C-12 or higher, mixtures	
Allyl chloride	107-05-1
Amylene	513-35-9
Amylenes, mixed	
Aniline	62-53-3
Benzene	71-43-2
Benzenesulfonic acid	98-11-3
Benzenesulfonic acid C-10-16-alkyl derivatives, sodium salts	68081-81-2
Benzoic acid, tech	65-85-0
Benzyl chloride	100-44-7
Biphenyl	92-52-4
Bisphenol A	80-05-7
Brometone	76-08-4
1,3-Butadiene	106-99-0
Butadiene and butene fractions	
n-Butane	106-97-8

Appendix:
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Chemical Name	CAS No.[i]
1,4-Butanediol	110-63-4
Butanes, mixed	
1-Butene	106-98-9
2-Butene	25167-67-3
Butenes, mixed	
n-Butyl acetate	123-86-4
Butyl acrylate	141-32-2
n-Butyl alcohol	71-36-3
sec-butyl alcohol	78-92-2
tert-butyl alcohol	75-65-0
Butylbenzyl phthalate	85-68-7
Butylene glycol	107-88-0
tert-Butyl hydroperoxide	75-91-2
2-Butene-1,4-diol	110-65-6
Butyraldehyde	123-72-8
Butyric anhydride	106-31-0
Caprolactam	105-60-2
Carbon disulfide	75-1-50
Carbon tetrabromide	558-13-4
Carbon tetrachloride	56-23-5
Chlorobenzene	108-90-7
2-Chloro-4-(ethlyamino)-6-(isopropylamino)-s-triazine	1912-24-9
Chloroform	67-66-3
p-chloronitrobenzene	100-00-5
Chloroprene	126-99-8
Citric acid	77-92-9
Crotonaldehyde	4170-30-0
Crotonic acid	3724-65-0
Cumene	98-82-8
Cumene hydroperoxide	80-15-9
Cyanuric chloride	108-77-0
Cyclohexane	110-82-7

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Chemical Name	CAS No.[i]
Cyclohexane, oxidized	68512-15-2
Cyclohexanol	108-93-0
Cyclohexanone	108-94-1
Cyclohexanone oxime	100-64-1
Cyclohexene	110-83-8
1,3-Cyclopentadiene	542-92-7
Cyclopropane	75-19-4
Diacetone alcohol	123-42-2
Dibutanized aromatic concentrate	
1,4-Dichlorobutene	110-57-6
3,4-Dichloro-1-butene	64037-54-3
Dichlorodifluoromethane	75-71-8
Dichlorodimethylsaline	75-78-5
Dichlorofluoromethane	75-43-4
-Dichlorohydrin	96-23-1
Diethanolamine	111-42-2
Diethylbenzene	25340-17-4
Diethylene glycol	111-46-6
Di-n-heptyl-n-nonyl undecyl phthalate	85-68-7
Di-isodecyl phthalate	26761-40-0
Diisononyl phthalate	28553-12-0
Dimethylamine	124-40-3
Dimethyl terephthalate	120-61-6
2,4-Dinitrotoluene	121-14-2
2,4-(and 2,6)-Dinitrotoluene	121-14-2 606-20-2
Dioctyl phalate	117-81-7
Dodecene	25378-22-7
Dodecylbenzene, non linear	
Dodecylbenzenesulfonic acid	27176-87-0
Dodecylbenzenesulfonic acid, sodium salt	25155-30-0
Epichlorohydrin	106-89-8
Ethanol	64-17-5

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Chemical Name	CAS No.[i]
Ethanolamine	141-43-5
Ethyl acetate	141-78-6
Ethyl acrylate	140-88-5
Ethylbenzene	100-41-4
Ethyl chloride	75-00-3
Ethyl cyanide	107-12-0
Ethylene	74-85-1
Ethylene dibromide	106-93-4
Ethylene dichloride	107-06-2
Ethylene glycol	107-21-1
Ethylene glycol monobutyl	111-76-2
Ethylene glycol monoethy ether	110-80-5
Ethylene glycol monethyl ether acetate	111-15-9
Ethylene glycol monomethyl ether	109-86-4
Ethylene oxide	75-21-8
2-Ethylhexanal	26266-68-2
Ethylhexyl alcohol	104-76-7
(2-Ethylhexyl) amine	104-75-6
Ethylmethylbenzene	25550-14-5
6-ethyl-1,2,3,4-trtrahydro 9,10-antracenedione	15547-17-8
Formaldehyde	50-00-0
Glycerol	56-81-5
n-Heptane	142-82-5
Heptanes (mixed)	
Hexadecyl chloride	
Hexamethylene diamine	124-09-4
Hexamethylene diamine adipate	3323-53-3
Hexamethylenetetramine	100-97-0
Hexane	110-54-3
2-Hexanedinitrile	13042-02-9
3-Hexanedinitrile	1119-85-3
Hydrogen cyanide	74-90-8

Appendix:
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Chemical Name	CAS No.[i]
Isobutane	75-28-5
Isobutanol	78-83-1
Isobutylene	115-11-7
Isobutyraldehyde	78-84-2
Isodecyl alcohol	25339-17-7
Isooctyl alcohol	26952-21-6
Isopentane	78-78-4
Isophthalic acid	121-91-5
Isoprene	78-79-5
Isopropanol	67-63-0
Ketene	463-51-4
Linear alcohols, ethoxylated, mixed	
Linear alcohols, ethoxylated, and sulfonated, sodium salt, mixed	
Linear alcohols, sulfonated, sodium salt, mixed	
Linear alkylbenzene	123-01-3
Magnesium acetate	142-72-3
Maleic anhydride	108-31-6
Melamine	108-78-1
Methacrylonitrile	126-98-7
Methanol	67-56-1
Methylamine	74-89-5
ar-Methylbenzenediamine	25376-45-8
Methyl chloride	74-87-3
Methylene chloride	75-09-2
Methyl ethyl ketone	78-93-3
Methyl iodine	74-88-4
Methyl isobutyl ketone	108-10-1
Methyl methacrylate	80-62-6
2-Methylpentane	107-83-5
1-Methyl-2-pyrrolidone	872-50-4
Methyl tert-butyl ether	
Naphthalene	91-20-3

Appendix:
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Chemical Name	CAS No.[i]
Nitrobenzene	98-95-3
1-Nonene	27215-95-8
Nonyl alcohol	143-08-08
Nonylphenol	25154-52-3
Nonylphenol, ethoxylated	9016-45-9
Octene	25377-83-7
Oil soluble petroleum sulfonate, calcium salt	
Oil soluble petroleum sulfonate, sodium salt	
Pentaerythritol	115-77-5
n-Pentane	109-66-0
3-Pentenenitrile	4635-87-4
Pentenes, mixed	109-67-1
Perchloroethylene	127-18-4
Phenol	108-95-2
Phenylethyl hyroperoxide	3071-32-7
Phenylpropane	103-65-1
Phosgene	75-44-5
Phthalic anhydride	85-44-9
Propane	74-98-6
Propionaldehyde	123-38-6
Propionic acid	79-09-4
Propyl alcohol	71-23-8
Propylene	115-07-1
Propylene chlorohydrin	127-00-4
Propylene glycol	57-55-6
Propylene oxide	75-56-9
Sodium cyanide	143-33-9
Sorbitol	50-70-4
Styrene	100-42-5
Terephthalic acid	100-21-0
1,1,2,2-Tetrachloroethane	79-34-5
Tetraethyl lead	78-00-2

Appendix:
NSPS Subpart NNN

Chemical Name	CAS No.[i]
Tetrahydrofuran	109-99-9
Tetra (methyl-ethyl) lead	
Tetramethyl lead	75-74-1
Toluene	108-88-3
Toluene-2,4-diamine	95-80-7
Toluene-2,4-(and, 2,6)-diisocyanate (80/20 mixture)	26471-62-5
Tribromomethane	75-25-2
1,1,1-trichloroethane	71-55-6
1,1,2-trichloroethane	79-00-5
Trichloroethylene	79-01-6
Trichlorofluoromethane	75-69-4
1,1,2-trichloro-1,2,2-trifluoroethane	76-13-1
Triethanolamine	102-71-6
Triethylene glycol	112-27-6
Vinyl acetate	108-05-4
Vinyl chloride	75-01-4
Vinylidene chloride	75-35-4
m-xylene	108-38-3
o-xylene	95-47-6
p-xylene	106-42-3
Xylenes (mixed)	1330-20-7
m-Xylenol	576-26-1

[i] CAS numbers refer to the Chemical Abstracts Registry numbers assigned to specific chemicals, isomers, or mixtures of chemicals. Some isomers or mixtures that are covered by the standards do not have CAS numbers assigned to them. The standards apply to all of the chemicals listed, whether CAS numbers have been assigned or not.

§60.668 Delegation of authority.

(a) In delegating implementation and enforcement authority to a State under §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 will not be delegated to States: §60.663(e).

Subpart J-National Emission Standard for Equipment Leaks (Fugitive Emission Sources) of Benzene

Source: 49 FR 23513, June 6, 1984, unless otherwise noted.

§61.110 Applicability and designation of sources.

(a) The provisions of this subpart apply to each of the following sources that are intended to operate in benzene service: pumps, compressors, pressure relief devices, sampling connections, systems, open-ended valves or lines, valves, flanges and other connectors, product accumulator vessels, and control devices or systems required by this subpart.

(b) The provisions of this subpart do not apply to sources located in coke by-product plants.

(c)(1) If an owner or operator applies for one of the exemptions in this paragraph, then the owner or operator shall maintain records as required in §61.246(i).

(2) Any equipment in benzene service that is located at a plant site designed to produce or use less than 1,000 megagrams of benzene per year is exempt from the requirements of §61.112.

(3) Any process unit (defined in §61.241) that has no equipment in benzene service is exempt from the requirements of §61.112.

(d) While the provisions of this subpart are effective, a source to which this subpart applies that is also subject to the provisions of 40 CFR part 60 only will be required to comply with the provisions of this subpart.

§61.111 Definitions.

As used in this subpart, all terms not defined herein shall have the meaning given them in the Act, in subpart A of part 61, or in subpart V of part 61, and the following terms shall have the specific meanings given them:

In benzene service means that a piece of equipment either contains or contacts a fluid (Liquid or gas) that is at least 10 percent benzene by weight as determined according to the provisions of §61.245(d). The provisions of §61.245(d) also specify how to determine that a piece of equipment is not in benzene service.

Semiannual means a 6-month period; the first semiannual period concludes on the last day of the last month during the 180 days following initial startup for new sources; and the first semiannual period concludes on the last day of the last full month during the 180 days after June 6, 1984 for existing sources.

§61.112 Standards.

(a) Each owner or operator subject to the provisions of this subpart shall comply with the requirements of subpart V of this part.

(b) An owner or operator may elect to comply with the requirements of §§61.243-1 and 61.243-2.

(c) An owner or operator may apply to the Administrator for a determination of an alternative means of emission limitation that achieves a reduction in emissions of benzene at least equivalent to the reduction in emissions of benzene achieved by the controls required in this subpart. In doing so, the owner or operator shall comply with requirements of §61.244.

Subpart V-National Emission Standard for Equipment Leaks (Fugitive Emission Sources)

Source: 49 FR 23513, June 6, 1984, unless otherwise noted.

§61.240 Applicability and designation of sources.

(a) The provisions of this subpart apply to each of the following sources that are intended to operate in volatile hazardous air
pollutant (VHAP) service: pumps, compressors, pressure relief devices, sampling connection systems, open-ended valves or lines, valves, flanges and other connectors, product accumulator vessels, and control devices or systems required by this subpart.

(b) The provisions of this subpart apply to the sources listed in paragraph (a) after the date of promulgation of a specific subpart in part 61.

(c) While the provisions of this subpart are effective, a source to which this subpart applies that is also subject to the provisions of 40 CFR part 60 only will be required to comply with the provisions of this subpart.

§61.241 Definitions.

As used in this subpart, all terms not defined herein shall have the meaning given them in the Act, in subpart A of part 61, or in specific subparts of part 61; and the following terms shall have specific meaning given them:

Closed-vent system means a system that is not open to atmosphere and that is composed of piping, connections, and, if necessary, flow-inducing devices that transport gas or vapor from a piece or pieces of equipment to a control device.

Connector means flanged, screwed, welded, or other joined fittings used to connect two pipe lines or a pipe line and a piece of equipment. For the purpose of reporting and recordkeeping, connector means flanged fittings that are not covered by insulation or other materials that prevent location of the fittings.

Control device means an enclosed combustion device, vapor recovery system, or flare.

Double block and bleed system means two block valves connected in series with a bleed valve or line that can vent the line between the two block valves.

Equipment means each pump, compressor, pressure relief device, sampling connection system, open-ended valve or line, valve, flange or other connector, product accumulator vessel in VHAP service, and any control devices or systems required by this subpart.

First attempt at repair means to take rapid action for the purpose of stopping or reducing leakage of organic material to atmosphere using best practices.

In gas/vapor service means that a piece of equipment contains process fluid that is in the gaseous state at operating conditions.

In liquid service means that a piece of equipment is not in gas/vapor service.

In-situ sampling systems means nonextractive samplers or in-line samplers.

In vacuum service means that equipment is operating at an internal pressure which is at least 5 kilopascals (kPa) below ambient pressure.

In VHAP service means that a piece of equipment either contains or contacts a fluid (liquid or gas) that is at least 10 percent by weight a volatile hazardous air pollutant (VHAP) as determined according to the provisions of §61.245(d). The provisions of §61.245(d) also specify how to determine that a piece of equipment is not in VHAP service.

In VOC service means, for the purposes of this subpart, that (a) the piece of equipment contains or contacts a process fluid that is at least 10 percent VOC by weight (see 40 CFR 60.2 for the definition of volatile organic compound or VOC and 40 CFR 60.485(d) to determine whether a piece of equipment is not in VOC service) and (b) the piece of equipment is not in heavy liquid service as defined in 40 CFR 60.481.

Open-ended valve or line means any valve, except pressure relief valves, having one side of the valve seat in contact with process fluid and one side open to atmosphere, either directly or through open piping.

Pressure release means the emission of materials resulting from the system pressure being greater than the set pressure of the pressure relief device.

Process unit means equipment assembled to produce a VHAP or its derivatives as intermediates or final products, or equipment assembled to use a VHAP in the production of a product. A process unit can operate independently if supplied with sufficient feed or raw materials and sufficient product storage facilities.

Process unit shutdown means a work practice or operational procedure that stops production from a process unit or part of a process unit. An unscheduled work practice or operational procedure that stops production from a process unit or part of a process unit for less than 24 hours is not a process unit shutdown. The use of spare equipment and technically feasible bypassing of equipment without stopping production are not process unit shutdowns.

Product accumulator vessel means any distillate receiver, bottoms receiver, surge control vessel, or product separator in VHAP service that is vented to atmosphere either directly or through a vacuum-producing system. A product accumulator vessel is in VHAP service if the liquid or the vapor in the vessel is at least 10 percent by weight VHAP.

Repaired means that equipment is adjusted, or otherwise altered, to eliminate a leak.

Semiannual means a 6-month period; the first semiannual period concludes on the last day of the last month during the 180 days following initial startup for new sources; and the first semiannual period concludes on the last day of the last full month during the 180 days after the effective date of a specific subpart that references this subpart for existing sources.

Sensor means a device that measures a physical quantity or the change in a physical quantity, such as temperature, pressure, flow rate, pH, or liquid level.

Stuffing box pressure means the fluid (liquid or gas) pressure inside the casing or housing of a piece of equipment, on the process side of the inboard seal.

Volatile hazardous air pollutant or VHAP means a substance regulated under this part for which a standard for equipment leaks of the substance has been proposed and promulgated. Benzene is a VHAP. Vinyl chloride is a VHAP.

[49 FR 23513, June 6, 1984; 49 FR 38946, Oct. 2, 1984, as amended at 51 FR 34915, Sept. 30, 1986; 54 FR 38076, Sept. 14, 1989]

§61.242-1 Standards: General.

(a) Each owner or operator subject to the provisions of this subpart shall demonstrate compliance with the requirements of §§61.242-1 to 61.242-11 for each new and existing source as required in 40 CFR 61.05, except as provided in §§61.243 and 61.244.

(b) Compliance with this subpart will be determined by review of records, review of performance test results, and inspection using the methods and procedures specified in §61.245.

(c)(1) An owner or operator may request a determination of alternative means of emission limitation to the requirements of §§61.242-2, 61.242-3, 61.242-5, 61.242-6, 61.242-7, 61.242-8, 61.242-9 and 61.242-11 as provided in §61.244.

(2) If the Administrator makes a determination that a means of emission limitation is at least a permissible alternative to the requirements of §§61.242-2,61.242-3, 61.242-5, 61.242-6, 61.242-7, 61.242-8, 61.242-9 or 61.242-11, an owner or operator shall comply with the requirements of that determination.

(d) Each piece of equipment to which this subpart applies shall be marked in such a manner that it can be distinguished readily from other pieces of equipment.

(e) Equipment that is in vacuum service is excluded from the requirements of §61.242-2, to §61.242-11 if it is identified as required in §61.246(e)(5).

[49 FR 23513, June 6, 1984; 49 FR 38946, Oct. 2, 1984]

§61.242-2 Standards: Pumps.

(a)(1) Each pump shall be monitored monthly to detect leaks by the methods specified in §61.245(b), except as provided in §61.242-1(c) and paragraphs (d), (e), and (f) of this section.

(2) Each pump shall be checked by visual inspection each calendar week for indications of liquids dripping from the pump seal.

(b)(1) if an instrument reading of 10,000 ppm or greater is measured, a leak is detected.

(2) If there are indications of liquids dripping from the pump seal, a leak is detected.

(c)(1) When a leak is detected, it shall be repaired as soon as practicable, but not later than 15 calendar days after it is detected, except as provided in §61.242-10.

(2) A first attempt at repair shall be made no later than 5 calendar days after each leak is detected.

(d) Each pump equipped with a dual mechanical seal system that includes a barrier fluid system is exempt from the requirements of paragraphs (a) and (b) of this section, provided the following requirements are met:

(1) Each dual mechanical seal system is:

(i) Operated with the barrier fluid at a pressure that is at all times greater than the pump stuffing box pressure; or

(ii) Equipped with a barrier fluid degassing reservoir that is connected by a closed-vent system to a control device that complies with the requirements of §61.242-11; or

(iii) Equipped with a system that purges the barrier fluid into a process stream with zero VHAP emissions to atmosphere.

(2) The barrier fluid is not in VHAP service and, if the pump is covered by standards under 40 CFR part 60, is not in VOC service.

(3) Each barrier fluid system is equipped with a sensor that will detect failure of the seal system, the barrier fluid system, or both.

(4) Each pump is checked by visual inspection each calendar week for indications of liquids dripping from the pump seal.

(i) If there are indications of liquid dripping from the pump seal at the time of the weekly inspection, the pump shall be monitored as specified in §61.245 to determine the presence of VOC and VHAP in the barrier fluid.

(ii) If the monitor reading (taking into account any background readings) indicates the presence of VHAP, a leak is detected. For the purpose of this paragraph, the monitor may be calibrated with VHAP, or may employ a gas chromatography column to limit the response of the monitor to VHAP, at the option of the owner or operator.

(iii) If an instrument reading of 10,000 ppm or greater (total VOC) is measured, a leak is detected.

(5) Each sensor as described in paragraph (d)(3) of this section is checked daily or is equipped with an audible alarm.

(6)(i) The owner or operator determines, based on design considerations and operating experience, criteria applicable to the presence and frequency of drips and to the sensor that indicates failure of the seal system, the barrier fluid system, or both.

(ii) If indications of liquids dripping from the pump seal exceed the criteria established in paragraph (d)(6)(i) of this section, or if, based on the criteria established in paragraph (d)(6)(i) of this section, the sensor indicates failure of the seal system, the barrier fluid system, or both, a leak is detected.

(iii) When a leak is detected, it shall be repaired as soon as practicable, but no later than 15 calendar days after it is detected, except as provided in §61.242-10.

(iv) A first attempt at repair shall be made no later than five calendar days after each leak is detected.

(e) Any pump that is designated, as described in §61.246(e)(2), for no detectable emissions, as indicated by an instrument reading of less than 500 ppm above background, is exempt from the requirements of paragraphs (a), (c), and (d) if the pump:

(1) Has no externally actuated shaft penetrating the pump housing,

(2) Is demonstrated to be operating with no detectable emissions, as indicated by an instrument reading of less than 500 ppm above background, as measured by the method specified in §61.245(c), and

(3) Is tested for compliance with paragraph (e)(2) initially upon designation, annually, and at other times requested by the Administrator.

(f) If any pump is equipped with a closed-vent system capable of capturing and transporting any leakage from the seal or seals to a control device that complies with the requirements of §61.242-11, it is exempt from the requirements of paragraphs (a)-(e).

(g) Any pump that is located within the boundary of an unmanned plant site is exempt from the weekly visual inspection requirement of paragraphs (a)(2) and (d)(4) of this section, and the daily requirements of paragraph (d)(5)(i) of this section, provided that each pump is visually inspected as often as practicable and at least monthly.

[49 FR 23513, June 6, 1984, as amended at 49 FR 38946, Oct. 2, 1984; 55 FR 28349, July 10, 1990]

§61.242-3 Standards: Compressors.

(a) Each compressor shall be equipped with a seal system that includes a barrier fluid system and that prevents leakage of process fluid to atmosphere, except as provided in §61.242-1(c) and paragraphs (h) and (i) of this section.

(b) Each compressor seal system as required in paragraph (a) shall be:

(1) Operated with the barrier fluid at a pressure that is greater than the compressor stuffing box pressure; or

(2) Equipped with a barrier fluid system that is connected by a closed-vent system to a control device that complies with the requirements of §61.242-11; or

(3) Equipped with a system that purges the barrier fluid into a process stream with zero VHAP emissions to atmosphere.

(c) The barrier fluid shall not be in VHAP service and, if the compressor is covered by standards under 40 CFR part 60, shall not be in VOC service.

(d) Each barrier fluid system as described in paragraphs (a)-(c) of this section shall be equipped with a sensor that will detect failure of the seal system, barrier fluid system, or both.

(e)(1) Each sensor as required in paragraph (d) of this section shall be checked daily or shall be equipped with an audible alarm unless the compressor is located within the boundary of an unmanned plant site.

(2) The owner or operator shall determine, based on design considerations and operating experience, a criterion that indicates failure of the seal system, the barrier fluid system, or both.

(f) If the sensor indicates failure of the seal system, the barrier fluid system, or both based on the criterion determined under paragraph (e)(2) of this section, a leak is detected.

(g)(1) When a leak is detected, it shall be repaired as soon as practicable, but not later than 15 calendar days after it is detected, except as provided in §61.242-10.

(2) A first attempt at repair shall be made no later than 5 calendar days after each leak is detected.

(h) A compressor is exempt from the requirements of paragraphs (a) and (b) if it is equipped with a closed-vent system capable of capturing and transporting any leakage from the seal to a control device that complies with the requirements of §61.242-11, except as provided in paragraph (i).

(i) Any Compressor that is designated, as described in §61.246(e)(2), for no detectable emission as indicated by an instrument reading of less than 500 ppm above background is exempt from the requirements of paragraphs (a)-(h) if the compressor:

(1) Is demonstrated to be operating with no detectable emissions, as indicated by an instrument reading of less than 500 ppm above background, as measured by the method specified in §61.245(c); and

(2) Is tested for compliance with paragraph (i)(1) initially upon designation, annually, and at other times requested by the Administrator.

[49 FR 23513, June 6, 1984; 49 FR 38946, Oct. 2, 1984]

§61.242-4 Standards: Pressure relief devices in gas/vapor service.

(a) Except during pressure releases, each pressure relief device in gas/vapor service shall be operated with no detectable emissions, as indicated by an instrument reading of less than 500 ppm above background, as measured by the method specified in §61.245(c).

(b)(1) After each pressure release, the pressure relief device shall be returned to a condition of no detectable emissions, as indicated by an instrument reading of less than 500 ppm above background, as soon as practicable, but no later than 5 calendar days after each pressure release, except as provided in §61.242-10.

(2) No later than 5 calendar days after the pressure release, the pressure relief device shall be monitored to confirm the condition of no detectable emissions, as indicated by an instrument reading of less than 500 ppm above background, as measured by the method specified in §61.245(c).

(c) Any pressure relief device that is equipped with a closed-vent system capable of capturing and transporting leakage from the pressure relief device to a control device as described in §61.242-11 is exempt from the requirements of paragraphs (a) and (b).

[49 FR 23513, June 6, 1984; 49 FR 38946, Oct. 2, 1984]

§61.242-5 Standards: Sampling connecting systems.

(a) Each sampling connection system shall be equipped with a closed-purge system or closed vent system, except as provided in §61.242-1(c).

(b) Each closed-purge system or closed-vent system as required in paragraph (a) shall:

(1) Return the purged process fluid directly to the process line with zero VHAP emissions to atmosphere; or

(2) Collect and recycle the purged process fluid with zero VHAP emissions to atmosphere; or

(3) Be designed and operated to capture and transport all the purged process fluid to a control device that complies with the requirements of §61.242-11.

(c) In-situ sampling systems are exempt from the requirements of paragraphs (a) and (b).

§61.242-6 Standards: Open-ended valves or lines.

(a)(1) Each open-ended valve or line shall be equipped with a cap, blind flange, plug, or a second valve, except as provided in §61.242-1(c).

(2) The cap, blind flange, plug, or second valve shall seal the open end at all times except during operations requiring process fluid flow through the open-ended valve or line.

(b) Each open-ended valve or line equipped with a second valve shall be operated in a manner such that the valve on the process fluid end is closed before the second valve is closed.

(c) When a double block and bleed system is being used, the bleed valve or line may remain open during operations that require venting the line between the block valves but shall comply with paragraph (a) at all other times.

§61.242-7 Standards: Valves.

(a) Each valve shall be monitored monthly to detect leaks by the method specified in §61.245(b) and shall comply with paragraphs (b)-(e), except as provided in paragraphs (f), (g), and (h) of this section, §61.243-1 or §61.243-2, and §61.242-1(c).

(b) If an instrument reading of 10,000 ppm or greater is measured, a leak is detected.

(c)(1) Any valve for which a leak is not detected for 2 successive months may be monitored the first month of every quarter, beginning with the next quarter, until a leak is detected.

(2) If a leak is detected, the valve shall be monitored monthly until a leak is not detected for 2 successive months.

(d)(1) When a leak is detected, it shall be repaired as soon as practicable, but no later than 15 calendar days after the leak is detected, except as provided in §61.242-10.

(2) A first attempt at repair shall be made no later than 5 calendar days after each leak is detected.

(e) First attempts at repair include, but are not limited to, the following best practices where practicable:

(1) Tightening of bonnet bolts;

(2) Replacement of bonnet bolts;

(3) Tightening of packing gland nuts; and

(4) Injection of lubricant into lubricated packing.

(f) Any valve that is designated, as described in §61.246(e)(2), for no detectable emissions, as indicated by an instrument reading of less than 500 ppm above background, is exempt from the requirements of paragraph (a) if the valve:

(1) Has no external actuating mechanism in contact with the process fluid;

(2) Is operated with emissions less than 500 ppm above background, as measured by the method specified in §61.245(c); and

(3) Is tested for compliance with paragraph (f)(2) initially upon designation, annually, and at other times requested by the Administrator.

(g) Any valve that is designated, as described in §61.246(f)(1), as an unsafe-to-monitor valve is exempt from the requirements of paragraph (a) if:

(1) The owner or operator of the valve demonstrates that the valve is unsafe to monitor because monitoring personnel would be exposed to an immediate danger as a consequence of complying with paragraph (a); and

(2) The owner or operator of the valve has a written plan that requires monitoring of the valve as frequent as practicable during safe-to-monitor times.

(h) Any valve that is designated, as described in §61.246(f)(2), as a difficult-to-monitor valve is exempt from the requirements of paragraph (a) if:

(1) The owner or operator of the valve demonstrates that the valve cannot be monitored without elevating the monitoring personnel more than 2 meters above a support surface;

(2) The process unit within which the valve is located is an existing process unit; and

(3) The owner or operator of the valve follows a written plan that requires monitoring of the valve at least once per calendar year.

§61.242-8 Standards: Pressure relief devices in liquid service and flanges and other connectors.

(a) Pressure relief devices in liquid service and flanges and other connectors shall be monitored within 5 days by the method specified in §61.245(b) if evidence of a potential leak is found by visual, audible, olfactory, or any other detection method, except at provided in §61.242-1(c).

(b) If an instrument reading of 10,000 ppm or greater is measured, a leak is detected.

(c)(1) When a leak is detected, it shall be repaired as soon as practicable, but not later than 15 calendar days after it is detected, except as provided in §61.242-10.

(2) The first attempt at repair shall be made no later than 5 calendar days after each leak is detected.

(d) First attempts at repair include, but are not limited to, the best practices described under §61.242-7(e).

[49 FR 23513, June 6, 1984; 49 FR 38946, Oct. 2, 1984]

§61.242-9 Standards: Product accumulator vessels.

Each product accumulator vessel shall be equipped with a closed-vent system capable of capturing and transporting any leakage from the vessel to a control device as described in §61.242-11, except as provided in §61.242-1(c).

[49 FR 23513, June 6, 1984; 49 FR 38946, Oct. 2, 1984]

§61.242-10 Standards: Delay of repair.

(a) Delay of repair of equipment for which leaks have been detected will be allowed if the repair is technically infeasible without a process unit shutdown. Repair of this equipment shall occur before the end of the next process unit shutdown.

(b) Delay of repair of equipment for which leaks have been detected will be allowed for equipment that is isolated from the process and that does not remain in VHAP service.

(c) Delay of repair for valves will be allowed if:

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

(2) When repair procedures are effected, the purged material is collected and destroyed or recovered in a control device complying with §61.242-11.

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

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

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

(e) Delay of repair beyond a process unit shutdown will be allowed for a valve if valve assembly replacement is necessary during the process unit shutdown, valve assembly supplies have been depleted, and valve assembly supplies had been sufficiently stocked before the supplies were depleted. Delay of repair beyond the next process unit shutdown will not be allowed unless the next process unit shutdown occurs sooner than 6 months after the first process unit shutdown.

§61.242-11 Standards: Closed-vent systems and control devices.

(a) Owners or operators of closed-vent systems and control devices used to comply with provisions of this subpart shall comply with the provisions of this section, except as provided in §61.242-1(c).

(b) Vapor recovery systems (for example, condensers and adsorbers) shall be designed and operated to recover the organic vapors vented to them with an efficiency of 95 percent or greater.

(c) Enclosed combustion devices shall be designed and operated to reduce the VHAP emissions vented to them with an efficiency of 95 percent or greater or to provide a minimum residence time of 0.50 seconds at a minimum temperature of 760EC.

(d) Flares shall used to comply with this subpart shall comply with the requirements of §60.18.

(e) Owners or operators of control devices that are used to comply with the provisions of this subpart shall monitor these control devices to ensure that they are operated and maintained in conformance with their design.

(f)(1) Closed-vent systems shall be designed for and operated with no detectable emissions, as indicated by an instrument reading of less than 500 ppm above background and by visual inspections, as determined by the methods specified as §61.245(c).

(2) Closed-event systems shall be monitored to determine compliance with this section initially in accordance with §61.05, annually, and at other times requested by the administrator.

(3) Leaks, as indicated by an instrument reading greater than 500 ppm and visual inspections, shall be repaired as soon as practicable, but not later than 15 calendar days after the leak is detected.

(4) A first attempt at repair shall be made no later than 5 calendar days after the leak is detected.

(g) Closed-vent systems and control devices use to comply with provisions of this subpart shall be operated at all times when emissions may be vented to them.

[49 FR 23513, June 6, 1984; 49 FR 38946, Oct. 2, 1984, as amended at 51 FR 2702, Jan. 21, 1986]

§61.243-1 Alternative standards for valves in VHAP service-allowable percentage of valves leaking.

(a) An owner or operator may elect to have all valves within a process unit to comply with an allowable percentage of valves leaking of equal to or less than 2.0 percent.

(b) The following requirements shall be met if an owner or operator decides to comply with an allowable percentage of valves leaking:

(1) An owner or operator must notify the Administrator that the owner or operator has elected to have all valves within a process unit to comply with the allowable percentage of valves leaking before implementing this alternative standard, as specified in §61.247(d).

(2) A performance test as specified in paragraph (c) of this section shall be conducted initially upon designation, annually, and at other times requested by the Administrator.

(3) If a valve leak is detected, it shall be repaired in accordance with §61.242-7(d) and (e).

(c) Performance tests shall be conducted in the following manner:

(1) All valves in VHAP service within the process unit shall be monitored within 1 week by the methods specified in §61.245(b).

(2) If an instrument reading of 10,000 ppm or greater is measured, a leak is detected.

(3) The leak percentage shall be determined by dividing the number of valves in VHAP service for which leaks are detected by the number of valves in VHAP service within the process unit.

(d) Owner or operators who elect to have all valves comply with this alternative standard shall not have a process unit with a leak percentage greater than 2.0 percent.

(e) If an owner or operator decides no longer to comply with §61.243-1, the owner or operator must notify the Administrator in writing that the work practice standard described in §61.242-7(a)-(e) will be followed.

§61.243-2 Alternative standards for valves in VHAP service-skip period leak detection and repair.

(a)(1) An owner or operator may elect for all valves within a process unit to comply with one of the alternative work practices specified in paragraphs (b)(2) and (3) of this section.

(2) An owner or operator must notify the Administrator before implementing one of the alternative work practices, as specified in §61.247(d).

(b)(1) An owner or operator shall comply initially with the requirements for valves, as described in §61.242-7.

(2) After 2 consecutive quarterly leak detection periods with the percentage of valves leaking equal to or less than 2.0, an owner or operator may begin to skip 1 of the quarterly leak detection periods for the valves in VHAP service.

(3) After 5 consecutive quarterly leak detection periods with the percentage of valves leaking equal to or less than 2.0, an owner or operator may begin to skip 3 of the quarterly leak detection periods for the valves in VHAP service.

(4) If the percentage of valves leaking is greater than 2.0, the owner or operator shall comply with the requirements as described in §61.242-7 but may again elect to use this section.

§61.244 Alternative means of emission limitation.

(a) Permission to use an alternative means of emission limitation under section 112(e)(3) of the Clean Air Act shall be governed by the following procedures:

(b) Where the standard is an equipment, design, or operational requirement:

(1) Each owner or operator applying for permission shall be responsible for collecting and verifying test data for an alternative means of emission limitation to test data for the equipment, design, and operational requirements.

(3) The Administrator may condition the permission on requirements that may be necessary to assure operation and maintenance to achieve the same emission reduction as the equipment, design, and operational requirements.

(c) Where the standard is a work practice:

(1) Each owner or operator applying for permission shall be responsible for collecting and verifying test data for an alternative means of emission limitation.

(2) For each source for which permission is requested, the emission reduction achieved by the required work practices shall be demonstrated for a minimum period of 12 months.

(3) For each source for which permission is requested, the emission reduction achieved by the alternative means of emission limitation shall be demonstrated.

(4) Each owner or operator applying for permission shall commit in writing each source to work practices that provide for emission reductions equal to or greater than the emission reductions achieved by the required work practices.

(5) The Administrator will compare the demonstrated emission reduction for the alternative means of emission limitation to the demonstrated emission reduction for the required work practices and will consider the commitment in paragraph (c)(4).

(6) The Administrator may condition the permission on requirements that may be necessary to assure operation and maintenance to achieve the same emission reduction as the required work practices of this subpart.

(d) An owner or operator may offer a unique approach to demonstrate the alternative means of emission limitation.

(e)(1) Manufacturers of equipment used to control equipment leaks of a VHAP may apply to the Administrator for permission for an alternative means of emission limitation that achieves a reduction in emissions of the VHAP achieved by the equipment, design, and operational requirements of this subpart.

(2) The Administrator will grant permission according to the provisions of paragraphs (b), (c), and (d).

§61.245 Test methods and procedures.

(a) Each owner or operator subject to the provisions of this subpart shall comply with the test methods and procedures requirements provided in this section.

(b) Monitoring, as required in §§61.242, 61.243, 61.244, and 61.135, shall comply with the following requirements:

(1) Monitoring shall comply with Method 21 of appendix A of 40 CFR part 60.

(2) The detection instrument shall meet the performance criteria of Reference Method 21.

(3) The instrument shall be calibrated before use on each day of its use by the procedures specified in Reference Method 21.

(4) Calibration gases shall be:

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

(ii) A mixture of methane or n-hexane and air at a concentration of approximately, but less than, 10,000 ppm methane or n-hexane.

(5) The instrument probe shall be traversed around all potential leak interfaces as close to the interface as possible as described in Reference Method 21.

(c) When equipment is tested for compliance with or monitored for no detectable emissions, the owner or operator shall comply with the following requirements:

(1) The requirements of paragraphs (b) (1) through (4) shall apply.

(2) The background level shall be determined, as set forth in Reference Method 21.

(3) The instrument probe shall be traversed around all potential leak interfaces as close to the interface as possible as described in Reference Method 21.

(4) The arithmetic difference between the maximum concentration indicated by the instrument and the background level is compared with 500 ppm for determining compliance.

(d)(1) Each piece of equipment within a process unit that can conceivably contain equipment in VHAP service is presumed to be in VHAP service unless an owner or operator demonstrates that the piece of equipment is not in VHAP service. For a piece of equipment to be considered not in VHAP service, it must be determined that the percent VHAP content can be reasonably expected never to exceed 10 percent by weight. For purposes of determining the percent VHAP content of the process fluid that is contained in or contacts equipment, procedures that conform to the methods described in ASTM Method D-2267 (incorporated by the reference as specified in §61.18) shall be used.

(2)(i) An owner or operator may use engineering judgment rather than the procedures in paragraph (d)(1) of this section to demonstrate that the percent VHAP content does not exceed 10 percent by weight, provided that the engineering judgment demonstrates that the VHAP content clearly does not exceed 10 percent by weight. When an owner or operator and the Administrator do not agree on whether a piece of equipment is not in VHAP service, however, the procedures in paragraph (d)(1) of this section shall be used to resolve the disagreement.

(ii) If an owner or operator determines that a piece of equipment is in VHAP service, the determination can be revised only after following the procedures in paragraph (d)(1) of this section.

(3) Samples used in determining the percent VHAP content shall be representative of the process fluid that is contained in or contacts the equipment or the gas being combusted in the flare.

(e)(1) Method 22 of appendix A of 40 CFR part 60 shall be used to determine compliance of flares with the visible emission provisions of this subpart.

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

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

$$HT = K \left(\sum_{i=1}^{n} C_i H_i \right)$$

Where:

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

K=Constant, 1.74*108-7 (1/ppm) (gmole/scm) (MJ/kcal) where standard temperature for (g mole/scm) is 20EC

Ci=Concentration of sample component i in ppm, as measured by Reference Method 18 of appendix A of 40 FR part 60 and ASTM D2504-67 (reapproved 1977) (incorporated by reference as specified in §61.18).

Hi=Net heat of combustion of sample component i, kcal/g mole. The heats of combustion may be determined using ASTM D2382-76 (incorporated by reference as specified in §61.18) if published values are not available or cannot be calculated.

(4) The actual exit velocity of a flare shall be determined by dividing the volumetric flow rate (in units of standard temperature and pressure), as determined by Reference Method 2, 2A, 2C, or 2D, as appropriate, by the

unobstructed (free) cross section area of the flare tip.

(5) The maximum permitted velocity, Vmax, for air-assisted flares shall be determined by the following equation:

$$VMax=8.76+0.7084(HT)$$

Where:
VMax=Maximum permitted velocity, m/sec
8.706=Constant.
0.7084=Constant.
HT=The net heating value as determined in paragraph (e)(3) of this section.

[49 FR 23513, June 6, 1984, as amended at 49 FR 38946, Oct. 2, 1984; 49 FR 43647, Oct. 31, 1984; 53 FR 36972, Sept. 23, 1988; 54 FR 38077, Sept. 14, 1989]

§61.246 Recordkeeping requirements.

(a)(1) Each owner or operator subject to the provisions of this subpart shall comply with the recordkeeping requirements of this section.

(2) An owner or operator of more than one process unit subject to the provisions of this subpart may comply with the recordkeeping requirements for these process units in one recordkeeping system if the system identifies each record by each process unit.

(b) When each leak is detected as specified in §§61.242-2, 61.242-3, 61.242-7, 61.242-8, and 61.135, the following requirements apply:

(1) A weatherproof and readily visible identification, marked with the equipment identification number, shall be attached to the leaking equipment.

(2) The identification on a valve may be removed after it has been monitored for 2 successive months as specified in §61.242-7(c) and no leak has been detected during those 2 months.

(3) The identification on equipment, except on a valve, may be removed after it has been repaired.

(c) When each leak is detected as specified in §§61.242-2, 61.242-3, 61.242-7, 61.242-8, and 61.135, the following information shall be recorded in a log and shall be kept for 2 years in a readily accessible location:

(1) The instrument and operator identification numbers and the equipment identification number.

(2) The date the leak was detected and the dates of each attempt to repair the leak.

(3) Repair methods applied in each attempt to repair the leak.

(4) ``Above 10,000'' if the maximum instrument reading measured by the methods specified in §61.245(a) after each repair attempt is equal to or greater than 10,000 ppm.

(5) ``Repair delayed'' and the reason for the delay if a leak is not repaired within 15 calendar days after discovery of the leak.

(6) The signature of the owner or operator (or designate) whose decision it was that repair could not be effected without a process shutdown.

(7) The expected date of successful repair of the leak if a leak is not repaired within 15 calendar days unrepaired.

(9) The date of successful repair of the leak.

(d) The following information pertaining to the design requirements for closed-vent systems and control devices described in §61.242-11 shall be recorded and kept in a readily accessible location:

(1) Detailed schematics, design specifications, and piping and instrumentation diagrams.

(2) The dates and descriptions of any changes in the design specifications.

(3) A description of the parameter or parameters monitored, as required in §61.242-11(e), to ensure that control devices are operated and maintained in conformance with their design and an explanation of why that parameter (or parameters) was selected for the monitoring.

(4) Periods when the closed-vent systems and control devices required in §§61.242-2, 61.242-3, 61.242-4, 61.242-5 and 61.242-9 are not operated as designed, including periods when a flare pilot light does not have a flame.

(5) Dates of startups and shutdowns of the closed-vent systems and control devices required in §§61.242-2, 61.242-3, 61.242-4, 61.242-5 and 61.242-9.

(e) The following information pertaining to all equipment to which a standard applies shall be recorded in a log that is kept in a readily accessible location:

(1) A list of identification numbers for equipment (except welded fittings) subject to the requirements of this subpart.

(2)(i) A list of identification numbers for equipment that the owner or operator elects to designate for no detectable emissions as indicated by an instrument reading of less than 500 ppm above background.

(ii) The designation of this equipment for no detectable emissions shall be signed by the owner or operator.

(3) A list of equipment identification numbers for pressure relief devices required to comply with §61.242-4(a).

(4)(i) The dates of each compliance test required in §§61.242-2(e), 61.242-3(i), 61.242-4, 61.242-7(f), and 61.135(g).

(ii) The background level measured during each compliance test.

(iii) The maximum instrument reading measured at the equipment during each compliance test.

(5) A list of identification numbers for equipment in vacuum service.

(f) The following information pertaining to all valves subject to the requirements of §61.242-7(g) and (h) shall be recorded in a log that is kept in a readily accessible location:

(1) A list of identification numbers for valves that are designated as unsafe to monitor, an explanation for each valve stating why the valve is unsafe to monitor, and

the plan for monitoring each valve.
(2) A list of identification numbers for valves that are designated as difficult to monitor, an explanation for each valve stating why the valve is difficult to monitor, and the planned schedule for monitoring each valve.
(g) The following information shall be recorded for valves complying with §61.243-2:
(1) A schedule of monitoring.
(2) The percent of valves found leaking during each monitoring period.
(h) The following information shall be recorded in a log that is kept in a readily accessible location:
(1) Design criterion required in §§61.242-2(d)(5), 61.242-3(e)(2), and 61.135(e)(4) and an explanation of the design criterion; and
(2) Any changes to this criterion and the reasons for the changes.
(i) The following information shall be recorded in a log that is kept in a readily accessible location for use in determining exemptions as provided in the applicability section of this subpart and other specific subparts:
(1) An analysis demonstrating the design capacity of the process unit, and
(2) An analysis demonstrating that equipment is not in VHAP service.
(j) Information and data used to demonstrate that a piece of equipment is not in VHAP service shall be recorded in a log that is kept in a readily accessible location.

(Approved by the Office of Management and Budget under control number 2060-0068) [49 FR 23513, June 6, 1984, as amended at 49 FR 38946, Oct. 2, 1984; 54 FR 38077, Sept. 14, 1989]

§61.247 Reporting requirements.

(a)(1) An owner or operator of any piece of equipment to which this subpart applies shall submit a statement in writing notifying the Administrator that the requirements of §§61.242, 61.245, 61.246, and 61.247 are being implemented.
(2) In the case of an existing source or a new source which has an initial startup date preceding the effective date, the statement is to be submitted within 90 days of the effective date, unless a waiver of compliance is granted under §61.11, along with the information required under §61.10. If a waiver of compliance is granted, the statement is to be submitted on a date scheduled by the Administrator.
(3) In the case of new sources which did not have an initial startup date preceding the effective date, the statement shall be submitted with the application for approval of construction, as described in §61.07.
(4) The statement is to contain the following information for each source:
(i) Equipment identification number and process unit identification.
(ii) Type of equipment (for example, a pump or pipeline valve).
(iii) Percent by weight VHAP in the fluid at the equipment.
(iv) Process fluid state at the equipment (gas/vapor or liquid).
(v) Method of compliance with the standard (for example, ``monthly leak detection and repair'' or ``equipped with dual mechanical seals'').
(b) A report shall be submitted to the Administrator semiannually starting 6 months after the initial report required in paragraph
(a) of this section, that includes the following information:
(1) Process unit identification.
(2) For each month during the semiannual reporting period,
(i) Number of valves for which leaks were detected as described in §61.242-7(b) of § 61.243-2.
(ii) Number of valves for which leaks were not repaired as required in §61.242-7(d).
(iii) Number of pumps for which leaks were detected as described in §61.242-2 (b) and (d)(6).
(iv) Number of pumps for which leaks were not repaired as required in §61.242-2 (c) and (d)(6).
(v) Number of compressors for which leaks were detected as described in §61.242-3(f).
(vi) Number of compressors for which leaks were not repaired as required in §61.242-3(g).
(vii) The facts that explain any delay of repairs and, where appropriate, why a process unit shutdown was technically infeasible.
(3) Dates of process unit shutdowns which occurred within the semiannual reporting period.
(4) Revisions to items reported according to paragraph (a) if changes have occurred since the initial report or subsequent revisions to the initial report.

Note: Compliance with the requirements of §61.10(c) is not required for revisions documented under this paragraph.

(5) The results of all performance tests and monitoring to determine compliance with no detectable emissions and with §§61.243-1 and 61.243-2 conducted within the semiannual reporting period.
(c) In the first report submitted as required in paragraph (a) of this section, the report shall include a reporting schedule stating the months that semiannual reports shall be submitted. Subsequent reports shall be submitted according to that schedule, unless a revised schedule has been submitted in a previous semiannual report.
(d) An owner or operator electing to comply with the provisions of §§61.243-1 and 61.243-2 shall notify the Administrator of the alternative standard selected 90 days before implementing either of the provisions.

(e) An application for approval of construction or modification, §§61.05(a) and 61.07, will not be required if-

(1) The new source complies with the standard, §61.242;

(2) The new source is not part of the construction of a process unit; and

(3) In the next semiannual report required by paragraph (b) of this section, the information in paragraph (a)(4) of this section is reported.

[49 FR 23513, June 6, 1984, as amended at 49 FR 38947, Oct. 2, 1984; 54 FR 38077, Sept. 14, 1989]

Public Notice

Pursuant to Section (i) of the Arkansas Plan of Implementation for Air Pollution Control (Regulation 19), the Arkansas Department of Pollution Control and Ecology gives the following notice:

Eastman Chemical Company, Arkansas Eastman Division, operates a chemical processing plant (Organic Chemical Intermediates) (SIC Code 2869) which is located at 2800 Gap Road, Highway 394, in Batesville. Eastman Chemical Company proposes (1) to increase potential VOC emissions from the Waste Chemical Destructor (6M03-5) from 0.5 tpy to 8.8 tpy due to anticipated future increase in business and a corresponding increase in the amount of wastes that could be potentially generated; and (2) to increase potential Inorganics emissions from 16.3 tpy to 43.8 tpy from the two RTOs due to an anticipated increase in chlorinated compounds production.

The application has been reviewed by the staff of the Department and has received the Department's tentative approval subject to the terms of this notice.

Citizens wishing to examine the permit application and staff findings and recommendations may do so by contacting Michelle Gillham. Citizens desiring technical information concerning the application or permit should contact Shane Byrum. Both Michelle Gillham and Shane Byrum can be reached at the Department's central office, 8001 National Drive, Little Rock, (501) 682-0744.

Copies of the draft permit and permit application have been placed in the White River Regional Library, 368 East Main, Batesville, AR 72501. This information may be reviewed during the Library's normal business hours.

Interested or affected persons may also submit written comments on the proposal to the Department at the above address - Attention: Michelle Gillham. In order to be considered, the comments must be submitted within thirty (30) days of publication of this notice. Although the Department is not proposing to conduct a public hearing, one will be scheduled if significant comments on the permit provisions are received. If a hearing is scheduled, adequate public notice will be given in the newspaper of largest circulation in the county in which the facility in question is, or will be, located.

The Director shall make a final decision to issue or deny this application or to impose special conditions in accordance with Part III of this Department's Administrative Procedures (Regulation #8).

Dated this

Randall Mathis
Director

Arkansas Department of Pollution Control and Ecology
Division of Air Pollution Control

DETERMINATION OF APPLICABILITY

Name & Location: Eastman Chemical Company, Arkansas Eastman Division, Highway 394 Souh
Contact Name: Jim Ross

Mailing Address: P.O. Box 2357

City: Batesville State: AR ZIP: 72503

Process Description: Chemical Processing Plant (Organic Chemical Intermediates

CSN: 32-0036 Permit No.: 1085-AR-10 Engineer: Shane Byrum

Date(s) of DOA Attempts: 8/21/96; 10/21/96

Applicable Programs: SIP _X_,PSD _X_,NSPS _X_,NESHAPS _X_,Non-Attainment ___,Air Code Only ___,Not Determinable ___

EMISSION SUMMARY TOTALS (TPY)

Pollutant	Existing	Contemp. Decrease	Contemp. Increase	Net Change	Significant Increase	After Permit
PM/PM_{10}	290.3	_____	_____	+7.7	15	298
SO_2	6399.8	_____	_____	+3.5	40	6403.3
VOC	613.9	_____	_____	+ 3.8	40	617.7
CO	4452.0	_____	_____	-	100	4452
NO_X	3967.8	_____	_____	+0.2	40	3968
Inorganic	81.9	_____	_____	-0.3	_____	81.6

Is facility on 28 list (100 TPY)? Yes _X_ No ___ Additional Information Required ___
Facility is "Major Source" before permit? Yes _X_ No ___ Facility is "Major Source" after Permit? Yes _X_ No ___
Majorr modification? Yes ___ No _X_ Not applicable ___ Will facility emit toxic emissions? Yes ___ No _X_
Is the source within 10 km of a Class I area? Yes ___ No _X_ If yes, is maximum impact > 1Fg/m^3 (24 hr)? Yes ___ No ___
Is facility located in a non-attainment area? Yes ___ No _X_
For **PSD/Non-Attainment Review:**

	Monitoring (Fg/m^3-time)	Ambient Impact (Fg/m^3)	Monitoring Required YES/NO	BACT/LEAR
PM/PM_{10}	______	______	______	______
SO_2	______	______	______	______
VOC	______	______	______	______
CO	______	______	______	______
No_x	______	______	______	______
Other	______	______	______	______

Limits required on hours of operation, feed rates, etc.? Yes _x_ No ___

AIR DIVISION

INVOICE REQUEST FORM

(2-96)

Route To: FELICIA INMAN

Facility Name & Address: J. W. Ross
Environmental Associate
Eastman Chemical Company, Arkansas Eastman Division
2800 Gap Road, Highway 394 South
P.O. Box 2357
Batesville, AR 72503

CSN: 32-0036 **Permit No**:1085-AR-10

Permit Description: A, S, H, N

(e.g. A = AIR CODE, S=SIP, H=NESHAP, P=PSD, N=NSPS)

Initial Fee Calculations:

FEE = 17.39*(TPY PREDOMINANT POLLUTANT, EXCEPT CO)
not greater than $65,760 or less than $500

F_I =

Mod Fee Calculations:

FEE = 17.39*(TPY INCREASE PREDOMINANT POLLUTANT, EXCEPT CO)
no less than $400

F_M = 3.5 x 17.39=60.87=400.00

Fee Amount: $ 400.00

Engineer: Shane Byrum

Date: May 30, 2002.

SIP CHECKLIST

Facility Name: Eastman Chemical Company, Arkansas Eastman Division

Permit No.: 1085-AR-10 CSN: 33-0036 Region: 20

ADMINISTRATIVE SECTION

PRIOR TO ROUTING:	COMPLETED
1. Request invoice from Felicia (3 copies)	________
2. Type permit, stamp draft	________
3. Type mailing list	________
4. Type public notice letters to the following:	
a. Applicant - draft and final letters	________
b. Newspapers - local and statewide papers	________
c. Depository/library - send certified	________
d. Mayor	________
e. County Judge	________
5. Route file to: Program Coordinator Testing/CEMS staff Enforcement Air Division Chief	________
6. When file comes back to you, check to see if the proof of publication for the receipt of application has been received.	________
7. After corrections have been made and the Chief has signed the draft permit, make 10 copies of the public notice, 6 copies of the mailing list, 1 copy of the letters, type envelopes, and mail.	________
8. Send a copy of the public notice and the mailing list to Michelle Gillham.	________
9. When the public comment period is up, the fee is paid, and the proofs of publication have been received, route to Air Division Chief for	________

signature. Make 6 copies of the permit and mail.
Copies go to Enforcement, Testing/CEMS, Division Chief,
and 3 to Permit Engineer (engineer, file, & summary book).

ENGINEERING SIP CHECKLIST

Facility Name: Eastman Chemical Company, Arkansas Eastman Division

Permit No.: 1085-AR-10 CSN: 32-0036

Permit Package must contain the following prior to the DRAFT routing.

U	**Draft Permit**
____	**Proof of publication of receipt of notice of application**. Please note that ten (10) days must have elapsed from the date of this notice before a public notice on intent can be published.
U	**DOA Form**
U	**Fee Worksheet**
U	**Technical Justification Worksheet**
U	**Copy of Plot Plan for Local Inspector**

The following must be received and placed in the permit package prior to **FINAL** routing.

____	**Proof of publication and payment of notice of intent to issue.**
____	**Fee Payment** (Check PFAQ)
____	**45 days have elapsed from the time of last publication of the public notice of intent to issue.**
____	**All required attachments are enclosed (i.e. plot plan, area map, etc.)**

JUSTIFICATION WORKSHEET

Specific Conditions (list applicable specific conditions) were included in Air Permit
 1085-AR-10 to comply with:

1. New Source Performance Standard Subpart **Subpart Kb**
   Subpart NNN
   Subpart VV

2. Prevention of Significant Deterioration Regulations.

   Coal-Fired Boilers

3. NESHAPS. **Subpart J**
   Subpart V

4. Compliance with SIP.

   The specific conditions listed in the permit were included in the permit to determine compliance with the permit applicated and the Arkansas Plan of Implementation for Pollution Control (SIP).

5. Specific Conditions
   ______ **1h, 2h, 9h, 11h, 1l** ______ were included in this permit to assure compliance with submitted operational descriptions and/or emission limits.

6. National Ambient Air Quality Standards (NAAQS) & Pulaski County Maintenance Regulations.

   N/A