PROPOSED RULEMAKING

ENVIRONMENTAL QUALITY BOARD

[25 PA. CODE CHS. 121 AND 129]

Control of VOC Emissions from Oil and Natural Gas Sources

The Environmental Quality Board (Board) proposes to amend Chapters 121 and 129 (relating to general provisions; and standards for sources) to read as set forth in Annex A. This proposed rulemaking will add §§ 129.121—129.130 to adopt reasonably available control technology (RACT) requirements and RACT emission limitations for oil and natural gas sources of volatile organic compound (VOC) emissions which are in existence on or before the effective date of this proposed rulemaking, when published as a final-form rulemaking. These sources include: storage vessels; natural gas-driven pneumatic controllers; natural gas-driven diaphragm pumps; reciprocating and centrifugal compressors; and fugitive emissions components. This proposed rulemaking will also add definitions, acronyms and the United States Environmental Protection Agency (EPA) methods to § 129.122 (relating to definitions, acronyms and EPA methods) to support the interpretation of the measures.

This proposed rulemaking will be submitted to the EPA for approval as a revision to the Commonwealth's State Implementation Plan (SIP) following promulgation of the final-form rulemaking.

This proposed rulemaking was adopted by the Board at its meeting on December 17, 2019.

A. *Effective Date*

This proposed rulemaking will be effective upon final-form publication in the *Pennsylvania Bulletin*.

B. *Contact Persons*

For further information, contact Virendra Trivedi, Chief, Division of Permits, Bureau of Air Quality, Rachel Carson State Office Building, P.O. Box 8468, Harrisburg, PA 17105-8468, (717) 783-9476; or Jennie Demjanick, Assistant Counsel, Bureau of Regulatory Counsel, Rachel Carson State Office Building, P.O. Box 8464, Harrisburg, PA 17105-8464, (717) 787-7060. Information regarding submitting comments on this proposed rulemaking appears in section J of this preamble. Persons with a disability may use the Pennsylvania AT&T Relay Service, (800) 654-5984 (TDD users) or (800) 654-5988 (voice users). This proposed rulemaking is available on the Department of Environmental Protection's (Department) web site at www.dep.pa.gov (select "Public Participation," then "Environmental Quality Board").

C. *Statutory Authority*

This proposed rulemaking is authorized under section 5(a)(1) of the Air Pollution Control Act (APCA) (35 P.S. § 4005(a)(1)), which grants the Board the authority to adopt rules and regulations for the prevention, control, reduction and abatement of air pollution in this Commonwealth. Section 5(a)(8) of the APCA also grants the Board the authority to adopt rules and regulations designed to implement the provisions of the Clean Air Act (CAA) (42 U.S.C.A. §§ 7401—7671q).

D. *Background and Purpose*

The purpose of this proposed rulemaking is to implement control measures to reduce VOC emissions from existing oil and natural gas sources in this Commonwealth. There are five source categories that will be affected by this proposal: storage vessels; natural gas-driven pneumatic controllers; natural gas-driven diaphragm pumps; reciprocating and centrifugal compressors; and fugitive emissions components.

In accordance with sections 172(c)(1), 182(b)(2)(A) and 184(b)(1)(B) of the CAA (42 U.S.C.A. §§ 7502(c)(1), 7511a(b)(2)(A) and 7511c(b)(1)(B)), this proposed rulemaking establishes the VOC emission limitations and other requirements of the EPA's recommendations in the Control Techniques Guidelines for the Oil and Natural Gas Industry, EPA 453/B-16-001, Office of Air Quality Planning and Standards, EPA, October 2016 (2016 O&G CTG) as RACT for these sources in this Commonwealth. See 81 FR 74798 (October 27, 2016). The EPA defines RACT as "the lowest emission limitation that a particular source is capable of meeting by the application of control technology that is reasonably available considering technological and economic feasibility." See 44 FR 53761 (September 17, 1979).

Under section 108 of the CAA (42 U.S.C.A. § 7408), the EPA is responsible for establishing National Ambient Air Quality Standards (NAAQS) for six criteria pollutants considered harmful to public health and the environment: ground-level ozone; particulate matter; nitrogen oxides (NO_x); carbon monoxide; sulfur dioxide; and lead. Section 109 of the CAA (42 U.S.C.A. § 7409) established two types of NAAQS: primary standards, which are limits set to protect public health; and secondary standards, which are limits set to protect public welfare and the environment. In section 302(h) of the CAA (42 U.S.C.A. § 7602(h)), effects on welfare are defined to include protection against visibility impairment and from damage to animals, crops, vegetation and buildings.

VOCs are precursors to the formation of ground-level ozone, a public health and welfare hazard. Ground-level ozone is not emitted directly to the atmosphere from oil and natural gas sources but is formed by a photochemical reaction between emissions of VOC and NO_x in the presence of sunlight. Ground-level ozone is a highly reactive gas, which at sufficiently high concentrations can produce a wide variety of effects harmful to public health and welfare. Additionally, climate change may exacerbate the need to address ground-level ozone. According to the EPA, atmospheric warming, as a result of climate change, may increase ground-level ozone in regions across the United States. This impact could also be an issue for states trying to comply with future ozone standards.

Ozone is an irritant and repeated exposure to ozone pollution for both healthy people and those with existing conditions may cause a variety of adverse health effects, including difficulty in breathing, chest pains, coughing, nausea, throat irritation and congestion. In addition, people with bronchitis, heart disease, emphysema, asthma and reduced lung capacity may have their symptoms exacerbated by ozone pollution. Asthma, in particular, is a significant and growing threat to children and adults in this Commonwealth. Ozone can also cause both physical and economic damage to important food crops, forests and wildlife, as well as materials such as rubber and plastics. The implementation of additional measures to address ozone air quality in this Commonwealth is necessary to protect the public health and welfare and the environment. Because VOCs are precursors for ground-level ozone formation, implementing the RACT recommendations of the 2016 O&G CTG will help the Commonwealth achieve and maintain the 1997, 2008 and 2015 ozone NAAQS.

In July 1997, the EPA promulgated primary and secondary ozone standards at a level of 0.08 parts per million (ppm) averaged over 8 hours. See 62 FR 38856 (July 18, 1997). In 2004, the EPA designated 37 counties in this Commonwealth as 8-hour ozone nonattainment areas for the 1997 8-hour ozone NAAQS. See 69 FR 23858, 23931 (April 30, 2004). Based on the certified ambient air monitoring data for the 2015 ozone season as well as the preliminary 2016 ozone season data, all monitored areas of this Commonwealth are attaining the 1997 8-hour ozone NAAQS. The Department submitted maintenance plans to the EPA, which were approved for the 1997 ozone standard. See 82 FR 31464 (July 7, 2017) and 84 FR 20274 (May 9, 2019).

In accordance with section 175A(a) of the CAA (42 U.S.C.A. § 7505a(a)), the maintenance plans include permanent and enforceable control measures that will provide for the maintenance of the ozone NAAQS for at least 10 years following the EPA's redesignation of the areas to attainment. Under section 175A(b) of the CAA, 8 years after the EPA redesignates an area to attainment, additional maintenance plans approved by the EPA must also provide for the maintenance of the ozone standard for another 10 years following the expiration of the initial 10-year period.

In March 2008, the EPA lowered the primary and secondary ozone NAAQS to 0.075 ppm (75 parts per billion (ppb)) averaged over 8 hours to provide greater protection for children, other at-risk populations and the environment against the array of ozone-induced adverse health and welfare effects. See 73 FR 16436 (March 27, 2008). In April 2012, the EPA designated five areas in this Commonwealth as nonattainment for the 2008 ozone NAAQS. See 77 FR 30088, 30143 (May 21, 2012). These areas include all or a portion of Allegheny, Armstrong, Beaver, Berks, Bucks, Butler, Carbon, Chester, Delaware, Fayette, Lancaster, Lehigh, Montgomery, Northampton, Philadelphia, Washington and Westmoreland Counties. With regard to the 2008 ozone NAAQS, the certified 2015 ambient air ozone season monitoring data indicate that all areas of this Commonwealth are monitoring attainment of the 2008 ozone NAAQS.

The Department's analysis of the 2019 ambient air ozone season monitoring data shows that all ozone samplers in this Commonwealth, except the Bristol sampler in Bucks County, are monitoring attainment of the 2008 ozone NAAQS. As with the 1997 ozone NAAQS, the Department must ensure that the 2008 ozone NAAQS is attained and maintained by implementing permanent and enforceable control measures. Adoption of the VOC emission control measures in this proposed rulemaking would allow the Commonwealth to continue its progress in attaining and maintaining the 2008 8-hour ozone NAAQS.

On October 26, 2015, the EPA again lowered the primary and secondary ozone NAAQS, this time to 0.070 ppm (70 ppb) averaged over 8 hours. See 80 FR 65291 (October 26, 2015). As required under section 107(d) of the CAA (42 U.S.C.A. § 7407(d)), the Commonwealth submitted designation recommendations based on the ambient ozone concentrations from the 2013—2015 ozone seasons for the 2015 ozone NAAQS to the EPA on October 3, 2016, and a revised designation recommendation on April 11, 2017. The EPA finalized designations for the 2015 ozone NAAQS in two separate actions. See 82 FR 54232 (November 16, 2017) and 83 FR 25776 (June 4, 2018). On June 4, 2018, the EPA designated Bucks, Chester, Delaware, Montgomery and Philadelphia Counties as marginal nonattainment, with the rest of this Commonwealth designated attainment/unclassifiable. See 83 FR 25776.

The Department must ensure that the 2015 8-hour ozone NAAQS is attained and maintained by implementing permanent and Federally enforceable control measures. Reductions in VOC emissions that are achieved following the adoption and implementation of RACT emission control measures for source categories covered by this proposed rulemaking will assist the Commonwealth in making substantial progress in achieving and maintaining the ozone NAAQS. To the extent that any of the requirements in this proposed rulemaking are more stringent than any provisions of the 2016 O&G CTG, the Board has determined that the proposed requirements are reasonably necessary to attain and maintain the health-based and welfare based 8-hour ozone NAAQS in this Commonwealth and to satisfy related CAA requirements.

Section 110(a) of the CAA (42 U.S.C.A. § 7410(a)) provides that each state shall adopt and submit to the EPA a plan to implement measures (a SIP) to enforce the NAAQS or a revision to the NAAQS promulgated under section 109(b) of the CAA. A SIP includes the regulatory programs, actions and commitments a state will carry out to implement its responsibilities under the CAA. Once approved by the EPA, a SIP is legally enforceable under both Federal and state law. Section 172(c)(1) of the CAA provides that SIPs for nonattainment areas must include "reasonably available control measures," including RACT, for sources of emissions of VOC and NO_x.

Section 182(b)(2) of the CAA provides that for moderate ozone nonattainment areas, states must revise their SIPs to include RACT for sources of VOC emissions covered by control techniques guidelines (CTG) documents issued by the EPA prior to the area's date of attainment of the applicable ozone NAAQS. More importantly, section 184(b)(1)(B) of the CAA requires states in the Ozone Transport Region (OTR), including this Commonwealth, submit a SIP revision requiring implementation of RACT for all sources of VOC emissions in the state covered by a specific CTG and not just for those sources located in designated nonattainment areas of the state.

Consequently, the Commonwealth's SIP must include regulations applicable Statewide to control VOC emissions from oil and natural gas sources that are not regulated elsewhere in Chapter 129. This proposed rulemaking should achieve VOC emission reductions and lowered concentrations of ground-level ozone locally as well as in downwind states. Adoption of VOC emission reduction requirements is part of the Commonwealth's strategy, in concert with other OTR jurisdictions, to further reduce the transport of VOC ozone precursors and ground-level ozone throughout the OTR to attain and maintain the 8-hour ozone NAAQS. This proposed rulemaking will be submitted to the EPA for approval as a revision to the Commonwealth's SIP following promulgation of the final-form rulemaking.

The EPA issues guidance, in the form of a CTG, in place of regulations where the guidelines will be "substantially as effective as regulations" in reducing VOC emissions from an existing product or source category in ozone nonattainment areas. States with ozone nonattainment areas are required to revise their SIP to implement

RACT for existing sources of VOCs under section 172(c)(1) of the CAA. States, such as this Commonwealth, that are part of an OTR, designated under section 184(b) of the CAA are required to revise their SIP to implement RACT with respect to all sources of VOCs covered by a CTG in the state, regardless of their attainment status.

On October 27, 2016, the EPA issued the 2016 O&G CTG for emissions of VOCs from existing sources. See 81 FR 74798. The 2016 O&G CTG provides states with the EPA's recommendation of what constitutes RACT for the covered category. States can use the Federal recommendations provided in the 2016 O&G CTG to inform their own determination as to what constitutes RACT for VOC emissions from the covered category. State air pollution control agencies may implement other technically-sound approaches that are consistent with the CAA requirements and the EPA's implementing regulations or guidelines.

Following promulgation of the "Oil and Natural Gas Sector: Emission Standards for New, Reconstructed, and Modified Sources," published on June 3, 2016 (2016 NSPS), the EPA received petitions for reconsideration of several provisions of the 2016 NSPS. See 81 FR 35823 (June 3, 2016). On June 5, 2017, the EPA granted the reconsideration regarding fugitive emissions requirements, well site pneumatic pump standards and professional engineer certification requirements for closed vent systems. See 82 FR 25730 (June 5, 2017).

On March 9, 2018, the EPA requested comment and additional information from states on a potential withdrawal of the 2016 O&G CTG. See 83 FR 10478 (March 9, 2018). In the notice, the EPA stated that the 2016 O&G CTG relied upon underlying data and conclusions made in the 2016 NSPS. In light of the fact that EPA is reconsidering the 2016 NSPS and because the 2016 NSPS and CTG share certain key pieces of data and information, EPA proposed to withdraw the CTG in its entirety. The Department submitted comments against the proposed comprehensive withdrawal of the 2016 O&G CTG, on April 23, 2018. To date, EPA has not acted on its proposed withdrawal.

On October 15, 2018, the EPA proposed reconsideration amendments to the 2016 NSPS. See 83 FR 52056 (October 15, 2018). The proposed amendments include: changing the frequency of monitoring for fugitive emissions to annually at well sites, biennially at low-production well sites, and either annually or semi-annually at compressor stations; recognizing existing fugitive emissions monitoring and repair plans from certain states, including this Commonwealth, as an approved alternative means of emissions limitation (AMEL) to comply with the Federal requirements; removing the differentiation of "greenfield" and "non-greenfield" sites and the ability to rule out routing pump emissions due to technical infeasibility. The proposed amendments additionally include relaxing the requirement for a professionally licensed engineer to certify the determination of technical infeasibility to route pump emissions to a control and the design and capacity of a closed vent system by allowing in-house engineers with appropriate expertise to also make the required certification.

On December 17, 2018, the Department submitted a comment letter on the EPA's proposed reconsideration amendments to the 2016 NSPS that recommended not reducing the leak detection and repair (LDAR) inspection frequency for well sites and compressor stations; not allowing a step-down provision for LDAR inspections at well sites as it is not appropriate to reduce semi-annual inspection frequencies; requiring that the LDAR inspection frequency be based upon the economic feasibility and not the production of a well; recognizing the Department's Category 38(c) (Exemption 38(c)) of the Air Quality Permit Exemptions as AMEL; and not requiring owners and operators to notify the Administrator of their use of an AMEL as it will be self-evident in their annual report. In the EPA's 1995 Protocol for Equipment Leak Emission Estimates, the emission factors do not factor in production or line pressure and the EPA stated it is unable to account for lower operational pressures or pressure changes in the model plants used to determine the cost effectiveness for LDAR inspections in the NSPS. The Department also referenced its LDAR inspection program, in effect since February 2, 2013, which requires monthly audio, visual, olfactory (AVO) inspections and quarterly LDAR inspections at these facilities. Since the Department's LDAR inspection requirements are recognized by the EPA as AMEL for the 2016 NSPS, and this proposed rulemaking implements RACT requirements which are more stringent than the recommendations in the 2016 O&G CTG, any changes finalized by EPA's reconsideration of the 2016 NSPS will not affect this proposed rulemaking. See 83 FR 52056, 52081.

The Department concurred with the EPA's proposal in the 2016 NSPS reconsideration to remove the differentiation of "greenfield" and "non-greenfield" sites when determining whether it is technically feasible to route pump emissions to a control. A "greenfield" site is defined as a site, other than a natural gas processing plant, which is entirely new construction. This change would have no bearing on existing sources, as by definition they would all be "non-greenfield" sites under the 2016 NSPS. The EPA did not distinguish between "greenfield" and "non-greenfield" sites in the 2016 O&G CTG.

The Department also concurred with the EPA's proposal to allow in-house engineers to certify the determination of technical infeasibility to route pump emissions to a control and the design and capacity of a closed vent system, regardless of professional licensure. An in-house engineer is held to the same level of accountability as a professional engineer when complying with the certification requirements. Therefore, the Department incorporates the ability to use in-house engineers for the certification requirements in this proposed rulemaking. If this change is not adopted in the EPA's final 2016 NSPS rule and subsequently incorporated into the 2016 O&G CTG, this could be interpreted as a relaxation of the recommendation; however, the EPA could either accept the language in this proposed rulemaking or request that the Department modify the language in the final-form rulemaking.

The EPA states in the proposed withdrawal that "if finalized, the withdrawal would remove the mandatory RACT review requirement for affected sources in ozone nonattainment areas classified as Moderate or higher and states in the OTR." See 83 FR 10478, 10479. However, the EPA noted that "unless and until EPA decides to withdraw the CTG, states remain obligated to revise their SIPs to address RACT requirements for oil and gas sources in ozone nonattainment areas classified as Moderate or higher and the states in the OTR." Id. The EPA goes on to state that "withdrawal of the CTG would not hinder states from establishing, where desired or otherwise required, emissions standards for sources in the oil and natural gas industry, including standards based on the recommendations contained in the withdrawn CTG." Id.

If the 2016 O&G CTG is not withdrawn, states subject to RACT requirements must revise their SIPs for the

2008 and later ozone standards to include their RACT determinations for the oil and natural gas sources covered by the 2016 O&G CTG, no later than January 21, 2021. As previously stated, the states are responsible for attaining and maintaining the NAAQS.

The Department reviewed the RACT recommendations included in the 2016 O&G CTG for their applicability to the ground-level ozone reduction measures necessary for this Commonwealth and determined that the VOC emission reduction measures and other requirements are appropriate for this source category; however, the Department determined in two cases that more stringent RACT requirements are necessary. In the first, the Department determined that a lower VOC applicability threshold is necessary for storage vessels at unconventional well sites installed on or after August 10, 2013, to prevent backsliding and that the lower applicability threshold also represents RACT for storage vessels at gathering and boosting stations, processing plants, and transmission stations. In the second, the Department determined that owners or operators must conduct monthly AVO inspections and quarterly LDAR inspections of fugitive emissions components at their facilities. The Board has determined that these more stringent requirements are reasonably necessary to achieve or maintain the NAAQS.

This proposed rulemaking is designed to adopt VOC emission limitations and other requirements as RACT to meet the requirements of sections 172(c)(1), 182(b)(2) and 184(b)(1)(B) of the CAA. These VOC emission limitations and other requirements would apply across this Commonwealth as required under section 184(b)(1)(B) of the CAA. The proposed control measures would reduce VOC emissions from oil and natural gas sources throughout this Commonwealth at those affected sources that are not regulated elsewhere under Chapter 129.

Even though a finalized withdrawal of the 2016 O&G CTG would relieve this Commonwealth of the requirement to address RACT for existing oil and gas sources, the Department is still obligated to reduce ozone and VOC emissions as a precursor under section 110 of the CAA. The Board has the authority under section 5(a)(1) of the APCA to adopt rules and regulations for the prevention, control, reduction and abatement of air pollution in this Commonwealth. Addressing existing sources of VOC emissions is necessary to attain and maintain the NAAQS and protect the public health and welfare from harmful air pollution.

The Board is moving forward with this proposed rulemaking for a number of reasons. First, the Department reviewed EPA's reconsideration of the 2016 NSPS and, based on that proposed rule, made changes to this proposed rulemaking as discussed previously.

Second, adoption of the VOC emission control measures and other requirements in this proposed rulemaking would allow the Commonwealth to make substantial progress in achieving and maintaining the 1997, 2008 and 2015 8-hour ozone NAAQS Statewide. Implementation of and compliance with the proposed VOC emission reduction measures would also assist the Commonwealth in reducing the levels of ozone precursor emissions that contribute to potential nonattainment of the 2015 ozone NAAQS. As a result, the VOC emission control measures are reasonably necessary to attain and maintain the health-based and welfare-based 8-hour ozone NAAQS in this Commonwealth and to satisfy related CAA requirements. It would also establish VOC RACT as required for natural gas processing plants which have RACT requirements under the 1983 CTG for Control of Volatile Organic Compound Equipment Leaks from Natural Gas/Gasoline Processing Plants, EPA 450/3-83-007, Office of Air Quality Planning and Standards, EPA, December 1983. The Department would be able to certify this proposed rulemaking as RACT, if published as a final-form rulemaking, instead of certifying the NSPS requirements as meeting RACT for natural gas processing facilities.

Third, the Department estimates that implementation of the proposed control measures could reduce VOC emissions by as much as 983 tons per year (TPY) from fugitive emissions components through the performance of quarterly LDAR inspections, by as much as 121 TPY from the installation of controls for storage vessels with actual emissions based on the Department's more stringent applicability thresholds, 109 TPY from pneumatic pumps and 3,191 TPY from pneumatic controllers. Approximately 294 TPY of these emission reductions are due to the additional stringency the Department proposes when compared to the 2016 O&G CTG. These reductions would benefit the health and welfare of the approximately 12.8 million residents and the numerous animals, crops, vegetation and natural areas of this Commonwealth by reducing the amount of ground-level ozone air pollution resulting from these sources.

Finally, this proposed rulemaking will provide consistency among all oil and natural gas sources in this Commonwealth for monitoring fugitive emissions components by including monthly AVO inspection requirements and quarterly LDAR inspection requirements. These requirements are consistent with the LDAR inspection requirements specified in the Department's General Plan Approval and General Operating Permit for Natural Gas Compression Stations, Processing Plants and Transmission Stations (GP-5), the General Plan Approval and General Operating Permit for Unconventional Natural Gas Well Site Operations and Remote Pigging Stations (GP-5A), and the Air Quality Permit Exemptions, Exemption 38. Since the Commonwealth's LDAR inspection program is recognized as AMEL for the 2016 NSPS and the requirements of the 2016 NSPS and the 2016 O&G CTG are identical, the Commonwealth's LDAR inspection program should be acceptable as AMEL for purposes of implementing the RACT requirements of the 2016 O&G CTG. This would have the benefit of providing owners and operators of both new and existing facilities with the ability to merge both types of sources into one LDAR inspection program.

This proposed rulemaking is also consistent with Governor Tom Wolf's strategy to reduce emissions of methane from the oil and natural gas industry in this Commonwealth. In the strategy, announced on January 19, 2016, the Department committed to developing a regulation for existing sources to reduce leaks at existing oil and natural gas facilities based on the RACT recommendations in the 2016 O&G CTG. The strategy also states that the Commonwealth will reduce emissions by requiring LDAR inspections and more frequent use of leak-sensing technologies. This proposed rulemaking fulfills that part of the strategy.

While this proposed rulemaking requires VOC emission reductions, methane emissions are also reduced as a co-benefit, because both VOC and methane are emitted from oil and natural gas operations. Except for storage vessels, the requirements for control of emissions are not dependent on an applicability threshold for VOC, meaning that most requirements have no minimum level of VOC emissions under which sources are granted an exemption. For example, continuous bleed natural gas-driven pneumatic controllers are required to limit their bleed rate to 6 standard cubic feet (scf) per hour of natural gas, regardless of the VOC concentration, which also serves to limit methane emissions. Reciprocating compressors at gathering and boosting stations and natural gas processing plants are required to replace the rod end packing or route the rod end packing emissions to a closed vent system regardless of the actual VOC emissions, which serves to reduce both VOC and methane emissions by limiting natural gas leakage. Both wet seal centrifugal compressor degassing systems and natural gas-driven diaphragm pumps are required to control their VOC emissions by 95.0% by weight or greater regardless of the actual VOC emissions, which also effectively controls methane emissions. Also, for fugitive emissions components, the AVO inspection program and LDAR inpsection program detect natural gas leakage, which, with the repair requirement, serves to reduce emissions of both VOC and methane.

These control measures for VOC emissions, if implemented, will simultaneously control methane emissions and provide VOC emission reductions of approximately 4,404 TPY and methane emission reductions of approximately 75,603 TPY. The additional stringency in this proposed rulemaking results in a greater reduction of VOC and methane emissions than the 2016 O&G CTG, amounting to 294 TPY of VOCs and 2,627 TPY of methane. These reductions are significant, and the Board does not want to trade this environmental benefit for the uncertain withdrawal of the 2016 O&G CTG, which has already been judged technically sound.

This proposed rulemaking strives to ensure regulatory certainty for the oil and natural gas industry in this Commonwealth. The Department is aware of approximately 89,320 unconventional and conventional oil and natural gas wells, of which the Department estimates that 8,403 unconventional and 71,229 conventional wells are currently in production. These facilities also include approximately 435 midstream compressor stations, 120 transmission compressor stations and 10 natural gas processing facilities in this Commonwealth whose owners and operators may be subject to the proposed VOC emission reduction measures, work practice standards, and reporting and recordkeeping requirements. It is possible that owners and operators of additional facilities that have not been identified could be subject to this proposed rulemaking.

The Department estimates that the cost of complying with this proposed rulemaking would be about $35.3 million per year. However, implementation of the proposed control measures would also potentially save the oil and natural gas industry about $9.9 million per year due to a lower natural gas loss rate during production. This estimate consists of two major categories of data. The first is the estimated cost per year for each piece of equipment or site affected. This number was provided by the EPA in the 2016 O&G CTG. The second is the number of potentially affected facilities, which was obtained from several data sources including the Department's database for oil and natural gas well production, the Department's air emissions inventory, the Environmental Facility Application Compliance Tracking System and Air Information Management System databases, the United States Energy Information Agency's list of natural gas processing plants, and the EPA emissions inventory.

Of the 71,229 conventional wells reporting production, only 303 are above the 15 barrels of oil equivalent per day production threshold as reported in the Department's 2017 oil and natural gas production database and will have fugitive emissions component requirements. For sources located at a natural gas well site, the anticipated cost to comply with the requirements would be based on the sources present at the site, the applicability of those sources and the type of control used to comply. In the 2016 O&G CTG, the EPA estimates the costs for control of the various sources as follows:

- Implementation of a quarterly LDAR inspection program using optical gas imaging (OGI) costs $4,220 per year resulting in a cost per ton of VOC reduced of $3,453.
- Routing emissions from a natural gas-driven diaphragm pump to a process costs $774 per year resulting in a cost per ton of VOC reduced of $847.
- Replacing a continuous high-bleed natural gas-driven pneumatic controller costs $296 per year resulting in a cost per ton of VOC reduced of $209.
- Routing emissions from a storage vessel to a control device costs $25,194 per year with a cost per ton of VOC reduced of $4,420.

Most of the anticipated costs are due to new regulatory requirements but many of the costs associated with this proposed rulemaking are from common sense practices and controls that operators are already implementing. Some examples include periodic inspections which can prevent releases which in turn prevents environmental damage and significant financial losses for the operator. The Department anticipates there will be areas of cost savings that will occur as a result of this proposed rulemaking as well. In addition, the Department estimates most small business stationary sources will be below the applicability thresholds. However, affected small businesses may incur minimal cost as a result of this proposed rulemaking. Overall, the Department does not anticipate that this proposed rulemaking will result in any significant adverse impact on small oil and natural gas operators.

The Department consulted with the Air Quality Technical Advisory Committee (AQTAC) and the Small Business Compliance Advisory Committee (SBCAC) in the development of this proposed rulemaking. On December 14, 2017, the Department presented concepts to AQTAC on a potential rulemaking incorporating the 2016 O&G CTG recommendations. The Department returned to AQTAC on December 13, 2018, for an informational presentation on a preliminary draft Annex A. This proposed rulemaking was presented to AQTAC on April 11, 2019, and SBCAC on April 17, 2019. Both committees concurred with the Department's recommendation to move this proposed rulemaking forward to the Board for consideration.

The Department also conferred with the Citizens Advisory Council's (CAC) Policy and Regulatory Oversight Committee concerning this proposed rulemaking on May 7, 2019. On June 18, 2019, the full CAC concurred with the Department's recommendation to move this proposed rulemaking forward to the Board for consideration.

E. *Summary of Regulatory Requirements*

§ 121.1. Definitions

This section contains definitions relating to the air quality regulations. This proposed rulemaking would amend the terms "CPMS—continuous parameter monitoring system," "fugitive emissions" and "responsible official," and add the abbreviation "ppm" to support the proposed amendments to Chapter 129.

§ 129.121. General provisions and applicability

Subsection (a) provides that this proposed rulemaking would apply statewide to the owner or operator of the following, which were in existence on or before the effective date of the final-form rulemaking: a storage vessel in all segments except natural gas distribution; natural gas-driven pneumatic controller; natural gas-driven diaphragm pump; reciprocating compressor; centrifugal compressor; or fugitive emissions component.

Subsection (b) provides that compliance with the requirements of this proposed rulemaking would assure compliance with the requirements of an operating permit issued under §§ 129.91—129.95 (relating to stationary sources of NO_x and VOCs) or §§ 129.96—129.100 (relating to additional RACT requirements for major sources of NO_x and VOCs) except to the extent the operating permit contains more stringent requirements.

§ 129.122. Definitions, acronyms and EPA methods

Section 129.122 adds definitions, acronyms and EPA methods applicable to this proposed rulemaking.

§ 129.123. Storage vessels

Subsection (a) establishes the applicability threshold for the owner or operator of a storage vessel based on potential VOC emissions. For a storage vessel at a conventional well site or at an unconventional well site installed prior to August 10, 2013, the potential to emit (PTE) threshold of 6.0 TPY VOC is as recommended in Section A.1(a) of the 2016 O&G CTG. For a storage vessel at an unconventional well site installed on or after August 10, 2013, or at a natural gas gathering and boosting station, a natural gas processing plant, or in the natural gas transmission and storage segment, the PTE threshold is 2.7 TPY VOC. The more stringent 2.7 TPY threshold is based on the threshold used under Exemption 38(b) of the Air Quality Permit Exemptions List, which has been in effect since August 10, 2013. Subsection (a) also establishes the methodology required for calculating the potential VOC emissions of a storage vessel.

Subsection (b) establishes the compliance requirements for the owner or operator of a storage vessel to reduce VOC emissions by 95.0% by weight or greater by either routing emissions to a control device or installing a floating roof that meets the requirements of 40 CFR Part 60, Subpart Kb (relating to 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). If the owner or operator decides to route emissions to a control device, then the cover and closed vent systems must meet the requirements in § 129.128 (relating to covers and closed vent systems).

Subsection (c) provides for exceptions to the emissions limitations and control requirements in subsection (b) based on a storage vessel's actual VOC emissions and lists compliance demonstration requirements for owners or operators claiming an exception.

Subsection (d) lists three categorical exemptions from the emissions limitations and control requirements of subsection (b).

Subsection (e) lists the requirements for removing a storage vessel from service.

Subsection (f) lists the requirements for a storage vessel returned to service.

Subsection (g) references the recordkeeping and reporting requirements under § 129.130(b) (relating to recordkeeping and reporting) and § 129.130(k)(1) for owners or operators of storage vessels subject to this section.

§ 129.124. Natural gas-driven pneumatic controllers

Subsection (a) establishes the applicability for the owner or operator of a natural gas-driven pneumatic controller based on the controller's location.

Subsection (b) provides for certain exceptions related to this subsection.

Subsection (c) establishes VOC emissions limitation requirements.

Subsection (d) sets forth compliance demonstration requirements.

Subsection (e) identifies the recordkeeping and reporting requirements.

§ 129.125. Natural gas-driven diaphragm pumps

Subsection (a) establishes the applicability for the owner or operator of a natural gas-driven diaphragm pump based on the pump's location.

Subsection (b) establishes the compliance requirements for the owner or operator of a natural gas-driven diaphragm pump to reduce VOC emissions by 95.0% by weight or greater. For natural gas-driven diaphragm pumps located at a well site, the owner or operator shall reduce VOC emissions by connecting the natural gas-driven diaphragm pump to a control device through a closed vent system that meets the requirements of § 129.128(b) and routing the emissions to a control device or process that meets the requirements of § 129.129 (relating to control devices). For natural gas-driven diaphragm pumps located at a natural gas processing plant, the owner or operator shall reduce VOC emissions by maintaining an emission rate of zero standard cubic feet per hour.

Subsection (c) provides for three exceptions to the emissions limitations and control requirements in subsection (b) based on the presence of a control device, the capability of the control device, or technical infeasibility of routing emissions to the control device.

Subsection (d) provides for a categorical exemption for natural gas-driven diaphragm pumps located at a well site which operates less than 90 days per calendar year, so long as the owner or operator maintains records of the operating days.

Subsection (e) establishes the compliance requirements for the owner or operator when removing a control device or process to which emissions from a natural gas-driven diaphragm pump are routed.

Subsection (f) references the recordkeeping and reporting requirements listed under § 129.130(d) and (k)(3) for owners or operators of natural gas-driven diaphragm pumps.

§ 129.126. Compressors

Subsection (a) establishes the applicability for the owner or operator of a reciprocating compressor or centrifugal compressor based on the compressor's location.

Subsection (b) establishes the compliance requirements for the owner or operator of a reciprocating compressor choosing to either replace the rod packing or use a rod packing emissions collection system.

Subsection (c) establishes the compliance requirements for the owner or operator of a centrifugal compressor to reduce VOC emissions by 95.0% by weight or greater by connecting to a control device through a cover and closed vent system that meets the requirements of § 129.128.

Subsection (d) lists two categorical exemptions from the emissions limitation and control requirements of subsection (b) and (c) for compressors located at a well site or at an adjacent well site where the compressor services more than one well site.

Subsection (e) references the recordkeeping and reporting requirements listed under § 129.130(e) and (k)(4) for owners or operators of reciprocating compressors and under § 129.130(f) and (k)(5) for owners or operators of centrifugal compressors.

§ 129.127. Fugitive emissions components

Subsection (a) establishes the applicability for the owner or operator of a fugitive emissions component based on the component's location. This subsection also establishes that a fugitive emissions component at a well site with a well that produces less than 15 barrels of oil equivalent per day is not subject to this section.

Subsection (b) establishes the compliance requirements for producing well sites based on the gas to oil ratio (GOR) of the well. The owner or operator of a well site with a GOR less than 300 scf of gas per barrel of oil produced must maintain the records under § 129.130(g)(1). The owner or operator of a well site with a GOR greater than or equal to 300 scf of gas per barrel of oil must implement monthly AVO inspections and quarterly instrument based LDAR inspections. Owners and operators of well sites have the option of tracking the percentage of leaking components and reducing the LDAR inspection frequency to semiannually if less than 2% of components are leaking.

Subsection (c) establishes the LDAR inspection requirements for shut-in wells.

Subsection (d) establishes the compliance requirements for the owner or operator of a natural gas gathering and boosting station or natural gas processing plant to implement monthly AVO inspections and quarterly LDAR inspections.

Subsection (e) provides an option for owners or operators to request an extension of the LDAR inspection interval.

Subsection (f) establishes the requirement for owners or operators to develop and maintain a written fugitive emissions monitoring plan.

Subsection (g) establishes the verification procedures for OGI equipment identified in the fugitive emissions monitoring plan.

Subsection (h) establishes the verification procedures for gas leak detection equipment using EPA Method 21 identified in the fugitive emissions monitoring plan.

Subsection (i) establishes the requirement for a fugitive emissions detection device to be operated and maintained in accordance with the manufacturer-recommended procedures and as required by the test method or a Department approved method.

Subsection (j) establishes that the owner or operator may opt to perform the no detectable emissions procedure of Section 8.3.2 of EPA Method 21.

Subsection (k) establishes the requirements to repair a leak detected from a fugitive emissions component and to resurvey the fugitive emissions component within 30 days of the leak repair.

The LDAR inspection requirements in this proposed rulemaking are in line with the LDAR inspection requirements listed in the Air Quality Permit Exemptions, GP-5A and GP-5. The EPA recognized the Commonwealth's LDAR inspection requirements in GP-5A and GP-5 as an AMEL under the reconsideration of the 2016 NSPS. Since the LDAR inspection program is recognized as AMEL for the 2016 NSPS, and the requirements of the 2016 NSPS and the 2016 O&G CTG are identical, the EPA should also accept the Commonwealth's LDAR inspection program in this proposed rulemaking as AMEL. By establishing consistent LDAR inspection requirements for both new and existing sources, the Department is providing owners and operators with the ability to merge both types of sources into one LDAR inspection program.

Subsection (l) references the recordkeeping and reporting requirements for owners or operators of fugitive emissions components listed under § 129.130(g) and (k)(6).

§ 129.128. Covers and closed vent systems

Subsection (a) establishes the requirements for the owner or operator of a cover on a storage vessel, reciprocating compressor or centrifugal compressor, including a monthly AVO inspection requirement. The monthly AVO inspection requirement is consistent with the AVO inspection requirement for fugitive emissions components.

Subsection (b) establishes the design, operation and repair requirements for the owner or operator of a closed vent system installed on a subject source.

Subsection (c) establishes the requirement that the owner or operator of a closed vent system perform a design and capacity assessment and allows either a qualified professional engineer or an in-house engineer, as defined in § 129.122, to perform the assessment as proposed in the 2016 NSPS reconsideration.

Subsection (d) establishes the requirement that the owner or operator conduct a no detectable emissions test procedure under Section 8.3.2 of EPA Method 21.

§ 129.129. Control devices

Subsection (a) establishes the applicability for the owner or operator of a control device based on whether the control device receives a liquid, gas, vapor or fume from one or more subject storage vessel, natural gas-driven diaphragm pump or wet seal centrifugal compressor degassing system. The owner or operator must operate each control device whenever a liquid, gas, vapor or fume is routed to the device and must maintain the records under § 129.130(j) and submit reports under § 129.130(k)(9).

Subsection (b) establishes the general compliance requirements for the owner or operator of a control device. Subsections (c)—(i) outline specific requirements that apply for each type of control device in addition to the general requirements in subsection (b).

Subsection (c) lists the compliance requirements for a manufacturer-tested combustion device, meaning a control device tested under 40 CFR 60.5413a(d) (relating to what are the performance testing procedures for control devices used to demonstrate compliance at my centrifugal compressor and storage vessel affected facilities?). The performance testing procedure in 40 CFR 60.5413a(d) is incorporated by reference in Chapter 122 (relating to national standards of performance for new stationary sources).

Subsection (d) lists the compliance requirements for an enclosed combustion device.

Subsection (e) lists the compliance requirements for a flare. The flare must meet the requirements under 40 CFR 60.18(b) (relating to general control device and work practice requirements).

Subsection (f) lists the compliance requirements for a carbon adsorption system.

Subsection (g) lists specific compliance requirements for a regenerative carbon adsorption system.

Subsection (h) lists specific compliance requirements for a non-regenerative carbon adsorption system.

Subsection (i) lists the compliance requirements for condensers and other non-destructive control devices.

Subsection (j) identifies the general performance test requirements.

Subsection (k) identifies the performance test method for demonstrating compliance with the control device percent VOC emission reduction requirements referenced in subsections (c), (d), (f) and (i).

Subsection (l) identifies the performance test method for demonstrating compliance with the outlet concentration requirements referenced in subsections (d), (f) and (i).

Subsection (m) lists the continuous parameter monitoring system requirements (CPMS) for control devices that are required to install CPMS.

§ 129.130. Recordkeeping and reporting

In an effort to assist the regulated community, the Department created a separate section for all the applicable recordkeeping and reporting requirements pertaining to each regulated source.

Subsection (a) establishes the general requirement for all owners or operators of regulated sources to maintain applicable records onsite or at the nearest local field office for 5 years and for the records to be made available to the Department upon request.

Subsection (b) establishes the specific recordkeeping requirements for storage vessels.

Subsection (c) establishes the specific recordkeeping requirements for natural gas-driven pneumatic controllers.

Subsection (d) establishes the specific recordkeeping requirements for natural gas-driven diaphragm pumps.

Subsection (e) establishes the specific recordkeeping requirements for reciprocating compressors.

Subsection (f) establishes the specific recordkeeping requirements for centrifugal compressors.

Subsection (g) establishes the specific recordkeeping requirements for fugitive emissions components.

Subsection (h) establishes the specific recordkeeping requirements for covers.

Subsection (i) establishes the specific recordkeeping requirements for closed vent systems.

Subsection (j) establishes the specific recordkeeping requirements for control devices.

Subsection (k) establishes the reporting requirements for all owners or operators of regulated sources to submit an initial report 1 year after the effective date of this rulemaking and subsequent annual reports, including an option to extend the due date of the initial report.

F. *Benefits, Costs and Compliance*

Benefits

The Department estimates that implementation of the proposed control measures could reduce VOC emissions by as much as 983 TPY from fugitive emissions components through the performance of quarterly LDAR inspections, by as much as 121 TPY from the installation of controls for storage vessels with actual emissions based on the Department's more stringent applicability thresholds, 109 TPY from pneumatic pumps and 3,191 TPY from pneumatic controllers. These VOC emission reductions would benefit the health and welfare of the approximately 12.8 million residents and the numerous animals, crops, vegetation and natural areas of this Commonwealth by reducing the amount of ground-level ozone air pollution resulting from these sources.

As previously discussed, this proposed rulemaking is consistent with Governor Tom Wolf's strategy to reduce emissions of methane from the oil and natural gas industry in this Commonwealth. Methane is a potent greenhouse gas with a global warming potential more than 28 times that of carbon dioxide over a 100-year time period, according to the EPA. The EPA has identified methane, the primary component of natural gas, as the second-most prevalent greenhouse gas emitted in the United States from human activities. According to Federal estimates, the natural gas and oil industries account for a quarter of United States methane emissions. In addition to climate change impacts, methane and VOC emissions have harmful effects on air quality and human health. Thus, reducing methane leaks from oil and natural gas sources is essential to reducing global greenhouse gas emissions and protecting public health.

While this proposed rulemaking requires VOC emission reductions, methane emissions are also reduced as a co-benefit, because both VOCs and methane are emitted from oil and natural gas operations. Except for storage vessels, the requirements for control of emissions are not dependent on an applicability threshold for VOCs, meaning that most requirements have no minimum level of VOC emissions under which sources are granted an exemption. The control measures implemented for VOC emissions simultaneously control methane emissions and could reduce methane emissions by as much as 11,582 TPY from fugitive emissions components through the performance of quarterly LDAR inspections, by as much as 17 TPY from the installation of controls for storage vessels with actual emissions based on the Department's more stringent applicability thresholds, 2,583 TPY from pneumatic pumps, and 61,421 TPY from pneumatic controllers. Approximately 2,627 TPY of these methane emission reductions are due to the additional stringency the Department proposes when compared to the 2016 O&G CTG.

Adoption of the VOC emission control measures and other requirements in this proposed rulemaking would allow the Commonwealth to make substantial progress in achieving and maintaining the 1997, 2008 and 2015 8-hour ozone NAAQS Statewide. Implementation of and compliance with the proposed VOC emission reduction measures would also assist the Commonwealth in reducing the levels of ozone precursor emissions that contribute to potential nonattainment of the 2015 ozone NAAQS. As a result, the VOC emission control measures are reasonably necessary to attain and maintain the health-based and welfare-based 8-hour ozone NAAQS in this Commonwealth and to satisfy related CAA requirements.

Repeated exposure to ozone pollution for both healthy people and those with existing conditions may cause a variety of adverse health effects including difficulty breathing, chest pains, coughing, nausea, throat irritation and congestion. In addition, people with bronchitis, heart disease, emphysema, asthma and reduced lung capacity may have their symptoms exacerbated by ozone pollution. Asthma is a significant and growing threat to children and adults in this Commonwealth. Reduced ambient concentrations of ground-level ozone would reduce the incidences of hospital admissions for respiratory ailments including asthma and improve the quality of life for citizens overall. High levels of ground-level ozone also affect animals including pets, livestock and wildlife, in ways similar to humans. Reduced ambient concentrations of ground-level ozone would improve the quality of life of animals, preserve this Commonwealth's biodiversity and reduce veterinary costs to farmers and citizens with pets.

In addition to causing adverse human and animal health effects, high levels of ground-level ozone affect vegetation and ecosystems, leading to reductions in agricultural crop and commercial forest yields by destroying chlorophyll; reduced growth and survivability of tree seedlings; and increased plant susceptibility to disease, pests and other environmental stresses, including harsh weather. In long-lived species, these effects may become evident only after several years or even decades and have the potential for long-term adverse impacts on forest ecosystems.

This Commonwealth has more than 58,000 farms occupying more than 7.7 million acres of farmland which account for 81,345 direct jobs and $9.2 billion in direct economic output from production agriculture. In addition to production agriculture, the industry also raises revenue and supplies jobs through support services such as food processing, marketing, transportation, farm equipment and landscaping. In total, the Department of Agriculture (PDA) estimates that production agriculture and agribusiness contribute 215,985 jobs and $78.8 billion to this Commonwealth's economy. The economic value of crop yield loss due to high concentration of ground-level ozone can be calculated from both reduced seed production and visible injury to some leaf crops, including lettuce, spinach and tobacco, as well as visible injury to ornamental plants, including grass, flowers and shrubs. Reducing ground-level ozone concentrations will serve to protect agricultural yield and reduce losses to production agriculture and agribusiness in this Commonwealth.

This Commonwealth is forested over a total of 16.8 million acres, which represents 58% of the land area. Federal, State and local government hold 5.1 million acres in public ownership, with the remaining 11.7 million acres in private ownership. The forest product industry only owns 0.4 million acres of forest, with the remainder held by an estimated 750,000 individuals, families, partnerships or corporations. This Commonwealth leads the Nation in volume of hardwood with over 120.5 billion board feet of standing sawtimber. Recent data shows that this Commonwealth's forest growth-to-harvest rate is better than 2 to 1. As the leading producer of hardwood lumber in the United States, this Commonwealth also leads in the export of hardwood lumber, exporting nearly $560 million in 2017, and over $1.3 billion in lumber, logs, furniture and paper products to more than 70 countries around the world. Production is estimated at 1 billion board feet of lumber annually. This vast renewable resource puts the hardwoods industry at the forefront of manufacturing in this Commonwealth.

Both the United States Department of Agriculture and the PDA estimate that forestry production and processing account for 64,515 direct jobs and $27.7 billion in direct economic output and direct value added to this Commonwealth's economy. Excessive ground-level ozone is known to result in forest biomass loss. East of the Mississippi river, this Commonwealth is the state hardest hit by forest loss with the worst effects in western Pennsylvania. Reducing ground-level ozone concentrations will serve to protect this Commonwealth's position as the leader of growing volume of hardwood species and producer of hardwood lumber in the Nation.

The Department of Conservation and Natural Resources (DCNR) is the steward of the State-owned forests and parks. DCNR awards millions of dollars in construction contracts each year to build and maintain the facilities in its parks and forests. Hundreds of concessions throughout the park system help complete the park experience for both in-State and out-of-State visitors. Ozone damage to the foliage of trees and other plants can decrease the aesthetic value of ornamental species used in residential landscaping, as well as the natural beauty of parks and recreation areas. However, the effects of the reduced aesthetic value of trees in heavily visited parks may not be quantifiable. Reducing the concentration of ground-level ozone will help maintain the benefits to this Commonwealth's economy due to tourism.

Through deposition, ground-level ozone also contributes to pollution in the Chesapeake Bay which can have adverse impacts including loss of species diversity and changes to habitat quality and water and nutrient cycles. High levels of ground-level ozone can also cause damage to buildings and synthetic fibers, including nylon, plastic and rubber, and reduced visibility on roadways and in natural areas. The reduction of ground-level ozone air pollution concentrations directly benefits the human and animal populations of this Commonwealth with improved ambient air quality and healthier environments. The agriculture and timber industries and related businesses benefit directly from reduced economic losses that result from damage to crops and timber. Likewise, the natural areas and infrastructure within this Commonwealth and downwind states benefit directly from reduced environmental damage and economic losses.

The EPA estimated that the monetized health benefits of attaining the 2008 8-hour ozone NAAQS of 0.075 ppm range from $8.3 billion to $18 billion on a National basis by 2020. Prorating that benefit to this Commonwealth, based on population, results in a public health benefit of $337 million to $732 million. Similarly, the EPA estimated that the monetized health benefits of attaining the 2015 8-hour ozone NAAQS of 0.070 ppm range from $1.5 billion to $4.5 billion on a National basis by 2025. Prorating that benefit to this Commonwealth, based on population, results in a public health benefit of $63 million to $189 million. The Department is not stating that these estimated monetized health benefits would all be the result of implementing the proposed RACT measures, but the EPA estimates are indicative of the benefits to Commonwealth residents of attaining the 2008 and 2015 8-hour ozone NAAQS through the implementation of a suite of measures to control VOC emissions in the aggregate from different source categories.

This proposed rulemaking may create economic opportunities for VOC emission control technology innovators, manufacturers and distributors through an increased demand for new or improved equipment. In addition, the owners and operators of regulated facilities may be required to install and operate an emissions monitoring system or equipment necessary for an emissions monitoring method to comply with this proposed rulemaking, thereby creating an economic opportunity for the emissions monitoring industry.

This proposed rulemaking will provide consistency among all oil and natural gas sources in this Commonwealth for monitoring fugitive emissions components by including monthly AVO inspection requirements and quarterly LDAR inspection requirements. These requirements are consistent with the LDAR inspection requirements specified in the Department's GP-5, GP-5A and Air Quality Permit Exemption 38. This would have the benefit of providing owners and operators of both new and existing facilities with the ability to merge both types of sources into one LDAR inspection program. This would also benefit the Department in ensuring compliance of these sources.

Compliance costs

Compliance costs will vary for each facility depending on which compliance option is chosen by the owner or operator. For storage vessels, installing an enclosed combustion device will cost $25,194 per year and installing a vapor recovery unit will cost $32,006 per year. For pneumatic controllers, installing a pneumatic controller that utilizes instrument air when an instrument air system is already onsite costs $285 per year. Replacing a controller with a low bleed continuous controller costs $296 per year. Routing a diaphragm pump to a process costs $774 per year. Replacing the rod end packings on a reciprocating compressor at a gathering and boosting station costs $2,153 per year; at a processing plant the costs is $1,631 per year. Routing the wet seal centrifugal compressor degassing system to a process costs $2,553 per year.

Conducting quarterly LDAR inspections with OGI at a well site costs $4,220 and at a gathering and boosting station $25,049 per year. Conducting an EPA Method 21, 40 CFR Part 60, Subpart VVa (relating to standards of performance for equipment leaks of VOC in the synthetic organic chemicals manufacturing industry for which construction, reconstruction, or modification commenced after November 7, 2006) inspection at a processing plant costs $12,959. The Department assumes that using the OGI alternative method for EPA Method 21 at a processing plant costs $25,049 per year for a gathering and boosting station.

Based on the previously listed compliance costs and the number of applicable sources, the Department estimates that this proposed rulemaking will cost operators approximately $35.3 million (based on 2012 dollars) without consideration of the economic benefit of the saved natural gas. The value of the saved natural gas, in 2012 dollars, yields a savings of approximately $9.9 million, resulting in a total net cost of approximately $25.4 million for this proposed rulemaking.

If the owner or operator cannot meet the provisions of this proposed rulemaking, then they have the option to demonstrate to the Department's satisfaction that it is economically or technically infeasible to meet the applicable VOC RACT emission limitation in a case-by-case RACT permit application. Providing the option to apply for a case-by-case RACT permit may minimize compliance costs to the owner or operator of an affected facility.

The VOC RACT requirements established by this proposed rulemaking will not require the owner or operator to submit an application for amendments to an existing operating permit. These requirements will be incorporated when the permit is renewed, if less than 3 years remain in the permit term, as specified under § 127.463(c) (relating to operating permit revisions to incorporate applicable standards). If 3 years or more remain in the permit term, the requirements would be incorporated as applicable requirements in the permit within 18 months of the promulgation of the final-form rulemaking, as required under § 127.463(b).

Compliance assistance plan

The Department plans to educate and assist the public and the regulated community in understanding the proposed requirements and how to comply with them. The Department will continue to work with the Department's provider of Small Business Stationary Source Technical and Environmental Compliance Assistance. These services are currently provided by the Environmental Management Assistance Program (EMAP) of the Pennsylvania Small Business Development Centers. The Department has partnered with EMAP to fulfill the Department's obligation to provide confidential technical and compliance assistance to small businesses as required by the APCA, section 507 of the CAA (42 U.S.C.A. § 7661f) and authorized by the Small Business and Household Pollution Prevention Program Act (35 P.S. §§ 6029.201—6029.209).

In addition to providing one-on-one consulting assistance and onsite assessments, EMAP also operates a toll-free phone line to field questions from small businesses in this Commonwealth, as well as businesses wishing to start up in, or relocate to, this Commonwealth. EMAP operates and maintains a resource-rich environmental assistance web site and distributes an electronic newsletter to educate and inform small businesses about a variety of environmental compliance issues.

Paperwork requirements

The recordkeeping and reporting requirements for owners and operators of applicable sources under this proposed rulemaking are minimal because the records required are in line with the records already required to be kept for emission inventory purposes and for other Federal and State requirements.

G. *Pollution Prevention*

The Pollution Prevention Act of 1990 (42 U.S.C.A. §§ 13101—13109) established a National policy that promotes pollution prevention as the preferred means for achieving state environmental protection goals. The Department encourages pollution prevention, which is the reduction or elimination of pollution at its source, through the substitution of environmentally friendly materials, more efficient use of raw materials and the incorporation of energy efficiency strategies. Pollution prevention practices can provide greater environmental protection with greater efficiency because they can result in significant cost savings to facilities that permanently achieve or move beyond compliance.

This proposed rulemaking would help ensure that the citizens of this Commonwealth would benefit from reduced emissions of VOC and methane from regulated sources. Reduced levels of VOC and methane would promote healthful air quality and ensure the continued protection of the environment and public health and welfare.

H. *Sunset Review*

This Board is not establishing a sunset date for this proposed rulemaking, since it is needed for the Department to carry out its statutory authority. The Department will closely monitor this proposed rulemaking after promulgation as a final-form rulemaking in the *Pennsylvania Bulletin* for its effectiveness and recommend updates to the Board as necessary.

I. *Regulatory Review*

Under section 5(a) of the Regulatory Review Act (71 P.S. § 745.5(a)), on April 27, 2020, the Department submitted a copy of this proposed rulemaking to the Legislative Reference Bureau for publication in the *Pennsylvania Bulletin* and to the Independent Regulatory Review Commission (IRRC) and the Chairpersons of the House and Senate Environmental Resources and Energy Committees. In addition to submitting this proposed rulemaking, the Department has provided IRRC and the House and Senate Committees with a copy of a detailed Regulatory Analysis Form prepared by the Department. A copy of this material is available to the public upon request.

Under section 5(g) of the Regulatory Review Act, IRRC may convey any comments, recommendations or objections to the proposed rulemaking within 30 days of the close of the public comment period. The comments, recommendations or objections must specify the regulatory review criteria in section 5.2 of the Regulatory Review Act (71 P.S. § 745.5b) which have not been met. The Regulatory Review Act specifies detailed procedures for review, prior to final publication of the rulemaking by the Department, the General Assembly and the Governor.

J. *Public Comments*

Interested persons are invited to submit to the Board written comments, suggestions, support or objections regarding this proposed rulemaking. Comments, suggestions, support or objections must be received by the Board by July 27, 2020.

Comments may be submitted to the Board by accessing the Board's online comment system at http://www.ahs.dep.pa.gov/eComment.

Comments may also be submitted by e-mail to RegComments@pa.gov. A subject heading of this proposed rulemaking and a return name and address must be included in each transmission.

If an acknowledgement of comments submitted online or by e-mail is not received by the sender within 2 working days, the comments should be retransmitted to the Board to ensure receipt. Comments submitted by facsimile will not be accepted.

Comments may also be submitted to the Board by mail or express mail. Written comments should be mailed to the Environmental Quality Board, P.O. Box 8477, Harrisburg, PA 17105-8477. Express mail should be sent to the Environmental Quality Board, Rachel Carson State Office Building, 16th Floor, 400 Market Street, Harrisburg, PA 17101-2301.

K. *Public Hearings*

In accordance with Governor Tom Wolf's emergency disaster declaration and based on advice from the Department of Health regarding the mitigation of the spread of the novel coronavirus (COVID-19), the Board will hold three virtual public hearings for the purpose of accepting comments on this proposed rulemaking. The hearings will be held as follows:

June 23, 2020, at 6 p.m.
June 24, 2020, at 2 p.m.
June 25, 2020, at 6 p.m.

Persons wishing to present testimony at a hearing must contact Jennifer Swan for the Department and the Board, at either (717) 783-8727 or RA-EPEQB@pa.gov a minimum of 24 hours in advance of the hearing to reserve a time to present testimony.

Witnesses must be a resident of this Commonwealth to provide testimony. Organizations are limited to designating one witness to present testimony on their behalf at only one hearing. Verbal testimony is limited to 5 minutes for each witness. Video demonstrations and screen sharing by witnesses will not be permitted.

Witnesses are requested to submit written copy of their verbal testimony by e-mail to RegComments@pa.gov after providing testimony at the hearing.

Information on how to access the hearings will be available on the Board's webpage found through the Public Participation tab on the Department's web site at www.dep.pa.gov (select "Public Participation," then "Environmental Quality Board"). Prior to each hearing, individuals are encouraged to visit the Board's webpage for the most current information for accessing each hearing.

Any members of the public wishing to observe the public hearing without providing testimony are also directed to access the Board's webpage. Those who have not registered in advance as described previously will remain muted for the duration of the public hearing.

Persons in need of accommodations as provided for in the Americans with Disabilities Act of 1990 should contact the Board at (717) 783-8727 or through the Pennsylvania AT&T Relay Service at (800) 654-5984 (TDD) or (800) 654-5988 (voice users) to discuss how the Board may accommodate their needs.

PATRICK McDONNELL,
Chairperson

Fiscal Note: 7-544. No fiscal impact; (8) recommends adoption.

Annex A

TITLE 25. ENVIRONMENTAL PROTECTION

PART I. DEPARTMENT OF ENVIRONMENTAL PROTECTION

Subpart C. PROTECTION OF NATURAL RESOURCES

ARTICLE III. AIR RESOURCES

CHAPTER 121. GENERAL PROVISIONS

§ 121.1. Definitions.

The definitions in section 3 of the act (35 P.S. § 4003) apply to this article. In addition, the following words and terms, when used in this article, have the following meanings, unless the context clearly indicates otherwise:

* * * * *

CPMS—Continuous parameter monitoring system—**[For purposes of Chapter 127, Subchapter E, all of the]** <u>**The**</u> equipment necessary to meet the data acquisition and availability requirements to monitor process and control device operational parameters (for example, control device secondary voltages and electric currents), and other information (for example, gas flow rate, O_2 or CO_2 concentrations), and to record average operational parameter values on a continuous basis.

* * * * *

Fugitive emissions—**[For purposes of Chapter 127 (relating to construction, modification, reactivation**

and operation of sources), those emissions] **Emissions** which could not reasonably pass through a stack, chimney, vent or other functionally equivalent opening.

* * * * *

PM-10—Particulate matter with an effective aerodynamic diameter of less than or equal to a nominal 10 micrometer body as measured by the applicable reference method or an equal method.

***ppm*—Parts per million.**

ppmvd—Parts per million dry volume.

* * * * *

Responsible official—An individual who is:

(i) For a corporation: a president, secretary, treasurer or vice president of the corporation in charge of a principal business function, or another person who performs similar policy or decision making functions for the corporation, or an authorized representative of the person if the representative is responsible for the overall operation of one or more manufacturing, production, or operating facilities applying for, or subject to, a permit and one of the following applies:

(A) The facility employs more than 250 persons or has gross annual sales or expenditures exceeding $25 million (in second quarter 1980 dollars).

(B) The delegation of authority to the representative is approved, in advance, in writing, by the Department.

(ii) For a partnership or sole proprietorship: a general partner or the proprietor, respectively.

(iii) For a municipality, State, Federal or other public agency: a principal executive officer or ranking elected official. A principal executive officer of a Federal agency includes the chief executive officer having responsibility for the overall operations of a principal geographic unit of the agency—for example, a regional administrator of the EPA.

(iv) For affected sources:

(A) The designated representatives in so far as actions, standards, requirements or prohibitions under Title IV of the Clean Air Act (42 U.S.C.A. §§ 7641 and 7642) or the regulations thereunder are concerned.

(B) The designated representative or a person meeting provisions of subparagraphs (i)—(iii) for any other purpose under 40 CFR Part 70 (relating to operating permit programs) **[or],** Chapter 127 (relating to construction, modification, reactivation and operation of sources) **or Chapter 129**.

* * * * *

CHAPTER 129. STANDARDS FOR SOURCES

Control of VOC Emissions from Oil and Natural Gas Sources

(*Editor's Note*: Sections 129.121—129.130 are proposed to be added and are printed in regular type to enhance readability.)

§ 129.121. General provisions and applicability.

(a) *Applicability*. Beginning ______ (*Editor's Note*: The blank refers to the effective date of this rulemaking, when published as a final-form rulemaking.), this section and §§ 129.122—129.130 apply to an owner or operator of one or more of the following oil and natural gas sources of VOC emissions in this Commonwealth which were in existence on or before ______ (*Editor's Note*: The blank refers to the effective date of this rulemaking, when published as a final-form rulemaking.):

(1) Storage vessels in all segments except natural gas distribution.

(2) Natural gas-driven pneumatic controllers.

(3) Natural gas-driven diaphragm pumps.

(4) Reciprocating compressors and centrifugal compressors.

(5) Fugitive emissions components.

(b) *Existing RACT permit*. Compliance with the requirements of this section and §§ 129.122—129.130 assures compliance with the requirements of a permit issued under §§ 129.91—129.95 (relating to stationary sources of NO_x and VOCs) or §§ 129.96—129.100 (relating to additional RACT requirements for major sources of NO_x and VOCs) to the owner or operator of a source subject to subsection (a) prior to ______ (*Editor's Note*: The blank refers to the effective date of this rulemaking, when published as a final-form rulemaking.), to control, reduce or minimize VOC emissions from oil and natural gas sources listed in subsection (a), except to the extent the operating permit contains more stringent requirements.

§ 129.122. Definitions, acronyms and EPA methods.

(a) *Definitions and acronyms*. The following words and terms, when used in this section, §§ 129.121 and 129.123—129.130, have the following meanings, unless the context clearly indicates otherwise:

AVO—Audible, visual and olfactory.

Bleed rate—The rate in standard cubic feet per hour at which natural gas is continuously vented from a pneumatic controller.

Centrifugal compressor—

(i) A machine for raising the pressure of natural gas by drawing in low-pressure natural gas and discharging significantly higher pressure natural gas by means of mechanical rotating vanes or impellers.

(ii) The term does not include a screw compressor, sliding vane compressor or liquid ring compressor.

Closed vent system—A system that is not open to the atmosphere and that is composed of hard-piping, ductwork, connections and, if necessary, flow-inducing devices that transport gas or vapor from a piece or pieces of equipment to a control device or back to a process.

Completion combustion device—

(i) An ignition device, installed horizontally or vertically, used in exploration and production operations to combust otherwise vented emissions from completions.

(ii) The term includes pit flares.

Compressor station—

(i) A permanent combination of one or more compressors that move natural gas at increased pressure through a gathering or transmission pipeline or into or out of storage.

(ii) The term includes a gathering and boosting station and a transmission compressor station.

(iii) The term does not include the combination of one or more compressors located at a well site or located at an onshore natural gas processing plant.

Condensate—Hydrocarbon liquid separated from natural gas that condenses due to changes in the temperature, pressure, or both, and remains liquid at standard conditions.

Connector—

(i) A flanged fitting, screwed fitting or other joined fitting used to connect two pipelines or a pipeline and a piece of process equipment or that closes an opening in a pipe that could be connected to another pipe.

(ii) The term does not include a joined fitting welded completely around the circumference of the interface.

Continuous bleed—A continuous flow of pneumatic supply natural gas to a pneumatic controller.

Control device—An enclosed combustion device, vapor recovery system or flare.

Custody transfer—The transfer of natural gas after processing or treatment, or both, in the producing operation or from a storage vessel or an automatic transfer facility or other equipment, including a product loading rack, to a pipeline or another form of transportation.

Deviation—An instance in which the owner or operator of a source subject to this section, §§ 129.121 and 129.123—129.130 fails to meet one or more of the following:

(i) A requirement or an obligation established in this section, § 129.121 or §§ 129.123—129.130, including an emission limit, operating limit or work practice standard.

(ii) A term or condition that is adopted to implement an applicable requirement in this section, § 129.121 or §§ 129.123—129.130 and which is included in the operating permit for the affected source.

(iii) An emission limit, operating limit or work practice standard in this section, § 129.121 or §§ 129.123—129.130 during startup, shutdown or malfunction, regardless of whether a failure is permitted by this section, § 129.121 or §§ 129.123—129.130.

FID—Flame ionization detector.

First attempt at repair—Action taken for the purpose of stopping or reducing leakage of organic material to the atmosphere using best practices.

Flare—

(i) A thermal oxidation system using an open flame without an enclosure.

(ii) The term does not include a completion combustion device.

Flow line—A pipeline used to transport oil or gas, or both, to a processing facility or a mainline pipeline.

Fuel gas—A gas that is combusted to derive useful work or heat.

Fuel gas system—The offsite and onsite piping and flow and pressure control system that gathers one or more gaseous streams generated by onsite operations, may blend them with other sources of gas and transports the gaseous stream for use as fuel gas in combustion devices or in-process combustion equipment, such as furnaces and gas turbines, either singly or in combination.

Fugitive emissions component—

(i) A piece of equipment that has the potential to emit fugitive emissions of VOC at a well site, a gathering and boosting station or a natural gas processing plant, including the following:

(A) A valve.

(B) A connector.

(C) A pressure relief device.

(D) An open-ended line.

(E) A flange.

(F) A compressor.

(G) An instrument.

(H) A meter.

(I) A cover or closed vent system not subject to § 129.128 (relating to covers and closed vent systems).

(J) A thief hatch or other opening on a controlled storage vessel not subject to § 129.123 (relating to storage vessels).

(ii) The term does not include a device, such as a natural gas-driven pneumatic controller or a natural gas-driven diaphragm pump, that vents as part of normal operations if the gas is discharged from the device's vent.

GOR—Gas-to-oil ratio—The ratio of the volume of gas at standard temperature and pressure that is produced from a volume of oil when depressurized to standard temperature and pressure.

Gathering and boosting station—

(i) A permanent combination of one or more compressors that collects natural gas from one or more well sites and moves the natural gas at increased pressure into a gathering pipeline to the natural gas processing plant or into the pipeline.

(ii) The term does not include the combination of one or more compressors located at a well site or located at an onshore natural gas processing plant.

Hard-piping—Pipe or tubing that is manufactured and properly installed using good engineering judgment and standards.

Hydraulic fracturing—The process of directing pressurized fluids containing a combination of water, proppant and added chemicals to penetrate tight formations, such as shale or coal formations, that subsequently require high rate, extended flowback to expel fracture fluids and solids during a completion.

Hydraulic refracturing—Conducting a subsequent hydraulic fracturing operation at a well that has previously undergone a hydraulic fracturing operation.

In-house engineer—An individual who is qualified by education, technical knowledge and experience to make an engineering judgment and the required specific technical certification.

Intermediate hydrocarbon liquid—A naturally occurring, unrefined petroleum liquid.

LDAR—Leak detection and repair.

Leak—

(i) A positive indication, whether audible, visual or odorous, determined during an AVO inspection.

(ii) An emission detected by OGI equipment calibrated according to § 129.127(g) (relating to fugitive emissions components).

(iii) An emission detected with a concentration of 500 ppm or greater as methane or equivalent, detected by a gas leak detector calibrated according to § 129.127(h).

Maximum average daily throughput—The single highest daily average throughput during the 30-day potential to emit evaluation period employing generally accepted methods.

Monitoring system malfunction—

(i) A sudden, infrequent, not reasonably preventable failure of the monitoring system to provide valid data.

(ii) The term does not include a system failure caused by poor maintenance or careless operation.

Natural gas and oil production segment—

(i) The well and all related processes used in the extraction, production, recovery, lifting, stabilization, separation or treating of natural gas, condensate or oil.

(ii) A stand-alone site where natural gas, condensate, oil and produced water from several wells may be separated, stored and treated.

(iii) A low-pressure, small diameter gathering pipeline and related components that collect and transport the natural gas, condensate, oil and other materials and wastes from the well to the natural gas processing plant or refinery.

Natural gas distribution segment—The delivery of natural gas to the end user by a distribution company after the distribution company receives the natural gas from the natural gas transmission and storage segment.

Natural gas-driven diaphragm pump—

(i) A positive displacement pump powered by pressurized natural gas that uses the reciprocating action of flexible diaphragms in conjunction with check valves to pump a fluid.

(ii) The term does not include either of the following:

(A) A pump in which a fluid is displaced by a piston driven by a diaphragm.

(B) A lean glycol circulation pump that relies on energy exchange with the rich glycol from the contactor.

Natural gas-driven pneumatic controller—An automated instrument used for maintaining a process condition such as liquid level, pressure, delta-pressure or temperature powered by pressurized natural gas.

Natural gas liquids—The hydrocarbons, such as ethane, propane, butane and pentane that are extracted from field gas.

Natural gas processing plant or gas plant—

(i) A processing site engaged in the extraction of natural gas liquids from field gas, fractionation of mixed natural gas liquids to natural gas products, or both.

(ii) The term does not include a Joule-Thompson valve, a dew point depression valve or an isolated or standalone Joule-Thompson skid.

Natural gas processing segment—The separation and recovery of natural gas liquids or other non-methane gases and liquids from a stream of produced natural gas to produce pipeline quality dry natural gas.

Natural gas transmission and storage segment—The pipelines, compressor stations, and aboveground storage facilities and underground storage facilities that transport and store natural gas between the natural gas processing plant and natural gas distribution segment.

OGI—Optical gas imaging.

Open-ended valve or *line*—A valve, except a safety relief valve, 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.

Produced water—Water that is extracted from the earth from an oil or natural gas production well or that is separated from crude oil, condensate or natural gas after extraction.

Qualified professional engineer—

(i) An individual who is licensed by a state as a Professional Engineer to practice one or more disciplines of engineering and who is qualified by education, technical knowledge and experience to make the required specific technical certification.

(ii) The individual making this certification must be currently licensed in this Commonwealth or another state in which the responsible official, as defined in § 121.1 (relating to definitions), is located and with which the Commonwealth offers reciprocity.

Quality assurance or *quality control activity*—An activity such as a system accuracy audit and a zero and span adjustment that ensures the proper calibration and operation of monitoring equipment.

Reciprocating compressor—A piece of equipment that employs linear movement of a driveshaft to increase the pressure of a process gas by positive displacement.

Reciprocating compressor rod packing—

(i) A series of flexible rings in machined metal cups that fit around the reciprocating compressor piston rod to create a seal limiting the amount of compressed natural gas that escapes to the atmosphere.

(ii) Another mechanism that provides the same function.

Removed from service—A storage vessel that has been physically isolated and disconnected from the process for a purpose other than maintenance.

Repaired—A piece of equipment that is adjusted or otherwise altered to eliminate a leak and is remonitored to verify that emissions from the equipment are at or below the applicable leak limitation.

Returned to service—A storage vessel that was removed from service which has been:

(i) Reconnected to the original source of liquids or has been used to replace another storage vessel.

(ii) Installed in another location and introduced with crude oil, condensate, intermediate hydrocarbon liquids or produced water.

Routed to a process or *route to a process*—The emissions are conveyed by means of a closed vent system to an enclosed portion of a process that is operational where the emissions are controlled in one or more of the following ways:

(i) Predominantly recycled or consumed, or both, in the same manner as a material that fulfills the same function in the process.

(ii) Transformed by chemical reaction into materials that are not regulated.

(iii) Incorporated into a product.

(iv) Recovered for beneficial use.

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

Storage vessel—

(i) A container used to collect crude oil, condensate, intermediate hydrocarbon liquids or produced water that is constructed primarily of non-earthen materials which provide structural support.

(ii) The term includes a container described in subparagraph (i) that is skid-mounted or permanently attached to something that is mobile which has been located at a site for 180 or more consecutive days.

(iii) The term does not include the following:

(A) A process vessel such as a surge control vessel, bottoms receiver or knockout vessel.

(B) A pressure vessel used to store a liquid or a gas and is designed to operate in excess of 204.9 kilopascals (29.7 pounds per square inch, absolute) and to not vent to the atmosphere as a result of compression of the vapor headspace during filling of the vessel.

(C) A container described in subparagraph (i) with a capacity greater than 100,000 gallons used to recycle water that has been passed through two-stage separation.

Surface site—A combination of one or more graded pad sites, gravel pad sites, foundations, platforms or the immediate physical location upon which equipment is physically affixed.

TOC—Total organic compounds—For purposes of this section, §§ 129.121 and 129.123—129.130, the results of EPA Method 25A.

Transmission compression station—

(i) The pipelines used for the long-distance transport of natural gas, excluding processing.

(ii) The term includes the land, mains, valves, meters, boosters, regulators, storage vessels, dehydrators, compressors, and their driving units and appurtenances, and equipment used for transporting gas from a production plant, delivery point of purchased gas, gathering system, storage area or other wholesale source of gas to one or more distribution areas.

Underground storage vessel—A storage vessel stored below ground.

VRU—Vapor recovery unit—A device used to route a vapor from a storage or other vessel either back to the vessel or to a line carrying hydrocarbon fluids.

Well—A hole drilled for producing oil or natural gas or into which a fluid is injected.

Wellhead—

(i) The piping, casing, tubing and connected valves protruding above the earth's surface for an oil or natural gas well.

(ii) The wellhead ends where the flow line connects to a wellhead valve.

(iii) The term does not include other equipment at the well site except for a conveyance through which gas is vented to the atmosphere.

Well site—

(i) One or more surface sites that are constructed for the drilling and subsequent operation of an oil well, natural gas well or injection well.

(ii) For purposes of the fugitive emissions standards in § 129.127, the term also means a separate tank battery surface site collecting crude oil, condensate, intermediate hydrocarbon liquids or produced water from a well not located at the well site, for example, a centralized tank battery.

(b) *EPA methods*. The EPA methods referenced in this section and §§ 129.123—129.130, are those listed as follows, unless the context clearly indicates otherwise:

EPA Method 1—EPA Method 1, 40 CFR Part 60, Appendix A-1 (relating to test methods 1 through 2F), regarding sample and velocity traverses for stationary sources.

EPA Method 1A—EPA Method 1A, 40 CFR Part 60, Appendix A-1, regarding sample and velocity traverses for stationary sources with small stacks or ducts.

EPA Method 2—EPA Method 2, 40 CFR Part 60, Appendix A-1, regarding determination of stack gas velocity and volumetric flow rate (Type S pitot tube).

EPA Method 2A—EPA Method 2A, 40 CFR Part 60, Appendix A-1, regarding direct measurement of gas volume through pipes and small ducts.

EPA Method 2C—EPA Method 2C, 40 CFR Part 60, Appendix A-1, regarding determination of gas velocity and volumetric flow rate in small stacks or ducts (standard pitot tube).

EPA Method 2D—EPA Method 2D, 40 CFR Part 60, Appendix A-1, regarding measurement of gas volume flow rates in small pipes and ducts.

EPA Method 3A—EPA Method 3A, 40 CFR Part 60, Appendix A-2 (relating to test methods 2G through 3C), regarding determination of oxygen and carbon dioxide concentrations in emissions from stationary sources (instrumental analyzer procedure).

EPA Method 3B—EPA Method 3B, 40 CFR Part 60, Appendix A-2, regarding gas analysis for the determination of emission rate correction factor or excess air.

EPA Method 4—EPA Method 4, 40 CFR Part 60, Appendix A-3 (relating to test methods 4 through 5I), regarding determination of moisture content in stack gases.

EPA Method 18—EPA Method 18, 40 CFR Part 60, Appendix A-6 (relating to test methods 16 through 18), regarding measurement of gaseous organic compound emissions by gas chromatography.

EPA Method 21—EPA Method 21, 40 CFR Part 60, Appendix A-7 (relating to test methods 19 through 25E), regarding determination of volatile organic compound leaks.

EPA Method 22—EPA Method 22, 40 CFR Part 60, Appendix A-7, regarding visual determination of fugitive emissions from material sources and smoke emissions from flares.

EPA Method 25A—EPA Method 25A, 40 CFR Part 60, Appendix A-7, regarding determination of total gaseous organic concentration using a flame ionization analyzer.

§ 129.123. Storage vessels.

(a) *Applicability*.

(1) *Potential VOC emissions*. Except as specified in subsections (c) and (d), this section applies to the owner or operator of a storage vessel subject to § 129.121(a)(1) (relating to general provisions and applicability) that meets one of the following:

(i) Is installed at a conventional well site and has the potential to emit 6.0 TPY or greater VOC emissions.

(ii) Is installed at an unconventional well site before August 10, 2013, and has the potential to emit 6.0 TPY or greater VOC emissions.

(iii) Is installed at an unconventional well site on or after August 10, 2013, and has the potential to emit 2.7 TPY or greater VOC emissions.

(iv) Is installed at a gathering and boosting station and has the potential to emit 2.7 TPY or greater VOC emissions.

(v) Is installed at a natural gas processing plant and has the potential to emit 2.7 TPY or greater VOC emissions.

(vi) Is installed at a facility in the natural gas transmission and storage segment and has the potential to emit 2.7 TPY or greater VOC emissions.

(2) *Calculation of potential VOC emissions*.

(i) The potential VOC emissions in paragraph (1) must be calculated using a generally accepted model or calculation methodology, based on the maximum average daily throughput prior to ________ (*Editor's Note*: The blank refers to the effective date of this rulemaking, when published as a final-form rulemaking.) for an existing storage vessel.

(ii) The determination of potential VOC emissions must consider requirements under a legally and practically enforceable limit established in an operating permit or plan approval approved by the Department.

(iii) Vapor from the storage vessel that is recovered and routed to a process through a VRU is not required to be included in the determination of potential VOC emissions for purposes of determining applicability, if the owner or operator meets the following:

(A) The cover requirements in § 129.128(a) (relating to covers and closed vent systems).

(B) The closed vent system requirements in § 129.128(b).

(iv) If the apparatus that recovers and routes vapor to a process is removed from operation or is operated inconsistently with § 129.128, the owner or operator shall determine the storage vessel's potential VOC emissions under this paragraph within 30 calendar days of the date of apparatus removal or inconsistent operation.

(b) *VOC emissions limitations and control requirements*. Except as specified in subsections (c) and (d), beginning ________ (*Editor's Note*: The blank refers to the date 1 year after the effective date of this rulemaking, when published as a final-form rulemaking.), the owner or operator of a storage vessel subject to this section shall reduce VOC emissions by 95.0% by weight or greater. The owner or operator shall comply with paragraph (1) or paragraph (2) as applicable.

(1) *Route the VOC emissions to a control device*. The owner or operator shall do the following:

(i) Equip the storage vessel with a cover that meets the requirements of § 129.128(a).

(ii) Connect the storage vessel to a control device or process through a closed vent system that meets the requirements of § 129.128(b).

(iii) Route the emissions from the storage vessel to a control device or a process that meets the applicable requirements of § 129.129 (relating to control devices).

(iv) Demonstrate that the VOC emissions are reduced as specified in § 129.129(k).

(2) *Equip the storage vessel with a floating roof*. The owner or operator shall install a floating roof that meets the requirements of 40 CFR 60.112b(a)(1) or (2) (relating to standard for volatile organic compounds (VOC)) and the relevant monitoring, inspection, recordkeeping and reporting requirements in 40 CFR Part 60, Subpart Kb (relating to 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).

(c) *Exceptions*.

(1) The emissions limitations and control requirements in subsection (b) do not apply to the owner or operator of a storage vessel that meets one or more of the following:

(i) Has a VOC potential to emit limit of 6.0 TPY, if actual VOC emissions are less than 4.0 TPY as determined on a 12-month rolling basis. An owner or operator claiming this exception shall perform the compliance demonstration requirements under paragraph (2) and maintain the records under subsection (g), as applicable.

(ii) Has a VOC potential to emit limit of 2.7 TPY, if actual VOC emissions are less than 2.7 TPY as determined on a 12-month rolling basis. An owner or operator claiming this exception shall perform the compliance demonstration requirements under paragraph (2) and maintain the records under subsection (g), as applicable.

(2) The owner or operator of a storage vessel claiming exception under this subsection shall perform the following:

(i) Calculate the actual VOC emissions monthly using a generally accepted model or calculation methodology. The monthly calculations must meet the following:

(A) Be separated by at least 15 calendar days but not more than 30 calendar days.

(B) Be based on the maximum daily average throughput for the previous 30 calendar days.

(ii) Comply with subsection (b) within 30 calendar days of the date of the monthly calculation showing that VOC emissions from the storage vessel have increased to the applicable actual VOC emission threshold or greater and the increase is not associated with hydraulically fracturing or refracturing a well feeding the storage vessel.

(iii) If a well feeding a subject storage vessel undergoes fracturing or refracturing, comply with subsection (b) as soon as liquids from the well following fracturing or refracturing are routed to the storage vessel.

(d) *Exemptions*. The emissions limitations and control requirements in subsection (b) do not apply to the owner or operator of a storage vessel that meets one or more of the following:

(1) Is skid-mounted or permanently attached to something that is mobile for which records are available to document that it has been located at a site for less than 180 consecutive days. An owner or operator claiming this exemption shall maintain the records under subsection (g), as applicable.

(2) Is used in the natural gas distribution segment.

(3) Is controlled under 40 CFR Part 60, Subpart Kb or 40 CFR Part 63, Subpart G, Subpart CC, Subpart HH or Subpart WW.

(e) *Requirements for a storage vessel removed from service*. A storage vessel subject to this section that is removed from service is not an affected source for the period that it is removed from service if the owner or operator performs the following:

(1) Completely empties and degasses the storage vessel so that the storage vessel no longer contains crude oil, condensate, produced water or intermediate hydrocarbon liquids. A storage vessel where liquid is left on walls, as bottom clingage or in pools due to floor irregularity is considered to be completely empty.

(2) Submits a notification in the next annual report required under § 129.130(k)(1) (relating to recordkeeping and reporting) identifying each storage vessel removed from service during the reporting period and the date of its removal from service.

(f) *Requirements for a storage vessel returned to service*. The owner or operator of a storage vessel identified in subsection (e) that is returned to service shall submit a notification in the next annual report required under § 129.130(k)(1) identifying each storage vessel that has been returned to service during the reporting period and the date of its return to service.

(g) *Recordkeeping and reporting requirements*. The owner or operator of a storage vessel subject to this section shall maintain the records under § 129.130(b) and submit the reports under § 129.130(k)(1).

§ 129.124. Natural gas-driven pneumatic controllers.

(a) *Applicability*. This section applies to the owner or operator of a natural gas-driven pneumatic controller subject to § 129.121(a)(2) (relating to general provisions and applicability) located prior to the point of custody transfer of oil to an oil pipeline or of natural gas to the natural gas transmission and storage segment.

(b) *Exception*. An owner or operator may use a natural gas-driven pneumatic controller subject to this section with a bleed rate greater than the applicable requirements in subsection (c) based on functional requirements. An owner or operator claiming this exception shall perform the compliance demonstration requirements under subsection (d) and maintain the records under subsection (e), as applicable.

(c) *VOC emissions limitation requirements*. Except as specified in subsection (b), beginning ________ (*Editor's Note*: The blank refers to the date 1 year after the effective date of this rulemaking, when published as a final-form rulemaking.), the owner or operator of a natural gas-driven pneumatic controller subject to this section shall do the following:

(1) Ensure the natural gas-driven pneumatic controller has a natural gas bleed rate:

(i) Of less than or equal to 6.0 standard cubic feet per hour, if located between a wellhead and either of the following:

(A) A natural gas processing plant.

(B) A point of custody transfer to an oil pipeline.

(ii) Of zero standard cubic feet per hour, if located at a natural gas processing plant.

(2) Perform the compliance demonstration requirements under subsection (d).

(d) *Compliance demonstration requirements*. The owner or operator shall tag each affected natural gas-driven pneumatic controller with the following:

(1) The date the natural gas-driven pneumatic controller is required to comply with this section.

(2) An identification number that ensures traceability to the records for that natural gas-driven pneumatic controller.

(e) *Recordkeeping and reporting requirements*. The owner or operator of a natural gas-driven pneumatic controller subject to this section shall maintain the records under § 129.130(c) (relating to recordkeeping and reporting) and submit the reports under § 129.130(k)(2).

§ 129.125. Natural gas-driven diaphragm pumps.

(a) *Applicability*. This section applies to the owner or operator of a natural gas-driven diaphragm pump subject to § 129.121(a)(3) (relating to general provisions and applicability) located at a well site or natural gas processing plant.

(b) *VOC emissions limitation and control requirements*. Except as specified in subsections (c) and (d), beginning ________ (*Editor's Note*: The blank refers to the date 1 year after the effective date of this rulemaking, when published as a final-form rulemaking.), the owner or operator of a natural gas-driven diaphragm pump subject to this section shall reduce the VOC emissions by 95.0% by weight or greater. The owner or operator shall comply with the following:

(1) *Well site*. The owner or operator of a natural gas-driven diaphragm pump located at a well site shall do the following:

(i) Connect the natural gas-driven diaphragm pump to a control device or process through a closed vent system that meets the applicable requirements of § 129.128(b) (relating to covers and closed vent systems).

(ii) Route the emissions from the natural gas-driven diaphragm pump to a control device or a process that meets the applicable requirements of § 129.129 (relating to control devices).

(iii) Demonstrate that the VOC emissions are reduced as specified in § 129.129(k).

(2) *Natural gas processing plant*. The owner or operator of a natural gas-driven diaphragm pump located at a natural gas processing plant shall maintain an emission rate of zero standard cubic feet per hour.

(c) *Exceptions*. The emissions limitations and control requirements in subsection (b) do not apply to the owner or operator of a natural gas-driven diaphragm pump located at a well site which meets one or more of the following:

(1) Routes emissions to a control device which is unable to reduce VOC emissions by 95.0% by weight or greater and there is no ability to route VOC emissions to a process.

(i) An owner or operator that claims this exception shall do the following:

(A) Maintain the records under § 129.130(d)(7) (relating to recordkeeping and reporting).

(B) Connect the natural gas-driven diaphragm pump to the control device through a closed vent system that meets the requirements of § 129.128(b).

(C) Demonstrate the percentage by which the VOC emissions are reduced as specified in § 129.129(k).

(2) Has no available control device or process.

(i) An owner or operator that claims this exception shall do the following:

(A) Maintain the records under § 129.130(d)(5).

(B) Certify that there is no available control device or process in the next annual report required by § 129.130(k)(3)(ii).

(C) Route emissions from the natural gas-driven diaphragm pump within 30 days of the installation of a control device or process. Once the emissions are routed to a control device or process, the certification of clause (B) is no longer required and the applicable requirements of this section shall be met.

(3) Is technically infeasible of connecting to a control device or process.

(i) An owner or operator claiming this exception shall maintain the records under § 129.130(d)(6).

(ii) An owner or operator that claims this exception shall perform an assessment of technical infeasibility which must include the following:

(A) Be prepared under the supervision of an in-house engineer or qualified professional engineer.

(B) Include a technical analysis of safety considerations, the distance from an existing control device, the pressure losses and differentials in the closed vent system and the ability of the control device to handle the increase in emissions routed to them.

(C) Be certified, signed, and dated by the engineer supervising the assessment, including the statement: "I certify that the assessment of technical infeasibility was prepared under my supervision. I further certify that the assessment was conducted, and this report was prepared under the requirements of 25 Pa. Code § 129.125(c)(3). Based on my professional knowledge and experience, and inquiry of personnel involved in the assessment, the certification submitted herein is true, accurate, and complete. I am aware that there are penalties for knowingly submitting false information."

(d) *Exemptions*. The emissions limitations and control requirements in subsection (b) do not apply to the owner or operator of a natural gas-driven diaphragm pump located at a well site which operates less than 90 days per calendar year. An owner or operator claiming this exemption shall maintain the records under § 129.130(d)(3).

(e) *Removal of control device or process*. The owner or operator of a natural gas-driven diaphragm pump located at a well site that routes emissions to a control device or process which is removed or is no longer available shall comply with one of the exceptions in subsection (c), as applicable.

(f) *Recordkeeping and reporting requirements*. The owner or operator of a natural gas-driven diaphragm pump subject to this section shall maintain the records under § 129.130(d) and submit the reports under § 129.130(k)(3).

§ 129.126. Compressors.

(a) *Applicability*. This section applies to the owner or operator of a reciprocating compressor or centrifugal compressor subject to § 129.121(a)(4) (relating to general provisions and applicability) that meets the following:

(1) *Reciprocating compressor*. Each reciprocating compressor located between the wellhead and point of custody transfer to the natural gas transmission and storage segment.

(2) *Centrifugal compressor*. Each centrifugal compressor using wet seals that is located between the wellhead and point of custody transfer to the natural gas transmission and storage segment.

(b) *VOC emissions control requirements for a reciprocating compressor*. Except as specified in subsection (d), beginning ________ (*Editor's Note*: The blank refers to the date 1 year after the effective date of this rulemaking, when published as a final-form rulemaking.), the owner or operator of a reciprocating compressor subject to this section shall meet one of the following:

(1) Replace the reciprocating compressor rod packing on or before one of the following:

(i) The reciprocating compressor has operated for 26,000 hours. The number of hours of operation must be continuously monitored beginning on the later of:

(A) The date of the most recent reciprocating compressor rod packing replacement.

(B) ________ (*Editor's Note*: The blank refers to the effective date of this rulemaking, when published as a final-form rulemaking.), for a reciprocating compressor rod packing that has not yet been replaced.

(ii) The reciprocating compressor has operated for 36 months. The number of months of operation must be continuously monitored beginning on the later of:

(A) The date of the most recent reciprocating compressor rod packing replacement.

(B) ________ (*Editor's Note*: The blank refers to the date 36 months after the effective date of this rulemaking, when published as a final-form rulemaking.), for a reciprocating compressor rod packing that has not yet been replaced.

(2) Route the VOC emissions to a process by using a reciprocating compressor rod packing emissions collection system that operates under negative pressure and meets the cover requirements of § 129.128(a) (relating to covers and closed vent systems) and the closed vent system requirements of § 129.128(b).

(c) *VOC emissions limitation and control requirements for a centrifugal compressor*. Except as specified in subsection (d), the owner or operator of a centrifugal compressor subject to this section shall perform the following:

(1) Reduce the VOC emissions from each centrifugal compressor wet seal fluid degassing system by 95.0% by weight or greater.

(2) Equip the wet seal fluid degassing system with a cover that meets the requirements of § 129.128(a) through a closed vent system that meets the requirements of § 129.128(b) to a control device or a process that meets the applicable requirements of § 129.129 (relating to control devices).

(3) Demonstrate that the VOC emissions are reduced as specified in § 129.129(k).

(d) *Exemptions*. Subsections (b) and (c) do not apply to the owner or operator of a reciprocating compressor or a centrifugal compressor that meets the following:

(1) Is located at a well site.

(2) Is located at an adjacent well site and services more than one well site.

(e) *Recordkeeping and reporting requirements*. The owner or operator of a reciprocating compressor or centrifugal compressor subject to this section shall do the following, as applicable:

(1) For a reciprocating compressor, maintain the records under § 129.130(e) (relating to recordkeeping and reporting) and submit the reports under § 129.130(k)(4).

(2) For a centrifugal compressor, maintain the records under § 129.130(f) and submit the reports under § 129.130(k)(5).

§ 129.127. Fugitive emissions components.

(a) *Applicability*. This section applies to the owner or operator of a fugitive emissions component subject to § 129.121(a)(5) (relating to general provisions and applicability), located at one or more of the following:

(1) A well site with a well that produces, on average, greater than 15 barrels of oil equivalent per day.

(2) A natural gas gathering and boosting station.

(3) A natural gas processing plant.

(b) *Requirements for a producing well site*. The owner or operator of a producing well site shall perform the following:

(1) Determine the GOR of the well using generally accepted methods.

(i) If the GOR is less than 300 standard cubic feet of gas per barrel of oil produced, the owner or operator shall maintain the records under § 129.130(g)(1) (relating to recordkeeping and reporting).

(ii) If the GOR is equal to or greater than 300 standard cubic feet of gas per barrel of oil produced, the owner or operator shall perform the following:

(A) Conduct an AVO inspection within 30 days after ________ (*Editor's Note*: The blank refers to the effective date of this rulemaking, when published as a final-form rulemaking.), with monthly inspections separated by at least 15 calendar days but not more than 30 calendar days.

(B) Conduct an LDAR inspection program within 60 days after ________ (*Editor's Note*: The blank refers to the effective date of this rulemaking, when published as a final-form rulemaking.), with quarterly inspections separated by at least 60 calendar days but not more than 90 calendar days using one or more of the following:

(I) OGI equipment.

(II) A gas leak detector that meets the requirements of EPA Method 21.

(III) Another leak detection method approved by the Department.

(2) The owner or operator of a producing well site required to conduct an LDAR inspection under paragraph (1)(ii)(B) may track the percentage of leaking components identified during the LDAR inspection. The owner or operator may adjust the frequency of the LDAR inspection required under paragraph (1)(ii)(B) as follows:

(i) If the percentage of leaking components is less than 2% for two consecutive quarterly inspections, the owner or operator may reduce the LDAR inspection frequency to semiannually with inspections separated by at least 120 calendar days but not more than 180 calendar days.

(ii) If the percentage of leaking components is equal to or greater than 2%, the owner or operator shall resume the LDAR inspection frequency specified in paragraph (1)(ii)(B).

(c) *Requirements for a shut-in well*. The owner or operator of a well that is temporarily shut-in is not required to perform an LDAR inspection of the well until one of the following occurs, whichever is first:

(1) Sixty days after the well is put into production.

(2) The date of the next required LDAR inspection.

(d) *Requirements for a natural gas gathering and boosting station or a natural gas processing plant*. The owner or operator of a natural gas gathering and boosting station or a natural gas processing plant shall conduct the following:

(1) An AVO inspection within 30 days after ______ (*Editor's Note*: The blank refers to the effective date of this rulemaking, when published as a final-form rulemaking.), with monthly inspections separated by at least 15 calendar days but not more than 30 calendar days.

(2) An LDAR inspection program within 60 days after ________ (*Editor's Note*: The blank refers to the effective date of this rulemaking, when published as a final-form rulemaking.), with quarterly inspections separated by at least 60 calendar days but not more than 90 calendar days using one or more of the following:

(i) OGI equipment.

(ii) A gas leak detector that meets the requirements of EPA Method 21.

(iii) Another leak detection method approved by the Department.

(e) *Requirements for extension of the LDAR inspection interval*. The owner or operator of an affected facility may request, in writing, an extension of the LDAR inspection interval from the Air Program Manager of the appropriate Department Regional Office.

(f) *Fugitive emissions monitoring plan*. The owner or operator shall develop, in writing, an emissions monitoring plan that covers the collection of fugitive emissions components at the subject facility within each company-defined area. The written plan must include the following elements:

(1) The technique used for determining fugitive emissions.

(2) A list of fugitive emissions detection equipment, including the manufacturer and model number, that may be used at the facility.

(3) A list of personnel that may conduct the monitoring surveys at the facility, including their training and experience.

(4) The procedure and timeframe for identifying and fixing a fugitive emissions component from which fugitive emissions are detected, including for a component that is unsafe-to-repair.

(5) The procedure and timeframe for verifying fugitive emissions component repairs.

(6) The procedure and schedule for verifying the fugitive emissions detection equipment is operating properly.

(i) For OGI equipment, the verification must be completed as specified in subsection (g).

(ii) For gas leak detection equipment using EPA Method 21, the verification must be completed as specified in subsection (h).

(iii) For a Department-approved method, a copy of the request for approval that shows the method's equivalence to subsection (g) or subsection (h).

(7) A sitemap.

(8) If using OGI, a defined observation path that meets the following:

(i) Ensures that all fugitive emissions components are within sight of the path.

(ii) Accounts for interferences.

(9) If using EPA Method 21, a list of the fugitive emissions components to be monitored and an identification method to locate them in the field.

(10) A written plan for each fugitive emissions component designated as difficult-to-monitor or unsafe-to-monitor which includes the following:

(i) A method to identify a difficult-to-monitor or unsafe-to-monitor component in the field.

(ii) The reason each component was identified as difficult-to-monitor or unsafe-to-monitor.

(iii) The monitoring schedule for each component identified as difficult-to-monitor or unsafe-to-monitor. The monitoring schedule for difficult-to-monitor components must include at least one survey per year no more than 12 months apart.

(g) *Verification procedures for OGI equipment*. An owner or operator that identifies OGI equipment in the fugitive emissions monitoring plan in subsection (f)(6)(i) shall complete the verification by doing the following:

(1) Demonstrating that the OGI equipment is capable of imaging a gas:

(i) In the spectral range for the compound of highest concentration in the potential fugitive emissions.

(ii) That is half methane, half propane at a concentration of 10,000 ppm at a flow rate of less than or equal to 60 grams per hour (2.115 ounces per hour) from a 1/4-inch diameter orifice.

(2) Performing a daily verification check.

(3) Determining the equipment operator's maximum viewing distance from the fugitive emissions component and how the equipment operator will ensure that this distance is maintained.

(4) Determining the maximum wind speed during which monitoring can be performed and how the equipment operator will ensure monitoring occurs only at wind speeds below this threshold.

(5) Conducting the survey that determines how the equipment operator will perform the following:

(i) Ensure an adequate thermal background is present to view potential fugitive emissions.

(ii) Deal with adverse monitoring conditions, such as wind.

(iii) Deal with interferences, such as steam.

(6) Following the manufacturer's recommended calibration and maintenance procedures.

(h) *Verification procedures for gas leak detection equipment using EPA Method 21*. An owner or operator that identifies gas leak detection equipment using EPA Method 21 in the fugitive emissions monitoring plan in subsection (f)(6)(ii) shall complete the verification by doing the following:

(1) Verifying that the gas leak detection equipment meets:

(i) The requirements of Section 6.0 of EPA Method 21 with a fugitive emissions definition of 500 ppm or greater calibrated as methane using an FID-based instrument.

(ii) A site-specific fugitive emission definition that would be equivalent to subparagraph (i) for other equipment approved for use in EPA Method 21 by the Department.

(2) Using the average composition of the fluid, not the individual organic compounds in the stream, when performing the instrument response factor of Section 8.1.1 of EPA Method 21.

(3) Calculating the average stream response factor on an inert-free basis for process streams that contain nitrogen, air or other inert gases that are not organic hazardous air pollutants or VOCs.

(4) Calibrating the gas leak detection instrument in accordance with Section 10.1 of EPA Method 21 on each day of its use using zero air, defined as a calibration gas with less than 10 ppm by volume of hydrocarbon in air, and a mixture of methane in air at a concentration less than 10,000 ppm by volume as the calibration gases.

(5) Conducting the surveys, which at a minimum, must comply with the relevant sections of EPA Method 21, including Section 8.3.1.

(i) *Fugitive emissions detection devices*. Fugitive emissions detection devices must be operated and maintained in accordance with manufacturer-recommended procedures and as required by the test method or a Department-approved method.

(j) *Background adjustment*. For LDAR inspections using a gas leak detector in accordance with EPA Method 21, the owner or operator may choose to adjust the gas leak detection instrument readings to account for the background organic concentration level as determined by the procedures of Section 8.3.2 of EPA Method 21.

(k) *Repair and resurvey provisions*. The owner or operator shall repair a leak detected from a fugitive emissions component as follows:

(1) A first attempt at repair must be made within 5 calendar days of detection, and repair must be completed no later than 15 calendar days after the leak is detected unless:

(i) The purchase of a part is required. The repair must be completed no later than 10 calendar days after the receipt of the purchased part.

(ii) The repair is technically infeasible because of one of the following reasons:

(A) It requires vent blowdown.

(B) It requires facility shutdown.

(C) It requires a well shut-in.

(D) It is unsafe to repair during operation of the unit.

(iii) A repair that is technically infeasible under subparagraph (ii) must be completed at the earliest of the following:

(A) After a planned vent blowdown.

(B) The next facility shutdown.

(C) Within 2 years.

(2) The owner or operator shall resurvey the fugitive emissions component no later than 30 calendar days after the leak is repaired.

(3) For a repair that cannot be made during the monitoring survey when the leak is initially found, the owner or operator shall do one of the following:

(i) Take a digital photograph of the fugitive emissions component which includes:

(A) The date the photo was taken.

(B) Clear identification of the component by location, such as by latitude and longitude or other descriptive landmarks visible in the picture.

(ii) Tag the component for identification purposes.

(4) A gas leak is considered repaired if:

(i) There are no detectable emissions consistent with Section 8.3.2 of EPA Method 21.

(ii) A leak concentration of less than 500 ppm as methane is detected when the gas leak detector probe inlet is placed at the surface of the fugitive emissions component for a gas leak detector calibrated according to subsection (h).

(iii) There is no visible leak image when using OGI equipment calibrated according to subsection (g).

(iv) There is no bubbling at the leak interface using the soap solution bubble test specified in Section 8.3.3 of EPA Method 21.

(l) *Recordkeeping and reporting requirements*. The owner or operator of a fugitive emissions component subject to this section shall maintain the records under § 129.130(g) and submit the reports under § 129.130(k)(6).

§ 129.128. Covers and closed vent systems.

(a) *Requirements for a cover on a storage vessel, reciprocating compressor or centrifugal compressor*. The owner or operator shall perform the following for a cover of a source subject to § 129.123(b)(1)(i) or § 129.126(b)(2) or (c)(2) (relating to storage vessels; and compressors), as applicable:

(1) Ensure that the cover and all openings on the cover form a continuous impermeable barrier over each subject source as follows:

(i) The entire surface area of the liquid in the storage vessel.

(ii) The entire surface area of the liquid in the wet seal fluid degassing system of a centrifugal compressor.

(iii) The rod packing emissions collection system of a reciprocating compressor.

(2) Ensure that each cover opening is covered by a gasketed lid or cap that is secured in a closed, sealed position except when it is necessary to use an opening for one or more of the following:

(i) To inspect, maintain, repair or replace equipment.

(ii) To route a liquid, gas, vapor or fume from the source to a control device or a process that meets the applicable requirements of § 129.129 (relating to control devices) through a closed vent system designed and operated in accordance with subsection (b).

(iii) To inspect or sample the material in a storage vessel.

(iv) To add material to or remove material from a storage vessel, including openings necessary to equalize or balance the internal pressure of the storage vessel following changes in the level of the material in the storage vessel.

(3) Ensure that each storage vessel thief hatch is equipped, maintained and operated with the following:

(i) A mechanism to ensure that the lid remains properly seated and sealed under normal operating conditions, including when working, standing or breathing, or when flash emissions may be generated.

(ii) A gasket made of a suitable material based on the composition of the fluid in the storage vessel and weather conditions.

(4) Conduct an AVO inspection within 30 days after ________ (*Editor's Note*: The blank refers to the effective date of this rulemaking, when published as a final-form rulemaking.), with monthly inspections separated by at least 15 calendar days but not more than 30 calendar days for defects that could result in air emissions. Defects include the following:

(i) A visible crack, hole or gap in the cover.

(ii) A visible crack, hole or gap between the cover and the separator wall.

(iii) A broken, cracked or otherwise damaged seal or gasket on a closure device.

(iv) A broken or missing hatch, access cover, cap or other closure device.

(5) Inspect only those portions of the cover that extend to or above the surface and the connections on those portions of the cover, including fill ports, access hatches and gauge wells that can be opened to the atmosphere for a storage vessel that is partially buried or entirely underground.

(6) Repair a detected leak or defect as specified in § 129.127(k) (relating to fugitive emissions components).

(7) Maintain the records under § 129.130(h) (relating to recordkeeping and reporting) and submit the report under § 129.130(k)(7).

(b) *Requirements for a closed vent system*. The owner or operator shall perform the following for each closed vent system installed on a source subject to § 129.125(b)(1)(i) or (c)(1)(i)(B) (relating to natural gas-driven diaphragm pumps) or § 129.126(b)(2) or (c)(2):

(1) Design the closed vent system to route the liquid, gas, vapor or fume emitted from the source to a control device or process that meets the applicable requirements in § 129.129.

(2) Operate the closed vent system with no detectable emissions as determined by the following:

(i) Conduct an AVO inspection within 30 days after ________ (*Editor's Note*: The blank refers to the effective date of this rulemaking, when published as a final-form rulemaking.), with monthly inspections separated by at least 15 calendar days but not more than 30 calendar days for defects that could result in air emissions. Defects include the following:

(A) A visible crack, hole or gap in piping.

(B) A loose connection.

(C) A liquid leak.

(D) A broken or missing cap or other closure device.

(ii) Conducting a no detectable emissions inspection as specified in subsection (d) within 30 days after ________ (*Editor's Note*: The blank refers to the effective date of this rulemaking, when published as a final-form rulemaking.), with quarterly inspections separated by at least 60 calendar days but not more than 90 calendar days.

(3) Repair a detected leak or defect as specified in § 129.127(k).

(4) Except as specified in subparagraph (iii), if the closed vent system contains one or more bypass devices that could be used to divert the liquid, gas, vapor or fume

from routing to the control device or to the process under paragraph (1), perform one or more of the following:

(i) Install, calibrate, operate and maintain a flow indicator at the inlet to the bypass device so when the bypass device is open it does one of the following:

(A) Sounds an alarm.

(B) Initiates a notification by means of a remote alarm to the nearest field office.

(ii) Secure the bypass device valve installed at the inlet to the bypass device in the non-diverting position using the following procedure:

(A) Installing either of the following:

(I) A car-seal.

(II) A lock-and-key configuration.

(B) Visually inspecting the mechanism in clause (A) to verify that the valve is maintained in the non-diverting position within 30 days after ________ (*Editor's Note*: The blank refers to the effective date of this rulemaking, when published as a final-form rulemaking.), with monthly inspections separated by at least 15 calendar days but not more than 30 calendar days.

(C) Maintaining the records under § 129.130(i)(4).

(iii) Subparagraphs (i) and (ii) do not apply to a low leg drain, high point bleed, analyzer vent, open-ended valve or line, or safety device.

(5) Conduct an assessment that meets the requirements of subsection (c).

(6) Maintain the records under § 129.130(i) and submit the reports under § 129.130(k)(8).

(c) *Requirements for closed vent system design and capacity assessment*. An owner or operator that installs a closed vent system under subsection (b) shall perform a design and capacity assessment which must include the following:

(1) Be prepared under the supervision of an in-house engineer or qualified professional engineer.

(2) Verify the following:

(i) That the closed vent system is of sufficient design and capacity to ensure that the emissions from the emission source are routed to the control device or process.

(ii) That the control device or process is of sufficient design and capacity to accommodate the emissions from the emission source.

(3) Be certified, signed, and dated by the engineer supervising the assessment, including the statement: "I certify that the closed vent design and capacity assessment was prepared under my supervision. I further certify that the assessment was conducted, and this report was prepared under the requirements of 25 Pa. Code § 129.128(c). Based on my professional knowledge and experience, and inquiry of personnel involved in the assessment, the certification submitted herein is true, accurate, and complete. I am aware that there are penalties for knowingly submitting false information."

(d) *No detectable emissions procedures*. The owner or operator shall conduct the no detectable emissions test procedure under Section 8.3.2 of EPA Method 21.

(1) The owner or operator shall perform the following:

(i) Use a gas leak detection instrument that meets § 129.127(h).

(ii) Determine if a potential leak interface operates with no detectable emissions, if the gas leak detection instrument reading is not a leak as defined in § 129.122(a) (relating to definitions, acronyms and EPA methods).

(2) The owner or operator may adjust the gas leak detection instrument readings in paragraph (1)(ii) as specified in § 129.127(j).

§ 129.129. Control devices.

(a) *Applicability*. This section applies to the owner or operator of each control device that receives a liquid, gas, vapor or fume from a source subject to § 129.123(b)(1)(iii), § 129.125(b)(1)(ii) or (c)(1), or § 129.126(b)(2) or (c)(2) (relating to storage vessels; natural gas-driven diaphragm pumps; and compressors).

(1) The owner or operator shall perform the following:

(i) Operate each control device whenever a liquid, gas, vapor or fume is routed to the control device.

(ii) Maintain the records under § 129.130(j) (relating to recordkeeping and reporting) and submit the reports under § 129.130(k)(9).

(2) The owner or operator may route the liquid, gas, vapor or fume from more than one source subject to § 129.123(b)(1)(iii), § 129.125(b)(1)(ii) or (c)(1), or § 129.126(b)(2) or (c)(2) to a control device installed and operated under this section.

(b) *General requirements for a control device*. The owner or operator of a control device subject to this section shall install and operate one or more control devices listed in subsections (c)—(i). The owner or operator shall meet the following requirements, as applicable:

(1) Operate the control device following the manufacturer's written operating instructions, procedures and maintenance schedule to ensure good air pollution control practices for minimizing VOC emissions.

(2) Ensure that the control device is maintained in a leak-free condition by conducting a physical integrity check according to the manufacturer's instructions, with monthly inspections separated by at least 15 calendar days but not more than 30 calendar days.

(3) Maintain a pilot flame while operating the control device and monitor the pilot flame by installing a heat sensing CPMS as specified under subsection (m)(3). If the heat sensing CPMS indicates the absence of the pilot flame or if the control device is smoking or shows other signs of improper equipment operation, ensure the control device is returned to proper operation by performing the following procedures:

(i) Checking the air vent for obstruction and clearing an observed obstruction.

(ii) Checking for liquid reaching the combustor.

(4) Operate the control device with no visible emissions, except for periods not to exceed a total of 1 minute during a 15-minute period as determined by conducting a visible emissions test according to Section 11 of EPA Method 22.

(i) Each monthly visible emissions test shall be separated by at least 15 calendar days but not more than 30 calendar days.

(ii) The observation period for the test in subparagraph (i) shall be 15 minutes.

(5) Repair the control device if it fails the visible emissions test of paragraph (4) as specified in subpara-

graph (i) or subparagraph (ii) and return the control device to compliant operation.

(i) The manufacturer's repair instructions, if available.

(ii) The best combustion engineering practice outlined in the control device inspection and maintenance plan of paragraph (1).

(6) Ensure the control device passes the EPA Method 22 visual emissions test described in paragraph (4) following return to operation from a maintenance or repair activity.

(7) Record the inspection, repair and maintenance activities for the control device in a maintenance and repair log.

(c) *Compliance requirements for a manufacturer-tested combustion device*. The owner or operator of a control device subject to this section that installs a control device tested under 40 CFR 60.5413a(d) (relating to what are the performance testing procedures for control devices used to demonstrate compliance at my centrifugal compressor and storage vessel affected facilities?) shall meet subsection (b)(1)—(7) and the following:

(1) Maintain the inlet gas flow rate at less than or equal to the maximum flow rate specified by the manufacturer. This is confirmed by one of the following:

(i) Installing, operating and maintaining a flow CPMS that meets subsection (m)(1) and (2)(i) to measure gas flow rate at the inlet to the control device.

(ii) Conducting a periodic performance test under subsection (k) instead of installing a flow CPMS.

(2) Submit an electronic copy of the performance test results to the EPA as required by 40 CFR 60.5413a(d) in accordance with 40 CFR 60.5413a(e)(6).

(d) *Compliance requirements for an enclosed combustion device*. The owner or operator of a control device subject to this section that installs an enclosed combustion device, such as a thermal vapor incinerator, catalytic vapor incinerator, boiler or process heater, shall meet subsection (b)(1)—(7) and the following:

(1) Ensure the enclosed combustion control device is designed and operated to meet one of the following performance requirements:

(i) To reduce the mass content of VOC in the gases vented to the device by 95.0% by weight or greater, as determined under subsection (k).

(ii) To reduce the concentration of TOC in the exhaust gases at the outlet to the device to a level less than or equal to 275 ppmvd as propane corrected to 3% oxygen as determined under subsection (l).

(iii) To operate at a minimum temperature of 760 °Celsius (1,400 °Fahrenheit), if it is demonstrated during the performance test conducted under subsection (k) that combustion zone temperature is an indicator of destruction efficiency.

(iv) To introduce the vent stream into the flame zone of the boiler or process heater if a boiler or process heater is used as the control device.

(2) Install, calibrate, operate and maintain a CPMS according to the manufacturer's specifications and subsection (m) to measure the values of the operating parameters appropriate to the control device as follows:

(i) For a thermal vapor incinerator that demonstrates under subsection (m)(6)(i) that combustion zone temperature is an accurate indicator of performance, a temperature CPMS that meets subsection (m)(1) and (4) with the temperature sensor installed at a location representative of the combustion zone temperature.

(ii) For a catalytic vapor incinerator, a temperature CPMS capable of monitoring temperature at two locations and that meets subsection (m)(1) and (4) with one temperature sensor installed in the vent stream at the nearest feasible point to the catalyst bed inlet and a second temperature sensor installed in the vent stream at the nearest feasible point to the catalyst bed outlet.

(iii) For a boiler or process heater that demonstrates under subsection (m)(6)(i) that combustion zone temperature is an accurate indicator of performance, a temperature CPMS that meets subsection (m)(1) and (4) with the temperature sensor installed at a location representative of the combustion zone temperature. The monitoring requirements do not apply if the boiler or process heater meets either of the following:

(A) Has a design heat input capacity of 44 megawatts (150 MMBtu per hour) or greater.

(B) Introduces the vent stream with the primary fuel or uses the vent stream as the primary fuel.

(iv) For a control device complying with paragraph (1)(ii), an organic concentration CPMS that meets subsection (m)(1) and (5) that measures the concentration level of organic compounds in the exhaust vent stream from the control device.

(3) Operate the control device in compliance with the operating parameter value established under subsection (m)(6).

(4) Calculate the daily average of the monitored operating parameter for each operating day, using the valid data recorded by the monitoring system under subsection (m)(7).

(5) Ensure that the daily average of the monitoring parameter value calculated under paragraph (4) complies with the parameter value established under paragraph (3) as specified in subsection (m)(9).

(6) Operate the CPMS installed under paragraph (2) whenever the source is operating, except during the times specified in subsection (m)(8)(iii).

(e) *Compliance requirements for a flare*. The owner or operator of a control device subject to this section that installs a flare designed and operated in accordance with 40 CFR 60.18(b) (relating to general control device and work practice requirements) shall meet subsection (b)(3)—(7).

(f) *Compliance requirements for a carbon adsorption system*. The owner or operator of a control device subject to this section that installs a carbon adsorption system shall meet subsection (b)(1) and (2) and the following:

(1) Design and operate the carbon adsorption system to reduce the mass content of VOC in the gases vented to the device as demonstrated by one of the following:

(i) Determining the VOC emission reduction is 95.0% by weight or greater as specified in subsection (k).

(ii) Reducing the concentration of TOC in the exhaust gases at the outlet to the device to a level less than or equal to 275 ppmvd as propane corrected to 3% oxygen as determined under subsection (l).

(iii) Conducting a design analysis in accordance with subsection (g)(6) or subsection (h)(2) as applicable.

(2) Include a carbon replacement schedule in the design of the carbon adsorption system.

(3) Replace the carbon in the control device with fresh carbon on a regular schedule that is no longer than the carbon service life established according to the design analysis in subsection (g)(6) or subsection (h)(2) or according to the replacement schedule in paragraph (2).

(4) Manage the spent carbon removed from the carbon adsorption system in paragraph (3) by one of the following:

(i) Regenerating or reactivating the spent carbon in one of the following:

(A) A thermal treatment unit for which the owner or operator has been issued a permit or authorization by the Department's Bureau of Waste Management.

(B) A unit equipped with operating organic air emission controls in accordance with an emissions standard for VOC under a subpart in 40 CFR Part 60 (relating to standards of performance for new stationary sources) or 40 CFR Part 63 (relating to national emission standards for hazardous air pollutants for source categories).

(ii) Burning the spent carbon in one of the following:

(A) A hazardous waste incinerator, boiler or industrial furnace for which the owner or operator complies with the requirements of 40 CFR Part 63, Subpart EEE (relating to national emission standards for hazardous air pollutants from hazardous waste combustors) and has submitted a Notification of Compliance under 40 CFR 63.1207(j) (relating to what are the performance testing requirements?).

(B) An industrial furnace for which the owner or operator has been issued a permit or authorization by the Department's Bureau of Waste Management.

(C) An industrial furnace designed and operated in accordance with the interim status requirements of 40 CFR Part 266, Subpart H (relating to hazardous waste burned in boilers and industrial furnaces).

(g) *Additional compliance requirements for a regenerative carbon adsorption system*. The owner or operator of a control device subject to this section that installs a regenerative carbon adsorption system shall meet subsection (f) and the following:

(1) Install, calibrate, operate and maintain a CPMS according to the manufacturer's specifications and the applicable requirements of subsection (m) to measure the values of the operating parameters appropriate to the control device as follows:

(i) For a source complying with subsection (f)(1)(i), a flow CPMS system that meets the requirements of subsection (m)(1) and (2)(ii) to measure and record the average total regeneration steam mass flow or volumetric flow during each carbon bed regeneration cycle. The owner or operator shall inspect the following:

(A) The mechanical connections for leakage with monthly inspections separated by at least 15 calendar days but not more than 30 calendar days.

(B) The components of the flow CPMS for physical and operational integrity if the flow CPMS is not equipped with a redundant flow sensor with quarterly inspections separated by at least 60 calendar days but not more than 90 calendar days.

(C) The electrical connections of the flow CPMS for oxidation and galvanic corrosion if the flow CPMS is not equipped with a redundant flow sensor with quarterly inspections separated by at least 60 calendar days but not more than 90 calendar days.

(ii) For a source complying with subsection (f)(1)(i), a temperature CPMS that meets the requirements of subsection (m)(1) and (4) to measure and record the average carbon bed temperature for the duration of the carbon bed steaming cycle and measure the actual carbon bed temperature after regeneration and within 15 minutes of completing the cooling cycle.

(iii) For a source complying with subsection (f)(1)(ii), an organic concentration CPMS that meets subsection (m)(1) and (5) that measures the concentration level of organic compounds in the exhaust vent stream from the control device.

(2) Operate the control device in compliance with the operating parameter value established under subsection (m)(6).

(3) Calculate the daily average of the applicable monitored operating parameter for each operating day, using the valid data recorded by the CPMS as specified in subsection (m)(7).

(4) Ensure that the daily average of the monitoring parameter value calculated under paragraph (3) complies with the parameter value established under paragraph (2) as specified in subsection (m)(9).

(5) Operate the CPMS installed in paragraph (1) whenever the source is operating, except during the times specified in subsection (m)(8)(iii).

(6) Ensure that the design analysis to meet subsection (f)(1)(iii) and (2) for the regenerable carbon adsorption system meets the following:

(i) Includes an analysis of the vent stream, including the following information:

(A) Composition.

(B) Constituent concentrations.

(C) Flowrate.

(D) Relative humidity.

(E) Temperature.

(ii) Establishes the following parameters for the regenerable carbon adsorption system:

(A) Design exhaust vent stream organic compound concentration level.

(B) Adsorption cycle time.

(C) Number and capacity of carbon beds.

(D) Type and working capacity of activated carbon used for the carbon beds.

(E) Design total regeneration stream flow over the period of each complete carbon bed regeneration cycle.

(F) Design carbon bed temperature after regeneration.

(G) Design carbon bed regeneration time.

(H) Design service life of the carbon.

(h) *Additional compliance requirements for a non-regenerative carbon adsorption system*. The owner or operator of a control device subject to this section that installs a non-regenerative carbon adsorption system shall meet subsection (f) and the following:

(1) Monitor the design carbon replacement interval established in subsection (f)(2) or paragraph (2). The design carbon replacement interval must be based on the

total carbon working capacity of the control device and the source operating schedule.

(2) Ensure that the design analysis to meet subsection (f)(1)(iii) and (2) for a non-regenerable carbon adsorption system, such as a carbon canister, meets the following:

(i) Includes an analysis of the vent stream including the following information:

(A) Composition.

(B) Constituent concentrations.

(C) Flowrate.

(D) Relative humidity.

(E) Temperature.

(ii) Establishes the following parameters for the non-regenerable carbon adsorption system:

(A) Design exhaust vent stream organic compound concentration level.

(B) Capacity of the carbon bed.

(C) Type and working capacity of activated carbon used for the carbon bed.

(D) Design carbon replacement interval based on the total carbon working capacity of the control device and the source operating schedule.

(iii) Incorporates dual carbon canisters in case of emission breakthrough occurring in one canister.

(i) *Compliance requirements for a condenser or non-destructive control device*. The owner or operator of a control device subject to this section that installs a condenser or other non-destructive control device shall meet subsection (b)(1) and (2) and the following:

(1) Design and operate the condenser or other non-destructive control device to reduce the mass content of VOC in the gases vented to the device as demonstrated by one of the following:

(i) Determining the VOC emissions reduction is 95.0% by weight or greater under subsection (k).

(ii) Reducing the concentration of TOC in the exhaust gases at the outlet to the device to a level less than or equal to 275 ppmvd as propane corrected to 3% oxygen as determined under subsection (l).

(iii) Conducting a design analysis in accordance with paragraph (7).

(2) Prepare a site-specific monitoring plan that addresses the following CPMS design, data collection, and quality assurance and quality control elements:

(i) The performance criteria and design specifications for the CPMS equipment, including the following:

(A) The location of the sampling interface that allows the CPMS to provide representative measurements. For a temperature CPMS that meets the requirements of subsection (m)(1) and (4) the sensor must be installed in the exhaust vent stream as detailed in the procedures of the site-specific monitoring plan.

(B) Equipment performance checks, system accuracy audits or other audit procedures.

(I) Performance evaluations of each CPMS shall be conducted in accordance with the site-specific monitoring plan.

(II) CPMS performance checks, system accuracy audits or other audit procedures specified in the site-specific monitoring plan shall be conducted at least once every 12 months.

(ii) Ongoing operation and maintenance procedures in accordance with 40 CFR 60.13(b) (relating to monitoring requirements).

(iii) Ongoing reporting and recordkeeping procedures in accordance with 40 CFR 60.7(c), (d) and (f) (relating to notification and record keeping).

(3) Install, calibrate, operate and maintain a CPMS according to the site-specific monitoring plan described in paragraph (2) and the applicable requirements of subsection (m) to measure the values of the operating parameters appropriate to the control device as follows:

(i) For a source complying with paragraph (1)(i), a temperature CPMS that meets subsection (m)(1) and (4) to measure and record the average condenser outlet temperature.

(ii) For a source complying with paragraph (1)(ii), an organic concentration CPMS that meets subsection (m)(1) and (5) that measures the concentration level of organic compounds in the exhaust vent stream from the control device.

(4) Operate the control device in compliance with the operating parameter value established under subsection (m)(6).

(5) Calculate the daily average of the applicable monitored operating parameter for each operating day, using the valid data recorded by the CPMS as follows:

(i) For a source complying with paragraph (1)(i), use the calculated daily average condenser outlet temperature as specified in subsection (m)(7) and the condenser performance curve established under subsection (m)(6)(iii) to determine the condenser efficiency for the current operating day. Calculate the 365-day rolling average TOC emission reduction, as appropriate, from the condenser efficiencies as follows:

(A) If there is less than 120 days of data for determining average TOC emission reduction, calculate the average TOC emission reduction for the first 120 days of operation. Compliance is demonstrated with paragraph (1)(i) if the 120-day average TOC emission reduction is equal to or greater than 95.0% by weight.

(B) After 120 days and no more than 364 days of operation, calculate the average TOC emission reduction as the TOC emission reduction averaged over the number of days of operation for which there is data. Compliance is demonstrated with paragraph (1)(i) if the average TOC emission reduction is equal to or greater than 95.0% by weight.

(C) If there is data for 365 days or more of operation, compliance is demonstrated with the TOC emission reduction if the rolling 365-day average TOC emission reduction calculated in subparagraph (i) is equal to or greater than 95.0% by weight.

(ii) For a source complying with paragraph (1)(ii), calculate the daily average concentration for each operating day, using the data recorded by the CPMS as specified in subsection (m)(7). Compliance is demonstrated with paragraph (1)(ii) if the daily average concentration is less than the operating parameter under paragraph (4) as specified in subsection (m)(9).

(6) Operate the CPMS installed in accordance with paragraph (3) whenever the source is operating, except during the times specified in subsection (m)(8)(iii).

(7) Ensure that the design analysis to meet paragraph (1)(iii) for a condenser or other non-destructive control device meets the following:

(i) Includes an analysis of the vent stream including the following information:

(A) Composition.

(B) Constituent concentrations.

(C) Flowrate.

(D) Relative humidity.

(E) Temperature.

(ii) Establishes the following parameters for the condenser or other non-destructive control device:

(A) Design outlet organic compound concentration level.

(B) Design average temperature of the condenser exhaust vent stream.

(C) Design average temperatures of the coolant fluid at the condenser inlet and outlet.

(j) *General performance test requirements*. The owner or operator shall meet the following performance test requirements:

(1) Conduct an initial performance test within 180 days after ________ (*Editor's Note*: The blank refers to the effective date of this rulemaking, when published as a final-form rulemaking.) unless the owner or operator:

(i) Installs a manufacturer-tested combustion device that meets the requirements of subsection (c).

(ii) Installs a flare that meets the requirements of subsection (e).

(iii) Installs a boiler or process heater with a design heat input capacity of 44 megawatts (150 MMBtu per hour) or greater.

(iv) Installs a boiler or process heater which introduces the vent stream with the primary fuel or uses the vent stream as the primary fuel.

(v) Installs a boiler or process heater which burns hazardous waste that meets one or more of the following:

(A) For which an operating permit was issued under 40 CFR Part 270 (relating to EPA administered permit programs: the hazardous waste permit program) and complies with the requirements of 40 CFR Part 266, Subpart H.

(B) For which compliance with the interim status requirements of 40 CFR Part 266, Subpart H has been certified.

(C) Which complies with 40 CFR Part 63, Subpart EEE and for which a Notification of Compliance under 40 CFR 63.1207(j) was submitted to the Department.

(D) Which complies with 40 CFR Part 63, Subpart EEE and for which a Notification of Compliance under 40 CFR 63.1207(j) will be submitted to the Department within 90 days of the completion of the initial performance test report unless a written request for an extension is submitted to the Department.

(vi) Installs a hazardous waste incinerator which meets the requirements of 40 CFR Part 63, Subpart EEE and for which the Notification of Compliance under 40 CFR 63.1207(j):

(A) Was submitted to the Department.

(B) Will be submitted to the Department within 90 days of the completion of the initial performance test report unless a written request for an extension is submitted to the Department.

(vii) Requests the performance test be waived under 40 CFR 60.8(b) (relating to performance tests).

(2) Conduct a periodic performance test no more than 60 months after the most recent performance test unless the owner or operator:

(i) Monitors the inlet gas flow for a manufacturer-tested combustion device under subsection (c)(1)(i).

(ii) Installs a control device exempt from testing requirements under paragraph (1)(ii)—(vii).

(iii) Establishes a correlation between firebox or combustion chamber temperature and the VOC performance level for an enclosed combustion device under subsection (d)(2)(iii).

(3) Conduct a performance test when establishing a new operating limit.

(k) *Performance test method for demonstrating compliance with a control device weight-percent VOC emission reduction requirement*. Demonstrate compliance with the control device weight-percent VOC emission reduction requirements of subsections (c)(1)(ii), (d)(1)(i), (f)(1)(i) and (i)(1)(i) by meeting subsection (j) and the following:

(1) Conducting a minimum of three test runs of at least 1-hour duration.

(2) Using EPA Method 1 or EPA Method 1A, as appropriate, to select the sampling sites which must be located at the inlet of the first control device and at the outlet of the final control device. References to particulate mentioned in EPA Method 1 or EPA Method 1A do not apply to this paragraph.

(3) Using EPA Method 2, EPA Method 2A, EPA Method 2C or EPA Method 2D, as appropriate to determine the gas volumetric flowrate.

(4) Using EPA Method 25A to determine compliance with the control device percent VOC emission reduction performance requirement using the following procedure:

(i) Convert the EPA Method 25A results to a dry basis, using EPA Method 4.

(ii) Compute the mass rate of TOC using the following equations:

$$E_i = K_2 C_i M_p Q_i$$

$$E_o = K_2 C_o M_p Q_o$$

Where:

E_i = Mass rate of TOC at the inlet of the control device on a dry basis, in kilograms per hour (pounds per hour).

E_o = Mass rate of TOC at the outlet of the control device on a dry basis, in kilograms per hour (pounds per hour).

K_2 = Constant, 2.494×10^{-6} (ppm) (mole per standard cubic meter) (kilogram per gram) (minute per hour) where standard temperature (mole per standard cubic meter) is 20° Celsius

Or

K_2 = Constant, 1.554×10^{-7} (ppm) (lb-mole per standard cubic feet) (minute per hour), where standard temperature (lb-mole per standard cubic feet) is 68° Fahrenheit.

C_i = Concentration of TOC, as propane, of the gas stream as measured by EPA Method 25A at the inlet of the control device, ppmvd.

C_o = Concentration of TOC, as propane, of the gas stream as measured by EPA Method 25A at the outlet of the control device, ppmvd.

M_p = Molecular weight of propane, 44.1 gram per mole (pounds per lb-mole).

Q_i = Flowrate of gas stream at the inlet of the control device in dry standard cubic meter per minute (dry standard cubic feet per minute).

Q_o = Flowrate of gas stream at the outlet of the control device in dry standard cubic meter per minute (dry standard cubic feet per minute).

(iii) Calculate the percent reduction in TOC as follows:

$$R_{cd} = \frac{E_i - E_o}{E_i} * 100\%$$

Where:

R_{cd} = Control efficiency of control device, percent.

E_i = Mass rate of TOC at the inlet to the control device as calculated in subparagraph (ii), kilograms per hour (pounds per hour).

E_o = Mass rate of TOC at the outlet of the control device as calculated in subparagraph (ii), kilograms per hour (pounds per hour).

(iv) If the vent stream entering a boiler or process heater with a performance testing requirement is introduced with the combustion air or as a secondary fuel, the owner or operator shall:

(A) Calculate E_i in subparagraph (ii) by using the TOC concentration in all combusted vent streams, primary fuels and secondary fuels as C_i.

(B) Calculate E_o in subparagraph (ii) by using the TOC concentration exiting the device as C_o.

(C) Determine the weight-percent reduction of TOC across the device in accordance with subparagraph (iii).

(5) The weight-percent reduction of TOC across the control device represents the VOC weight-percent reduction for demonstration of compliance with subsections (c)(1)(ii), (d)(1)(i), (f)(1)(i) and (i)(1)(i).

(l) *Performance test method for demonstrating compliance with an outlet concentration requirement*. Demonstrate compliance with the TOC concentration requirement of subsections (d)(1)(ii), (f)(1)(ii) and (i)(1)(ii) by meeting subsection (j) and the following:

(1) Conducting a minimum of three test runs of at least 1-hour duration.

(2) Using EPA Method 1 or EPA Method 1A, as appropriate, to select the sampling sites which must be located at the outlet of the control device. References to particulate mentioned in EPA Method 1 or EPA Method 1A do not apply to this paragraph.

(3) Using EPA Method 2, EPA Method 2A, EPA Method 2C, or EPA Method 2D, as appropriate to determine the gas volumetric flowrate.

(4) Using EPA Method 25A to determine compliance with the TOC concentration requirement using the following procedures:

(i) Measure the TOC concentration, as propane.

(ii) For a control device subject to subsection (f) or subsection (i), the results of EPA Method 25A in subparagraph (i) may be adjusted by subtracting the concentration of methane and ethane measured using EPA Method 18 taking either:

(A) An integrated sample.

(B) A minimum of four grab samples per hour using the following procedures:

(I) Taking the samples at approximately equal intervals in time, such as 15-minute intervals during the run.

(II) Taking the samples during the same time as the EPA Method 25A sample.

(III) Determining the average methane and ethane concentration per run.

(iii) The TOC concentration must be adjusted to a dry basis, using EPA Method 4.

(iv) The TOC concentration must be corrected to 3% oxygen as follows:

(A) The oxygen concentration must be determined using the emission rate correction factor for excess air, integrated sampling and analysis procedures from one of the following methods:

(I) EPA Method 3A.

(II) EPA Method 3B.

(III) ASTM D6522-00.

(IV) ANSI/ASME PTC 19.10-1981, Part 10.

(B) The samples for clause (A) must be taken during the same time that the samples are taken for determining the TOC concentration.

(C) The TOC concentration for percent oxygen must be corrected as follows:

$$C_c = C_m \left(\frac{17.9}{20.9 - \%O_{2m}} \right)$$

Where:

C_c = TOC concentration, as propane, corrected to 3% oxygen, ppmvd.

C_m = TOC concentration, as propane, ppmvd.

$\%O_{2m}$ = Concentration of oxygen, percent by volume as measured, dry.

(m) *Continuous parameter monitoring system requirements*. The owner or operator of a source subject to § 129.121(a) (relating to general provisions and applicability) and controlled by a device listed in subsections (c)—(i) that is required to install a CPMS shall:

(1) Ensure the CPMS measures the applicable parameter at least once every hour and continuously records either:

(i) The measured operating parameter value.

(ii) The block average operating parameter value for each 1-hour period calculated using the following procedures:

(A) The block average from all measured data values during each period.

(B) If values are measured more frequently than once per minute, a single value for each minute may be used instead of all measured values.

(2) Ensure the flow CPMS has either:

(i) An accuracy of ±2% or better at the maximum expected flow rate.

(ii) A measurement sensitivity of 5% of the flow rate or 10 standard cubic feet per minute, whichever is greater.

(3) Ensure the heat-sensing CPMS indicates the presence of the pilot flame while emissions are routed to the control device. Heat-sensing CPMS are exempt from the calibration, quality assurance and quality control requirements in this section.

(4) Ensure the temperature CPMS has a minimum accuracy of ±1% of the temperature being monitored in °Celsius (±1.8% in °Fahrenheit) or ±2.5 °Celsius (±4.5 °Fahrenheit), whichever value is greater.

(5) Ensure the organic concentration CPMS meets the requirements of Performance Specification 8 or 9 of 40 CFR Part 60, Appendix B (relating to performance specifications).

(6) Establish the operating parameter value to define the conditions at which the control device must be operated to continuously achieve the applicable performance requirement as follows:

(i) For a parameter value established while conducting a performance test under subsection (k) or subsection (l):

(A) Base each minimum operating parameter value on the value established while conducting the performance test and supplemented, as necessary, by the design analysis of subsection (g)(6), subsection (h)(2) or subsection (i)(7), the manufacturer's recommendations, or both.

(B) Base each maximum operating parameter value on the value established while conducting the performance test and supplemented, as necessary, by the design analysis of subsection (g)(6), subsection (h)(2) or subsection (i)(7), the manufacturer's recommendations, or both.

(ii) Except as specified in clause (C), for a parameter value established using a design analysis in subsection (g)(6), subsection (h)(2) or subsection (i)(7):

(A) Base each minimum operating parameter value on the value established in the design analysis and supplemented, as necessary, by the manufacturer's recommendations.

(B) Base each maximum operating parameter value on the value established in the design analysis and supplemented, as necessary, by the manufacturer's recommendations.

(C) If the owner or operator and the Department do not agree on a demonstration of control device performance using a design analysis as specified in clause (A) or (B), then the owner or operator shall perform a performance test under subsection (k) or subsection (l) to resolve the disagreement. The Department may choose to have an authorized representative observe the performance test.

(iii) For a condenser, establish a condenser performance curve showing the relationship between condenser outlet temperature and condenser control efficiency that demonstrates the condenser complies with the applicable performance requirements in subsection (i)(1) as follows:

(A) Based on the value measured while conducting a performance test under subsection (k) or subsection (l) and supplemented, as necessary, by a condenser design analysis performed under subsection (i)(7), the manufacturer's recommendations, or both.

(B) Based on the value from a condenser design analysis performed under subsection (i)(7) supplemented, as necessary, by the manufacturer's recommendations.

(7) Except for the CPMS in paragraphs (2) and (3), calculate the daily average for each monitored parameter for each operating day using the data recorded by the CPMS. Valid data points must be available for 75% of the operating hours in an operating day to compute the daily average where the operating day is:

(i) A 24-hour period if the control device operation is continuous.

(ii) The total number of hours of control device operation per 24-hour period.

(8) Except as specified in subparagraph (iii), do both of the following:

(i) Ensure the data recorded by the CPMS is used to assess the operation of the control device and associated control system.

(ii) Report the failure to collect the required data in paragraph (1) as a deviation of the monitoring requirements.

(iii) The requirements of subparagraphs (i) and (ii) do not apply during:

(A) A monitoring system malfunction.

(B) A repair associated with a monitoring system malfunction.

(C) A required monitoring system quality assurance or quality control activity.

(9) Determine compliance with the established parameter value by comparing the calculated daily average to the established operating parameter value as follows:

(i) For a minimum operating parameter established in paragraph (6)(i)(A) or paragraph (6)(ii)(A), the control device is in compliance if the calculated value is equal to or greater than the established value.

(ii) For a maximum operating parameter established in paragraph (6)(i)(B) or paragraph (6)(ii)(B), the control device is in compliance if the calculated value is less than or equal to the established value.

§ 129.130. Recordkeeping and reporting.

(a) *Recordkeeping*. The owner or operator of a source subject to §§ 129.121—129.129 shall maintain the applicable records onsite or at the nearest local field office for 5 years. The records shall be made available to the Department upon request.

(b) *Storage vessels*. The records for each storage vessel must include the following, as applicable:

(1) The identification and location of each storage vessel subject to § 129.123 (relating to storage vessels). The location of the storage vessel shall be in latitude and longitude coordinates in decimal degrees to an accuracy and precision of 5 decimals of a degree using the North American Datum of 1983.

(2) Each deviation when the storage vessel was not operated in compliance with the requirements specified in § 129.123.

(3) The identity of each storage vessel removed from service under § 129.123(e) and the date on which it was removed from service.

(4) The identity of each storage vessel returned to service under § 129.123(f) and the date on which it was returned to service.

(5) The identity of each storage vessel and the VOC potential to emit calculation under § 129.123(a)(2).

(6) The identity of each storage vessel and the actual VOC emission calculation under § 129.123(c) including the following information:

(i) The date of each monthly calculation performed under § 129.123(c)(1).

(ii) The calculation determining the actual VOC emissions each month.

(iii) The calculation demonstrating that the actual VOC emissions are less than the applicable VOC emission threshold on a 12-month rolling basis.

(7) The records documenting the time the skid-mounted or mobile storage vessel under § 129.123(d)(3) is located on site. If a skid-mounted or mobile storage vessel is removed from a site and either returned or replaced within 30 calendar days to serve the same or similar function, count the entire period since the original storage vessel was removed towards the number of consecutive days.

(8) The identity of each storage vessel required to reduce VOC emissions under § 129.123(b)(1) and the demonstration under § 129.123(b)(1)(iv).

(c) *Natural gas-driven pneumatic controllers*. The records for each natural gas-driven pneumatic controller must include the following, as applicable:

(1) The date, identification, location and manufacturer specifications for each natural gas-driven pneumatic controller subject to § 129.124 (relating to natural gas-driven pneumatic controllers).

(2) Each deviation when the pneumatic controller was not operated in compliance with the requirements specified in § 129.124.

(3) If the pneumatic controller is located at a natural gas processing plant, the documentation that the natural gas bleed rate is zero.

(4) For a natural gas-driven pneumatic controller under § 129.124(b), the determination based on a functional requirement for why a natural gas bleed rate greater than the applicable standard is required. A functional requirement includes one or more of the following:

(i) Response time.

(ii) Safety.

(iii) Positive actuation.

(d) *Natural gas-driven diaphragm pumps*. The records for each natural gas-driven diaphragm pump must include the following, as applicable:

(1) The date, location and manufacturer specifications for each natural gas-driven diaphragm pump subject to § 129.125 (relating to natural gas-driven diaphragm pumps).

(2) Each deviation when the natural gas-driven diaphragm pump was not operated in compliance with the requirements specified in § 129.125.

(3) For a natural gas-driven diaphragm pump under § 129.125(d), the records of the days of operation each calendar year. Any period of operation during a calendar day counts toward the 90-calendar-day threshold.

(4) For a natural gas-driven diaphragm pump under § 129.125(c)(1), maintain the following records:

(i) The records under subsection (j) for the control device type.

(ii) One of the following:

(A) The results of a performance test under § 129.129(k) or (l) (relating to control devices).

(B) A design evaluation indicating the percentage of VOC emissions reduction the control device is designed to achieve.

(C) The manufacturer's specifications indicating the percentage of VOC emissions reduction the control device is designed to achieve.

(5) For a well site with no available control device or process under § 129.125(c)(2), maintain a copy of the certification submitted under subsection (k)(3)(ii)(B).

(6) The engineering assessment substantiating a claim under § 129.125(c)(3), including the certification under § 129.125(c)(3)(ii)(C).

(7) For a natural gas-driven diaphragm pump required to reduce VOC emissions under § 129.125(c)(1), the demonstration under § 129.125(c)(1)(iii).

(e) *Reciprocating compressors*. The records for each reciprocating compressor must include the following, as applicable:

(1) For a reciprocating compressor under § 129.126(b)(1)(i) (relating to compressors), the following records:

(i) The cumulative number of hours of operation.

(ii) The date and time of each rod packing replacement.

(2) For a reciprocating compressor under § 129.126(b)(1)(ii), the following records:

(i) The number of months since the previous replacement of the rod packing.

(ii) The date of each rod packing replacement.

(3) For a reciprocating compressor under § 129.126(b)(2), the following records:

(i) A statement that emissions from the rod packing are being routed to a process through a closed vent system under negative pressure.

(ii) The date of installation of a rod packing emissions collection system and closed vent system as specified in § 129.126(b)(2).

(4) Each deviation when the reciprocating compressor was not operated in compliance with § 129.126(b).

(f) *Centrifugal compressors*. The records for each centrifugal compressor must include the following, as applicable:

(1) An identification of each existing centrifugal compressor using a wet seal system subject to § 129.126(c).

(2) Each deviation when the centrifugal compressor was not operated in compliance with § 129.126(c).

(3) For a centrifugal compressor required to reduce VOC emissions under § 129.126(c)(1), the demonstration under § 129.126(c)(3).

(g) *Fugitive emissions components*. The records for each fugitive emissions component must include the following, as applicable:

(1) For a well site subject to § 129.127(b)(1)(i) (relating to fugitive emissions components):

(i) The location of the well and the United States Well ID Number.

(ii) The annual analysis documenting a GOR of less than 300 standard cubic feet of gas per stock barrel of oil produced, conducted using generally accepted methods. The analysis must be signed by and include a certification by the responsible official stating that, based on information and belief formed after reasonable inquiry, the statements and information in the document are true, accurate and complete.

(2) For a well site subject to § 129.127(b)(2), a natural gas gathering and boosting station and a natural gas processing plant:

(i) The fugitive emissions monitoring plan under § 129.127(f).

(ii) The records of each monitoring survey conducted under § 129.127(b)(1)(ii) or § 129.127(d)(2). The monitoring survey must include the following information:

(A) The facility name and location.

(B) The date, start time and end time of the survey.

(C) The name of the equipment operator performing the survey.

(D) The monitoring instrument used.

(E) The ambient temperature, sky conditions and maximum wind speed at the time of the survey.

(F) Each deviation from the monitoring plan or a statement that there were none.

(G) Documentation of each fugitive emission including:

(I) The identification of each component from which fugitive emissions were detected.

(II) The instrument reading of each fugitive emissions component that meets the definition of a leak under § 129.122(a) (relating to definitions, acronyms and EPA methods).

(III) The repair methods applied in each attempt to repair the component.

(IV) The tagging or digital photographing of each component not repaired during the monitoring survey in which the fugitive emissions were discovered.

(V) The reason a component was placed on delay of repair.

(VI) The date of successful repair of the component.

(VII) If repair of the component was not completed during the monitoring survey in which the fugitive emissions were discovered, the information on the instrumentation or the method used to resurvey the component after repair.

(3) For a well site subject to § 129.127(b)(1)(ii) for which the owner or operator opts to comply with § 129.127(b)(2), the calculations demonstrating the percentage of leaking components.

(h) *Covers*. The records for each cover includes the results of each cover inspection under § 129.128(a) (relating to covers and closed vent systems).

(i) *Closed vent systems*. The records for each closed vent system must include the following, as applicable:

(1) The results of each closed vent system inspection under § 129.128(b)(2).

(2) For the no detectable emissions inspections of § 129.128(d), a record of the monitoring survey as specified under subsection (g)(2)(ii).

(3) The engineering assessment under § 129.128(c), including the certification under § 129.128(c)(3).

(4) If the closed vent system includes a bypass device subject to § 129.128(b)(4), a record of:

(i) Each time the alarm is activated.

(ii) Each time the key is checked out, as applicable.

(iii) Each inspection required under § 129.128(b)(4)(ii)(B).

(j) *Control devices*. The records for each control device must include the following, as applicable:

(1) Make, model and serial number of the purchased device.

(2) Date of purchase.

(3) Copy of purchase order.

(4) Location of the control device in latitude and longitude coordinates in decimal degrees to an accuracy and precision of 5 decimals of a degree using the North American Datum of 1983.

(5) For the general requirements under § 129.129(b):

(i) The manufacturer's written operating instructions, procedures and maintenance schedule to ensure good air pollution control practices for minimizing emissions under § 129.129(b)(1).

(ii) The results of each monthly physical integrity check performed under § 129.129(b)(2).

(iii) The CPMS data which indicates the presence of a pilot flame during the device's operation under § 129.129(b)(3).

(iv) The results of the visible emissions test under § 129.129(b)(4) using Figure 22-1 in EPA Method 22 or a form which includes the following:

(A) The name of the company.

(B) The location of the control device.

(C) The name of the person performing the observation.

(D) The sky conditions at the time of observation.

(E) Type of control device.

(F) The clock start time.

(G) The observation period duration, in minutes and seconds.

(H) The accumulated emission time, in minutes and seconds.

(I) The clock end time.

(v) The results of the visible emissions test required in § 129.129(b)(6) under subparagraph (iv) following a return to operation from a maintenance or repair activity performed under § 129.129(b)(5).

(vi) The maintenance and repair log under § 129.129(b)(7).

(6) For a manufacturer-tested combustion control device under § 129.129(c), maintain the following records:

(i) The records specified in paragraph (5)(i)—(vi).

(ii) The manufacturer's specified inlet gas flow rate.

(iii) The CPMS results under § 129.129(c)(1)(i).

(iv) The results of each performance test conducted under § 129.129(c)(1)(ii) as performed under § 129.129(k).

(7) For an enclosed combustion device in § 129.129(d):

(i) The records specified in paragraph (5)(i)—(vi).

(ii) The results of each performance test conducted under § 129.129(d)(1)(i) as performed under § 129.129(k).

(iii) The results of each performance test conducted under § 129.129(d)(1)(ii) as performed under § 129.129(l).

(iv) The data and calculations for the CPMS installed, operated or maintained under § 129.129(d)(2).

(8) For a flare in § 129.129(e), the records specified in paragraph (5)(iii)—(vi).

(9) For a regenerative carbon adsorption device in § 129.129(g):

(i) The records specified in paragraph (5)(i) and (ii).

(ii) The results of the performance test conducted under § 129.129(f)(1)(i) as performed under § 129.129(k).

(iii) The results of the performance test conducted under § 129.129(f)(1)(ii) as performed under § 129.129(l).

(iv) The control device design analysis, if one is performed under § 129.129(g)(6).

(v) The data and calculations for a CPMS installed, operated or maintained under § 129.129(g)(1)—(5).

(vi) The schedule for carbon replacement, as determined by § 129.129(f)(2) or the design analysis requirements of § 129.129(g)(6) and records of each carbon replacement under § 129.129(f)(3) and (4).

(10) For a non-regenerative carbon adsorption device in § 129.129(h):

(i) The records specified in paragraph (5)(i) and (ii).

(ii) The results of the performance test conducted under § 129.129(f)(1)(i) as performed under § 129.129(k).

(iii) The results of the performance test conducted under § 129.129(f)(1)(ii) as performed under § 129.129(l).

(iv) The control device design analysis, if one is performed under § 129.129(h)(2).

(v) The schedule for carbon replacement, as determined by § 129.129(f)(2) or the design analysis requirements of § 129.129(h)(2) and records of each carbon replacement under § 129.129(f)(3) and (4).

(11) For a condenser or other non-destructive control device in § 129.129(i):

(i) The records specified in paragraph (5)(i) and (ii).

(ii) The results of the performance test conducted under § 129.129(i)(1)(i) as performed under § 129.129(k).

(iii) The results of the performance test conducted under § 129.129(i)(1)(ii) as performed under § 129.129(l).

(iv) The control device design analysis, if one is performed under § 129.129(i)(7).

(v) The site-specific monitoring plan under § 129.129(i)(2).

(vi) The data and calculations for a CPMS installed, operated or maintained under § 129.129(i)(3)—(5).

(k) *Reporting*. The owner or operator of a source subject to § 129.121(a) (relating to general provisions and applicability) shall submit an initial report to the Air Program Manager of the appropriate Department Regional Office by ________ (*Editor's Note*: The blank refers to the date 1 year after the effective date of this rulemaking, when published as a final-form rulemaking.) and annually thereafter. The responsible official must sign, date and certify compliance and include the certification in the initial report and each subsequent annual report. The due date of the initial report can be extended with the written approval of the Air Program Manager of the appropriate Department Regional Office.

(1) *Storage vessels*. The report for each storage vessel must include the information specified in subsection (b)(1)—(4) for the reporting period, as applicable.

(2) *Natural gas-driven pneumatic controllers*. The initial report for each natural gas-driven pneumatic controller must include the information specified in subsection (c), as applicable. Subsequent reports must include the following:

(i) The information specified in subsection (c)(1) and (2) for each natural gas-driven pneumatic controller.

(ii) The information specified in subsection (c)(3) and (4) for each natural gas-driven pneumatic controller installed during the reporting period.

(3) *Natural gas-driven diaphragm pumps*. The report for each natural gas-driven diaphragm pump must include the following:

(i) The information specified in subsection (d)(1) and (2) for the reporting period, as applicable.

(ii) A certification of the compliance status of each natural gas-driven diaphragm pump during the reporting period using one of the following:

(A) A certification that the emissions from the natural gas-driven diaphragm pump are routed to a control device or process under § 129.125(b)(1)(ii) or (c)(1). If the control device is installed during the reporting period under § 129.125(c)(2)(i)(C), include the information specified in subsection (d)(4).

(B) A certification under § 129.125(c)(2) that there is no control device or process available at the facility during the reporting period. This includes if a control device or process is removed from the facility during the reporting period.

(C) A certification according to § 129.125(c)(3)(ii)(C) that it is technically infeasible to capture and route emissions from:

(I) A natural gas-driven diaphragm pump installed during the reporting period to an existing control device or process.

(II) An existing natural gas-driven diaphragm pump to a control device or process installed during the reporting period.

(III) An existing natural gas-driven diaphragm pump to another control device or process located at the facility due to the removal of the original control device or process during the reporting period.

(4) *Reciprocating compressors*. The report for each reciprocating compressor must include the information specified in subsection (e) for the reporting period, as applicable.

(5) *Centrifugal compressors*. The report for each centrifugal compressor must include the information specified in subsection (f) for the reporting period, as applicable.

(6) *Fugitive emissions components*. The report for each fugitive emissions component must include the records of each monitoring survey conducted during the reporting period as specified in subsection (g)(2)(ii).

(7) *Covers*. The report for each cover must include the information specified in subsection (h) for the reporting period, as applicable.

(8) *Closed vent systems*. The report for each closed vent system must include the information specified in subsection (i)(1) and (2) for the reporting period, as applicable. The information specified in subsection (i)(3) is only required if the closed vent system was installed during the reporting period.

(9) *Control devices*. The report for each control device must include the information specified in subsection (j), as applicable.

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