RULES AND REGULATIONS

Title 25—ENVIRONMENTAL PROTECTION

ENVIRONMENTAL QUALITY BOARD

[25 PA. CODE CHS. 121 AND 129]

Control of VOC Emissions from Unconventional Oil and Natural Gas Sources

The Environmental Quality Board (Board) amends Chapters 121 and 129 (relating to general provisions; and standards for sources) to read as set forth in Annex A. This final-form rulemaking adds §§ 129.121—129.130 to adopt reasonably available control technology (RACT) requirements and RACT emission limitations for unconventional oil and natural gas sources of volatile organic compound (VOC) emissions. These sources include natural gas-driven continuous bleed pneumatic controllers, natural gas-driven diaphragm pumps, reciprocating compressors, centrifugal compressors, fugitive emissions components and storage vessels installed at unconventional well sites, gathering and boosting stations and natural gas processing plants, as well as storage vessels in the natural gas transmission and storage segment. The Board adds definitions, acronyms and United States Environmental Protection Agency (EPA) methods to § 129.122 (relating to definitions, acronyms and EPA methods) to support the implementation of the control measures, as well as amends certain terms in and adds an abbreviation to § 121.1 (relating to definitions) to support the amendments to Chapter 129.

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

This final-form rulemaking was adopted by the Board at its meeting on June 14, 2022.

A. *Effective Date*

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

B. *Contact Persons*

For further information, contact Viren 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. Persons with a disability may use the Pennsylvania Hamilton Relay Service, (800) 654-5984 (TDD users) or (800) 654-5988 (voice users). This final-form 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" and then navigate to the Board meeting of June 14, 2022).

C. *Statutory Authority*

This final-form 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 and section 5(a)(8) of the APCA, which 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 final-form rulemaking is to implement control measures to reduce VOC emissions from unconventional oil and natural gas sources in this Commonwealth. Five air contamination source categories are affected by this final-form rulemaking: storage vessels; natural gas-driven continuous bleed pneumatic controllers; natural gas-driven diaphragm pumps; reciprocating and centrifugal compressors; and fugitive emissions components. These sources were selected by the EPA because data and information has indicated that they are significant sources of VOC emissions.

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 final-form rulemaking establishes the VOC emission limitations and other RACT requirements consistent with 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).

Background on the Ozone National Ambient Air Quality Standards (NAAQS)

Under section 108 of the CAA (42 U.S.C.A. § 7408), the EPA is responsible for establishing the NAAQS, or maximum allowable concentrations in the ambient air, 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. The EPA established primary and secondary ground-level ozone NAAQS to protect public health and public welfare, including the environment.

On April 30, 1971, the EPA promulgated primary and secondary NAAQS for photochemical oxidants, which include ground-level ozone, under section 109 of the CAA. See 36 FR 8186 (April 30, 1971). These standards were set at an hourly average of 0.08 parts per million (ppm) total photochemical oxidants not to be exceeded more than 1 hour per year. On February 8, 1979, the EPA revised the level of the primary 1-hour ozone standard from 0.08 ppm to 0.12 ppm and set the secondary standard identical to the primary standard. See 44 FR 8202 (February 8, 1979). This revised 1-hour standard was reaffirmed on March 9, 1993. See 58 FR 13008 (March 9, 1993).

On July 18, 1997, the EPA concluded that revisions to the then-current 1-hour ozone primary standard to provide increased public health protection were appropriate to protect public health with an adequate margin of safety. Further, the EPA determined that it was appropriate to establish a primary standard of 0.08 ppm averaged over 8 hours. At this time, the EPA also established a secondary standard equal to the primary standard. 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 Department's certified ambient air monitoring data for the Commonwealth's 2020 ozone season, all monitored areas of this Commonwealth are attaining and maintaining the 1997 8-hour ozone NAAQS.

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 May 2012, the EPA designated five areas in this Commonwealth as marginal nonattainment for the 2008 ozone NAAQS with the rest of this Commonwealth designated as attainment. See 77 FR 30088, 30143 (May 21, 2012). The five designated 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. Per the 1997 ozone NAAQS, the Department must ensure that the 2008 ozone NAAQS is attained and maintained by implementing permanent and enforceable control measures. Based on the Department's certified ambient air monitoring data for the Commonwealth's 2020 ozone season, all monitored areas of this Commonwealth are attaining and maintaining the 2008 8-hour ozone NAAQS. Adoption of the VOC emission control measures in this final-form 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). On June 4, 2018, the EPA designated Bucks, Chester, Delaware, Montgomery and Philadelphia Counties as marginal nonattainment for the 2015 ozone NAAQS, with the rest of this Commonwealth designated as attainment. See 83 FR 25776 (June 4, 2018). The Department must ensure that the 2015 8-hour ozone NAAQS is attained and maintained by implementing permanent and Federally enforceable control measures. The certified ambient air ozone season monitoring data for the 2020 ozone season shows that all ozone samplers in this Commonwealth, except the Bristol sampler in Bucks County and the Northeast Airport and Northeast Waste samplers in Philadelphia County, are monitoring attainment of the 2015 ozone NAAQS. Reductions in VOC emissions that are achieved following the adoption and implementation of RACT emission control measures for source categories covered by this final-form rulemaking will assist the Commonwealth in making substantial progress in achieving and maintaining the 2015 ozone NAAQS.

Clean Air Act (CAA) requirements: Implementation of permanent and Federally enforceable control measures for attaining and maintaining the ozone NAAQS

Section 101(a)(3) of the CAA (42 U.S.C.A. § 7401(a)(3)) provides that air pollution prevention (that is, the reduction or elimination, through any measures, of the amount of pollutants produced or created at the source) and air pollution control at its source is the primary responsibility of states and local governments. Section 110(a) of the CAA (42 U.S.C.A. § 7410(a)) gives states the primary responsibility for achieving the NAAQS in nonattainment areas and for maintaining the NAAQS in areas of the state that are in attainment. Section 110(a) of the CAA provides that each state shall adopt and submit to the EPA a plan (a SIP) for implementation, maintenance and enforcement of the NAAQS or a revision to the NAAQS promulgated under section 109(b) of the CAA. Additionally, section 110(a) of the CAA provides that the plan shall contain adequate provisions to prevent emissions activity within a state from contributing significantly to nonattainment in, or interference with maintenance by, any other state with respect to a NAAQS. The entirety of the 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 and incorporated into the state's SIP, the measures of a SIP are legally enforceable under both Federal and state law.

Section 172(c)(1) of the CAA provides that a SIP for states with nonattainment areas must include "reasonably available control measures," including RACT, for affected sources of VOC and NO_x emissions. Upon submittal to the EPA, state regulations to control VOC emissions from affected sources are reviewed by the EPA to determine if the provisions meet the RACT requirements of the CAA and its implementing regulations designed to attain and maintain the ground-level ozone NAAQS. If the EPA determines that the provisions meet the applicable requirements of the CAA, the provisions are approved and incorporated as amendments to the state's SIP.

Section 182 of the CAA (42 U.S.C.A. § 7511a) requires that, for areas which exceed the ground-level ozone NAAQS, states must develop and implement a program that mandates certain major stationary sources develop and implement a RACT emission reduction program. Section 182(b)(2) of the CAA provides that for moderate ozone nonattainment areas, a state must revise its SIP to include RACT for sources of VOC emissions covered by a Control Techniques Guidelines (CTG) document issued by the EPA prior to the area's date of attainment of the applicable ozone NAAQS. CTG documents provide states with information about a VOC emission source category and recommendations of what the EPA considers to be RACT for the source category to attain and maintain the applicable ozone NAAQS. State air pollution control agencies may use the Federal recommendations provided in the CTG to inform their own determination as to what constitutes RACT for VOC emissions from the covered source category for subject sources located within the state. 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.

Although the designated nonattainment areas in this Commonwealth for the 2008 and 2015 ground-level ozone NAAQS are classified as "marginal" nonattainment, this entire Commonwealth is treated as a "moderate" ozone nonattainment area for RACT purposes because this Commonwealth is included in the Ozone Transport Region (OTR) established by operation of law under sections 176A and 184 of the CAA (42 U.S.C.A. §§ 7506a and 7511c). Section 176A grants the Administrator of the EPA the authority to establish an interstate transport region and the associated transport commission. Section 184(a) of the CAA established the OTR comprised of the states of Connecticut, Delaware, Maine, Maryland, Massachusetts, New Hampshire, New Jersey, New York, Pennsylvania, Rhode Island, Vermont and the Consolidated Metropolitan Statistical Area that includes the District of Columbia. More importantly, section 184(b)(1)(B) of the CAA requires that states in the OTR, including this Commonwealth, submit a SIP revision requiring implementation of RACT for all major stationary sources of VOC emissions in the state covered by a specific CTG and not just for those sources that are located in designated nonattainment areas of the state.

Consequently, the Commonwealth's SIP must include regulations implementing RACT requirements Statewide to control VOC emissions from the oil and natural gas sources covered by the 2016 O&G CTG. These sources, which are not regulated elsewhere in Chapter 129, were selected by the EPA because data and information has indicated that they are significant sources of VOC emissions. Significantly, this final-form rulemaking should achieve VOC emission reductions and lowered concentrations of ground-level ozone locally as well as in downwind states. Additionally, 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 final-form rulemaking will be submitted to the EPA for approval as a revision to the Commonwealth's SIP following promulgation of this final-form rulemaking.

Need to limit VOC emissions and ground-level ozone pollution

VOC emissions are precursors to the formation of ground-level ozone, a public health, welfare and environmental hazard. However, ground-level ozone is not emitted directly to the atmosphere from any sources, including unconventional oil and natural gas sources. Ground-level ozone is formed by a photochemical reaction between emissions of VOC and NO_x in the presence of sunlight; oil and gas sources do emit these two pollutants. 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 and the environment. 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.

Ground-level ozone is a respiratory irritant and repeated exposure to high ambient concentrations of ground-level 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 high ambient concentrations of ground-level 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 precursor emissions impacts on air quality in this Commonwealth is necessary to protect the public health and welfare and the environment. Because VOC emissions are precursors for ground-level ozone formation, adoption of the VOC emission control measures and other requirements in this final-form rulemaking is in the public interest as it will allow the Commonwealth to continue to make substantial progress in maintaining the 1997 and 2008 NAAQS as well as attaining and maintaining the 2015 8-hour ozone NAAQS Statewide. Implementation of and compliance with the final-form VOC emission reduction measures will assist the Commonwealth in reducing the levels of ozone precursor emissions that contribute to potential nonattainment of the 2015 ozone NAAQS in downwind states. 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.

The EPA's Control Techniques Guidelines for the Oil and Natural Gas Industry

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 a product or source category in ozone nonattainment areas. On October 27, 2016, the EPA issued the 2016 O&G CTG which provided information to assist states in determining what constitutes RACT for VOC emissions from select oil and natural gas industry emission sources. See 81 FR 74798 (October 27, 2016). On March 9, 2018, the EPA had proposed to withdraw the 2016 O&G CTG in its entirety because the CTG had relied upon underlying data and conclusions made in the 2016 new source performance standards which the EPA was reconsidering. See 83 FR 10478 (March 9, 2018). However, on March 5, 2020, the EPA announced in the United States Office of Management and Budget's Spring 2020 Unified Agenda and Regulatory Plan that the EPA was no longer pursuing the action to withdraw the CTG and "the CTG will remain in place as published on October 27, 2016." See Supplemental Notice of Potential Withdrawal of the Control Techniques Guidelines for the Oil and Natural Gas Industry at https://www.reginfo.gov/public/do/eAgendaViewRule?pubId=202004&RIN=2060-AT76&operation=OPERATION_PRINT_RULE.

While the EPA provided information and RACT recommendations through the 2016 O&G CTG for VOC emissions, it is up to the Department to determine what is RACT for each source category of VOC emissions. As explicitly stated by the EPA in the 2016 O&G CTG, state air pollution control agencies are free to implement other technically-sound approaches that are consistent with the CAA and the EPA's regulations. See 81 FR 74798, 74799 (October 27, 2016). The EPA also further clarified that "the information contained in the CTG document is provided only as guidance" and "this guidance does not change, or substitute for, requirements specified in applicable sections of the CAA or the EPA's regulations; nor is it a regulation itself." Id. While the EPA will ultimately need to approve the Department's RACT determinations by reviewing and approving the revision to the Commonwealth's SIP, the Department has made the initial RACT determinations in this final-form rulemaking based on the entirety of information available to the Department, including the 2016 O&G CTG. In other words, the Department's obligation is to affirmatively determine what constitutes RACT for the source group identified in the 2016 O&G CTG and the EPA's provision of guidance and data in the 2016 O&G CTG does not obliviate that legal requirement. In the time since the 2016 O&G CTG was issued by the EPA, the Department acquired additional information and current emissions data specific to this Commonwealth that it analyzed to determine the RACT emission limitations and requirements established in this final-form rulemaking.

Findings of Failure to Submit, sanctions and deadline for action

If the EPA finds that a state has failed to submit an approvable SIP revision or has failed to implement the requirements of an approved measure in the SIP, the EPA issues a "finding of failure to submit notice." On November 16, 2020, the EPA issued a Final Rule entitled "Findings of Failure To Submit State Implementation Plan Revisions in Response to the 2016 Oil and Natural Gas Industry Control Techniques Guidelines for the 2008 Ozone National Ambient Air Quality Standards (NAAQS) and for States in the Ozone Transport Region," with an effective date of December 16, 2020. See 85 FR 72963 (November 16, 2020). This Commonwealth was one of the five states issued a finding of failure to submit a SIP revision addressing the RACT requirements associated with the 2016 O&G CTG by October 27, 2018. The EPA's finding triggers the sanction clock under section 179 of the CAA (42 U.S.C.A. § 7509). However, sanctions cannot be imposed until 18 months after the EPA makes the determination, and sanctions cannot be imposed if a deficiency has been corrected within the 18-month period. Thus, the Commonwealth must have submitted this final-form rulemaking as an SIP revision and the EPA must have determined that the submittal is complete by June 16, 2022, or sanctions could take effect.

On December 16, 2021, the EPA issued "Findings of Failure to Submit State Implementation Plan Revisions for the 2016 Oil and Natural Gas Control Techniques Guidelines for the 2015 Ozone National Ambient Air Quality Standards and for States in the Ozone Transport Region," with an effective date of January 18, 2022. See 86 FR 71385 (December 16, 2021). This finding also triggers the sanction clock under section 179 of the CAA and the Commonwealth must submit an SIP revision and the EPA must determine that the submittal is complete by July 18, 2023.

Section 179 of the CAA authorizes the EPA to use two types of sanctions: 1) imposing what are called "2:1 offsets" on new or modified sources of emissions; and 2) withholding of certain Federal highway funds. Under section 179 of the CAA and its implementing regulations, the Administrator first imposes "2:1 offsets" sanctions for new or modified major stationary sources in the nonattainment area, and then, if the deficiency has not been corrected within 6 months, also applies Federal highway funding sanctions. See 40 CFR 52.31 (relating to selection of sequence of mandatory sanctions for findings made pursuant to section 179 of the Clean Air Act). The Commonwealth receives Federal transportation funding annually: $1.8 billion in 2020 and 2021.

Additionally, the findings trigger an obligation under section 110(c) of the CAA for the EPA to promulgate a Federal Implementation Plan (FIP) no later than 2 years after the effective date of the finding of failure to submit if the Commonwealth has not submitted, and the EPA has not approved, the required SIP submittal. If the EPA promulgates a FIP, the EPA could, in its discretion, also withhold a portion of the Department's air pollution grant funds provided for in section 105 of the CAA. However, if the Commonwealth makes the required SIP submittal and the EPA takes final action to approve the submittal within 2 years of the effective date of these findings, the EPA is not required to promulgate a FIP.

While this final-form rulemaking will not fully address the December 2021 and the November 2020 findings of failure to submit SIP revisions, the Department will develop a separate rulemaking for the RACT requirements for sources of VOC emissions installed at conventional well sites.

This final-form rulemaking is being promulgated to attain and maintain both the 2008 and the 2015 ozone NAAQS and will be submitted to the EPA for approval as a revision to the Commonwealth's SIP following promulgation. Once promulgated, the separate rulemaking for sources of VOC emissions installed at conventional well sites will also be submitted as a SIP revision. The Department is working toward completing both submittals by December 16, 2022, to avoid the Federal Highway sanctions.

VOC RACT requirements in this final-form rulemaking

Under section 4.2(b)(1) of the APCA (35 P.S. § 4004.2(b)(1)), the Board has the authority to adopt control measures that are more stringent than those required by the CAA if the Board determines that it is reasonably necessary for the control measure to exceed minimum CAA requirements for the Commonwealth to achieve or maintain the NAAQS. To the extent that a requirement in this final-form rulemaking is more stringent than the recommendations of the 2016 O&G CTG, the more stringent requirement is 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.

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, based on analysis of data available to the Department during the development of the proposed rulemaking as well as additional and updated data available during this final-form rulemaking development phase, the Department determined in three cases that RACT requirements more stringent than the recommendations in the 2016 O&G CTG are cost-effective and necessary to continue the Commonwealth's progress in attaining and maintaining the ground-level ozone NAAQS.

In the first case, the Department established in proposed § 129.123(a)(1)(i)—(vi) (relating to storage vessels) a tiered emissions threshold based on the potential to emit for affected owners or operators of subject storage vessels to prevent backsliding on the amount of controlled emissions for storage vessels subject to the Department's Air Quality Permit Exemptions 38(b) or 38(c). The tiered emission threshold established in proposed § 129.123(a)(1)(i) and (ii) was the potential to emit 6.0 tons per year (TPY) or greater VOC emissions for a storage vessel installed at a conventional well site or at an unconventional well site before August 10, 2013. The tiered emission threshold established in proposed § 129.123(a)(1)(iii)—(vi) was the potential to emit 2.7 TPY or greater VOC emissions for a storage vessel installed at an unconventional well site on or after August 10, 2013, a storage vessel installed at a gathering and boosting station, a storage vessel installed at a natural gas processing plant and a storage vessel installed at a facility in the natural gas transmission and storage segment.

However, during the development of this final-form rulemaking, the Department performed additional analysis which shows that the 2.7 TPY VOC emission threshold for storage vessels is RACT as it is technically and economically feasible for both potential to emit and actual emissions from all covered storage vessels. The analysis examined the sensitivity to the initial capital cost of the control device and found that the total cost per ton of VOC reduced is below the RACT benchmark of $6,600 per ton reduced. Therefore, a single 2.7 TPY VOC emission threshold is established in § 129.123(a)(1) in this final-form rulemaking that applies to affected owners or operators of storage vessels at unconventional well sites, gathering and boosting stations and natural gas processing plants, and in the natural gas transmission and storage segment. The tiered emissions thresholds, including requirements for storage vessels at conventional well sites, in proposed § 129.123(a)(1)(i)—(vi) are deleted in this final-form rulemaking.

In the second case, the proposed rulemaking included an exemption in § 129.126(d) for the owner or operator of a reciprocating compressor or a centrifugal compressor located at an unconventional well site or located at an adjacent well site and servicing more than one well site. However, the Department's additional analysis, further detailed in the Regulatory Analysis Form (RAF), for this final-form rulemaking shows that it is both technically and economically feasible to require reciprocating compressor rod packing replacements every 26,000 hours of operation or every 3 years for reciprocating compressors located at unconventional well sites. The analysis showed that the cost-effectiveness of the rod packing replacement is highly sensitive to the emissions factor used to represent emissions from reciprocating compressors. Using the average of several emission factors from the University of Texas at Austin's Emission Factor Improvement Study, the cost per ton of VOC reduced is approximately $6,600 which is consistent with the RACT benchmark. See Harrison, M., Galloway, K., Hendler, A., Shires, T., Allen, D., Foss, M., Thomas, J., Spinhirne, J., Natural Gas Industry Methane Emission Factor Improvement Study Final Report Cooperative Agreement No. XA-83376101, Dec. 2011 at https://dept.ceer.utexas.edu/ceer/GHG/files/FReports/XA_83376101_Final_Report.pdf. Therefore, the exemption in proposed § 129.126(d) for reciprocating compressors is deleted in this final-form rulemaking, meaning this final-form rulemaking requires affected owners or operators to implement reciprocating compressor rod packing replacements on reciprocating compressors located at well sites. This is a new requirement that was not included in the proposed rulemaking and was not one of the recommendations in the 2016 O&G CTG.

In the third case, the Department established a requirement in proposed § 129.127(b)(1)(ii)(A) and (B) (relating to fugitive emissions components) that affected owners or operators shall conduct monthly audible, visual, and olfactory (AVO) inspections and quarterly instrument-based leak detection and repair (LDAR) inspections of fugitive emissions components for well sites with at least one well that produces, on average, 15 barrels of oil equivalent (BOE) per day. In proposed § 129.127(b)(2), the Department also established a stepdown provision which enabled affected owners or operators to track the percentage of leaking components at each inspection and if, in two consecutive quarterly inspections, less than 2% of components were leaking emissions, the owner or operator could reduce the quarterly schedule of instrument-based LDAR inspections to semiannual.

This final-form rulemaking deletes the stepdown provisions of proposed § 129.127(b)(2)(i) and (ii). The Department's additional analysis shows that it is both technically and economically feasible for an affected owner or operator to implement instrument-based LDAR inspections at an unconventional well site with an average production of 15 BOE or more per day, with the frequency of inspections based on the production from each individual well at the well site. The owner or operator of an unconventional well site with an average production of 15 BOE or more per day and with at least one individual well producing 15 BOE or more per day, on average, shall conduct quarterly instrument-based LDAR inspections. The owner or operator of an unconventional well site with an average of 15 BOE or more per day and at least one individual well producing 5 BOE or more but less than 15 BOE per day, on average, shall conduct annual instrument-based LDAR inspections. In this final-form rulemaking, the Department also included an option for the owner or operator of an unconventional well site producing, on average, equal to or greater than 15 BOE per day, and at least one well producing, on average, equal to or greater than 5 BOE per day but less than 15 BOE, per day to submit to the Department a request for an exemption from the annual instrument-based LDAR requirement. However, the request must include, among other information, a demonstration that the annual LDAR requirement is not RACT (technically or economically feasible) for the well site. If approved, this exemption request will be submitted to the EPA as a revision to the Commonwealth's SIP.

In addition to the technically and economically feasible RACT requirements detailed previously, the Commonwealth is responsible for ensuring that the 2015 8-hour ozone NAAQS is attained and maintained by implementing permanent and Federally enforceable control measures. This final-form rulemaking is a primary component of the Commonwealth's strategy of ensuring that the ozone NAAQS are attained and maintained across this Commonwealth. Reductions in VOC emissions, that are achieved following the adoption and implementation of RACT VOC emission control measures for the select unconventional oil and natural gas source categories covered by this final-form rulemaking, will assist the Commonwealth in making substantial progress in achieving and maintaining the ozone NAAQS. To the extent that a requirement in this final-form rulemaking is more stringent than the recommendations of the 2016 O&G CTG, the more stringent requirement is 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.

VOC and methane emission reduction benefits

The Department estimates that in 2020, sources installed at unconventional well sites, gathering and boosting stations and natural gas processing plants emitted an estimated 5,648 TPY VOC and that implementation of the control measures in this final-form rulemaking could reduce VOC emissions by as much as 2,864 TPY. These VOC emission reductions will contribute to reductions in the formation of ground-level ozone and to achieving and maintaining the ozone NAAQS.

While this final-form rulemaking requires VOC emission reductions, methane emissions are also reduced as a cobenefit, because both VOC and methane are emitted from oil and gas operations. 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. The Department estimates that unconventional well sites, gathering and boosting stations and natural gas processing plants emitted 102,297 TPY methane in 2020, and that the cobenefit methane emissions reduction from this final-form rulemaking may be as much as 45,278 TPY.

Furthermore, the technically and economically feasible RACT determinations in this final-form rulemaking for storage vessels, reciprocating compressors at unconventional well sites and fugitive emissions components result in a greater reduction of VOC emissions than implementing the EPA's RACT recommendations from the 2016 O&G CTG resulting in an additional 411 TPY of VOC and 6,124 TPY of methane emissions reductions.

This final-form 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. The strategy also states that the Commonwealth will reduce emissions by requiring LDAR inspections and more frequent use of leak-sensing technologies. This final-form rulemaking fulfills those parts of the strategy.

Applicability of this final-form rulemaking

This final-form rulemaking will apply Statewide to owners or operators of one or more of the following unconventional oil and natural gas sources of VOC emissions which were constructed on or before the effective date of this final-form rulemaking: natural gas-driven continuous bleed pneumatic controllers, natural gas-driven diaphragm pumps, centrifugal compressors, reciprocating compressors, fugitive emission components and storage vessels installed at unconventional well sites, gathering and boosting stations and natural gas processing plants, as well as storage vessels in the natural gas transmission and storage segment.

The Department identified 577 owners or operators of approximately 3,889 facilities in this Commonwealth that may be affected by this final-form rulemaking. Approximately 306 of the 577 owners or operators may meet the definition of small business as defined in section 3 of the Regulatory Review Act (RRA) (71 P.S. § 745.3). Based on information supplied by commentators, the Oil and Gas Production Report and the Department's Air Information Management System (AIMS) database, the Department estimates there are 3,388 unconventional well sites, 486 gathering and boosting stations, 15 processing plants and 120 transmission stations. The Department estimates that these owners or operators have at least 44 storage vessels at 12 facilities, 8,572 pneumatic controllers at 3,874 facilities and 40 pneumatic pumps at 17 facilities that will be subject to requirements under this final-form rulemaking. The owners or operators of approximately 2,616 of 3,388 unconventional well sites will be required to implement instrument-based LDAR inspections or increase the current instrument-based LDAR inspection frequency under this final-form rulemaking. The owners or operators of approximately 264 of 486 gathering and boosting stations and 1 of 15 processing plants will be required to implement a new instrument-based LDAR inspection program or will be subject to new requirements under this final-form rulemaking.

The Department estimates that the total unconventional industry-wide cost of complying with this final-form rulemaking will be about $21.9 million per year. However, implementation of the control measures will also potentially save owners or operators in the unconventional oil and natural gas industry about $4.6 million per year due to a lower natural gas loss rate during production. This cost estimate consists of two major categories of data. The first is the annual cost to implement the RACT requirements for each affected source or affected facility as provided by the EPA in the 2016 O&G CTG and from the Department's own additional analysis. The second is the number of potentially affected facilities, which was obtained from several data sources including the Department's Oil and Gas Production Report, Environmental Facility Application Compliance Tracking System (eFACTS) database and AIMS. For the owners or operators of unconventional well sites, gathering and boosting stations and natural gas processing plants the anticipated annual cost to comply with the requirements will be based on the type of sources present at the site, the requirements that apply to those sources, and the type of control used to comply.

Most of the anticipated costs are due to new regulatory requirements but many of the costs associated with this final-form rulemaking are from common sense practices and controls, some of which owners or operators may already be implementing due to regulatory requirements or voluntary emission reduction programs. An example includes periodic AVO inspections which can prevent natural gas 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 final-form rulemaking. The Department estimates a majority of small business stationary sources will be below the applicability thresholds. However, affected small businesses may incur some cost as a result of this final-form rulemaking; net costs of approximately $6,370 per facility or, on average, $30,053 per owner or operator. Overall, the Department does not anticipate that this final-form rulemaking will result in any significant adverse impact on small businesses.

Public outreach

The Department consulted with the Air Quality Technical Advisory Committee (AQTAC) and the Small Business Compliance Advisory Committee (SBCAC) in the development of the 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. The proposed rulemaking was presented for a vote to AQTAC on April 11, 2019, and SBCAC on April 17, 2019. Both committees concurred with the Department's recommendation to move the 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 the proposed rulemaking on May 7, 2019. On June 18, 2019, the full CAC concurred with the Department's recommendation to move the proposed rulemaking forward to the Board for consideration.

The Department also met with industry and environmental stakeholders to receive additional input on the proposed rulemaking. On January 24, 2019, the Department updated the Pennsylvania Grade Crude Development Advisory Council on the status of the proposed rulemaking. On March 21, 2019, the Department provided an informational presentation to the Oil and Gas Technical Advisory Board. On July 8, 2019, the Department met with industry stakeholders, including representatives from the Marcellus Shale Coalition, Penn Energy, Southwestern Energy, Range Resources and Chesapeake Energy. On August 27, 2019, the Department met with environmental stakeholders, including representatives from PennFuture, Environmental Defense Fund and the Clean Air Council.

This final-form rulemaking was presented to AQTAC on December 9, 2021, the CAC Policy and Regulatory Oversight Committee on January 12, 2022, and the full CAC on January 18, 2022, and SBCAC on January 27, 2022.

E. *Summary of Final-Form Rulemaking and Changes from Proposed to Final-Form Rulemaking*

§ 121.1. Definitions

This section contains definitions relating to the air quality regulations. This final-form rulemaking amends the terms "CPMS—continuous parameter monitoring system," "fugitive emissions" and "responsible official," and adds the abbreviation "ppm" to support the final-form amendments to Chapter 129.

There are no changes made to this section from the proposed rulemaking to this final-form rulemaking.

§ 129.121. General provisions and applicability

Subsection (a) establishes that this final-form rulemaking will apply Statewide to the owner or operator of the following: natural gas-driven continuous bleed pneumatic controllers, natural gas-driven diaphragm pumps, reciprocating compressors, centrifugal compressors, fugitive emissions components and storage vessels installed at unconventional well sites, gathering and boosting stations and natural gas processing plants, as well as storage vessels in the natural gas transmission and storage segment.

Subsection (a) is amended in this final-form rulemaking to replace "in existence" with "constructed" to clarify that the existing sources applicable under this final-form rulemaking are those that are constructed on or before the date of final publication. Subsection (a) is also amended in this final-form rulemaking to add "installed at an unconventional well site, a gathering and boosting station or a natural gas processing plant" to clarify that this final-form rulemaking is only applicable to unconventional sources in the oil and natural gas industry. Subsection (a)(1) is amended in this final-form rulemaking to clarify the requirements for storage vessels by removing "in all segments except natural gas distribution" and replacing it with "at an unconventional well site, a gathering and boosting station, a natural gas processing plant and in the natural gas transmission and storage segment." Subsection (a)(2) is amended in this final-form rulemaking to add "continuous bleed" to clarify that the natural gas-driven pneumatic controllers applicable under this final-form rulemaking as a source of VOC emissions are continuous bleed.

Subsection (b) provides that compliance with the requirements of this final-form rulemaking 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) except to the extent the operating permit contains more stringent requirements.

There is no change made to subsection (b) from the proposed rulemaking to this final-form rulemaking.

§ 129.122. Definitions, acronyms and EPA methods

Section 129.122 adds definitions, acronyms and EPA methods applicable to this final-form rulemaking.

Subsection (a) is amended in this final-form rulemaking to make clarifying edits to the following terms: "bleed rate," "connector," "first attempt at repair," "flare," "flow line," "fugitive emissions component," "in-house engineer," "leak," "natural gas-driven continuous bleed pneumatic controller," "natural gas processing plant," "natural gas transmission and storage segment," "TOC-total organic compounds," "VRU-vapor recovery unit" and "well site."

Subsection (a) is also amended in this final-form rulemaking to delete the following unnecessary terms: "completion combustion device," "compressor station," "continuous bleed," "fuel gas," "fuel gas system," "natural gas and oil production segment," "natural gas processing segment," "transmission compression station" and "underground storage vessel."

Subsection (a) is further amended in this final-form rulemaking to add the following terms: "UIC," "UIC class I oilfield disposal well," "UIC class II oilfield disposal well," "unconventional formation," "unconventional well" and "unconventional well site."

Subsection (b) lists the EPA methods referenced in this final-form rulemaking. There is no change made to subsection (b) from the proposed rulemaking to this final-form rulemaking.

§ 129.123. Storage vessels

Subsection (a)(1) establishes the applicability threshold for the owner or operator of a storage vessel based on potential VOC emissions.

Subsection (a)(1) is amended in this final-form rulemaking to remove the various potential to emit amounts and installation dates included in the proposed rulemaking and to instead have this final-form rulemaking apply to owners or operators of storage vessels that have the potential to emit 2.7 TPY or greater VOC emissions. 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)(2) establishes the methodology required for calculating the potential VOC emissions of a storage vessel. Subsection (a)(2)(i) is amended in this final-form rulemaking to add that the maximum average daily throughput is as defined in § 129.122 and to extend the calculation requirement from the date of publication to 60 days after. Subsection (a)(2)(ii) is amended in this final-form rulemaking to replace "must" with "may" to be consistent with the stringency in the 2016 O&G CTG.

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, the cover and closed vent systems must meet the requirements in § 129.128 (relating to covers and closed vent systems).

There is no change made to subsection (b) from the proposed rulemaking to this final-form rulemaking.

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

Subsection (c)(1) is amended in this final-form rulemaking to remove subparagraph (i) which had provided an exception for storage vessels with 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. Clarifying edits were also made to the exception in subparagraph (ii) due to the removal of subparagraph (i) and to have the actual VOC emissions determined on a 12-month rolling sum instead of basis.

Subsection (c)(2)(i) is amended in this final-form rulemaking to require the calculation of actual VOC emissions once per calendar month instead of monthly beginning on or before 30 days after final publication. The monthly calculations must also be separated by at least 15 calendar days, but not more than 45 calendar days, instead of 30 calendar days and be based on the monthly average throughput instead of the maximum daily throughput. Subparagraph (ii) is also amended to require compliance with subsection (b) within 1 year of the date of the monthly calculation instead of 30 calendar days and to remove language that is no longer needed. Additionally, subparagraph (iii) is deleted in this final-form rulemaking.

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

There is no change made to subsection (d) from the proposed rulemaking to this final-form rulemaking.

Subsection (e) lists the requirements for removing a storage vessel from service. There is no change made to subsection (e) from the proposed rulemaking to this final-form rulemaking.

Subsection (f) lists the requirements for a storage vessel returned to service. There is no change made to subsection (f) from the proposed rulemaking to this final-form rulemaking.

Subsection (g) references the recordkeeping and reporting requirements under § 129.130(b) (relating to recordkeeping and reporting) and § 129.130(k) for owners or operators of storage vessels subject to this section. Subsection (g) is amended in this final-form rulemaking to correct a cross-reference.

§ 129.124. Natural gas-driven continuous bleed 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.

This section is amended in this final-form rulemaking to add "continuous bleed" to all references to natural gas-driven pneumatic controllers as the Board further clarified under § 129.121 that this final-form rulemaking applies to natural gas-driven continuous bleed pneumatic controllers. Subsection (c) is also amended to clarify that only natural gas-driven continuous bleed pneumatic controllers with a natural gas bleed rate greater than 6.0 standard cubic feet per hour, at a location other than a natural gas processing plant, are required to maintain a natural gas bleed rate of less than or equal to 6.0 standard cubic feet per hour. Additionally, the Board made a revision to clarify that all natural gas-driven continuous bleed pneumatic controllers are required to maintain a natural gas bleed rate of zero standard cubic feet per hour, if they are located at a natural gas processing plant. These changes were made to ensure that the requirement is consistent with the Federal new source performance standards (NSPS) requirements. Subsections (d) and (e) are amended to clarify that the tagging and recordkeeping and reporting requirements are only for natural gas-driven continuous bleed pneumatic controllers affected under subsection (c). Subsection (e) is amended in this final-form rulemaking to correct a cross-reference.

§ 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. There is no change made to subsection (a) from the proposed rulemaking to this final-form rulemaking.

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 an unconventional 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 (b) is amended in this final-form rulemaking to remove the phrase "reduce the VOC emissions by 95.0% by weight or greater. The owner or operator shall" from subsection (b) and add it to subsection (b)(1). Subsection (b)(1) is amended in this final-form rulemaking to add "unconventional" before "well site."

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 (c) is amended in this final-form rulemaking to correct references, to make a few slight formatting changes and to renumber due to those changes.

Subsection (d) provides for a categorical exemption for 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, 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.

There are no changes made to subsections (d) and (e) from the proposed rulemaking to this final-form rulemaking.

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.

Subsection (f) is amended in this final-form rulemaking to correct a cross-reference.

§ 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.

There is no change made to subsection (a) from the proposed rulemaking to this final-form rulemaking.

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 (b) is amended in this final-form rulemaking to delete "except as specified in subsection (d)" from subsection (b) and to add further clarifying language to paragraph (2).

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 (c) is amended in this final-form rulemaking to remove a "relating to" reference that is no longer needed.

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

Subsection (d) is amended in this final-form rulemaking to remove the categorical exemption from the emissions limitation and control requirements of subsection (b) and to only allow the categorical exemption from the emissions limitation and control requirements of subsection (c) to apply to the owner or operator of a centrifugal compressor. In this final-form rulemaking, the owner or operator of a reciprocating compressor is no longer applicable under the exemption.

Subsection (e) references the recordkeeping and reporting requirements listed under § 129.130(e) and (k)(3)(iv) for owners or operators of reciprocating compressors and under § 129.130(f) and (k)(3)(v) for owners or operators of centrifugal compressors.

Subsection (e) is amended in this final-form rulemaking to correct two cross-references.

§ 129.127. Fugitive emissions components

This section is renumbered in this final-form rulemaking due to the Board's addition of the average production calculation procedure for a well site in subsection (b).

Subsection (a) establishes the applicability for the owner or operator of a fugitive emissions component based on the component's location.

Subsection (a) is amended in this final-form rulemaking to delete "A" and add "an unconventional" before "well site" in subsection (a)(1). Subsection (a)(1) is also amended to remove the phrase "with a well that produces, on average, greater than 15 barrels of oil equivalent per day."

Subsection (b) is added to this final-form rulemaking and establishes the average production calculation procedure for a well site.

Subsection (c), formerly subsection (b) in the proposed rulemaking, establishes the compliance requirements for unconventional well sites based on the gas to oil ratio (GOR) of the well and the production of the well site and the individual wells on the well site.

Subsection (c) is amended in this final-form rulemaking to renumber due to formatting changes, remove "a producing" from "requirements for a producing well site," add "an unconventional" before "well site" and remove "the owner or operator of a producing well site shall perform the following." The Board also removes "determine the GOR of the well using generally accepted methods" and replaces it with "for a well site consisting of only oil wells, the owner or operator shall" in paragraph (1). The Board adds new language to paragraph (1)(i) and adds "of the oil well site" and removes "the owner or operator shall" in paragraph (1)(ii). The Board also adds "of the oil well site," removes "the owner or operator shall perform the following:" and adds "meet the requirements of paragraph (2) or paragraph (3) based on the results of subsection (b)(1)" in paragraph (1)(iii). The Board adds new language in paragraph (2). The Board adds the word "initial" before AVO inspection and removes "within 60 days after" and replaces it with "on or before" 60 days after final publication in paragraph (2)(i). The Board also adds "thereafter" to indicate that the monthly inspections occur after the initial AVO inspections and extended the time period between the monthly inspections from 30 calendar days to 45 calendar days in paragraph (2)(i). Additionally, the Board adds the word "initial" before LDAR inspection and removed "within 60 days after" and replaces it with "on or before" 60 days after final publication in paragraph (2)(ii). The Board also adds "thereafter" to indicate that the quarterly inspections occur after the initial LDAR inspections and extended the time period between the quarterly inspections from 90 calendar days to 120 calendar days in paragraph (2)(ii).

Under subsection (c)(3), the Board also adds new AVO and LDAR inspection requirements for a well site producing, on average, equal to or greater than 15 barrels of oil equivalent per day, with at least one well producing, on average, equal to or greater than 5 barrels of oil equivalent per day but less than 15 barrels of oil equivalent per day.

Under subsection (c)(4), subsection (c)(2) in the proposed rulemaking, the Board removes "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;" adds "of a producing well site shall calculate the average production of the well site under subsection (b) for the previous calendar year not later than February 15 and;" adds the word "required" before LDAR inspection; and removes "required under paragraph (1)(ii)(B)."

Under subsection (c)(4)(i), the Board also removes "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" and replaces it with "if two consecutive calculations show reduced production, the owner or operator may adopt the requirements applicable to the reduced production level."

Under subsection (c)(4)(ii), the Board also removes "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)" and replaces it with "if a calculation shows higher production, the owner or operator shall adopt the requirements applicable to the higher production level immediately."

Additionally, the Board adds subsection (c)(5) to this final-form rulemaking to include an option for the owner or operator of a well site producing, on average, equal to or greater than 15 BOE per day, with at least one well producing, on average, equal to or greater than 5 BOE per day but less than 15 BOE per day to request an exemption from the new LDAR inspection requirements of paragraph (3)(ii). Subsection (c)(5) outlines the process and requirements for submitting a written request for an exemption. The Department will submit each exemption determination to the Administrator of the EPA for approval as a revision to the SIP and the owner or operator shall bear the costs of public hearings and notifications, including newspaper notices, required for the SIP submittal. In accordance with section 7.5(b) of the APCA (35 P.S. § 4007.5(b)), the Department will also provide public notice of each SIP revision in the *Pennsylvania Bulletin*.

Subsection (d) establishes the LDAR inspection requirements for shut-in unconventional well sites.

Subsection (d), formerly subsection (c) in the proposed rulemaking, is amended in this final-form rulemaking to add the word "unconventional" before "well" and the word "site" after "well" to clarify that the LDAR inspection requirements are for the unconventional well site as a whole and not an individual well. The Board also adds "after the unconventional well site is put into production" in paragraph (2).

Subsection (e), formerly subsection (d) in the proposed rulemaking, 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) is amended in this final-form rulemaking to add the word "initial" before AVO inspection and remove "within 30 days after" and replace it with "on or before" 60 days after final publication in paragraph (1). The Board also adds "thereafter" to indicate that the monthly inspections occur after the initial AVO inspections and extended the time period between the monthly inspections from 30 calendar days to 45 calendar days in paragraph (1). Additionally, the Board adds the word "initial" before LDAR inspection and removed "within 60 days after" and replaced it with "on or before" 60 days after final publication in paragraph (2). The Board also adds "thereafter" to indicate that the quarterly inspections occur after the initial LDAR inspections and extended the time period between the quarterly inspections from 90 calendar days to 120 calendar days in paragraph (2).

Subsection (f), formerly subsection (e) in the proposed rulemaking, provides an option for owners or operators to request an extension of the LDAR inspection interval. There is no change made to subsection (f) from the proposed rulemaking to this final-form rulemaking.

Subsection (g), formerly subsection (f) in the proposed rulemaking, establishes the requirement for owners or operators to develop and maintain a written fugitive emissions monitoring plan. Subsection (g) is amended in this final-form rulemaking to correct cross references in paragraph (6)(i)—(iii). The Board also increases the one survey per year requirement from no more than 12 months apart to no more than 13 months apart in paragraph (10)(iii).

Subsection (h), formerly subsection (g) in the proposed rulemaking, establishes the verification procedures for optical gas imaging (OGI) equipment identified in the fugitive emissions monitoring plan. Subsection (h) is amended in this final-form rulemaking to correct a cross reference. The Board also removes the word "daily" and adds "each day prior to use" in paragraph (2). Additionally, the Board removes "that determines how the equipment operator will perform the" and adds "by using the" and "procedures" in paragraph (5). The Board also made grammatical corrections in paragraph (5)(i)—(iii).

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

Subsection (i) is amended in this final-form rulemaking to correct a cross reference.

Subsection (j), formerly subsection (i) in the proposed rulemaking, 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. There is no change made to subsection (j) from the proposed rulemaking to this final-form rulemaking.

Subsection (k), formerly subsection (j) in the proposed rulemaking, establishes that the owner or operator may opt to perform the no detectable emissions procedure of section 8.3.2 of EPA Method 21. There is no change made to subsection (k) from the proposed rulemaking to this final-form rulemaking.

Subsection (l), formerly subsection (k) in the proposed rulemaking, 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 final-form rulemaking are in line with the LDAR inspection requirements listed in General Plan Approval and/or General Operating Permit for Natural Gas Compressor Stations, Processing Plants, and Transmission Stations (GP-5) the General Plan Approval and/or General Operating Permit for Unconventional Natural Gas Well Site Operations and Remote Pigging Stations (GP-5A) and Exemption 38 of the Air Quality Permit Exemptions list. The EPA recognized the Commonwealth's LDAR inspection requirements in GP-5A and GP-5 as an alternative means of emission limitation (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 final-form 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) is amended in this final-form rulemaking to remove "there are no detectable emissions consistent with section 8.3.2 of EPA method 21" and replace it with "there is no visible leak image when using OGI equipment calibrated according to subsection (h)" in paragraph (4)(i). The Board also corrects a cross reference in paragraph (4)(ii). Additionally, the Board removes "there is no visible leak image when using OGI equipment calibratedaccording to subsection (g)" and replaces it with "there are no detectable emissions consistent with section 8.3.2 of EPA method 21" in paragraph (4)(iii).

Subsection (m), formerly subsection (l) in the proposed rulemaking, references the recordkeeping and reporting requirements for owners or operators of fugitive emissions components listed under § 129.130(g) and (k)(3)(vi). Subsection (m) is amended in this final-form rulemaking to correct a cross-reference.

§ 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 (a) is amended in this final-form rulemaking to add the word "initial" before AVO inspection and to remove "within 30 days after" and replace it with "on or before" 60 days after final publication to extend the time period to conduct the initial AVO inspection in paragraph (4). The Board also adds "thereafter" to indicate that the monthly inspections occur after the initial AVO inspections and extended the time period between the monthly inspections from 30 calendar days to 45 calendar days in paragraph (4). Additionally, the Board corrects cross references in paragraphs (6) and (7).

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 (b) is amended in this final-form rulemaking to add the word "initial" before AVO inspection and to remove "within 30 days after" and replace it with "on or before" 60 days after final publication to extend the time period to conduct the initial AVO inspection in paragraph (2)(i). The Board adds "thereafter" to indicate that the monthly inspections occur after the initial AVO inspections and extended the time period between the monthly inspections from 30 calendar days to 45 calendar days in paragraph (2)(i). The Board removes "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" and replaces it with "during the facility's scheduled LDAR inspection in accordance with § 129.127(c)(2)(ii), (c)(3)(ii) or (e)(2)" in paragraph (2)(ii). The Board removes "within 30 days after" and replaces it with "on or before" 60 days after final publication to extend the time period to verify the valve is maintained and extended the time period between the monthly inspections from 30 calendar days to 45 calendar days in paragraph (4)(ii)(B).

Additionally, the Board also corrects a cross reference in subsection (b) and paragraphs (3) and (6).

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. There is no change made to subsection (c) from the proposed to this final-form rulemaking.

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.

Subsection (d) is amended in this final-form rulemaking to remove "test procedure under Section 8.3.2 of EPA Method 21" and replace it with "inspection required under subsection (b)(2)(ii) by performing one of the following." The Board also removes "the owner or operator shall perform the following:" and replaces it with "use OGI equipment that meets § 129.127(h)" in paragraph (1). The Board also corrects a cross reference and adds "the owner or operator may adjust the gas leak detection instrument readings as specified in § 129.127(k)" to paragraph (2), which was previously paragraph (1)(i) in the proposed rulemaking. The Board also adds paragraph (3) which states "use another leak detection method approved by the department." Additionally, paragraph (1)(ii) in the proposed rulemaking is now paragraph (4) in this final-form rulemaking. The Board also removes the language that was in paragraph (2) in the proposed rulemaking.

§ 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)(3)(ix). Subsection (a)(1)(ii) is amended in this final-form rulemaking to correct a cross-reference.

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 (b) is amended in this final-form rulemaking to lengthen the calendar days allowed between monthly inspections of control devices in paragraph (2) from 30 calendar days in the proposed rulemaking to 45 calendar days in this final-form rulemaking. The Board also amends paragraph (4)(i) to lengthen the calendar days allowed between monthly visible emissions tests from 30 calendar days in the proposed rulemaking to 45 calendar days in this final-form rulemaking. Additionally, the Board amends paragraph (5)(ii) to remove the language "outlined in the control device inspection and maintenance plan of paragraph (1)" and replace it with "applicable to the control device if the manufacturer's repair instructions are not available."

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 (c) is amended in this final-form rulemaking to add "to demonstrate that the mass content of VOC in the gases vented to the device is reduced by 95.0% by weight or greater" to paragraph (c)(1)(ii).

Subsection (d) lists the compliance requirements for an enclosed combustion device. There is no change made to subsection (d) from the proposed rulemaking to this final-form rulemaking.

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). There is no change made to subsection (e) from the proposed rulemaking to this final-form rulemaking.

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

Subsection (f) is amended in this final-form rulemaking to remove "or authorization by the Department's Bureau of Waste Management" and replace it with "under 40 CFR Part 270 (relating to EPA administered permit programs: the hazardous waste permit program) that implements the requirements of 40 CFR Part 264, Subpart X (relating to miscellaneous units)" in paragraph (4)(i)(A). The Board also removes "or authorization by the Department's Bureau of Waste Management" and replaces it with "under 40 CFR Part 270 that implements the requirements of 40 CFR Part 266, Subpart H (relating to hazardous waste burned in boilers and industrial furnaces)" in paragraph (4)(ii)(B). Additionally, the Board removes an unnecessary cross-reference from paragraph (4)(ii)(C).

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

Subsection (g) is amended in this final-form rulemaking to change the number of calendar days in paragraph (1)(i)(A) from 30 calendar days to 45 calendar days, and in paragraph (1)(i)(B) and (C) from 90 calendar days to 120 calendar days.

Subsection (h) lists specific compliance requirements for a non-regenerative carbon adsorption system. There is no change made to subsection (h) from the proposed rulemaking to this final-form rulemaking.

Subsection (i) lists the compliance requirements for condensers and other non-destructive control devices. There is no change made to subsection (i) from the proposed rulemaking to this final-form rulemaking.

Subsection (j) identifies the general performance test requirements.

Subsection (j) is amended in this final-form rulemaking to renumber due to formatting changes. Subsection (j) is also amended in this final-form rulemaking to remove "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" and replace it with "the owner or operator shall do the following, as applicable" under paragraph (1). The Board also adds new performance test requirements under paragraph (1)(i)—(iii).

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). There is no change made to subsection (k) from the proposed rulemaking to this final-form rulemaking.

Subsection (l) identifies the performance test method for demonstrating compliance with the outlet concentration requirements referenced in subsections (d), (f) and (i). There is no change made to subsection (l) from the proposed rulemaking to this final-form rulemaking.

Subsection (m) lists the continuous parameter monitoring system requirements (CPMS) for control devices that are required to install CPMS. There is no change made to subsection (m) from the proposed rulemaking to this final-form rulemaking.

§ 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. There is no change made to subsection (a) from the proposed rulemaking to this final-form rulemaking.

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

Subsection (b) is amended in this final-form rulemaking to remove "the applicable VOC emission threshold on" and replace it with "2.7 TPY determined as," as well as remove "basis" and replace it with "sum" in paragraph (6)(iii). The Board also corrects a cross reference in paragraph (7).

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

Subsection (c) is amended in this final-form rulemaking to add "continuous bleed" to all references to natural gas-driven pneumatic controllers as the Board further clarified under § 129.121 that this final-form rulemaking applies to natural gas-driven continuous bleed pneumatic controllers. The Board also amends subsection (c) to add "required compliance" before "date" in paragraph (1). The Board also clarifies that the recordkeeping requirements apply to natural gas-driven continuous bleed pneumatic controllers under § 129.124(c).

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

Subsection (d) is amended in this final-form rulemaking to add "required compliance" before "date" in paragraph (1) and to correct cross references in paragraph (7).

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

Subsection (e) is amended in this final-form rulemaking to add "control device or a" to paragraph (3)(i) to further clarify where the emissions from the rod packing are being routed.

Subsection (f) establishes the specific recordkeeping requirements for centrifugal compressors. There is no change made to subsection (f) from the proposed rulemaking to this final-form rulemaking.

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

Subsection (g) is amended in this final-form rulemaking to correct cross references and make minor edits in paragraphs (1) and (3). The Board also adds a new paragraph (2) which states "for each well site, the average production calculations required under § 129.127(b)(1) and § 129.127(c)(4)." Additionally, the Board deletes the following language "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" from what was paragraph (3) in the proposed rulemaking.

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

Subsection (h) is amended in this final-form rulemaking to make a minor grammar edit.

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

Subsection (i) is amended in this final-form rulemaking to correct a cross reference in paragraph (2).

Subsection (j) establishes the specific recordkeeping requirements for control devices. Subsection (j) is amended in this final-form rulemaking to add "that owns or operates the control device" after the name of the company in paragraph (5)(iv)(A), as well as "and affiliation" in paragraph (5)(iv)(C).

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 final-form rulemaking and subsequent annual reports, including an option to extend the due date of the initial report.

Subsection (k) is amended in this final-form rulemaking to make a few clarifying edits, renumber due to formatting changes and to add "continuous bleed" to the term natural gas-driven continuous bleed pneumatic controllers. Subsection (k)(1) is also amended to require the owner or operator of a source subject to § 129.121(a) to submit a report to the Air Program Manager of the appropriate Department Regional Office annually on or before June 1. The Board also adds language to subsection (k)(1) providing for the reports to be submitted in a manner prescribed by the Department and to submit the information specified in subparagraphs (i)—(ix) for each report as applicable.

F. *Summary of Comments and Responses on the Proposed Rulemaking*

The Board adopted the proposed rulemaking at its meeting on December 17, 2019. On May 23, 2020, the proposed rulemaking was published for a 66-day comment period at 50 Pa.B. 2633 (May 23, 2020). Three public hearings were held virtually on June 23, 24 and 25, 2020. Over 100 individuals provided verbal testimony. The comment period closed on July 27, 2020. The Board received over 4,500 comments, including comments from the House and Senate Environmental Resources and Energy Committees (ERE Committees), members of the General Assembly and the Independent Regulatory Review Commission (IRRC). The majority of the commentators expressed their support of the VOC RACT requirements, noting the need to address air emissions from the oil and gas sector. The comments received on the proposed rulemaking are summarized in this section and are addressed in a comment and response document which is available on the Department's web site.

IRRC states that section 2 of the RRA (71 P.S. § 745.2) explains why the General Assembly felt it was necessary to establish a regulatory review process. IRRC also notes that section 2(a) of the RRA states, "[t]o the greatest extent possible, this act is intended to encourage the resolution of objections to a regulation and the reaching of a consensus among the commission, the standing committees, interested parties and the agency." The vast majority of public comments are from individuals and environmental advocacy organizations in support of the proposed rulemaking, but still urging the Department to adopt more restrictive requirements in this final-form rulemaking. Numerous comments were also from parties representing the oil and gas industries who believe that the regulatory mandates for existing sources should not be more stringent than requirements for new or modified sources or the EPA's 2016 O&G CTG. Since the issues raised by the commentators are often in direct conflict with each other, IRRC recommends that the Board continue to actively seek input from all interested parties, including lawmakers, as it develops the final version of this rulemaking.

In response, the Board and the Department have and will continue to actively seek input from all interested parties, including lawmakers. In addition to the review outlined under the RRA, members of the General Assembly, particularly the House and Senate ERE Committees, have extensive involvement in the development of the Department's rulemakings through members appointed to the Department's advisory committees and four seats on the Board. The Board and the Department consistently seek opportunities to engage productively with interested parties, including the Legislature. The Department's Legislative Office works to address issues and ensure that the Legislature is informed of actions by the Department and the Board. Additionally, members of the public have several opportunities to provide input on the Department's rulemakings. This includes the formal proposed rulemaking public comment and hearing process, as well as opportunities to provide informal public comment at the Department's advisory committee meetings during both the proposed and final stages of development of a rulemaking.

1. This final-form rulemaking satisfies the criteria under the Regulatory Review Act.

a. *This final-form rulemaking is supported by acceptable data.*

IRRC states that section 28 of the RAF relates to the regulatory review criterion of whether the regulation is supported by acceptable data. If data is the basis for a regulation, this section of the RAF asks for a description of the data, how the data was obtained, and how it meets the acceptability standard for empirical, replicable and testable data that is supported by documentation, statistics, reports, studies or research. IRRC notes that the Board states that the basis for the proposed rulemaking is the Federally mandated RACT requirements found in the 2016 O&G CTG. Commentators representing the oil and gas industry assert that the 2016 O&G CTG requirements are similar to performance standards developed for "new" or "modified" sources and question the appropriateness of applying these standards to existing sources such as conventional oil and gas wells. IRRC asks the Board to explain how it determined that the proposed standards are appropriate for both the conventional and unconventional oil and gas industries in this Commonwealth.

In response, the Board amends this final-form rulemaking to clarify that the control measures are only applicable to unconventional sources of VOC emissions installed at unconventional well sites, gathering and boosting stations and natural gas processing plants. This final-form rulemaking implements control measures to reduce VOC emissions from five specific categories of air contamination sources, including storage vessels; natural gas-driven continuous bleed pneumatic controllers; natural gas-driven diaphragm pumps; reciprocating and centrifugal compressors; and fugitive emissions components.

The EPA selected these categories of sources for RACT recommendations because the information gathered and reviewed by the EPA indicated that they are significant sources of VOC emissions. In developing the 2016 O&G CTG, the EPA reviewed the oil and natural gas NSPS, including several technical support documents prepared in support of the NSPS actions for the oil and natural gas industry, as well as existing state and local VOC emission reduction approaches, and information on emissions, available VOC emission control technologies and costs. In producing and reviewing this information, the EPA's Scientific Integrity Policy establishes that the EPA adheres to the 2002 Office of Management and Budget (OMB) Information Quality Guidelines, the 2005 OMB Information Quality Bulletin for Peer Review, the EPA's Quality Policy for assuring the collection and use of sound, scientific data and information, the EPA's Peer Review Handbook for internal and external review of scientific products and the EPA's Information Quality Guidelines for maximizing the transparency, integrity and utility of information published on the EPA's web site.

During the development of the proposed rulemaking, the Department made the initial RACT determinations based on the entirety of information available to the Department, including the data and analysis provided in the 2016 O&G CTG as well as 2017 oil and gas production data reported to the Department's Oil and Gas Production Report and 2017 emissions data reported to the Department's air emissions inventory. In the time since the 2016 O&G CTG was issued by the EPA, the Department acquired additional information during the public comment period and from the 2020 oil and gas production data and air emissions data, which was used in a cost/benefit reanalysis (2020 reanalysis) to establish the RACT determinations in this final-form rulemaking.

b. *This final-form rulemaking sufficiently protects public health, safety and welfare, and this Commonwealth's natural resources.*

IRRC also remains concerned that this final-form rulemaking fulfills the Board's obligation to protect the quality and sustainability of the Commonwealth's natural resources. To that end, IRRC asks the Board to explain how the standards set forth in this final-form rulemaking meet the criterion under section 5.2(b)(2) of the RRA (71 P.S. § 745.5b(b)(2)) pertaining to the protection of the public health, safety and welfare and the effect on the Commonwealth's natural resources while imposing reasonable requirements upon the oil and natural gas industry.

In response, the Board maintains that this final-form rulemaking is protective of the public health, safety and welfare, as well as the environment because it implements VOC emission control measures that are reasonably necessary to protect the public health and welfare and the environment from harmful ground-level ozone pollution resulting from VOC emissions at unconventional oil and natural gas sources. Reduced levels of VOC and methane emissions will also promote healthful air quality and ensure the continued protection of the environment and public health and welfare. The control measures in this final-form rulemaking, when implemented, are expected to provide VOC emission reductions of approximately 2,864 TPY. 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 Board is not stating that these estimated monetized health benefits would all be the result of implementing the RACT measures contained in this final-form rulemaking, but the EPA estimates are indicative of the benefits to Commonwealth residents of attaining and maintaining the 2008 and 2015 8-hour ozone NAAQS. In addition to causing adverse human and animal health effects, the EPA has concluded that ground-level ozone affects vegetation and ecosystems, leading to reductions in agricultural crop and commercial forest yields. Furthermore, the same measures in this final-form rulemaking that control VOC emissions will also control methane emissions. When fully implemented, the control measures for VOCs are anticipated to reduce 45,278 TPY of methane as a cobenefit. Methane is a potent greenhouse gas with a higher global warming potential than carbon dioxide.

c. *This final-form rulemaking will not have a negative economic or fiscal impact to this Commonwealth.*

IRRC notes that the fiscal analysis provided by the Board estimates that the 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, will yield a savings of approximately $9.9 million, resulting in a total net cost of $25.4 million. These figures were based on 2012 EPA cost estimates contained in the 2016 O&G CTG. Commentators question the accuracy of the fiscal analysis because the supporting data is outdated and is not specific to this Commonwealth's oil and gas industry. IRRC agrees with the concerns raised by interested parties. For IRRC to determine whether this final-form rulemaking is in the public interest, the Board must submit a revised estimate of the costs or savings, or both, to the regulated community using data that is current and Commonwealth industry specific.

In response, the Board provides a revised estimate of the cost and savings to the regulated community using current and Commonwealth-specific data in the RAF for this final-form rulemaking. The updated fiscal analysis from the Department's 2020 reanalysis estimates that implementation of the control measures in this final-form rulemaking will cost affected owners and operators as a whole approximately $21.9 million (2021 dollars) without consideration of the economic benefit of the saved natural gas. The value of the saved natural gas using $1.70 per thousand cubic feet (Mcf) as suggested by several commentators yields a savings of $4.6 million (2021 dollars). This results in a total net cost of $17.3 million (2021 dollars), which is based on some of the worst conditions of the past decade. As the price of natural gas increases, the impact on industry is mitigated; at approximately $5 per Mcf during the 2020-2021 timeframe for the development of this final-form rulemaking, the impact on industry drops to a net cost of $8.5 million (2021 dollars). Although the natural gas saved as a result of implementation of this final-form rulemaking is significant, when the Department made the individual RACT determinations for the sources recommended in the 2016 O&G CTG, the value of the natural gas saved was not counted.

d. *This final-form rulemaking does not conflict with existing statutes or regulations.*

IRRC notes that the Department states that it "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." The proposed rulemaking defines "in-house engineer" as an individual who is qualified by education, technical knowledge and experience to make an engineering judgment and has the required specific technical certification. Since there is no requirement that the individual be employed by the facility, IRRC asks the Board to clarify the intent of this provision, including the problem or situation that is being addressed, why it is needed and whether the term "in-house engineer" should be retained or, as some commentators have suggested, be replaced with "qualified engineer." IRRC also asks the Board to explain how the term is consistent with the Engineer, Land Surveyor and Geologist Registration Law (Registration Law) (63 P.S. §§ 148—158.2) and the regulations governing professional qualified engineers and engineers-in-training. Additionally, IRRC requests that the Board include a fiscal analysis that compares the costs of using an "in-house engineer" versus a "qualified professional engineer" under these sections. Finally, IRRC states that the Board should explain how permitting an unlicensed individual to certify the system he or she may have designed is in the public interest.

In response, the Board explains that the EPA added the term "in-house engineer" to the Reconsideration of 40 CFR Part 60, Subpart OOOOa (relating to standards of performance for crude oil and natural gas facilities for which construction, modification or reconstruction commenced after September 18, 2015) to address a specific concern about the availability and costs associated with limiting the certification of closed vent system design and capacity or technical infeasibility of routing natural gas-driven diaphragm pump emissions to a control to a "qualified professional engineer" as defined in § 129.122. Because of the interrelatedness of the NSPS and the 2016 O&G CTG requirements, the Board pro-actively added this flexibility to the proposed rulemaking. The EPA stated in the Reconsideration that they "believe that an in-house engineer with knowledge of the design and operation of the [closed vent system] is capable of performing these certifications, regardless of licensure. . ." According to the EPA, a qualified professional engineer certification would cost $547 while allowing an in-house engineer to make the certification would cost $358. Unfortunately, the term "in-house engineer" was not defined in the NSPS or the 2016 O&G CTG, so the Board proposed the definition given. Based on comments received, the Board revises the definition of "in-house engineer" from the proposed rulemaking to this final-form rulemaking to require that the "in-house engineer" be employed by the same owner or operator as the responsible official that signs the certification required under § 129.130(k).

The term "in-house engineer" is consistent with the Registration Law and the regulations governing professional qualified engineers and engineers-in-training in that the term narrowly defines who is permitted to perform the certification of a natural gas-driven diaphragm pump or closed vent system in accordance with section 152 of the Registration Law (63 P.S. § 152), regarding exemption from licensure and registration. Clause (i) of the definition in this final-form rulemaking recognizes that in accordance with section 152(f) and (g) of the Registration Law, the individual must be an employee of the owner or operator. Clause (ii) of the definition tightens the criteria of section 152(f), (g) and (j) by requiring the individual be qualified by education, technical knowledge and expertise in the design and operation of a natural gas-driven diaphragm pump or closed vent system as those subsections of the Registration Law do not specify the level of technical knowledge required.

There are two provisions in this final-form rulemaking that authorize use of an in-house engineer: §§ 129.125(c)(3)(ii)(A) and 129.128(c)(1). The provision in § 129.125(c)(3)(ii)(A) allows an in-house engineer to perform an assessment to determine whether it is technically infeasible for a natural gas-driven diaphragm pump to connect to a control device or process. The provision in § 129.128(c)(1) allows an in-house engineer to perform a design and capacity assessment to ensure an installed closed vent system is sufficient to convey emissions to a control device that can accommodate those emissions. Authorizing the use of an in-house engineer in these two limited situations is in the public interest because it will not affect "the public safety or health or the property of some other person or entity" in accordance with section 152(f) and (g) of the Registration Law. In fact, in the 2016 O&G CTG, the EPA allowed for this certification by either a licensed professional engineer (PE) or an in-house engineer because in-house engineers may be more knowledgeable about site design and control than a third-party PE.

e. *The requirements, implementation procedures and timetables for compliance of this final-form rulemaking are reasonable.*

IRRC notes that the effective date of the proposed rulemaking is immediately upon publication as a final-form rulemaking in the *Pennsylvania Bulletin*. Commentators suggest that a minimum of a 60-day effective date would give owners or operators additional time to reasonably transition into the new requirements so that existing facilities are not required to immediately implement and comply with the new rules. Others suggest that owners or operators will need considerably more time to determine if their sources are required to comply with the final-form rulemaking, as well as mobilize the necessary resources to perform the required inspections. In addition, interested parties representing the oil and gas industry request that time periods between inspections be extended or made consistent with current 2016 O&G CTG timeframes to avoid duplicate compliance activities. IRRC encourages the Board to work with the regulated community to resolve issues pertaining to inspection timeframes and recommends revising the effective date of this final-form rulemaking to give sufficient time to the regulated community to implement and comply with requirements or explain why it is unnecessary to do so.

In response, this final-form rulemaking is effective upon publication in the *Pennsylvania Bulletin*; however, the Board notes that compliance dates are established throughout this final-form rulemaking to provide affected owners or operators sufficient time to identify and comply with the applicable requirements.

IRRC notes that the Benefits, Costs and Compliance section of the preamble describes how the VOC RACT requirements established by the proposed rulemaking will be incorporated into "an existing permit." IRRC asks how the process to incorporate the requirements into an existing permit will be implemented based on the compliance schedule in section 29F of the RAF (pertaining to expected date by which permits, licenses or other approvals must be obtained). IRRC asks the Board to provide a more detailed explanation of the process contained in this section and how it will be implemented.

In response, the Board explains that the incorporation of the requirements of this final-form rulemaking into an existing permit will follow the requirements of § 127.463 (relating to operating permit revisions to incorporate applicable standards). Owners or operators will not be required to submit an application for amendments to an existing operating permit. Instead, the 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). 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 this final-form rulemaking, as required under § 127.463(b).

IRRC states that interested parties representing environmental concerns commend the Board for including alternative leak detection methods in this final-form rulemaking. IRRC asks the Board to explain the approval process for alternative leak detection methods and whether alternative leak detection methods will be required to achieve equivalent emission reductions as currently allowed devices or methods. Additionally, IRRC asks the Board to describe the requirements and approval process for alternative leak detection methods in the preamble to this final-form rulemaking.

In response, the Board explains that the Department has adopted a performance-based approach for evaluating leak detection equipment and the equipment's documented ability to measure the compounds of interest at the detection level necessary to demonstrate compliance with the applicable requirement. In many cases, the technology has been evaluated by the EPA and appropriate quality assurance requirements have been specified. In addition to Method 21 and 40 CFR 60.18, 40 CFR 98.234 (relating to monitoring and QA/QC requirements) includes a list of other appropriate technologies and requirements. Since the Department's criteria are performance based, an owner or operator seeking to use an alternative method should provide documented evidence that the alternative technology is capable of detecting the leak at the specified leak threshold. For example, an alternative leak detection method with the appropriate performance criterion may be specified in a related, though not specifically applicable, regulation such as an NSPS or National Emission Standard for Hazardous Air Pollutants.

f. *This final-form rulemaking is needed.*

IRRC notes that the preamble and the RAF do not adequately describe the rationale or need for certain requirements or exclusions. Commentators representing environmental concerns identify two key provisions that they say are contrary to the goals of this final-form rulemaking. The first is the exemption of low-producing wells from the requirements of LDAR inspections. The second one is the "step down" provision that allows owners or operations to decrease the frequency of LDAR inspections if the percentage of leaking components is less than 2% for two consecutive quarterly inspections. Owners or operators would have the option to reduce the inspection frequency to semiannually. Opponents of these two measures say it is "faulty and risky" for the Department to assume that conventional operations do not emit at levels high enough to have a significant impact on air quality and climate. IRRC asks the Board to explain the need for each provision and how determinations were made, as well as what data was used to justify the exemptions. Section 11 of the RAF also states that the Department determined that owners or operators must conduct quarterly LDAR inspections at their facilities, as opposed to the recommended semiannual frequency in the 2016 O&G CTG. IRRC asks the Board to explain the need for the quarterly LDAR inspection requirement, the low production threshold LDAR exemption and the LDAR stepdown provision, and how the determinations were made, as well as what data was used to the justify the exemptions or more stringent regulations.

In response, the Board explains that the control measures in this final-form rulemaking are reasonably necessary to attain and maintain both the 2008 and 2015 ozone NAAQS. The Department removes the stepdown provision and altered the production thresholds for LDAR requirements in this final-form rulemaking. For fugitive emission components, the proposed rulemaking established monthly AVO inspections and quarterly instrument based LDAR inspections for well sites with a well that produces, on average, 15 BOE per well per day. The proposed rulemaking also established a stepdown provision which enabled owners or operators to track the percentage of leaking components at each inspection and, if in two consecutive inspections there were less than 2% of components leaking, the owner or operator could reduce the quarterly schedule of instrument based LDAR to semiannual. However, the 2020 reanalysis shows that it is cost effective to implement instrument based LDAR at unconventional well sites with an average production of 15 BOE per day, with the frequency based on individual well production on the well site. For applicable unconventional well sites with at least one well that produces equal to or greater than 15 BOE per day the owner or operator must perform quarterly instrument based LDAR inspections. For applicable unconventional well sites with at least one well that is less than 15 BOE per day and equal to or greater than 5 BOE per day, the owner or operator must perform annual instrument based LDAR inspections. The owner or operator is required to track well site production and the individual production of each well on the unconventional well site on an annual basis. The owner or operator may reduce the inspection frequency based on the production calculations which shows 2 consecutive years of production in the lower category. The owner or operator shall increase the inspection frequency immediately if the production calculations show an increase that is subject to more frequent inspections.

IRRC notes that representatives from the oil and gas industry observe that no analysis has been shared by the Board to support the Department's conclusion that the proposed requirements that are more stringent than the EPA's 2016 O&G CTG "are reasonably necessary" to achieve or maintain the NAAQS. Commentators question the need to exceed the 2016 O&G CTG when this Commonwealth is near universal compliance with the 1997, 2008 and 2015 ozone standards. IRRC further notes that the commentators explain that the state is not required to rely on the recommendations of the 2016 O&G CTG to establish the proposed rulemaking. Instead, it could make RACT determinations for a particular source on a case-by-case basis considering the technological and economic feasibility of the individual source.

In response, the Board agrees that the ambient air ozone monitoring data demonstrates that this Commonwealth is in near universal compliance with the 1997, 2008 and 2015 ozone NAAQS. The Department's analysis of the 2020 ambient air ozone season monitoring data shows that all ozone samplers in this Commonwealth are monitoring attainment of the 2015 8-hour ozone NAAQS except three: the Bristol sampler in Bucks County, the Philadelphia Air Management Services Northeast Airport and Northeast Waste samplers in Philadelphia County. Ambient air ozone samplers in this Commonwealth are projected to monitor attainment of the 1997 and 2008 8-hour ozone NAAQS. However, the Department must ensure that the 1997, 2008 and 2015 8-hour ozone NAAQS continue to be attained and maintained by implementing permanent and Federally enforceable control measures.

Additionally, section 182(b)(2) of the CAA requires states with moderate ozone nonattainment areas to revise their SIPs to include RACT for sources of VOC emissions covered by 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 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, since this Commonwealth is not designated by the EPA as in attainment with the 2015 ozone NAAQS and is not monitoring compliance Statewide with the 2015 ozone NAAQS, 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. These sources were selected by the EPA because data and information has indicated that they are significant sources of VOC emissions.

The Department is obligated under the CAA to analyze the source sector, as defined in the 2016 O&G CTG, and regulate sources that have control techniques or equipment that is "reasonably available." 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 a product or source category in ozone nonattainment areas. In other words, the 2016 O&G CTG has no legally binding effects. While the EPA provided information and RACT recommendations through the 2016 O&G CTG for VOC emissions, it is up to the Department to determine what is RACT for each source category of VOC emissions. As explicitly stated by the EPA in the 2016 O&G CTG, state air pollution control agencies are free to implement other technically-sound approaches that are consistent with the CAA and the EPA's regulations. See 81 FR 74798, 74799 (October 27, 2016). The EPA also further clarified that "the information contained in the CTG document is provided only as guidance" and "this guidance does not change, or substitute for, requirements specified in applicable sections of the CAA or the EPA's regulations; nor is it a regulation itself." Id. While the EPA will ultimately need to approve the Department's RACT determinations by reviewing and approving the revision to the Commonwealth's SIP, the Department has made the initial RACT determinations in this final-form rulemaking based on the entirety of information available to the Department, including the 2016 O&G CTG.

The Department's obligation is to affirmatively determine what constitutes RACT for the source group identified in the 2016 O&G CTG and the EPA's provision of guidance and data in the 2016 O&G CTG does not obliviate that legal requirement. In the time since the 2016 O&G CTG was issued by the EPA, the Department acquired additional information and current emissions data specific to this Commonwealth that it analyzed to determine the RACT emission limitations and requirements established in this final-form rulemaking.

The Department determined that the recommendations provided in the 2016 O&G CTG for natural gas-driven continuous bleed pneumatic controllers, natural gas driven-diaphragm pumps, and centrifugal compressors are RACT for sources in this Commonwealth. The EPA recommendations in the 2016 O&G CTG for storage vessels, reciprocating compressors, and fugitive emissions components were determined not to be RACT in this Commonwealth. The Department conducted a reanalysis to determine RACT for these three categories of sources: storage vessels, reciprocating compressor rod packing and fugitive emissions components. The information used in the 2020 reanalysis was obtained from the Department's Air Emission Inventory, Oil and Gas Production Database, and information provided by industry trade associations from the public comment period.

The quarterly LDAR inspection requirement for unconventional well sites with a well that produces, on average, 15 BOE per well per day is reasonably necessary to achieve and maintain the NAAQS for ozone and is technically and economically feasible. For applicable unconventional well sites with at least one well that is less than 15 BOE per day and equal to or greater than 5 BOE per day, the owner or operator must perform annual instrument based LDAR inspections. The Department determined that this is also reasonably necessary to achieve and maintain the NAAQS for ozone and is technically and economically feasible. Additionally, the Department notes that the leak rate-based LDAR stepdown provision has been removed in this final-form rulemaking.

To address the comment about case-by-case RACT determinations, the Board was incorrect in suggesting in the preamble for the proposed rulemaking that a case-by-case RACT determination is available for this CTG-based rule. The Board decided not to exercise its discretion to conduct case-by-case RACT analysis for this final-form rulemaking. The process for submitting RACT determinations on a case-by-case basis to the EPA is administratively burdensome, particularly given the larger number of regulated facilities. Instead, for this final-form rulemaking, the Department modifies the EPA's "presumptive norm" RACT recommendations. As stated by the EPA in a *Federal Register* notice on September 17, 1979, titled, "State Implementation Plans; General Preamble for Proposed Rulemaking on Approval of Plan Revisions for Nonattainment Areas—Supplement (on Control Techniques Guidelines)": "Along with information, each CTG contains recommendations to the States of what EPA calls the "presumptive norm" for RACT, based on EPA's current evaluation of the capabilities and problems general to the industry. Where the States finds the presumptive norm applicable to an individual source or group of sources, EPA recommends that the State adopt requirements consistent with the presumptive norm level in order to include RACT limitations in the SIP." 44 FR 53761 (September 17, 1979).

g. *This final-form rulemaking will not negatively impact small businesses.*

IRRC notes that section 5(a)(12.1) of the RRA (71 P.S. § 745.5(a)(12.1)) requires promulgating agencies to provide a regulatory flexibility analysis and to consider various methods of reducing the impact of the proposed regulation on small business. IRRC does not believe that the Board has met its statutory requirement of providing a regulatory flexibility analysis or considering various methods of reducing the impact the proposed regulation will have on small business in its responses to various sections and questions in the RAF. It is unclear from the RAF whether the 303 conventional wells subject to LDAR inspections are owned by small businesses. However, commentators believe most, if not all, are small businesses and strongly disagree that they will incur minimal costs as a result of the proposed rulemaking. In Section 15 of the RAF, the Board states that "further analysis is required to determine if any of the affected sources are owned or operated by small businesses." IRRC asks how the Board determined that costs would be minimal if it is unknown whether any of the affected sources are owned by small businesses. IRRC agrees with the commentators that further analysis is needed to determine the financial impact on small businesses and asks the Board to provide the required regulatory flexibility analysis when it submitted this final-form rulemaking.

In response, the Board notes that as stated in the RAF for the proposed rulemaking, of the 71,229 conventional wells reporting production, only 303 were found to be above the 15 BOE/day production threshold as reported in the Department's 2017 oil and gas production database and would have fugitive emissions component requirements. Upon further analysis by the Board, it seems that only 199 of the previously identified 303 conventional wells were potentially subject to the proposed LDAR requirements for fugitive emissions. In the analysis for the proposed rulemaking, the Board examined individual wells, not well sites. It is difficult to determine at the individual well level how many are owned or operated by small businesses as there may be several wells per well site. However, the costs to the owners or operators of those 199 conventional wells would have been minimal, because the Board's cost analysis for quarterly LDAR was based on hiring a contractor, not purchasing equipment, hiring and training personnel, and conducting quarterly surveys. Even so, the Board amends this final-form rulemaking to clarify that the control measures are only applicable to unconventional sources installed at unconventional well sites, gathering and boosting stations and natural gas processing plants.

The Board identified 577 client ID numbers for potentially affected owners or operators of unconventional facilities in this Commonwealth using the Department's eFACTS and AIMS databases and the North American Industry Classification Codes covered by the 2016 O&G CTG. These facilities include approximately 3,388 unconventional well sites, 486 gathering and boosting stations, and 15 natural gas processing facilities in this Commonwealth. Of these potential 577 owners or operators, approximately, 306 may meet the definition of small business as defined in section 3 of the RRA. However, it is possible that far fewer than the 577 owners or operators will be subject to the control measures of this final-form rulemaking, depending on the amount of VOC emissions that are emitted by the affected sources they own or operate or if they are subject to other regulations in Chapter 129 or if the same or more stringent permit conditions are already incorporated in their operating permit. While many of the anticipated costs are due to new regulatory requirements, many of the costs associated with this final-form rulemaking are from what the Board believes are best management practices and controls that affected owners or operators may already be implementing.

Additional details on small businesses and the effects of this final-form rulemaking on small businesses can be found in Sections 15, 24 and 27 of the RAF.

2. Act 52 of 2016 issues related to this final-form rulemaking.

IRRC comments that section 7(b) of the Pennsylvania Grade Crude Development Act (58 P.S. § 1207(b)), also known as Act 52 of 2016, requires any rulemaking concerning conventional oil and gas wells that is considered by the Board must "be undertaken separately and independently of unconventional wells or other subjects and shall include a regulatory analysis form submitted to the Independent Regulatory Review Commission that is restricted to the subject of conventional oil and gas wells." IRRC notes that lawmakers and commentators state that the Board has violated clear legislative directives by proposing a VOC emissions rule that includes requirements for conventional oil and gas well owners and operators along with, not "separately and independently" from, requirements for unconventional well operations. IRRC further notes that the Board has not prepared or submitted an RAF restricted to the need and impact of the rulemaking on the conventional oil and gas industry. IRRC highlights that lawmakers request that the provisions that apply to the conventional oil and gas industry be withdrawn from the rulemaking. IRRC asks the Board to explain how it has and will comply with the legislative directives of Act 52 of 2016.

The Board amends this final-form rulemaking to clarify that the control measures are only applicable to unconventional sources of VOC emissions installed at unconventional well sites, gathering and boosting stations and natural gas processing plants. Given the concerns expressed by the commentators, the Board will develop a separate rulemaking and RAF for the RACT requirements for sources of VOC emissions installed at conventional well sites.

At its March 15, 2022, meeting, the Board adopted the "Control of VOC Emissions from Oil and Natural Gas Sources" final-form rulemaking, which contained regulations applicable to both conventional and unconventional oil and natural gas sources of VOC emissions. After the final-form rulemaking was submitted to IRRC for final consideration, the House Environmental Resources and Energy Committee (Committee) voted to send a letter to IRRC disapproving the regulation and requesting IRRC's disapproval as well. The Committee's primary concern with the regulation centered on language in Act 52 of 2016. The Committee's letter stated that Act 52 of 2016 requires the Board to submit two rulemaking packages—one that applies only to conventional oil and natural gas sources and the other which would cover all other sources in the rulemaking.

The Committee's letter to IRRC initiated the concurrent regulatory review resolution process. Section 7(d) of the RRA (71 P.S. § 745.7(d)) establishes a process that allows the General Assembly to adopt a resolution that disapproves and permanently bars a final regulation from taking effect. Once the Committee reports the resolution, the General Assembly has 30 calendar days or 10 legislative days, whichever is longer, to vote on the resolution. If the resolution is adopted, the Governor then has the opportunity to veto, and the General Assembly would again have 30 calendar days or 10 legislative days, whichever is longer, to override the veto. Because the legislative session day calendar is subject to change, it is uncertain when the resolution process may conclude. The process could extend into 2023, which would prevent the

Department from submitting this final-form rulemaking to the EPA before the Federal highway sanctions deadline on December 16, 2022.

While the Board disagrees with the Committee's interpretation of Act 52 of 2016, to address the Committee's concerns and avoid the delay that a resolution would cause, the Board withdrew this final-form rulemaking from IRRC's consideration and revised it. This revised final-form rulemaking encompasses the VOC regulations applicable only to unconventional oil and natural gas sources. The Department will develop and present to the Board a separate rulemaking for sources of VOC emissions installed at conventional oil and natural gas well sites.

3. The EPA is no longer withdrawing the 2016 O&G CTG.

IRRC notes that the Board states in Section 9 of the RAF that "[e]ven though a finalized withdrawal of the 2016 O&G CTG would relieve the state of the requirement to address RACT for existing oil and gas sources, the Department is still obligated to reduce ozone and VOC emissions to ensure that the NAAQS are attained and maintained under section 110 of the CAA. 42 U.S.C.A. § 7410." Commentators have asked the Board to consider another public comment period should the Federal regulations or guidelines be significantly changed before promulgation of this final-form rulemaking. IRRC asks the Board to explain how it will proceed if there are significant changes made to the 2016 O&G CTG or 40 CFR Part 60, Subparts OOOO (relating to standards of performance for crude oil and natural gas facilities for which construction, modification, or reconstruction commenced after August 23, 2011, and on or before September 18, 2015) and OOOOa prior to the promulgation of the final-form rulemaking.

In response, the Board explains that the relevant Federal regulations and the 2016 O&G CTG have not significantly changed and will not change prior to promulgation of this final-form rulemaking. In March of 2020, the Department received notice that the EPA had decided not to proceed with the withdrawal of the 2016 O&G CTG. The EPA announced in the OMB's Spring 2020 Unified Agenda and Regulatory Plan that the CTG will remain in place as published on October 27, 2016. On November 16, 2020, the EPA issued a final rule entitled "Findings of Failure To Submit State Implementation Plan Revisions in Response to the 2016 Oil and Natural Gas Industry Control Techniques Guidelines for the 2008 Ozone NAAQS and for States in the Ozone Transport Region (OTR)." 85 FR 72963 (November 16, 2020). This Commonwealth was one of the five states issued a finding of failure to submit a SIP revision incorporating the 2016 O&G CTG RACT requirements by October 27, 2018. The EPA's finding triggers the sanction clock under the CAA. The Commonwealth must submit this final-form rulemaking as a SIP revision and the EPA must determine that the submittal is complete within 18 months of the effective date (December 16, 2020) of the EPA's finding, that is, by June 16, 2022, or sanctions may be imposed.

4. Provisions of this final-form rulemaking were amended for clarity.

IRRC notes that § 129.121(a) provides that the proposed rulemaking would apply to the owners or operators of storage vessels in all segments except natural gas distribution; natural gas-driven continuous bleed pneumatic controllers; natural gas driven diaphragm pumps; reciprocating compressors; centrifugal compressors; or fugitive emissions component which were in existence on or before the effective date of this final-form rulemaking. Commentators ask how "existing" will be interpreted under this final-form rulemaking since there may be facilities that have initiated construction but are not yet operational on the effective date of this final-form rulemaking. IRRC asks the Board to explain, in the preamble to this final-form rulemaking, how "existing" will be interpreted under this chapter.

In response, the Board revises the applicability section, § 129.121(a), of this final-form rulemaking by removing the phrase "in existence" and replacing it with "constructed" to clarify that the requirements apply to sources constructed on or before the effective date of this final-form rulemaking. Sources constructed after the effective date will not be subject to this final-form rulemaking. However, new sources are subject to best available technology (BAT) requirements, so it is likely that the requirements for new sources will be equivalent to or more stringent than the RACT requirements of this final-form rulemaking.

IRRC mentions that subparagraph (iii) of the definition of "deviation" includes a failure to meet an emission limit, operating limit, or work practice standard during start-up, shutdown or malfunction as a "deviation" regardless of whether a failure is permitted by these rules. IRRC requests that the Board clarify this definition because commentators have asked the Board to make clear that failure to meet a limit or standard should not be considered a "deviation" if permit conditions are met.

In response, the Board explains that a deviation under subparagraph (iii) is not considered to be a violation of this final-form rulemaking, or a permit and deviations must be recorded and reported as required under § 129.130. A facility that has a permit must evaluate the terms and conditions of the permit and the requirements of this final-form rulemaking and comply with the most stringent requirement. The deviation must be evaluated against the most stringent requirement. The Board will evaluate these instances for compliance with the applicable requirements and standards. Additionally, the definition of "deviation" is consistent with the EPA's guidance in the 2016 O&G CTG.

IRRC suggests that for consistency, the definition of "first attempt at repair" should be revised to replace "organic material" with "VOCs."

In response, the Board explains that in the proposed rulemaking it used the definition of "first attempt at repair" from the EPA's regulations at 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). While the term "first attempt at repair" is used in Sections A, D and G in the 2016 O&G CTG, it was not defined. After the EPA's Reconsideration of the NSPS, a definition that differed slightly from that in Subpart VVa was added to Subpart OOOOa. As the definition of "first attempt at repair" from Subpart OOOOa is closer in line with the usage in the 2016 O&G CTG, the Board revised the definition from the proposed rulemaking to this final-form rulemaking. The Board removed the proposed definition which stated, "action taken for the purpose of stopping or reducing leakage of organic material to the atmosphere using best practices" and replaces it with "for purposes of § 129.127 (relating to fugitive emissions components): an action using best practices taken to stop or reduce fugitive emissions to the atmosphere.'' The Board also clarifies that the term includes tightening bonnet bolts, replacing bonnet bolts, tightening packing gland nuts and injecting lubricant into lubricated packing. This change accommodates the revision suggested by the commentators.

IRRC asks what the Board means by the phrase ''an engineering judgment'' in the definition of ''in-house engineer'' and suggests that the Board define this term or explain why it is unnecessary to do so.

In response, the Board removes the phrase ''an engineering judgment'' and made further revisions to the definition of ''in-house engineer'' in this final-form rulemaking. Instead of the phrase ''an engineering judgment,'' the Board revises the definition of ''in-house engineer'' in this final-form rulemaking to require the engineer to be qualified by having expertise in the design and operation of a natural gas-driven diaphragm pump or closed vent system.

IRRC notes that subparagraph (i) in the definition of ''leak'' reads ''A positive indication, whether audible, visual or odorous, determined during an AVO inspection.'' IRRC also agrees with commentators who have suggested that this subparagraph be amended for clarity to state ''A positive indication of a leak. . .''

In response, the Board revised subparagraph (i) of the definition of ''leak'' from the proposed rulemaking to this final-form rulemaking by removing ''A positive indication, whether audible, visual or odorous, determined'' and replacing it with ''Through audible, visual or odorous evidence.'' The Board further clarifies the definition of ''leak'' by adding that it is ''an emission detected'' and providing for methods for detecting the emission. Additionally, the Board did not add ''A positive indication of a leak. . .'' to the definition as suggested by the commentators in accordance with § 2.11(h) (relating to definitions) of the *Pennsylvania Code and Bulletin Style Manual*. Section 2.11(h) states that ''the term being defined may not be included as part of the definition.''

IRRC suggests that the phrase ''For purposes of this section, §§ 129.121 and 129.123—129.130'' in the definition of ''TOC—Total organic compounds'' is unnecessary and should be deleted from the definition. In response, the Board agrees that the phrase ''For purposes of this section, §§ 129.121 and 129.123—129.130'' is redundant and removes that phrase from the definition in this final-form rulemaking.

IRRC questions the need for the provision in subparagraph (ii) of the definition of ''qualified professional engineer'' providing that ''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.'' In response, the Board explains that the EPA defined ''qualified professional engineer'' in the 2016 O&G CTG as ''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 specific technical certifications required under this subpart. Professional engineers making these certifications must be currently licensed in at least one state in which the certifying official is located.'' Therefore, the requirement that the ''qualified professional engineer'' be licensed in one of the states where the responsible official does business is part of the EPA's RACT recommendation. The Board adds the requirement for reciprocity due to requirements that an engineer be legally qualified to engage in the practice of engineering and that the standards of the other state or territory be at least equal to the standards of this Commonwealth.

IRRC recommends that the definitions of ''conventional well'' and ''unconventional well'' as defined in 25 Pa. Code §§ 78.1 and 78a.1 (relating to definitions) be included by reference in § 129.122(a). In response, the Board removes the references to ''conventional well'' and ''unconventional well'' from § 129.123(a) from the proposed rulemaking to this final-form rulemaking. Section 129.123(a) was the only section that included the terms ''conventional well'' and ''unconventional well'' in the proposed rulemaking. However, the Board adds definitions for ''unconventional formation,'' ''unconventional well'' and ''unconventional well site'' in this final-form rulemaking since the applicability section was amended to clarify that this final-form rulemaking only applies to unconventional sources installed at an ''unconventional well site.'' The definitions of ''unconventional formation'' and ''unconventional well'' in this final-form rulemaking are identical to the definitions in § 78a.1.

IRRC notes that § 129.123(a)(2)(i) requires that potential VOC emissions for conventional, unconventional, gathering and boosting station and at a facility in the natural gas transmission and storage segment use a generally accepted model or calculation methodology, based on the maximum average daily throughput prior to the effective date of the rulemaking. Commentators ask the Department to revise this section to allow all generally accepted models or calculation methodologies and request the language referencing historical data be deleted. However, commentators stated that use of past maximum averages that are no longer representative of the facilities' throughputs will not provide an accurate emissions profile to justify the proposed compliance requirements. IRRC requests that the Board explain its rationale for and the reasonableness of the provision relating to historical data.

In response, the Board revises § 129.123(a)(2)(i) in this final-form rulemaking to add that the maximum average daily throughput is as defined in § 129.122 and to extend the calculation requirement from the date of publication to 60 days after. This revision is made to provide clarity, to be more representative of the facility operations and to provide a more accurate emissions profile.

IRRC notes that § 129.123(a)(2)(ii) provides that 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. IRRC requests that the Board explain in the preamble to this final-form rulemaking whether state permitting programs such as GP-5, GP-5A and Exemption 38 of the Air Quality Permit Exemptions list will be considered satisfactory for this requirement.

In response, the Board explains that when calculating the potential VOC emissions for this final-form rulemaking, an owner or operator must ensure that they are complying with existing VOC limits in an operating permit or plan approval, including but not limited to GP-5 and GP-5A. Section 129.123(a)(2)(ii) has been revised to replace ''must'' with ''may'' to read ''The determination of potential VOC emissions may consider requirements under a legally and practically enforceable limit established in an operating permit or plan approval approved by the Department.'' It was not the EPA's recommendation, nor the Board's intent, to require that legally and practically enforceable limits be considered when calculating potential VOC emissions to determine applicability to the rule. The limits in GP-5 and GP-5A are both legally and practically enforceable, so they could be used when calculating potential VOC emissions to determine applicability to this final-form rulemaking. However, the only legally and practically enforceable limit that reduces VOC emissions is installation of a control device capable of meeting 95.0% reduction or greater by weight. Therefore, doing so is more of a demonstration that the storage vessel is already in compliance with the requirements of this final-form rulemaking. On the other hand, the conditions of Exemption 38 do not rise to the Federal definition of legally and practically enforceable, so therefore cannot be used when calculating potential VOC emissions to determine applicability to this final-form rulemaking.

IRRC notes that § 129.123(b)(1)(iii) requires routing emissions to a control device or process that meets the applicable requirements of § 129.129. Commentators note that § 129.129 contains requirements specific only to "control devices" and not to "processes." IRRC requests that the Board explain the intent of the proposed language and revise it if necessary. IRRC also notes that similar language appears in §§ 129.125(b)(1)(ii), 129.126(c)(2), 129.128(a)(2)(ii) and 129.128(b)(1).

In response, the Board explains that the requirements for "processes" can be found in § 129.129(d) of this final-form rulemaking. In particular, § 129.129(d)(1)(iv) of the proposed rulemaking, regarding compliance requirements for an enclosed combustion device, established the requirements for the use of a boiler or process heater—a "process"—to control the VOC emissions. VOC emissions routed to a boiler or process heater are considered controlled if the vent stream containing the VOC emissions is injected into the flame zone of the boiler or process heater. The Board retains this requirement in this final-form rulemaking.

IRRC notes that § 129.124(d) requires the owner or operator to tag each affected natural gas-driven pneumatic controller with the date the controller is required to comply with the requirements of this section and an identification number that ensures traceability to the records for that controller. IRRC asks the Board to explain the rationale for this requirement, including why it believes it is reasonable. In response, the Board explains that the requirement is based on the EPA's recommendation from the 2016 O&G CTG, and the Department has determined that the tagging would facilitate the determination that the owners or operators are in compliance with this final-form rulemaking, and is not overly burdensome.

IRRC asks the Board to specify a timeframe in § 129.127(a) that will be used to determine per-day average production figures for the 15 BOE per day applicability threshold or explain why it is unnecessary to do so. In response, the Board adds a calculation procedure to estimate the average production of a well site in § 129.127(b) of this final-form rulemaking. The owner or operator of a well site shall calculate the average production in BOE per day of the well site using the previous 12 calendar months of operation as reported to the Department.

IRRC asks the Board to clarify whether the adjustments to the LDAR inspection intervals in proposed § 129.127(b) are required under proposed § 129.127(e). In response, the Board explains that the LDAR inspection frequency reductions under § 129.127(c)(4)(i) of this final-form rulemaking, which replaces subsection (b)(2)(i) of the proposed rulemaking, do not require an owner or operator to request an extension of the LDAR inspection frequency under § 129.127(f) of this final-form rulemaking. Section 129.127(f) was § 129.127(e) in the proposed rulemaking.

IRRC notes that § 129.127(e) permits the owner or operator of an affected facility to request, in writing, an extension of the LDAR inspection interval. IRRC asks the Board to explain the need for an extension, including under what conditions or circumstances an owner or operator may request an extension. IRRC also asks whether certain conditions or requirements are needed to request an extension, how owners or operators will be informed about those conditions or requirements and what the maximum amount of time is that an extension may be granted.

In response, the Board notes that proposed § 129.127(e) is now § 129.127(f) in this final-form rulemaking. The Board explains that the flexibility granted to an owner or operator by allowing them to request an extension of the LDAR inspection interval may be for any reason. Examples for requesting an extension of the inspection frequency could include that the owner or operator's inspection equipment requires repair and will be unavailable when the inspection is due, the owner or operator has numerous facilities and it will take longer than the time allowed under this final-form rulemaking to determine applicability, plan, and perform the initial inspections, or it is not possible to have a contractor perform the required inspection when it is due because there are no contractors available by that date. However, the conditions required for and the duration of the extension will be determined on a case-by-case basis by the Air Program Manager of the appropriate Department Regional Office when approving the extension request.

IRRC notes that § 129.129(b)(5)(ii) refers to an "inspection and maintenance plan" in § 129.129(b)(1) that does not exist. IRRC asks the Board to clarify the intent of this subsection and revise, if necessary. In response, the Board revises the language of § 129.129(b)(5)(ii) from the proposed rulemaking to this final-form rulemaking to remove the reference to an "inspection and maintenance plan" and to instead require the use of the best combustion engineering practice applicable to the control device if the manufacturer's repair instructions are not available.

IRRC asks the Board to delete the reference to subsection (c)(l)(ii) in § 129.129(k)(5) since subsection (c)(l)(ii) does not require or refer to a weight-percent VOC emission reduction requirement. In response, the Board did not remove the reference to subsection (c)(l)(ii) in § 129.129(k)(5) and instead revises the language of § 129.129(c)(1)(ii) from the proposed rulemaking to this final-form rulemaking to add a weight-percent VOC emission reduction requirement.

IRRC notes that §§ 129.129(j)(1)(v)(D) and 129.129 (j)(1)(vi)(B) provide for requests for extension of initial performance test reports and asks the Board to refer to IRRC's comments regarding the LDAR inspection interval extension requests in § 129.127(e) as the questions apply also to this subsection.

In response, the Board explains that the allowance for an owner or operator to request an extension of the initial performance test requirements provides flexibility to the owner or operator. The owner or operator may request an extension for any reason. For example, it is possible that an operator could request an extension due to scheduling issues with source testing contractors. However, the conditions required for and the duration of the extension will be determined on a case-by-case basis by the Air Program Manager of the appropriate Department Regional Office when reviewing and approving/denying the extension request.

IRRC notes that § 129.130(d)(l) requires the records for each natural gas-driven diaphragm pump to include the date, location and manufacturer specifications for each pump. IRRC requests that the Board revise this section to clarify the date referenced. In response, the Board revises the language of § 129.130(d)(1) from the proposed rulemaking to this final-form rulemaking to clarify that the date is the "required compliance" date.

IRRC notes that § 129.130(g)(2)(ii)(G)(II) requires the "instrument reading of each fugitive emission component" that meets the definition of a leak under the rulemaking. IRRC asks if this subsection should be revised for consistency to account for leaks that are detected with OGI equipment. In response, the Board did not revise this subsection and explains that the instrument reading for OGI equipment is a visible leak.

IRRC notes that Section 15 of the RAF indicates that the table in Section 23 provides a breakdown of the cost data for the industry. The figures provided in the table in Section 23 of the RAF represent industry-wide cost and savings estimates. IRRC recommends that the Board either include in the chart as described in the RAF for this final-form rulemaking or remove this statement if one does not exist.

In response, the Board revises the response to Question 15 of the RAF to detail the breakdown of cost data for the industry on a per owner or operator and a per facility basis. The response to Question 19 of the RAF details the individual source costs, including the total industry cost based on the estimated number of affected sources in each category. The response to Question 23 still provides a breakdown of the total costs to the industry. Additionally, the Board removes the reference in the response to Question 15 to the table in the response to Question 23 as suggested.

IRRC recommends that in § 121.1, under the term "responsible official" subparagraph (iv) clause (B) after "or Chapter 129," the Board should include parentheses containing a description of what the chapter is relating to. In response, the Board respectfully disagrees with the suggestion as the parenthetical description is provided once per section the first time the referenced chapter is cited, in accordance with § 5.12(a)(4) (relating to cross-references) of the *Pennsylvania Code and Bulletin Style Manual*. The definition of "Compliant Coating" in § 121.1 references Chapter 129 and includes the parenthetical "(relating to standards of sources)" with the description of Chapter 129.

IRRC notes that § 129.122(a) states that "the following words and terms, when used in this section, §§ 129.121 and 129.123—120.130, have the following meaning. . ." IRRC suggests inserting "shall" before "have" and revising "section" to "chapter." Additionally, IRRC recommends deleting "section" replacing it with "chapter" in the definitions for "deviation" and "TOC—Total organic compounds."

In response, the Board respectfully disagrees with these recommendations and did not add the word "shall" as suggested as the phrasing used in § 129.122(a) is consistent with other sections in Chapter 129 as well as the phrasing used in § 121.1. This is also consistent with § 6.7(a) (relating to use of "shall," "will," "must" and "may") of the *Pennsylvania Code and Bulletin Style Manual*. Section 6.7(a) states that the term "shall" "expresses a duty or obligation. The subject of the sentence must be a person, committee or other nongovernmental entity that is required to or has the power to make a decision or take an action." Additionally, the definitions in § 129.122(a) apply only to §§ 129.121—129.130, not the entirety of Chapter 129; therefore, the Board did not revise "section" to read "chapter" as recommended.

IRRC notes that the following terms and definitions appear in § 129.122(a) but are not used in the text of the Annex: "completion combustion device," "fuel gas," "fuel gas system," "natural gas and oil production segment," "natural gas processing segment," "transmission compression station," and "underground storage vessel." IRRC suggests that these terms and definitions be deleted. In response, the Board agrees with this suggestion and deletes these terms from this final-form rulemaking.

IRRC recommends that for consistency the Board include a reference to the recordkeeping and reporting requirements found in § 129.130(i)(2) in § 129.128(d). In response, the Board notes that the recordkeeping and reporting requirements for closed vent systems in § 129.130(i)(2) are found in § 129.128(b)(6). The provisions of § 129.128(d) specify the procedures for the no detectable emissions inspection required in § 129.128(b)(2)(ii).

IRRC recommends amending § 129.130(k) to replace "can" with "may" so that the statement reads "The due date of the initial report may be extended with the written approval of the Air Program Manager of the appropriate Department Regional Office." In response, the Board agrees with this recommendation and revises § 129.130(k)(1)(ii) to replace "can" with "may."

5. The Board has fulfilled its duties as a trustee as set forth in Article I, Section 27 of the Pennsylvania Constitution.

Commentators, including members of the General Assembly, referenced the Commonwealth's Environmental Rights Amendment in Article I, Section 27 of the Pennsylvania Constitution, Pa.Const. Art. I, § 27, and note that it states, "The people have a right to clean air, pure water, and to the preservation of the natural, scenic, historic and esthetic values of the environment." They commented that the Board and the Department must satisfy their constitutional responsibilities.

In response, the Board has fulfilled its duties as a trustee of the environment, set forth in Article I, Section 27 of the Pennsylvania Constitution and the Pennsylvania Supreme Court Ruling on the Environmental Rights Amendment in *Pennsylvania Environmental Defense Foundation v. Commonwealth of Pennsylvania*, 161 A.3d 911 (Pa. 2017) during the development of this final-form rulemaking. This final-form rulemaking was developed under the authority of sections 5(a)(1) and (8) of the APCA. The APCA is built on a precautionary principle to protect the air resources of this Commonwealth for the protection of public health and welfare and the environment, including plant and animal life and recreational resources, as well as development, attraction and expansion of industry, commerce and agriculture. Implementation of the VOC emission control measures in this final-form rulemaking will help the Department protect the air resources of this Commonwealth as well as public health and welfare by reducing harmful VOC and methane emissions from the oil and gas industry. The Department recognizes the rights of this Commonwealth's residents and the Commonwealth's obligations under the Pennsylvania Constitution and must meet those obligations in every action the agency takes. Because this final-form rulemaking simultaneously reduces VOC and methane emissions, resulting in considerable health and other benefits, the Department is satisfied that its Article I, Section 27 obligations have been met with development of this final-form rulemaking.

G. *Benefits, Costs and Compliance*

Benefits

The Department estimates that implementation of the control measures could reduce VOC emissions by as much as 2,864 TPY. Approximately 411 TPY of these VOC emission reductions are due to the RACT determinations by the Department that reduce emissions over and above the EPA's RACT recommendations. 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.

Adoption of the VOC emission control measures and other requirements in this final-form 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 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. Achieving and maintaining the ground-level ozone NAAQS provides healthful air quality which attracts and retains residents and industry, supports healthy environmental conditions for agriculture and the ecosystems of this Commonwealth, and reduces transport of VOC emissions and ground-level ozone to downwind states.

While this final-form rulemaking requires VOC emission reductions, methane emissions are also reduced as a cobenefit, because both VOC and methane are emitted from oil and 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. The control measures implemented for VOC emissions simultaneously control methane emissions and could reduce methane emissions by as much as 45,278 TPY with 33 TPY from the installation of controls for storage vessels, 14,741 TPY from pneumatic controllers, 135 TPY from pneumatic pumps, 1,172 TPY from replacement of reciprocating compressor rod packings at well sites and 29,197 TPY from fugitive emissions components through the performance of LDAR inspections. Approximately 6,124 TPY of the methane emission reductions are due to the technically and economically feasible VOC RACT determination by the Department that is over and above the reductions from EPA's VOC RACT recommendations.

Additionally, as previously discussed, this final-form 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 unconventional oil and natural gas sources is essential to reducing global greenhouse gas emissions and protecting public health.

Adverse health and welfare effects of ground-level ozone on humans, animals and the environment

Exposure to high levels of ground-level ozone air pollution correlates to increased respiratory disease and higher mortality rates. Ozone can inflame and damage the lining of the lungs. Within a few days, the damaged cells are shed and replaced. Over a long time period, lung tissue may become permanently scarred, resulting in permanent loss of lung function and a lower quality of life. When ambient ozone levels are high, more people with asthma have attacks that require a doctor's attention or use of medication. Ozone also makes people more sensitive to allergens including pet dander, pollen and dust mites, all of which can trigger asthma attacks. The EPA has concluded that there is an association between high levels of ambient ozone and increased hospital admissions for respiratory ailments including asthma. While children, the elderly and those with respiratory problems are most at risk, even healthy individuals may experience increased respiratory ailments and other symptoms when they are exposed to high levels of ambient ozone while engaged in activities that involve physical exertion. High levels of ground-level ozone also affect animals including pets, livestock and wildlife, in ways similar to humans.

In addition to causing adverse human and animal health effects, the EPA has concluded that ground-level ozone affects vegetation and ecosystems, leading to reductions in agricultural crop and commercial forest yields. 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. Through deposition, ground-level ozone also contributes to pollution in the Chesapeake Bay. These effects can have adverse impacts including loss of species diversity and changes to habitat quality and water and nutrient cycles. The implementation of additional measures to address ground-level ozone precursor emissions impacts on air quality in this Commonwealth is necessary to protect the public health and welfare and the environment.

Adverse effects of ground-level ozone on this Commonwealth's economy

The economic value of the impacts of ground-level ozone on this Commonwealth's farm crops, fruit industries, forests, parks and timber due to high concentrations of ground-level ozone can be calculated, through things such as crop yield loss from both reduced growth and smaller, lower-quality seeds and tubers with less oil or protein. If ozone episodes last a few days, visible injury to some leaf crops, including lettuce, spinach and tobacco, as well as visible injury to the leaves of ornamental plants, including grass, flowers and shrubs, can appear. Other types of welfare loss may not be quantifiable, such as the reduced aesthetic value of trees growing in heavily visited parks.

Information about the economic benefit of the agricultural industry to this Commonwealth is provided by the Department of Agriculture. In 2019, this Commonwealth had more than 53,157 farms occupying more than 7.3 million acres of farmland which account for 75,475 direct jobs and $9 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 and beverage processing, marketing, transportation, farm equipment, forestry production and processing, and landscaping. In total, production agriculture and agribusiness support 232,463 direct jobs and contribute $59.7 billion to this Commonwealth's economy. The agriculture industry, including forestry, contributes 593,600 total direct, indirect, and induced jobs and $132.5 billion in total direct, indirect, and induced output. 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 16.6 million acres, which represents 58% of its 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 the State'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 $463 million in 2019, and over $1.1 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. Forestry production and processing account for 69,437 direct jobs and $21.8 billion in direct economic output and direct value added to this Commonwealth's economy. Reducing ground-level ozone concentrations will serve to protect the 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 State and out-of-State visitors. State forests, parks and game lands make up 3.9 million acres of forest land. This Commonwealth's 2.2 million-acre State forest system, found in 48 of this Commonwealth's 67 counties, comprises 13% of the forested area in this Commonwealth. The State forest represents one of the largest expanses of public forestland in the eastern United States, making it a priceless public asset. 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.

In sum, adoption and implementation of the VOC emission control measures in this final-form rulemaking for the owners or operators of certain sources in the oil and natural gas industry is reasonably necessary to allow the Commonwealth to continue its progress in attaining and maintaining the public health-based and welfare-based 8-hour ozone NAAQS and to satisfy related CAA requirements. The VOC emission reductions achieved through implementation of the regulatory requirements established in this final-form rulemaking and the associated decrease in formation of ground-level ozone will benefit the health and welfare of the residents of this Commonwealth as well as the health of tourists and visitors, with improved ambient air quality and healthier environments. The decrease in ground-level ozone formation will also benefit farmers, loggers, hunters and outdoor enthusiasts and the numerous animals, crops, vegetation and natural areas of this Commonwealth. The agriculture and timber industries and related businesses will benefit directly from reduced economic losses that result from ozone damage to crops and timber. Likewise, the natural areas and infrastructure within this Commonwealth and downwind states will benefit directly from reduced environmental damage and economic losses due to ground-level ozone.

Additionally, this final-form 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 or 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 final-form rulemaking, thereby creating an economic opportunity for the emissions monitoring industry.

Monetized public health benefits of attaining the 2015 ozone NAAQS

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 RACT measures, but the EPA estimates are indicative of the benefits to Commonwealth residents of attaining the 2015 8-hour ozone NAAQS through the implementation of a suite of measures to control VOC emissions in the aggregate from different source categories.

Compliance costs

Compliance costs will vary for each facility depending on which compliance option is chosen by the owner or operator. The costs were adjusted to 2021 dollars using the CPI adjustment using May as the reference month.

The annualized cost of $25,194 in 2012 dollars to control one storage vessel with a control device is based on the data in the 2016 O&G CTG, which is equivalent to $30,909 in 2021 dollars. The Department's additional analysis demonstrated that the annualized cost of routing emissions from a storage vessel to a control device ranges from $9,501 to $22,871 in 2021 dollars based on the data in the Department's Technical Support Document (TSD) for the General Plan Approval/General Operating Permit BAQ-GPA/BP-5 (GP-5) for natural gas compression stations, processing plants, and transmission stations and the General Plan Approval/General Operating Permit

BAQ-GPA/GP-5A (GP-5A) for unconventional natural gas well site operations and remote pigging stations. The Department used the EPA's annualized cost estimate of $30,909 in 2021 dollars to be conservative when estimating the effect on the oil and natural gas industry. The Department identified a total of 3,889 facilities with storage vessels from the Department's databases. There are 12 facilities with 44 storage vessels that emit 2.7 TPY or more of VOC with a total industry cost of $370,908 per year. The Department estimates that implementation of the final-form control measures could reduce VOC emissions by as much as 211 TPY from the installation of controls for storage vessels. This results in an average cost of approximately $1,758 per ton of VOC emissions reduced per year. Approximately 16 TPY of the VOC emissions reduction from this requirement is due to the technically and economically feasible RACT determination by the Department that is over and above the reductions from EPA's RACT recommendations.

The annualized cost of $296 in 2012 dollars to replace a continuous high-bleed pneumatic controller with a low-bleed pneumatic controller is based on the data in the 2016 O&G CTG, which is $347 per year in 2021 dollars. The Department identified a total of 3,874 facilities with an estimated 8,572 affected pneumatic controllers. The total industry cost is $2,974,484 per year. Using the EPA's estimate of natural gas emissions per controller and this Commonwealth's average natural gas composition, the Department estimates that implementation of the final-form control measures could reduce VOC emissions by as much as 766 TPY from pneumatic controllers located at these facilities. The requirements for natural gas-driven continuous bleed pneumatic controllers are identical to the EPA's 2016 O&G CTG recommendation which the EPA has determined to be cost-effective.

The annualized cost of $774 in 2012 dollars to control one natural gas-driven diaphragm pump is based on the data in the 2016 O&G CTG, which is $907 per year in 2021 dollars. The Department identified 17 well sites with an estimated 40 affected diaphragm pumps. The total industry cost is $36,265 per year. Using the EPA's estimate of natural gas emissions per pump, this Commonwealth's average natural gas composition, and a 95.0% emissions reduction, the Department estimates that implementation of the final-form control measures could reduce VOC emissions by as much as 7 TPY from natural gas-driven diaphragm pumps. The requirements for natural gas-driven diaphragm pumps are identical to the EPA's 2016 O&G CTG recommendation which the EPA has determined to be cost-effective.

The annualized cost of $782 in 2021 dollars to replace the rod packings for one reciprocating compressor at an unconventional well site is based on the data in the Department's TSD for GP-5 and GP-5A. The Department identified 448 well sites reporting a total of 535 engines. The Department assumes that all of the engines drive reciprocating compressors. The total industry cost is $418,456 per year. The Department estimates that implementation of the final-form control measures could reduce VOC emissions by as much as 61 TPY due to the replacement of reciprocating compressor rod packings located at well sites. The Department has determined this requirement to be cost-effective since the annualized cost, the sum of the annualized capital cost and the annual operating expenses, is only $782 per year. Annualized cost is one of many factors that the Department can consider when determining the cost-effectiveness of a control device or control technique. The 61 TPY of the VOC emissions reduction from this requirement is due to the technically and economically feasible RACT determination by the Department that is over and above the reductions from the EPA's RACT recommendations.

There are an estimated 423 gathering and boosting stations with at least 527 reciprocating compressors and an estimated 11 natural gas processing plants with at least 30 reciprocating compressors. The Department assumes that the owners or operators of these facilities are complying with the requirements of Subparts OOOO and OOOOa as none of these facilities were constructed prior to 2011. Therefore, they would have to do nothing further under this final-form rulemaking.

The annualized cost of $2,553 in 2012 dollars to control one wet seal degassing system for a centrifugal compressor is based on the data in the 2016 O&G CTG which is $2,990 in 2021 dollars. The Department identified three gathering and boosting stations reporting at least seven turbines and two processing plants reporting at least two turbines. The Department assumes that all of the turbines drive centrifugal compressors. These centrifugal compressors are all likely to be dry seal centrifugal compressors and the owners or operators of these sources would not have applicable VOC emission control requirements under this final-form rulemaking. If one or more of these compressors is a wet seal centrifugal compressor, the owner or operator would be subject to the applicable wet seal degassing system VOC emission control requirements of this final-form rulemaking. VOC emissions would be reduced by 95.0% at a cost of $2,990 per year per wet seal degassing system in 2021 dollars. The requirements for wet seal centrifugal compressor degassing systems are identical to the EPA's 2016 O&G CTG recommendation which the EPA has determined to be cost effective.

In the 2016 O&G CTG, the annualized cost in 2012 dollars to conduct annual LDAR inspections at an unconventional well site is $1,318, to conduct quarterly LDAR inspections at an unconventional well site is $4,220 and to conduct quarterly LDAR inspections at a gathering and boosting station is $25,049. These costs are $1,554, $4,937 and $29,307 in 2021 dollars, respectively. The Department's TSD for GP-5 and GP-5A also contained cost data for implementing LDAR programs, which are more conservative than the annual costs in the EPA's 2016 O&G CTG as the costs in the TSD are based on a contractor's quote. The annual cost for implementing an annual LDAR inspection program is $1,681 in 2021 dollars at an unconventional well site. The annual cost, in 2021 dollars, for implementing a quarterly LDAR inspection program is $6,723 at an unconventional well site and $13,447 for a gathering and boosting station or natural gas processing plant. It should be noted that the estimates for unconventional well sites assumed there are 1,000 components to monitor and that for gathering and boosting stations or natural gas processing plants there are 2,000 components to monitor. The EPA's assumptions for the number of components to monitor are between 127 and 671 for well sites and 3,091 for gathering and boosting stations or processing plants.

The Department identified a total of 3,889 facilities covered by this final-form rulemaking, including unconventional well sites, gathering and boosting stations, and natural gas processing plants. The calculation of fugitive emissions before control were based on estimates of the amount of natural gas leaked. The breakdown between the amounts of VOC and methane emissions is calculated using this Commonwealth's natural gas composition ratio of 4.47% VOC and 86.03% methane. The value of natural gas saved is calculated using the assumed cost of $1.70 per Mcf of natural gas in 2021 dollars.

There are approximately six unconventional well sites with no LDAR program currently in place that the Department assumes will be required to implement an annual LDAR program. The total annualized cost is $10,086 reducing VOC emissions by approximately 1 TPY for a total cost per ton of VOC reduced of $410,086. The 1 TPY of the VOC emissions reduction from this requirement is due to the technically and economically feasible RACT determination by the Department that is over and above the reductions from the EPA's RACT recommendations.

There are approximately 1,461 unconventional well sites with no LDAR program currently in place that the Department assumes will be required to implement a quarterly LDAR program. The total annualized cost is $9,822,303 reducing VOC emissions by approximately 501 TPY. The Department has determined this requirement to be cost-effective since the annualized cost is only $6,723 per year. Approximately 125 TPY of the VOC emissions reduction from this requirement is due to the technically and economically feasible RACT determination by the Department that is over and above the reductions from the EPA's RACT recommendations.

There are approximately 499 unconventional well sites currently required to perform annual LDAR that the Department assumes will be required to implement a quarterly LDAR program. The total annualized cost is $2,516,255 reducing VOC emissions by approximately 314 TPY. The Department has determined this requirement to be cost-effective since the incremental annualized cost is only $5,043 per year. Approximately 79 TPY of the VOC emissions reduction from this requirement is due to the technically and economically feasible RACT determination by the Department that is over and above the reductions from the EPA's RACT recommendations.

There are approximately 650 unconventional well sites currently required to perform semiannual LDAR that the Department assumes will be required to implement a quarterly LDAR program. The total annualized cost is $2,185,125 reducing VOC emissions by approximately 517. The Department has determined this requirement to be cost-effective since the incremental annualized cost is only $3,362 per year. Approximately 129 TPY of the VOC emissions reduction from this requirement is due to the technically and economically feasible RACT determination by the Department that is over and above the reductions from the EPA's RACT recommendations.

There are approximately 263 gathering and boosting stations with no LDAR program currently in place based on their construction date, the lack of LDAR requirements in their permits, or that have no reported fugitive emissions components. The Department assumes these facilities will be required to implement a quarterly LDAR program. The total annualized cost is $3,536,561. Using the EPA's estimate of fugitive natural gas emissions per gathering and boosting station and this Commonwealth's average natural gas composition, the Department estimates a VOC emissions reduction of 473 TPY. The requirements for quarterly LDAR at natural gas gathering and boosting stations are identical to the EPA's 2016 O&G CTG recommendation which the EPA has determined to be cost-effective.

There is one gathering and boosting station with an annual LDAR program currently in place that the Department assumes will be required to implement a quarterly program. The total annualized cost is $10,085. The requirements for quarterly LDAR at natural gas gathering and boosting stations are identical to the EPA's 2016 O&G CTG recommendation which the EPA has determined to be cost-effective.

There is one natural gas processing plant with no LDAR program currently in place that the Department assumes will be required to implement a quarterly LDAR program. The total annualized cost is $13,447 reducing VOC emissions by approximately 12 TPY for a total cost per ton of VOC reduced of $1,121.

The total industry cost is approximately $18,094,239 in 2021 dollars. The Department estimates that these final-form control measures could reduce VOC emissions by 1,819 TPY or more from the subject fugitive emissions components due to implementation of the required LDAR inspection program at these facilities.

Based on the previous compliance costs, and the number of applicable sources, the Department estimates that this final-form rulemaking will cost affected owners or operators approximately $21.9 million (based on 2021 dollars) per year without consideration of the economic benefit of the saved natural gas. The value of the saved natural gas, assuming a natural gas price of $1.70 per Mcf in 2021 dollars, yields a savings of approximately $4.6 million, resulting in a total net cost of approximately $17.3 million for this final-form rulemaking.

This estimate consists of two major categories of data. The first is the cost per year to control each piece of equipment or site affected, which came from either the 2016 O&G CTG or the Department's TSD for GP-5 and GP-5A, as detailed in the response to Question 17 of the RAF. The second is the number of potentially affected facilities, which were obtained from several data sources including the Department's Oil and Gas Production Report, eFACTS and AIMS. The cost per year to control each piece of equipment or site affected was multiplied by the number of each in this Commonwealth. The costs for each category of sources were added together to come up with a final estimated cost and savings.

The VOC RACT requirements established by this final-form rulemaking will not require the owner or operator to obtain an operating permit or submit an application for amendments to an existing operating permit. These requirements will be incorporated into the existing operating permit 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 this final-form rulemaking, as required under § 127.463(b).

Compliance assistance plan

The Department will continue to educate and assist the public and the regulated community in understanding the requirements and how to comply with them throughout the rulemaking process. 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 final-form rulemaking are minimal because the records required align with the records already required to be kept for emission inventory purposes and for other Federal and State requirements. To minimize the burden of these requirements, the Department allows electronic submission of most planning, reporting and recordkeeping forms required by this final-form rulemaking.

H. *Pollution Prevention*

The Pollution Prevention Act (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 final-form rulemaking helps to ensure that the residents of this Commonwealth benefit from reduced emissions of VOC and methane from regulated sources. Reduced levels of VOC and methane promote healthful air quality and ensure the continued protection of the environment and public health and welfare.

I. *Sunset Review*

This Board is not establishing a sunset date for this final-form rulemaking because it is needed for the Department to carry out its statutory authority. The Department will closely monitor this final-form rulemaking effectiveness and recommend updates to the Board as necessary.

J. *Regulatory Review*

Under section 5(a) of the RRA (71 P.S. § 745.5(a)), on April 27, 2020, the Department submitted a copy of the notice of proposed rulemaking, published at 50 Pa.B. 2633, to IRRC and to the Chairpersons of the House and Senate Environmental Resources and Energy Committees for review and comment.

Under section 5(c) of the RRA, IRRC and the House and Senate Committees were provided with copies of the comments received during the public comment period, as well as other documents when requested. In preparing this final-form rulemaking, the Department has considered all comments from IRRC, the House and Senate Committees and the public.

Under section 5.1(e) of the RRA, IRRC met on July 21, 2022, and approved this final-form rulemaking. This final-form rulemaking is deemed approved by the General Assembly.

K. *Findings of the Board*

The Board finds that:

(1) Public notice of proposed rulemaking was given under sections 201 and 202 of the act of July 31, 1968 (P.L. 769, No. 240) (45 P.S. §§ 1201 and 1202), referred to as the Commonwealth Documents Law, and regulations promulgated thereunder at 1 Pa. Code §§ 7.1 and 7.2 (relating to notice of proposed rulemaking required; and adoption of regulations).

(2) At least a 60-day public comment period was provided as required by law and all comments were considered.

(3) This final-form rulemaking does not enlarge the purpose of the proposed rulemaking published at 50 Pa.B. 2633.

(4) These regulations are reasonably necessary and appropriate for administration and enforcement of the authorizing acts identified in section C of this order.

(5) These regulations are reasonably necessary to attain and maintain the ozone NAAQS and to satisfy related CAA requirements.

L. *Order of the Board*

The Board, acting under the authorizing statutes, orders that:

(a) The regulations of the Department, 25 Pa. Code Chapters 121 and 129, are amended by amending § 121.1 and adding §§ 129.121—129.130 to read as set forth in Annex A, with ellipses referring to the existing text of the regulations.

(*Editor's Note*: Proposed § 129.124 was renamed from natural gas-driven pneumatic controllers to natural gas-driven continuous bleed pneumatic controllers in this final-form rulemaking.)

(b) The Chairperson of the Board shall submit this final-form rulemaking to the Office of General Counsel and the Office of Attorney General for review and approval as to legality and form, as required by law.

(c) The Chairperson of the Board shall submit this final-form rulemaking to IRRC and the House and Senate Committees as required by the RRA.

(d) The Chairperson of the Board shall certify this final-form rulemaking and deposit it with the Legislative Reference Bureau as required by law.

(e) This final-form rulemaking will be submitted to the EPA as a revision to the Commonwealth's SIP.

(f) This final-form rulemaking shall take effect immediately upon publication in the *Pennsylvania Bulletin*.

RAMEZ ZIADEH, P.E.,
Acting Chairperson

(*Editor's Note*: See 52 Pa.B. 4479 (August 6, 2022) for IRRC's approval order.)

Fiscal Note: Fiscal Note 7-544 remains valid for the final adoption of the subject regulations.

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—The 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—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), Chapter 127 (relating to construction, modification, reactivation and operation of sources) or Chapter 129.

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CHAPTER 129. STANDARDS FOR SOURCES

CONTROL OF VOC EMISSIONS FROM UNCONVENTIONAL OIL AND NATURAL GAS SOURCES

§ 129.121. General provisions and applicability.

(a) *Applicability*. Beginning December 10, 2022, this section and §§ 129.122—129.130 apply to an owner or operator of one or more of the following unconventional oil and natural gas sources of VOC emissions installed at an unconventional well site, a gathering and boosting station or a natural gas processing plant in this Commonwealth which were constructed on or before December 10, 2022:

(1) Storage vessels at:

(i) An unconventional well site.

(ii) A gathering and boosting station.

(iii) A natural gas processing plant.

(iv) The natural gas transmission and storage segment.

(2) Natural gas-driven continuous bleed 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 December 10, 2022, 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 (relating to general provisions and applicability) 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 natural gas-driven continuous bleed 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.

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 pipes or a pipe 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.

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—For purposes of § 129.127 (relating to fugitive emissions components):

(i) An action using best practices taken to stop or reduce fugitive emissions to the atmosphere.

(ii) The term includes:

(A) Tightening bonnet bolts.

(B) Replacing bonnet bolts.

(C) Tightening packing gland nuts.

(D) Injecting lubricant into lubricated packing.

Flare—

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

(ii) The term does not include a horizontally or vertically installed ignition device or pit flare used to combust otherwise vented emissions from completions.

Flow line—A pipeline used to transport oil or gas, or both, to processing equipment, compression equipment, storage vessel or other collection system for further handling or to a mainline pipeline.

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 continuous bleed 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 both of the following:

(i) Employed by the same owner or operator as the responsible official that signs the certification required under § 129.130(k) (relating to recordkeeping and reporting).

(ii) Qualified by education, technical knowledge and expertise in the design and operation of a natural gas-driven diaphragm pump or closed vent system to make the technical certification required under § 129.125(c)(3)(ii) (relating to natural gas-driven diaphragm pumps) or § 129.128(c)(3), or both, as applicable.

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

LDAR—Leak detection and repair.

Leak—An emission detected using one or more of the following methods:

(i) Through audible, visual or odorous evidence during an AVO inspection.

(ii) By OGI equipment calibrated according to § 129.127(h) (relating to fugitive emissions components).

(iii) With a concentration of 500 ppm or greater as methane or equivalent by a gas leak detector calibrated according to § 129.127(i).

(iv) Using an alternative leak detection method approved by the Department in § 129.127(c)(2)(ii)(C), (c)(3)(ii)(C) or (e)(2)(iii).

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 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 continuous bleed pneumatic controller—An automated instrument used for maintaining a process condition such as liquid level, pressure, delta-pressure or temperature powered by a continuous flow of 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—

(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 transmission and storage segment—The term includes the following:

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

(ii) The natural gas transmission stations which include the following:

(A) The land, mains, valves, meters, boosters, regulators, storage vessels, dehydrators and compressors.

(B) The driving units and appurtenances associated with the items listed in clause (A).

(C) The 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.

(iii) The 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—The results of EPA Method 25A.

UIC—Underground injection control.

UIC Class I oilfield disposal well—A well with a UIC Class I permit that meets the definition in 40 CFR 144.6(a)(2) (relating to classification of wells) and receives eligible fluids from oil and natural gas exploration and production operations.

UIC Class II oilfield disposal well—A well with a UIC Class II permit where wastewater resulting from oil and natural gas production operations is injected into underground porous rock formations not productive of oil or gas and sealed above and below by unbroken, impermeable strata.

Unconventional formation—A geological shale formation existing below the base of the Elk Sandstone or its geologic equivalent stratigraphic interval where natural gas generally cannot be produced at economic flow rates or in economic volumes except by vertical or horizontal well bores stimulated by hydraulic fracture treatments or by using multilateral well bores or other techniques to expose more of the formation to the well bore.

Unconventional well—A bore hole drilled or being drilled for the purpose of or to be used for the production of natural gas from an unconventional formation.

Unconventional well site—A location with one or more unconventional wells.

VRU—vapor recovery unit—A device used to recover vapor and route it to a process, flow line or other equipment.

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 unconventional 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.

(iii) For purposes of the fugitive emissions standards in § 129.127, the term does not include:

(A) A UIC Class I oilfield disposal well.

(B) A UIC Class II oilfield disposal well and disposal facility.

(C) The flange immediately upstream of the custody meter assembly.

(D) Equipment, including fugitive emissions components, located downstream of the flange in clause (C).

(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 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 as defined in § 129.122 (relating to definitions, acronyms and EPA methods) prior to February 8, 2023, for an existing storage vessel.

(ii) The determination of potential VOC emissions may 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 December 10, 2023, 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 maintains actual VOC emissions less than 2.7 TPY determined as a 12-month rolling sum. 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) Beginning on or before January 9, 2023, calculate the actual VOC emissions once per calendar month 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 45 calendar days.

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

(ii) Comply with subsection (b) within 1 year of the date of the monthly calculation showing that actual VOC emissions from the storage vessel have increased to 2.7 TPY VOC or greater.

(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)(3)(i).

§ 129.124. Natural gas-driven continuous bleed pneumatic controllers.

(a) *Applicability*. This section applies to the owner or operator of a natural gas-driven continuous bleed 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 continuous bleed 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 December 10, 2023, the owner or operator of a natural gas-driven continuous bleed pneumatic controller subject to this section shall do the following:

(1) Ensure each natural gas-driven continuous bleed pneumatic controller with a natural gas bleed rate greater than 6.0 standard cubic feet per hour, at a location other than a natural gas processing plant, maintains a natural gas bleed rate of less than or equal to 6.0 standard cubic feet per hour.

(2) Ensure each natural gas-driven continuous bleed pneumatic controller maintains a natural gas bleed rate of zero standard cubic feet per hour, if located at a natural gas processing plant.

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

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

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

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

(e) *Recordkeeping and reporting requirements*. The owner or operator of a natural gas-driven continuous bleed pneumatic controller affected under subsection (c) shall maintain the records under § 129.130(c) (relating to recordkeeping and reporting) and submit the reports under § 129.130(k)(3)(ii).

§ 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 December 10, 2023, the owner or operator of a natural gas-driven diaphragm pump subject to this section shall comply with the following:

(1) *Unconventional well site*. The owner or operator of a natural gas-driven diaphragm pump located at a well site shall reduce the VOC emissions by 95.0% by weight or greater. The owner or operator 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. An owner or operator that claims this exception shall do the following:

(i) Maintain the records under § 129.130(d)(4) (relating to recordkeeping and reporting).

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

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

(2) Has no available control device or process. An owner or operator that claims this exception shall do the following:

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

(ii) Certify that there is no available control device or process in the next annual report required by § 129.130(k)(1).

(iii) 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 subparagraph (ii) 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. An owner or operator that claims this exception shall do the following:

(i) Maintain the records under § 129.130(d)(6).

(ii) Perform an assessment of technical infeasibility which must meet 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)(iii).

§ 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*. Beginning December 10, 2023, 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) December 10, 2022, 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) December 10, 2025, for a reciprocating compressor rod packing that has not yet been replaced.

(2) Route the VOC emissions to a control device or a process that meets § 129.129 (relating to control devices) 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.

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

(d) *Exemptions*. Subsection (c) does not apply to the owner or operator of 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)(3)(iv).

(2) For a centrifugal compressor, maintain the records under § 129.130(f) and submit the reports under § 129.130(k)(3)(v).

§ 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) An unconventional well site.

(2) A natural gas gathering and boosting station.

(3) A natural gas processing plant.

(b) *Average production calculation procedure for a well site*. Beginning on or before January 9, 2023:

(1) The owner or operator of a well site subject to subsection (a)(1) shall calculate the average production in barrels of oil equivalent per day of the well site using the previous 12 calendar months of operation as reported to the Department and thereafter as specified in subsection (c)(4) for the previous calendar year. The owner or operator shall do the following:

(i) For each well at the well site with production reported to the Department:

(A) Record the barrels of oil produced for each active well.

(B) Convert the natural gas production for each active well to equivalent barrels of oil by dividing the standard cubic feet of natural gas produced by 6,000 standard cubic feet per barrel of oil equivalent.

(C) Convert the condensate production for each active well to equivalent barrels of oil by multiplying the barrels of condensate by 0.9 barrels of oil equivalent per barrel of condensate.

(ii) Calculate the total production for each active well, in barrels of oil equivalent, by adding the results of subparagraph (i)(A)—(C) for each active well.

(iii) Sum the results of subparagraph (ii) for all active wells at the well site and divide by 365 or 366 days for the previous 12 calendar months or the previous calendar year, as applicable.

(2) If the owner or operator does not know the production of an individual well at the well site, the owner or operator shall comply with subsection (c)(2).

(c) *Requirements for an unconventional well site*.

(1) For a well site consisting of only oil wells, the owner or operator shall:

(i) Determine the GOR of the oil well site using generally accepted methods.

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

(iii) If the GOR of the oil well site is equal to or greater than 300 standard cubic feet of gas per barrel of oil produced, meet the requirements of paragraph (2) or paragraph (3) based on the results of subsection (b)(1).

(2) For a well site producing, on average, equal to or greater than 15 barrels of oil equivalent per day, with at least one well producing, on average, equal to or greater than 15 barrels of oil equivalent per day, the owner or operator shall:

(i) Conduct an initial AVO inspection on or before February 8, 2023, with monthly inspections thereafter separated by at least 15 calendar days but not more than 45 calendar days.

(ii) Conduct an initial LDAR inspection program on or before February 8, 2023, with quarterly inspections thereafter separated by at least 60 calendar days but not more than 120 calendar days using one or more of the following:

(A) OGI equipment.

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

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

(3) For a well site producing, on average, equal to or greater than 15 barrels of oil equivalent per day, and at least one well producing, on average, equal to or greater than 5 barrels of oil equivalent per day but less than 15 barrels of oil equivalent per day, the owner or operator shall:

(i) Conduct an initial AVO inspection on or before February 8, 2023, with monthly inspections thereafter separated by at least 15 calendar days but not more than 45 calendar days.

(ii) Conduct an initial LDAR inspection program on or before May 9, 2023, with annual inspections thereafter separated by at least 335 calendar days but not more than 395 calendar days using one or more of the following:

(A) OGI equipment.

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

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

(4) The owner or operator of a producing well site shall calculate the average production of the well site under subsection (b) for the previous calendar year not later than February 15 and may adjust the frequency of the required LDAR inspection as follows:

(i) If two consecutive calculations show reduced production, the owner or operator may adopt the requirements applicable to the reduced production level.

(ii) If a calculation shows higher production, the owner or operator shall adopt the requirements applicable to the higher production level immediately.

(5) The owner or operator of a well site subject to paragraph (3) may submit to the appropriate Department Regional Office a request, in writing, for an exemption from the requirements of paragraph (3)(ii).

(i) The written request must include the following:

(A) Name and location of the well site.

(B) A demonstration that the requirements of paragraph (3)(ii) are not technically or economically feasible for the well site.

(C) Sufficient methods for demonstrating compliance with all applicable standards or regulations promulgated under the Clean Air Act or the Act.

(D) Sufficient methods for demonstrating compliance with this section, §§ 129.121—129.126 and 129.128—129.130.

(ii) The Department will review the complete written request submitted in accordance with subparagraph (i) and approve or deny the request in writing.

(iii) The Department will submit each exemption determination approved under subparagraph (ii) to the Administrator of the EPA for approval as a revision to the SIP. The owner or operator shall bear the costs of public hearings and notifications, including newspaper notices, required for the SIP submittal.

(iv) The owner or operator of the well site identified in subparagraph (i)(A) shall remain subject to the requirements of paragraphs (1), (3)(i) and (4).

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

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

(2) The date of the next required LDAR inspection after the unconventional well site is put into production.

(e) *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 initial AVO inspection on or before February 8, 2023, with monthly inspections thereafter separated by at least 15 calendar days but not more than 45 calendar days.

(2) An initial LDAR inspection program on or before February 8, 2023, with quarterly inspections thereafter separated by at least 60 calendar days but not more than 120 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.

(f) *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.

(g) *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 (h).

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

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

(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 13 months apart.

(h) *Verification procedures for OGI equipment*. An owner or operator that identifies OGI equipment in the fugitive emissions monitoring plan in subsection (g)(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 verification check each day prior to use.

(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 by using the following procedures:

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

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

(iii) Dealing with interferences, such as steam.

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

(i) *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 (g)(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.

(j) *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.

(k) *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.

(l) *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 is no visible leak image when using OGI equipment calibrated according to subsection (h).

(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 (i).

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

(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.

(m) *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)(3)(vi).

§ 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 initial AVO inspection on or before February 8, 2023, with monthly inspections thereafter separated by at least 15 calendar days but not more than 45 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(l) (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)(3)(vii).

(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 § 129.123(b)(1)(ii), § 129.125(b)(1)(i) or (c)(1)(ii) (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 initial AVO inspection on or before February 8, 2023, with monthly inspections thereafter separated by at least 15 calendar days but not more than 45 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) during the facility's scheduled LDAR inspection in accordance with § 129.127(c)(2)(ii), (c)(3)(ii) or (e)(2).

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

(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 on or before February 8, 2023, with monthly inspections separated by at least 15 calendar days but not more than 45 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)(3)(viii).

(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 inspection required under subsection (b)(2)(ii) by performing one of the following:

(1) Use OGI equipment that meets § 129.127(h).

(2) Use a gas leak detection instrument that meets § 129.127(i). The owner or operator may adjust the gas leak detection instrument readings as specified in § 129.127(k).

(3) Use another leak detection method approved by the Department.

(4) 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).

§ 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)(3)(ix).

(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 45 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 45 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 subparagraph (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 applicable to the control device if the manufacturer's repair instructions are not available.

(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 to demonstrate that the mass content of VOC in the gases vented to the device is reduced by 95.0% by weight or greater.

(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 under 40 CFR Part 270 (relating to EPA administered permit programs: the hazardous waste permit program) that implements the requirements of 40 CFR Part 264, Subpart X (relating to miscellaneous units).

(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 under 40 CFR Part 270 that implements the requirements of 40 CFR Part 266, Subpart H (relating to hazardous waste burned in boilers and industrial furnaces).

(C) An industrial furnace designed and operated in accordance with the interim status requirements of 40 CFR Part 266, Subpart H.

(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 45 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 120 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 120 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) The owner or operator shall do the following, as applicable:

(i) Except as specified in subparagraph (iii), conduct an initial performance test within 180 days after installation of a control device.

(ii) Except as specified in subparagraph (iii), conduct a performance test of an existing control device on or before August 7, 2023, unless the owner or operator of the control device is complying with an established performance test interval, in which case the current schedule should be maintained.

(iii) The performance test in subparagraph (i) or subparagraph (ii) is not required if the owner or operator meets one or more of the following:

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

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

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

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

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

(I) 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.

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

(III) 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.

(IV) 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.

(F) 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):

(I) Was submitted to the Department.

(II) 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.

(G) 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)(iii)(A)—(G).

(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)(2)(i) including the following information:

(i) The date of each monthly calculation performed under § 129.123(c)(2)(i).

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

(iii) The calculation demonstrating that the actual VOC emissions are less than 2.7 TPY determined as a 12-month rolling sum.

(7) The records documenting the time the skid-mounted or mobile storage vessel under § 129.123(d)(1) 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 continuous bleed pneumatic controllers*. The records for each natural gas-driven continuous bleed pneumatic controller must include the following, as applicable:

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

(2) Each deviation when the natural gas-driven continuous bleed pneumatic controller was not operated in compliance with the requirements specified in § 129.124(c).

(3) If the natural gas-driven continuous bleed 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 continuous bleed 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 required compliance 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)(iii)(B)(II).

(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(b)(1), the demonstration under § 129.125(b)(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 control device or 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 an oil well site subject to § 129.127(c)(1)(ii) (relating to fugitive emissions components):

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

(ii) The analysis documenting a GOR of less than 300 standard cubic feet of gas per 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 each well site, the average production calculations required under § 129.127(b)(1) and § 129.127(c)(4).

(3) For a well site subject to § 129.127(c)(2) or (c)(3), a natural gas gathering and boosting station or a natural gas processing plant:

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

(ii) The records of each monitoring survey conducted under § 129.127(c)(2)(ii), (c)(3)(ii) or (e)(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.

(h) *Covers*. The records for each cover include 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)(3)(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 that owns or operates the control device.

(B) The location of the control device.

(C) The name and affiliation 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 do the following:

(1) Submit an initial annual report to the Air Program Manager of the appropriate Department Regional Office by December 10, 2023, and annually thereafter on or before June 1.

(i) The responsible official must sign, date and certify compliance and include the certification in the initial report and each subsequent annual report.

(ii) The due date of the initial report may be extended with the written approval of the Air Program Manager of the appropriate Department Regional Office.

(2) Submit the reports under paragraph (3) in a manner prescribed by the Department.

(3) Submit the information specified in subparagraphs (i)—(ix) for each report as applicable:

(i) *Storage vessels*. The report for each storage vessel must include the information specified in subsection (b)(1)—(4) for the reporting period, as applicable.

(ii) *Natural gas-driven continuous bleed pneumatic controllers*. The initial report for each natural gas-driven continuous bleed pneumatic controller must include the information specified in subsection (c), as applicable. Subsequent reports must include the following:

(A) The information specified in subsection (c)(1) and (2) for each natural gas-driven continuous bleed pneumatic controller.

(B) The information specified in subsection (c)(3) and (4) for each natural gas-driven continuous bleed pneumatic controller installed during the reporting period.

(iii) *Natural gas-driven diaphragm pumps*. The report for each natural gas-driven diaphragm pump must include the following:

(A) The information specified in subsection (d)(1) and (2) for the reporting period, as applicable.

(B) A certification of the compliance status of each natural gas-driven diaphragm pump during the reporting period using one of the following:

(I) 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)(iii), include the information specified in subsection (d)(4).

(II) 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.

(III) A certification according to § 129.125(c)(3)(ii)(C) that it is technically infeasible to capture and route emissions from:

(-a-) A natural gas-driven diaphragm pump installed during the reporting period to an existing control device or process.

(-b-) An existing natural gas-driven diaphragm pump to a control device or process installed during the reporting period.

(-c-) 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.

(iv) *Reciprocating compressors*. The report for each reciprocating compressor must include the information specified in subsection (e) for the reporting period, as applicable.

(v) *Centrifugal compressors*. The report for each centrifugal compressor must include the information specified in subsection (f) for the reporting period, as applicable.

(vi) *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)(3)(ii).

(vii) *Covers*. The report for each cover must include the information specified in subsection (h) for the reporting period, as applicable.

(viii) *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 for the initial report or if the closed vent system was installed during the reporting period.

(ix) *Control devices*. The report for each control device must include the information specified in subsection (j), as applicable.

[Pa.B. Doc. No. 22-1924. Filed for public inspection December 9, 2022, 9:00 a.m.]

Title 25—ENVIRONMENTAL PROTECTION

ENVIRONMENTAL QUALITY BOARD

[25 PA. CODE CH. 129]

Control of VOC Emissions from Conventional Oil and Natural Gas Sources

The Environmental Quality Board (Board) amends Chapter 129 (relating to standards for sources) to read as set forth in Annex A. This final-omitted rulemaking adds §§ 129.131—129.140 (relating to control of VOC emissions from conventional oil and natural gas sources) to adopt reasonably available control technology (RACT) requirements and RACT emission limitations for conventional oil and natural gas sources of volatile organic compound (VOC) emissions. These sources include natural gas-driven continuous bleed pneumatic controllers, natural gas-driven diaphragm pumps, reciprocating compressors, centrifugal compressors, fugitive emissions components and storage vessels installed at conventional well sites, gathering and boosting stations and natural gas processing plants, as well as storage vessels in the natural gas transmission and storage segment. The Board adds definitions, acronyms and United States Environmental Protection Agency (EPA) methods to § 129.132 (relating to definitions, acronyms and EPA methods) to support the implementation of the control measures. Notice of proposed rulemaking is omitted under section 204(3) of the act of July 31, 1968 (P.L. 769, No. 240) (45 P.S. § 1204(3)), referred to as the Commonwealth Documents Law (CDL). This final-omitted rulemaking is also being submitted as an emergency certified regulation under section 6(d) of the Regulatory Review Act (RRA) (71 P.S. § 745.6(d)).

Rulemaking Background and History

On December 17, 2019, the Board adopted the Control of VOC Emissions from Oil and Natural Gas Sources proposed rulemaking (referred to as the combined rulemaking). On May 23, 2020, the combined rulemaking included VOC RACT requirements for five categories of oil and natural gas sources of VOC emissions in this Commonwealth, including sources used by the unconventional and conventional industries. The combined rulemaking was published for a 66-day comment period at 50 Pa.B. 2633 (May 23, 2020). Three public hearings were held virtually on June 23, 24 and 25, 2020. Over 100 individuals provided verbal testimony. The comment period closed on July 27, 2020. The Board received over 4,500 comments, including comments from the House and Senate Environmental Resources and Energy Committees (ERE Committees), members of the General Assembly and the Independent Regulatory Review Commission (IRRC). The majority of the commentators expressed their support for the VOC RACT requirements in the combined rulemaking, noting the need to address air emissions from the oil and gas sector. On March 15, 2022, the Board adopted the combined rulemaking as a final-form rulemaking.

Also, on March 15, 2022, the Board submitted the final-form combined rulemaking to IRRC for its consideration. On April 26, 2022, the House ERE Committee sent a letter to IRRC indicating their disapproval of the combined rulemaking due to their interpretation of language in the Pennsylvania Grade Crude Development Act, the act of June 23, 2016 (P.L. 375, No. 52) (58 P.S. §§ 1201—1208), known as Act 52 of 2016. The letter stated the House ERE Committee's position that Act 52 of 2016 requires the Board to submit two rulemaking packages—one that applies to unconventional oil and natural gas sources and one that applies to conventional oil and natural gas sources. The House ERE Committee's letter to IRRC initiated the concurrent resolution process under section 7(d) of the RRA (71 P.S. § 745.7(d)) which allows the General Assembly to adopt a resolution that disapproves and permanently bars a final regulation from taking effect.

While the Board disagrees with the House ERE Committee's interpretation of Act 52 of 2016, to address their concerns and avoid further delay, on May 4, 2022, the Board withdrew the combined rulemaking from IRRC's consideration. The Board then revised the combined rulemaking to apply only to unconventional oil and natural gas sources. On June 14, 2022, the Board adopted the revised Control of VOC Emissions from Unconventional Oil and Natural Gas Sources final-form rulemaking (referred to as the unconventional rulemaking). On July 21, 2022, IRRC unanimously approved the unconventional rulemaking.

Given the concerns expressed by the House ERE Committee and other commentators during the regulatory process for the combined rulemaking, the Department developed a separate rulemaking to control VOC emissions from conventional oil and natural gas sources. At the October 12, 2022, meeting, the Board adopted the "Control of VOC Emissions from Conventional Oil and Natural Gas Sources" final-omitted rulemaking, regulation # 7-579. On November 14, 2022, the House ERE Committee disapproved the previously adopted final-omitted regulation triggering the 14-calendar-day legislative review period under section 5.1(j.2) of the RRA (71 P.S. § 745.5a(j.2)). During that 14-day period, the regulation may not be published in the *Pennsylvania Bulletin*. The 14-day period began after IRRC issued its approval order of regulation # 7-579 on November 17, 2022, and the 2022 legislative session ended on November 30, 2022. Under section 5.1(j.3) of the RRA (71 P.S. § 745.5a(j.3)), the legislative review period will therefore run into the 2023 legislative session ensuring that regulation # 7-579 could not be published by the December 16, 2022, sanction deadline.

This final-omitted rulemaking, regulation # 7-580, is identical to the previous final-omitted rulemaking (regulation # 7-579) except it has received an emergency certification of need from Governor Tom Wolf.

Final-Omitted Rulemaking and Emergency Certification of Need

Under section 201 of the CDL (45 P.S. § 1201), an agency is required to provide public notice of its intention to promulgate, amend or repeal administrative regulations. Section 202 of the CDL (45 P.S. § 1202) also requires agencies to review and consider any written comments submitted under section 201 and authorizes agencies to hold public hearings as appropriate. However, under section 204 of the CDL, an agency may omit or modify the procedures specified in sections 201 and 202 of the CDL, if:

The agency for good cause finds (and incorporates the finding and a brief statement of the reasons therefor in the order adopting the administrative regulation or change therein) that the procedures specified in sections 201 and 202 of the CDL are in the circumstances impracticable, unnecessary, or contrary to the public interest.

Public notice and solicitation of public comments are impracticable, unnecessary and contrary to the public interest for the amendments included in this final-omitted rulemaking. These procedures are impracticable and unnecessary because the VOC RACT requirements for the conventional oil and natural gas sources covered by this final-omitted rulemaking are identical to those contained in the combined rulemaking. As detailed previously, the Board provided a comment period and three public hearings for the combined rulemaking and numerous members of the public provided testimony and submitted comments. Those comments were then used in the development of the final-form combined rulemaking and this final-omitted rulemaking. Therefore, this final-omitted rulemaking was already subject to a notice and comment process when the combined rulemaking was published in the *Pennsylvania Bulletin* on May 23, 2020.

The comment and response document included with this final-omitted rulemaking contains all comments received during the comment period for the combined rulemaking. A public comment period is also contrary to the public interest because it will delay the implementation of the VOC RACT requirements in this final-omitted rulemaking, resulting in the Commonwealth being unable to satisfy the December 16, 2022, sanction deadline, as explained in Section D of this preamble under "Findings of Failure to Submit, sanctions and deadline for action." If the Board were to provide notice of proposed rulemaking, and an additional public comment period and public hearings, the Commonwealth would be unable to submit this rulemaking to the EPA as a State Implementation Plan (SIP) revision by December 16, 2022. The entire rulemaking process in this Commonwealth takes about 2 years, sometimes longer, from start to finish, and the concurrent resolution process under the RRA further lengthens that timeline. Additional delay of this final-omitted rulemaking would further harm the public interest because the Commonwealth would lose hundreds of millions of dollars in Federal highway funding and much needed VOC and methane emission reductions. As a result, the Board finds that the use of the final-omitted rulemaking process is for good cause and that additional public comment in this case is not necessary or in the public interest.

This final-omitted rulemaking is also being submitted as an emergency certified regulation. Section 6(d) of the RRA allows an agency to immediately implement a final-omitted regulation when the Governor certifies that promulgation is necessary to respond to an emergency circumstance specified in the RRA. On November 30, 2022, Governor Tom Wolf issued a Certification of Need for Emergency Regulation finding that this final-omitted rulemaking is required to prevent "the need for supplemental or deficiency appropriations of greater than $1,000,000."

Governor Tom Wolf determined that this emergency certified final-omitted rulemaking is necessary to ensure the Commonwealth complies with the Federal Clean Air Act (CAA) and the Air Pollution Control Act (APCA). As discussed previously, if the Commonwealth does not submit this final-omitted rulemaking to the EPA as a SIP revision by the December 16, 2022, sanction deadline, Federal highway funding will be withheld until the submission is made. For the upcoming fiscal year, Federal highway funds subject to these sanctions are estimated to be in the hundreds of millions of dollars in the nonattainment areas. The Department of Transportation, the United States Department of Transportation Federal Highway Administration and the EPA have identified several projects in the nonattainment areas that would not receive funding and would therefore not be completed or would be subject to delay. Thus, this emergency certified final-omitted rulemaking will be effective upon publication in the *Pennsylvania Bulletin*.

This final-omitted rulemaking will be submitted to the EPA for approval as a revision to the Commonwealth's SIP following promulgation of the final-form regulation.

This final-omitted rulemaking was adopted by the Board at its meeting on November 30, 2022.

A. *Effective Date*

This final-omitted rulemaking will be effective upon notice or publication in the *Pennsylvania Bulletin*.

B. *Contact Persons*

For further information, contact Viren 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. Persons with a disability may use the Pennsylvania Hamilton Relay Service, (800) 654-5984 (TDD users) or (800) 654-5988 (voice users). This final-omitted 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 emergency certified final-omitted rulemaking is authorized under section 5(a)(1) of the 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 and section 5(a)(8) of the APCA, which grants the Board the authority to adopt rules and regulations designed to implement the provisions of the CAA (42 U.S.C.A. §§ 7401—7671q).

D. *Background and Purpose*

The purpose of this final-omitted rulemaking is to implement control measures to reduce VOC emissions from conventional oil and natural gas sources in this Commonwealth. Five air contamination source categories are affected by this final-omitted rulemaking: storage vessels; natural gas-driven continuous bleed pneumatic controllers; natural gas-driven diaphragm pumps; reciprocating and centrifugal compressors; and fugitive emissions components. These sources were selected by the EPA because data and information has indicated that they are significant sources of VOC emissions.

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 final-omitted rulemaking establishes the VOC emission limitations and other RACT requirements consistent with 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).

Background on the Ozone National Ambient Air Quality Standards (NAAQS)

Under section 108 of the CAA (42 U.S.C.A. § 7408), the EPA is responsible for establishing NAAQS, or maximum allowable concentrations in the ambient air, for six criteria pollutants considered harmful to public health and the environment: ground-level ozone; particulate matter; nitrogen oxides (NOx); 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. The EPA established primary and secondary ground-level ozone NAAQS to protect public health and public welfare, including the environment.

On April 30, 1971, the EPA promulgated primary and secondary NAAQS for photochemical oxidants, which include ground-level ozone, under section 109 of the CAA. See 36 FR 8186 (April 30, 1971). These standards were set at an hourly average of 0.08 parts per million (ppm) total photochemical oxidants not to be exceeded more than 1 hour per year. On February 8, 1979, the EPA revised the level of the primary 1-hour ozone standard from 0.08 ppm to 0.12 ppm and set the secondary standard identical to the primary standard. See 44 FR 8202 (February 8, 1979). This revised 1-hour standard was reaffirmed on March 9, 1993. See 58 FR 13008 (March 9, 1993).

On July 18, 1997, the EPA concluded that revisions to the then-current 1-hour ozone primary standard to provide increased public health protection were appropriate to protect public health with an adequate margin of safety. Further, the EPA determined that it was appropriate to establish a primary standard of 0.08 ppm averaged over 8 hours. At this time, the EPA also established a secondary standard equal to the primary standard. 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 Department's certified ambient air monitoring data for the Commonwealth's 2020 ozone season, all monitored areas of this Commonwealth are attaining and maintaining the 1997 8-hour ozone NAAQS.

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 May 2012, the EPA designated five areas in this Commonwealth as marginal nonattainment for the 2008 ozone NAAQS with the rest of this Commonwealth designated as attainment. See 77 FR 30088, 30143 (May 21, 2012). The five designated 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. Per the 1997 ozone NAAQS, the Department must ensure that the 2008 ozone NAAQS is attained and maintained by implementing permanent and enforceable control measures. Based on the Department's certified ambient air monitoring data for the Commonwealth's 2020 ozone season, all monitored areas of this Commonwealth are attaining and maintaining the 2008 8-hour ozone NAAQS. Adoption of the VOC emission control measures in this final-omitted rulemaking will 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). On June 4, 2018, the EPA designated Bucks, Chester, Delaware, Montgomery and Philadelphia Counties as marginal nonattainment for the 2015 ozone NAAQS, with the rest of this Commonwealth designated as attainment. See 83 FR 25776 (June 4, 2018). The Department must ensure that the 2015 8-hour ozone NAAQS is attained and maintained by implementing permanent and Federally enforceable control measures. The certified ambient air ozone season monitoring data for the 2020 ozone season shows that all ozone samplers in this Commonwealth, except the Bristol sampler in Bucks County and the Northeast Airport and Northeast Waste samplers in Philadelphia County are monitoring attainment of the 2015 ozone NAAQS. Reductions in VOC emissions that are achieved following the adoption and implementation of RACT emission control measures for source categories covered by this final-omitted rulemaking will assist the Commonwealth in making substantial progress in achieving and maintaining the 2015 ozone NAAQS.

CAA requirements: Implementation of permanent and Federally enforceable control measures for attaining and maintaining the ozone NAAQS

Section 101(a)(3) of the CAA (42 U.S.C.A. § 7401(a)(3)) provides that air pollution prevention (that is, the reduction or elimination, through any measures, of the amount of pollutants produced or created at the source) and air pollution control at its source is the primary responsibility of States and local governments. Section 110(a) of the CAA (42 U.S.C.A. § 7410(a)) gives states the primary responsibility for achieving the NAAQS in nonattainment areas and for maintaining the NAAQS in areas of the state that are in attainment. Section 110(a) of the CAA provides that each state shall adopt and submit to the EPA a plan (a SIP) for implementation, maintenance and enforcement of the NAAQS or a revision to the NAAQS promulgated under section 109(b) of the CAA. Additionally, section 110(a) provides that the plan shall contain adequate provisions to prevent emissions activity within a state from contributing significantly to nonattainment in, or interference with maintenance by, any other state with respect to a NAAQS. The entirety of the 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 and incorporated into the state's SIP, the measures of a SIP are legally enforceable under both Federal and state law.

Section 172(c)(1) of the CAA provides that a SIP for states with nonattainment areas must include "reasonably available control measures," including RACT, for affected sources of VOC and NOx emissions. Upon submittal to the EPA, state regulations to control VOC emissions from affected sources are reviewed by the EPA to determine if the provisions meet the RACT requirements of the CAA and its implementing regulations designed to attain and maintain the ground-level ozone NAAQS. If the EPA determines that the provisions meet the applicable requirements of the CAA, the provisions are approved and incorporated as amendments to the state's SIP.

Section 182 of the CAA requires that, for areas which exceed the ground-level ozone NAAQS, states must develop and implement a program that mandates certain major stationary sources develop and implement a RACT emission reduction program. Section 182(b)(2) of the CAA provides that for moderate ozone nonattainment areas, a state must revise its SIP to include RACT for sources of VOC emissions covered by a Control Techniques Guidelines (CTG) document issued by the EPA prior to the area's date of attainment of the applicable ozone NAAQS. CTG documents provide states with information about a VOC emission source category and recommendations of what the EPA considers to be RACT for the source category to attain and maintain the applicable ozone NAAQS. State air pollution control agencies may use the Federal recommendations provided in the CTG to inform their own determination as to what constitutes RACT for VOC emissions from the covered source category for subject sources located within the state. 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.

Although the designated nonattainment areas in this Commonwealth for the 2008 and 2015 ground-level ozone NAAQS are classified as "marginal" nonattainment, this entire Commonwealth is treated as a "moderate" ozone nonattainment area for RACT purposes because this Commonwealth is included in the Ozone Transport Region (OTR) established by operation of law under sections 176A (42 U.S.C.A. § 7506a) and 184 of the CAA. Section 176A of the CAA grants the Administrator of the EPA the authority to establish an interstate transport region and the associated transport commission. Section 184(a) of the CAA established the OTR comprised of the states of Connecticut, Delaware, Maine, Maryland, Massachusetts, New Hampshire, New Jersey, New York, Pennsylvania, Rhode Island, Vermont and the Consolidated Metropolitan Statistical Area that includes the District of Columbia. More importantly, section 184(b)(1)(B) of the CAA requires that states in the OTR, including this Commonwealth, submit a SIP revision requiring implementation of RACT for all major stationary sources of VOC emissions in the state covered by a specific CTG and not just for those sources that are located in designated nonattainment areas of the state.

Consequently, the Commonwealth's SIP must include regulations implementing RACT requirements Statewide to control VOC emissions from the oil and natural gas sources, including from conventional well sites, covered by the 2016 O&G CTG. These sources, which are not regulated elsewhere in Chapter 129, were selected by the EPA because data and information has indicated that they are significant sources of VOC emissions. Significantly, this final-omitted rulemaking should achieve VOC emission reductions and lowered concentrations of ground-level ozone locally as well as in downwind states. Additionally, 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 final-omitted rulemaking will be submitted to the EPA for approval as a revision to the Commonwealth's SIP following promulgation of this final-omitted rulemaking.

Need to limit VOC emissions and ground-level ozone pollution

VOC emissions are precursors to the formation of ground-level ozone, a public health, welfare and environmental hazard. However, ground-level ozone is not emitted directly to the atmosphere from any sources, including conventional oil and natural gas sources. Ground-level ozone is formed by a photochemical reaction between emissions of VOC and NOx in the presence of sunlight; oil and gas sources, including conventional well sites, do emit these two pollutants. 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 and the environment. 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.

Ground-level ozone is a respiratory irritant and repeated exposure to high ambient concentrations of ground-level 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 high ambient concentrations of ground-level 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 precursor emissions impacts on air quality in this Commonwealth is necessary to protect the public health and welfare and the environment. Because VOC emissions are precursors for ground-level ozone formation, adoption of the VOC emission control measures and other requirements in this final-omitted rulemaking is in the public interest as it will allow the Commonwealth to continue to make substantial progress in maintaining the 1997 and 2008 NAAQS as well as attaining and maintaining the 2015 8-hour ozone NAAQS Statewide. Implementation of and compliance with the final-omitted VOC emission reduction measures will assist the Commonwealth in reducing the levels of ozone precursor emissions that contribute to potential nonattainment of the 2015 ozone NAAQS in downwind states. 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.

The EPA's Control Techniques Guidelines for the oil and natural gas industry

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 a product or source category in ozone nonattainment areas. On October 27, 2016, the EPA issued the 2016 O&G CTG which provided information to assist states in determining what constitutes RACT for VOC emissions from select oil and natural gas industry emission sources. See 81 FR 74798 (October 27, 2016). On March 9, 2018, the EPA had proposed to withdraw the 2016 O&G CTG in its entirety because the CTG had relied upon underlying data and conclusions made in the 2016 new source performance standards which the EPA was reconsidering. See 83 FR 10478 (March 9, 2018). However, on March 5, 2020, the EPA announced in the United States Office of Management and Budget's Spring 2020 Unified Agenda and Regulatory Plan that the EPA was no longer pursuing the action to withdraw the CTG and "the CTG will remain in place as published on October 27, 2016." See Supplemental Notice of Potential Withdrawal of the Control Techniques Guidelines for the Oil and Natural Gas Industry at https://www.reginfo.gov/public/do/eAgendaViewRule?pubId=202004&RIN=2060-AT76&operation=OPERATION_PRINT_RULE.

While the EPA provided information and RACT recommendations through the 2016 O&G CTG for VOC emissions, it is up to the Department to determine what is RACT for each source category of VOC emissions. As explicitly stated by the EPA in the 2016 O&G CTG, state air pollution control agencies are free to implement other technically-sound approaches that are consistent with the CAA and the EPA's regulations. See 81 FR 74798, 74799 (October 27, 2016). The EPA also further clarified that "the information contained in the CTG document is provided only as guidance" and "this guidance does not change, or substitute for, requirements specified in applicable sections of the CAA or the EPA's regulations; nor is it a regulation itself." Id. While the EPA will ultimately need to approve the Department's RACT determinations by reviewing and approving the revision to the Commonwealth's SIP, the Department has made the initial RACT determinations in this final-omitted rulemaking based on the entirety of information available to the Department, including the 2016 O&G CTG. In other words, the Department's obligation is to affirmatively determine what constitutes RACT for the source group identified in the 2016 O&G CTG and the EPA's provision of guidance and data in the 2016 O&G CTG does not obliviate that legal requirement. In the time since the 2016 O&G CTG was issued by the EPA, the Department acquired additional information and current emissions data specific to this Commonwealth that it analyzed to determine the RACT emission limitations and requirements established in this final-omitted rulemaking.

Findings of failure to submit, sanctions and deadline for action

If the EPA finds that a state has failed to submit an approvable SIP revision or has failed to implement the requirements of an approved measure in the SIP, the EPA issues a "finding of failure to submit notice." On November 16, 2020, the EPA issued a Final Rule entitled "Findings of Failure To Submit State Implementation Plan Revisions in Response to the 2016 Oil and Natural Gas Industry Control Techniques Guidelines for the 2008 Ozone National Ambient Air Quality Standards (NAAQS) and for States in the Ozone Transport Region," with an effective date of December 16, 2020. 85 FR 72963 (November 16, 2020). This Commonwealth was one of the five states issued a finding of failure to submit a SIP revision to address the 2008 NAAQS and the RACT requirements associated with the 2016 O&G CTG by October 27, 2018. The EPA's finding triggers the sanction clock under section 179 of the CAA (42 U.S.C.A. § 7509). However, sanctions cannot be imposed until 18 months after the EPA makes the determination, and sanctions cannot be imposed if a deficiency has been corrected within the 18-month period. On June 16, 2022, the 18-month period ended. Thus, the Commonwealth must submit this final-omitted rulemaking as a SIP revision and the EPA must determine that the submittal is complete as soon as possible to remove the sanctions that took effect on June 16, 2022.

The EPA issued "Findings of Failure to Submit State Implementation Plan Revisions for the 2016 Oil and Natural Gas Industry Control Techniques Guidelines for the 2015 Ozone National Ambient Air Quality Standards (NAAQS) and for States in the Ozone Transport Region," with an effective date of January 18, 2022, at 86 FR 71385 (December 16, 2021). This finding also triggers the sanction clock under section 179 of the CAA and the Commonwealth must submit a SIP revision to address the 2015 NAAQS and the EPA must determine that the submittal is complete by July 18, 2023.

Section 179 of the CAA authorizes the EPA to use two types of sanctions: 1) imposing what are called "2:1 offsets" on new or modified sources of emissions; and 2) withholding of certain Federal highway funds. Under section 179 of the CAA and its implementing regulations, the Administrator first imposes "2:1 offsets" sanctions for new or modified major stationary sources in the nonattainment area which took effect on June 16, 2022, and then, if the deficiency has not been corrected within 6 months, also applies Federal highway funding sanctions. See 40 CFR 52.31 (relating to selection of sequence of mandatory sanctions for findings made pursuant to section 179 of the Clean Air Act).

Additionally, the findings trigger an obligation under section 110(c) of the CAA for the EPA to promulgate a Federal Implementation Plan (FIP) no later than 2 years after the effective date of the finding of failure to submit if the Commonwealth has not submitted, and the EPA has not approved, the required SIP submittal. If the EPA promulgates a FIP, the EPA could, in its discretion, also withhold a portion of the Department's air pollution grant funds provided for in section 105 of the CAA. However, if the Commonwealth makes the required SIP submittal and the EPA takes final action to approve the submittal within 2 years of the effective date of these findings, the EPA is not required to promulgate a FIP.

The 2:1 offset sanctions went into effect for new or modified major stationary sources in this Commonwealth on June 16, 2022. If this final-omitted rulemaking and the separate unconventional rulemaking are not submitted to the EPA before December 16, 2022, the Federal highway sanctions will go into effect. The Department estimates that this could result in the loss of hundreds of millions of dollars in Federal highway funds.

This final-omitted rulemaking is being promulgated to attain and maintain both the 2008 and the 2015 ozone NAAQS and will be submitted to the EPA for approval as a revision to the Commonwealth's SIP following promulgation. While this final-omitted rulemaking will not fully address the December 2021 and the November 2020 findings of failure to submit SIP revisions, the Department finalized a separate rulemaking for the RACT requirements for unconventional oil and natural gas sources of VOC emissions. Once published in the *Pennsylvania Bulletin* as a final-form rulemaking, the separate rulemaking for unconventional sources of VOC emissions will also be submitted as a SIP revision. Together these two rulemakings address all the sources identified by the EPA in the 2016 O&G CTG. The Department is working toward completing both submittals by December 16, 2022, to lift the existing sanctions and to stop the mandatory sanction clock.

VOC RACT requirements in this final-omitted rulemaking

Under section 4.2(b)(1) of the APCA (35 P.S. § 4004.2(b)(1)), the Board has the authority to adopt control measures that are more stringent than those required by the CAA if the Board determines that it is reasonably necessary for the control measure to exceed minimum CAA requirements for the Commonwealth to achieve or maintain the NAAQS. To the extent that a requirement in this final-omitted rulemaking is more stringent than the recommendations of the 2016 O&G CTG, the more stringent requirement is reasonably necessary to satisfy the Department's RACT requirements under the CAA and to attain and maintain the health-based and welfare based 8-hour ozone NAAQS in this Commonwealth.

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, based on analysis of data specific to this Commonwealth, the Department determined in three cases that RACT requirements more stringent than the recommendations in the 2016 O&G CTG are cost-effective and necessary to continue the Commonwealth's progress in attaining and maintaining the ground-level ozone NAAQS. The Department addressed VOC emissions from unconventional sources in a separate rulemaking.

In the first case, the Department determined that a 2.7 tons per year (TPY) VOC emission threshold for storage vessels is RACT as it is technically and economically feasible for both potential to emit and actual emissions from all covered storage vessels. The Department's analysis examined the sensitivity to the initial capital cost of the control device and found that the total cost per ton of VOC reduced is below the RACT benchmark of $6,600 per ton reduced. Therefore, in § 129.133(a)(1) (relating to storage vessels) of this final-omitted rulemaking a 2.7 TPY VOC emission threshold applies to conventional owners or operators of storage vessels installed at conventional well sites, gathering and boosting stations and natural gas processing plants, and in the natural gas transmission and storage segment, based on the Department's cost analysis.

In the second case, § 129.136 (relating to compressors) of this final-omitted rulemaking establishes requirements for conventional owners or operators to implement reciprocating compressor rod packing replacements on reciprocating compressors located at conventional well sites. The requirement is based on the Department's analysis, further detailed in the Regulatory Analysis Form (RAF), which shows that it is both technically and economically feasible to require reciprocating compressor rod packing replacements every 26,000 hours of operation or every 3 years for reciprocating compressors located at conventional well sites. The analysis showed that the cost-effectiveness of the rod packing replacement is highly sensitive to the emissions factor used to represent emissions from reciprocating compressors. Using the average of several emission factors from the University of Texas at Austin's Emission Factor Improvement Study, the cost per ton of VOC reduced is approximately $6,600 which is consistent with the RACT benchmark. See Harrison, M., Galloway, K., Hendler, A., Shires, T., Allen, D., Foss, M., Thomas, J., Spinhirne, J., Natural Gas Industry Methane Emission Factor Improvement Study Final Report Cooperative Agreement No. XA-83376101, Dec. 2011 at https://dept.ceer.utexas.edu/ceer/GHG/files/FReports/XA_83376101_Final_Report.pdf.

In the third case, the Department's analysis shows that it is both technically and economically feasible for an affected conventional owner or operator to implement instrument-based leak detection and repair (LDAR) inspections at a conventional well site with an average production of equal to or greater than 15 barrels of oil equivalent (BOE) per day with the frequency of inspections based on the production from each individual well at the well site. The owner or operator of a conventional well site with an average production of 15 BOE or more per day and with at least one individual well producing 15 BOE or more per day, on average, shall conduct monthly audible, visual, olfactory inspections (AVO) and quarterly instrument-based LDAR inspections of fugitive emissions components. The owner or operator of a conventional well site with an average of 15 BOE or more per day and at least one individual well producing 5 BOE or more but less than 15 BOE per day, on average, shall conduct monthly AVO inspections and annual instrument-based LDAR inspections of fugitive emissions components. In this final-omitted rulemaking, the Department also included an option for the owner or operator of a conventional well site producing, on average, equal to or greater than 15 BOE per day, and at least one well producing, on average, equal to or greater than 5 BOE per day but less than 15 BOE per day to submit to the Department a request for an exemption from the annual instrument-based LDAR requirement. However, the request must include, among other information, a demonstration that the annual LDAR requirement is not RACT (technically or economically feasible) for the well site. If approved, this exemption request will be submitted to the EPA as a revision to the Commonwealth's SIP.

In addition to the technically and economically feasible RACT requirements detailed previously, the Commonwealth is responsible for ensuring that the 2015 8-hour ozone NAAQS is attained and maintained by implementing permanent and Federally enforceable control measures. This final-omitted rulemaking is a primary component of the Commonwealth's strategy of ensuring that the ozone NAAQS are attained and maintained across this Commonwealth. Reductions in VOC emissions, that are achieved following the adoption and implementation of RACT VOC emission control measures for the select conventional oil and natural gas source categories covered by this final-omitted rulemaking, will assist the Commonwealth in making substantial progress in achieving and maintaining the ozone NAAQS. To the extent that a requirement in this final-omitted rulemaking is more stringent than the recommendations of the 2016 O&G CTG, the more stringent requirement is 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.

VOC and methane emission reduction benefits

The Department estimates that in 2020, sources installed at conventional well sites emitted an estimated 18,971 TPY VOC and that implementation of the control measures in this final-omitted rulemaking could reduce VOC emissions by as much as 9,204 TPY. These VOC emission reductions will contribute to reductions in the formation of ground-level ozone and to achieving and maintaining the ozone NAAQS.

While this final-omitted rulemaking requires VOC emission reductions, methane emissions are also reduced as a cobenefit, because both VOC and methane are emitted from oil and gas operations. Methane is a potent greenhouse gas (GHG) with a global warming potential more than 28 times that of carbon dioxide (CO_2) 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 GHG emitted in the United States from human activities. The Department estimates that conventional well sites emitted 365,103 TPY methane in 2020, and that the cobenefit methane emissions reduction from this final-omitted rulemaking may be as much as 175,788 TPY.

The emission reductions for gathering and boosting stations and natural gas processing plants are included in the control of VOC emissions from unconventional oil and natural gas sources final regulation. The Department does not have information and data on how many gathering and boosting stations and natural gas processing plants are used in the conventional industry. Therefore, to avoid double counting of emission reductions, all of the VOC and methane emission reductions from these sources are estimated in the control of VOC emissions from unconventional oil and natural gas sources final regulation.

Furthermore, the technically and economically feasible RACT determinations in this final-omitted rulemaking for storage vessels, reciprocating compressors at well sites and fugitive emissions components result in a greater reduction of VOC emissions than implementing the EPA's RACT recommendations from the 2016 O&G CTG resulting in an additional 304 TPY of VOC and 5,790 TPY of methane emissions reductions.

This final-omitted 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. The strategy also states that the Commonwealth will reduce emissions by requiring LDAR inspections and more frequent use of leak-sensing technologies. This final-omitted rulemaking fulfills those parts of the strategy.

Applicability of this final-omitted rulemaking

This final-omitted rulemaking will apply Statewide to owners or operators of one or more of the following conventional oil and natural gas sources of VOC emissions which were constructed on or before the effective date of this final-omitted rulemaking: natural gas-driven continuous bleed pneumatic controllers, natural gas-driven diaphragm pumps, centrifugal compressors, reciprocating compressors, fugitive emission components and storage vessels installed at conventional well sites, gathering and boosting stations and natural gas processing plants, as well as storage vessels in the natural gas transmission and storage segment.

The Department identified 4,719 conventional owners or operators of approximately 27,260 facilities in this Commonwealth that may be affected by this final-omitted rulemaking. Approximately 3,704 of the 4,719 conventional owners or operators may meet the definition of small business as defined in section 3 of the RRA (71 P.S. § 745.3). Based on information supplied by commentators on the proposed combined rulemaking, the Oil and Gas Production Report, and the Department's Air Information Management System (AIMS) database, the Department estimates there are 27,260 conventional well sites. There are also 486 gathering and boosting stations, 15 processing plants, and 120 transmission stations in this Commonwealth that the Department cannot distinguish between conventional and unconventional sources. If any of these sources are used by the conventional industry, they are regulated through this final-omitted rulemaking. The Department estimates that conventional owners or operators have at least 6 storage vessels at 6 conventional well sites and 26,284 pneumatic controllers at 26,284 conventional well sites that will be subject to requirements under this final-omitted rulemaking. The owners or operators of approximately 95 of 27,260 conventional well sites will be required to implement instrument-based LDAR inspections under this final-omitted rulemaking.

The Department estimates that the total industry-wide cost of complying with this final-omitted rulemaking will be about $9.8 million per year. However, implementation of the control measures will also potentially save conventional owners or operators about $15.7 million per year due to a lower natural gas loss rate during production. This cost estimate consists of two major categories of data. The first is the annual cost to implement the RACT requirements for each affected source or affected facility as provided by the EPA in the 2016 O&G CTG and from the Department's own analysis. The second is the number of potentially affected facilities, which was obtained from several data sources including the Department's Oil and Gas Production Report, Environmental Facility Application Compliance Tracking System (eFACTS) database and AIMS. For the owners or operators of conventional well sites or any gathering and boosting stations and natural gas processing plants used by the conventional industry, the anticipated annual cost to comply with the requirements will be based on the type of sources present at the site, the requirements that apply to those sources, and the type of control used to comply.

Most of the anticipated costs are due to new regulatory requirements but many of the costs associated with this final-omitted rulemaking are from common sense practices and controls, some of which conventional owners or operators may already be implementing due to regulatory requirements or voluntary emission reduction programs. An example includes periodic AVO inspections which can prevent natural gas releases, which in turn prevent 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 final-omitted rulemaking. The Department estimates that a majority of small business stationary sources will be below the applicability thresholds. However, affected small businesses may incur minimal costs as a result of this final-omitted rulemaking and gain net benefits of approximately $218 per facility or, on average, $1,258 per owner or operator. Overall, the Department does not anticipate that this final-omitted rulemaking will result in any significant adverse impact on small businesses.

Public outreach

During the development of the combined rulemaking, the Department consulted with the Air Quality Technical Advisory Committee (AQTAC) and the Small Business Compliance Advisory Committee (SBCAC). 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. The proposed combined rulemaking was presented for a vote to AQTAC on April 11, 2019, and SBCAC on April 17, 2019. Both committees concurred with the Department's recommendation to move the 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 the proposed combined control of VOC emissions from oil and natural gas sources rulemaking on May 7, 2019. On June 18, 2019, the full CAC concurred with the Department's recommendation to move the proposed rulemaking forward to the Board for consideration.

The Department also met with industry and environmental stakeholders to receive additional input on the proposed combined rulemaking. On January 24, 2019, the Department updated the Pennsylvania Grade Crude Development Advisory Council on the status of the rulemaking. On March 21, 2019, the Department provided an informational presentation to the Oil and Gas Technical Advisory Board. On July 8, 2019, the Department met with industry stakeholders, including representatives from the Marcellus Shale Coalition, Penn Energy, Southwestern Energy, Range Resources, and Chesapeake Energy. On August 27, 2019, the Department met with environmental stakeholders, including representatives from PennFuture, Environmental Defense Fund, and the Clean Air Council.

The final-form combined rulemaking was presented to AQTAC on December 9, 2021, the CAC Policy and Regulatory Oversight Committee on January 12, 2022, and the full CAC on January 18, 2022, and SBCAC on January 27, 2022.

E. *Summary of Final-Omitted Rulemaking*

§ 129.131. General provisions and applicability

Subsection (a) establishes that this final-omitted rulemaking will apply Statewide to the owner or operator of natural gas-driven continuous bleed pneumatic controllers, natural gas-driven diaphragm pumps, reciprocating compressors, centrifugal compressors, fugitive emissions components and storage vessels installed at conventional well sites, gathering and boosting stations and natural gas process plants, as well as storage vessels in the natural gas transmission and storage segment which were constructed on or before the effective date of this final-omitted rulemaking.

Subsection (b) provides that compliance with the requirements of this final-omitted rulemaking assures compliance with the requirements of a permit issued under §§ 129.91—129.95 (relating to stationary sources of NOx and VOCs) or §§ 129.96—129.100 (relating to additional RACT requirements for major sources of NOx and VOCs) except to the extent the operating permit contains more stringent requirements.

§ 129.132. Definitions, acronyms and EPA methods

Section 129.132 adds definitions, acronyms and EPA methods applicable to this final-omitted rulemaking.

§ 129.133. Storage vessels

Subsection (a)(1) establishes the applicability threshold for the owner or operator of a storage vessel based on potential VOC emissions. Subsection (a)(2) 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 § 129.138 (relating to covers and closed vent systems).

Subsection (c) provides for exceptions to the emissions limitations and control requirements in subsection (b) based on the actual VOC emissions of a storage vessel 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 § 129.140(b) (relating to recordkeeping and reporting) and § 129.140(k)(3)(i) for owners or operators of storage vessels subject to this section.

§ 129.134. Natural gas-driven continuous bleed pneumatic controllers

Subsection (a) establishes the applicability for the owner or operator of a natural gas-driven continuous bleed 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.

§ 129.135. 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 conventional 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 § 129.138(b) and routing the emissions to a control device or process that meets the requirements of § 129.139 (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 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, 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 § 129.140(d) and (k)(3)(iii) for owners or operators of natural gas-driven diaphragm pumps.

§ 129.136. 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 § 129.138.

Subsection (d) lists a categorical exemption from the emissions limitation and control requirements of subsection (c) for centrifugal 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 § 129.140(e) and (k)(3)(iv) for owners or operators of reciprocating compressors and under § 129.140(f) and (k)(3)(v) for owners or operators of centrifugal compressors.

§ 129.137. Fugitive emissions components

Subsection (a) establishes the applicability for the owner or operator of a fugitive emissions component based on the component's location.

Subsection (b) establishes the average production calculation procedure for a well site.

Subsection (c) establishes the compliance requirements for conventional well sites based on the gas to oil ratio (GOR) of the well and the production of the well site and the individual wells on the well site.

Subsection (d) establishes the LDAR inspection requirements for shut-in conventional well sites.

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

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

Subsection (h) establishes the verification procedures for optical gas imaging (OGI) equipment identified in the fugitive emissions monitoring plan.

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

Subsection (j) 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 (k) 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 (l) 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.

Subsection (m) references the recordkeeping and reporting requirements for owners or operators of fugitive emissions components listed under § 129.140(g) and (k)(3)(vi).

§ 129.138. 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 § 129.132, to perform the assessment as proposed in the 2016 new source performance standard (NSPS) reconsideration.

Subsection (d) establishes the requirement that the owner or operator conduct a no detectable emissions inspection, as required by subsection (b)(2)(ii).

§ 129.139. 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 § 129.140(j) and submit reports under § 129.140(k)(3)(ix).

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 weight-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.

§ 129.140. 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 continuous bleed 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. *Summary of Comments and Responses on the Proposed Combined Rulemaking*

The Board adopted the proposed combined rulemaking at its meeting on December 17, 2019. On May 23, 2020, the proposed combined rulemaking was published for a 66-day comment period at 50 Pa.B. 2633. Three public hearings were held virtually on June 23, 24 and 25, 2020. Over 100 individuals provided verbal testimony. The comment period closed on July 27, 2020. The Board received over 4,500 comments, including comments from the House and Senate Environmental Resources and Energy Committees (ERE Committees), members of the General Assembly and IRRC. The majority of the commentators expressed their support of the VOC RACT requirements, noting the need to address air emissions from the oil and gas sector. The comments received on the proposed combined rulemaking are summarized in this section and are addressed in a comment and response document which is available on the Department's web site.

IRRC stated that section 2 of the RRA (71 P.S. § 745.2) explains why the General Assembly felt it was necessary to establish a regulatory review process. IRRC also noted that section 2(a) of the RRA states, "[t]o the greatest extent possible, this act is intended to encourage the resolution of objections to a regulation and the reaching of a consensus among the commission, the standing committees, interested parties and the agency." The vast majority of public comments are from individuals and environmental advocacy organizations in support of the proposal, but still urging the Department to adopt more restrictive requirements in this final-omitted rulemaking. Numerous comments were also from parties representing the oil and gas industries who believe that the regulatory mandates for existing sources should not be more stringent than requirements for new or modified sources or the EPA's 2016 O&G CTG. Since the issues raised by the commentators are often in direct conflict with each other, IRRC recommends that the Board continue to actively seek input from all interested parties, including lawmakers, as it develops the final version of the rulemaking.

In response, the Board and the Department have and will continue to actively seek input from all interested parties, including lawmakers. In addition to the review outlined under the RRA, members of the General Assembly, particularly the House and Senate ERE Committees, have extensive involvement in the development of the Department's rulemakings through members appointed to the Department's advisory committees and four seats on the Board. The Board and the Department consistently seek opportunities to engage productively with interested parties, including the Legislature. The Department's Legislative Office works to address issues and ensure that the Legislature is informed of actions by the Department and the Board. Additionally, members of the public have several opportunities to provide input on the Department's rulemakings. This includes the formal proposed rulemaking public comment and hearing process, as well as opportunities to provide informal public comment at the Department's advisory committee meetings during both the proposed and final stages of development of a rulemaking.

1. This final-omitted rulemaking satisfies the criteria under the RRA.

a. *This final-omitted rulemaking is supported by acceptable data.*

IRRC stated that Section 28 of the RAF relates to the regulatory review criterion of whether the regulation is supported by acceptable data. If data is the basis for a regulation, this section of the RAF asks for a description of the data, how the data was obtained, and how it meets the acceptability standard for empirical, replicable and testable data that is supported by documentation, statistics, reports, studies or research. IRRC noted that the Board states that the basis for the proposed rulemaking is the Federally mandated RACT requirements found in the 2016 O&G CTG. Commentators representing the oil and gas industry assert that the 2016 O&G CTG requirements are similar to performance standards developed for "new" or "modified" sources and question the appropriateness of applying these standards to existing sources such as conventional oil and gas wells. IRRC asks the Board to explain how it determined that the proposed standards are appropriate for both the conventional and unconventional oil and gas industries in this Commonwealth.

In response, the Board establishes control measures in this final-omitted rulemaking that are only applicable to conventional sources of VOC emissions installed at conventional well sites, gathering and boosting stations and natural gas processing plants. This final-omitted rulemaking implements control measures to reduce VOC emissions from five specific categories of air contamination sources, including storage vessels; natural gas-driven continuous bleed pneumatic controllers; natural gas-driven diaphragm pumps; reciprocating and centrifugal compressors; and fugitive emissions components at conventional well sites.

The EPA selected these categories of sources for RACT recommendations because the information gathered and reviewed by the EPA indicated that they are significant sources of VOC emissions. In developing the 2016 O&G CTG, the EPA reviewed the oil and natural gas NSPS, including several technical support documents prepared in support of the NSPS actions for the oil and natural gas industry, as well as existing state and local VOC emission reduction approaches, and information on emissions, available VOC emission control technologies, and costs. In producing and reviewing this information, the EPA's Scientific Integrity Policy establishes that the EPA adheres to the 2002 Office of Management and Budget (OMB) Information Quality Guidelines, the 2005 OMB Information Quality Bulletin for Peer Review, the EPA's Quality Policy for assuring the collection and use of sound, scientific data and information, the EPA's Peer Review Handbook for internal and external review of scientific products, and the EPA's Information Quality Guidelines for maximizing the transparency, integrity and utility of information published on the EPA's web site.

During the development of the proposed combined rulemaking, the Department made initial RACT determinations based on the entirety of information available to the Department, including the data and analysis provided in the 2016 O&G CTG as well as 2017 oil and gas production data reported to the Department's Oil and Gas Production Report and 2017 emissions data reported to the Department's air emissions inventory. In the time since the 2016 O&G CTG was issued by the EPA, the Department acquired additional information during the public comment period and from the 2020 oil and gas production data and air emissions data, which was used in a cost/benefit reanalysis (2020 reanalysis) to establish the RACT determinations in this final-omitted rulemaking.

b. *This final-omitted rulemaking sufficiently protects public health, safety and welfare and this Commonwealth's natural resources.*

IRRC also remained concerned that this final-omitted rulemaking fulfills the Board's obligation to protect the quality and sustainability of the Commonwealth's natural resources. To that end, IRRC asked the Board to explain how the standards set forth in the regulation meet the criterion under section 5.2(b)(2) of the RRA (71 P.S. § 745.5b(b)(2)) pertaining to the protection of the public health, safety and welfare and the effect on this Commonwealth's natural resources while imposing reasonable requirements upon the oil and natural gas industry.

In response, the Board maintains that this final-omitted rulemaking is protective of the public health, safety and welfare, as well as the environment. The implementation of the VOC emission control measures in this final-omitted rulemaking is reasonably necessary to protect the public health and welfare and the environment from harmful ground-level ozone pollution. Reduced levels of VOC and methane emissions will also promote healthful air quality and ensure the continued protection of the environment and public health and welfare. The control measures in this final-omitted rulemaking, when implemented, are expected to provide VOC emission reductions of approximately 9,204 TPY. 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 Board is not stating that these estimated monetized health benefits would all be the result of implementing the RACT measures contained in this final-omitted rulemaking, but the EPA estimates are indicative of the benefits to Commonwealth residents of attaining and maintaining the 2008 and 2015 8-hour ozone NAAQS. In addition to causing adverse human and animal health effects, the EPA has concluded that ground-level ozone affects vegetation and ecosystems, leading to reductions in agricultural crop and commercial forest yields. Furthermore, the same measures in this final-omitted rulemaking that control VOC emissions will also control methane emissions. When fully implemented, the control measures for VOCs are anticipated to reduce approximately 175,788 TPY of methane as a cobenefit. Methane is a potent GHG with a higher global warming potential than CO_2.

c. *This final-omitted rulemaking will not have a negative economic or fiscal impact to this Commonwealth.*

IRRC noted that the fiscal analysis provided by the Board estimates that the 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, will yield a savings of approximately $9.9 million, resulting in a total net cost of $25.4 million. These figures were based on 2012 EPA cost estimates contained in the 2016 O&G CTG. Commentators question the accuracy of the fiscal analysis because the supporting data is outdated and is not specific to this Commonwealth's oil and gas industry. IRRC agreed with the concerns raised by interested parties. For IRRC to determine whether this final-omitted rulemaking is in the public interest, the Board must submit a revised estimate of the costs or savings, or both, to the regulated community using data that is current and Commonwealth industry specific.

In response, the Board provides an estimate of the cost and savings to the regulated community using current and Commonwealth-specific data in the RAF for this final-omitted rulemaking. The Department's analysis estimates that implementation of the control measures in this final-omitted rulemaking will cost affected conventional owners and operators as a whole approximately $9.8 million (2021 dollars) without consideration of the economic benefit of the saved natural gas. The value of the saved natural gas using $1.70 per thousand cubic feet (Mcf) as suggested by several commentators yields a savings of $15.7 million (2021 dollars). This results in a total net benefit of $5.9 million (2021 dollars), which is based on some of the worst conditions of the past decade. As the price of natural gas increases, the impact on industry is mitigated; at approximately $5.00 per Mcf during the 2020-2021 timeframe for the development of this final-omitted rulemaking, the impact on industry is a net benefit of $36.4 million (2021 dollars). Although the natural gas saved as a result of implementation of this final-omitted rulemaking is significant, when the Department made the individual RACT determinations for the sources recommended in the 2016 O&G CTG, the value of the natural gas saved was not counted.

d. *This final-omitted rulemaking does not conflict with existing statutes or regulations.*

IRRC noted that the Department states that it "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." The proposed rulemaking defined "in-house engineer" as an individual who is qualified by education, technical knowledge, and experience to make an engineering judgment and the required specific technical certification. Since there is no requirement that the individual be employed by the facility, IRRC asked the Board to clarify the intent of this provision, including the problem or situation that is being addressed, why it is needed and whether the term "in-house engineer" should be retained or, as some commentators have suggested, be replaced with "qualified engineer." IRRC also asked the Board to explain how the term is consistent with the Engineer, Land Surveyor, and Geologist Registration Law (Registration Law) (63 P.S. §§ 148—158.2) and the regulations governing professional qualified engineers and engineers-in-training. Additionally, IRRC requested that the Board include a fiscal analysis that compares the costs of using an "in-house engineer" versus a "qualified professional engineer" under these sections. Finally, IRRC states that the Board should explain how permitting an unlicensed individual to certify the system he or she may have designed is in the public interest.

In response, the Board explains that the EPA added the term "in-house engineer" to the Reconsideration of 40 CFR Part 60, Subpart OOOOa of the NSPS (relating to standards of performance for crude oil and natural gas facilities for which construction, modification or reconstruction commenced after September 18, 2015) to address a specific concern about the availability and costs associated with limiting the certification of closed vent system design and capacity or technical infeasibility of routing natural gas-driven diaphragm pump emissions to a control to a "qualified professional engineer" as defined in § 129.122 (relating to definitions, acronyms and EPA methods). Because of the interrelatedness of the NSPS and the 2016 O&G CTG requirements, the Board proactively added this flexibility to the proposed combined rulemaking. The EPA stated in the Reconsideration that they "believe that an in-house engineer with knowledge of the design and operation of the [closed vent system] is capable of performing these certifications, regardless of licensure..." According to the EPA, a qualified professional engineer certification would cost $547 while allowing an in-house engineer to make the certification would cost $358. Unfortunately, the term "in-house engineer" was not defined in the NSPS or the 2016 O&G CTG, so the Board proposed the definition given. Based on comments received, the Board revises the definition of "in-house engineer" to require that the "in-house engineer" be employed by the same owner or operator as the responsible official that signs the certification required under § 129.130(k).

The term "in-house engineer" is consistent with the Registration Law and the regulations governing professional qualified engineers and engineers-in-training in that it narrowly defines who is permitted to perform the certification of a natural gas-driven diaphragm pump or closed vent system in accordance with section 5 of the Registration Law (63 P.S. § 152). Clause (i) of the definition in this final-omitted rulemaking recognizes that in accordance with section 5(f) and (g) of the Registration Law, the individual must be an employee of the owner or operator. Clause (ii) of the definition tightens the criteria of section 5(f), (g) and (j) by requiring the individual be qualified by education, technical knowledge, and expertise in the design and operation of a natural gas-driven diaphragm pump or closed vent system as those subsections of the Registration Law do not specify the level of technical knowledge required.

There are two provisions in this final-omitted rulemaking that authorize use of an in-house engineer: § 129.135(c)(3)(ii)(A) (relating to natural gas-driven diaphragm pumps) and § 129.138(c)(1). The provision in § 129.135(c)(3)(ii)(A) allows an in-house engineer to perform an assessment to determine whether it is technically infeasible for a natural gas-driven diaphragm pump to connect to a control device or process. The provision in § 129.138(c)(1) allows an in-house engineer to perform a design and capacity assessment to ensure an installed closed vent system is sufficient to convey emissions to a control device that can accommodate those emissions. Authorizing the use of an in-house engineer in these two limited situations is in the public interest because it will not affect "the public safety or health or the property of some other person or entity" in accordance with section 5(f) and (g) of the Registration Law. In fact, in the 2016 O&G CTG, the EPA allowed for this certification by either a licensed professional engineer (PE) or an in-house engineer because in-house engineers may be more knowledgeable about site design and control than a third-party PE.

e. *The requirements, implementation procedures and timetables for compliance of this final-omitted rulemaking are reasonable.*

IRRC noted that the effective date of this final-omitted rulemaking is immediately upon publication in the *Pennsylvania Bulletin*. Commentators suggested that a minimum of a 60-day effective date would give owners or operators additional time to reasonably transition into the new requirements so that existing facilities are not required to immediately implement and comply with the new rules. Others suggested that owners or operators will need considerably more time to determine if their sources are required to comply with this final-omitted rulemaking, as well as mobilize the necessary resources to perform the required inspections. In addition, interested parties representing the oil and gas industry requested that time periods between inspections be extended or made consistent with current 2016 O&G CTG timeframes to avoid duplicate compliance activities. IRRC encouraged the Board to work with the regulated community to resolve issues pertaining to inspection timeframes and recommends revising the effective date of this final-omitted rulemaking to give sufficient time to the regulated community to implement and comply with requirements or explain why it is unnecessary to do so.

In response, this final-omitted rulemaking will be effective upon notice or publication in the *Pennsylvania Bulletin*; however, the Board notes that compliance dates are established throughout this final-omitted rulemaking to provide affected owners or operators sufficient time to identify and comply with the applicable requirements.

IRRC noted that the Benefits, Costs and Compliance section of the preamble describes how the VOC RACT requirements established by this final-omitted rulemaking will be incorporated into "an existing permit." IRRC asked how the process to incorporate the requirements into an existing permit will be implemented based on the compliance schedule in Section 29F of the RAF (pertaining to expected date by which permits, licenses or other approvals must be obtained). IRRC asked the Board to provide a more detailed explanation of the process contained in this section and how it will be implemented.

In response, the Board explains that the incorporation of the requirements of this final-omitted rulemaking into an existing permit will follow the requirements of § 127.463 (relating to operating permit revisions to incorporate applicable standards). Owners or operators will not be required to submit an application for amendments to an existing operating permit. Instead, the 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). 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-omitted rulemaking, as required under § 127.463(b).

IRRC stated that interested parties representing environmental concerns commend the Board for including alternative leak detection methods in the rulemaking. IRRC asked the Board to explain the approval process for alternative leak detection methods and whether alternative leak detection methods will be required to achieve equivalent emission reductions as currently allowed devices or methods. Additionally, IRRC asked the Board to describe the requirements and approval process for alternative leak detection methods in the preamble to this final-omitted rulemaking.

In response, the Board explains that the Department adopts a performance-based approach for evaluating leak detection equipment and the equipment's documented ability to measure the compounds of interest at the detection level necessary to demonstrate compliance with the applicable requirement. In many cases, the technology has been evaluated by the EPA and appropriate quality assurance requirements have been specified. In addition to Method 21 and 40 CFR 60.18, 40 CFR 98.234 (relating to monitoring and QA/QC requirements) includes a list of other appropriate technologies and requirements. Since the Department's criteria are performance based, an owner or operator seeking to use an alternative method should provide documented evidence that the alternative technology is capable of detecting the leak at the specified leak threshold. For example, an alternative leak detection method with the appropriate performance criterion may be specified in a related, though not specifically applicable, regulation such as an NSPS or National Emission Standard for Hazardous Air Pollutants.

f. *This final-omitted rulemaking is needed.*

IRRC noted that the preamble and the RAF do not adequately describe the rationale or need for certain requirements or exclusions. Commentators representing environmental concerns identify two key provisions that they say are contrary to the goals of this final-omitted rulemaking. The first is the exemption of low-producing wells from the requirements of LDAR inspections. The second one is the "step down" provision that allows owners or operations to decrease the frequency of LDAR inspections if the percentage of leaking components is less than 2% for two consecutive quarterly inspections. Owners or operators would have the option to reduce the inspection frequency to semi-annually. Opponents of these two measures say it is "faulty and risky" for the Department to assume that conventional operations do not emit at levels high enough to have a significant impact on air quality and climate. IRRC asked the Board to explain the need for each provision and how determinations were made, as well as what data was used to justify the exemptions. Section 11 of the RAF also states that the Department determined that owners or operators must conduct quarterly LDAR inspections at their facilities, as opposed to the recommended semiannual frequency in the 2016 O&G CTG. IRRC asked the Board to explain the need for the quarterly LDAR inspection requirement, the low production threshold LDAR exemption, and the LDAR stepdown provision and how the determinations were made, as well as what data was used to the justify the exemptions or more stringent regulations.

In response, the Board explains that the control measures in this final-omitted rulemaking are reasonably necessary to attain and maintain both the 2008 and 2015 ozone NAAQS. The Department removes the stepdown provision and altered the production thresholds for LDAR requirements in this final-omitted rulemaking. For fugitive emission components, the proposed combined rulemaking established monthly AVO inspections and quarterly instrument based LDAR inspections for well sites with a well that produces, on average, 15 BOE per well per day. The proposed combined rulemaking also established a stepdown provision which enabled owners or operators to track the percentage of leaking components at each inspection and, if in two consecutive inspections there were less than 2% of components leaking, the owner or operator could reduce the quarterly schedule of instrument based LDAR to semiannual. However, the Department's analysis shows that it is cost effective to implement instrument based LDAR at conventional well sites with an average production of 15 BOE per day, with the frequency based on individual well production on the well site. For applicable conventional well sites with at least one well that produces equal to or greater than 15 BOE per day the owner or operator must perform quarterly instrument based LDAR inspections. For applicable conventional well sites with at least one well that is less than 15 BOE per day and equal to or greater than 5 BOE per day, the owner or operator must perform annual instrument based LDAR inspections. The owner or operator is required to track well site production and the individual production of each well on the conventional well site on an annual basis. The owner or operator may reduce the inspection frequency based on the production calculations which shows two consecutive years of production in the lower category. The owner or operator shall increase the inspection frequency immediately if the production calculations show an increase that is subject to more frequent inspections.

IRRC noted that representatives from the oil and gas industry observe that no analysis has been shared by the Board to support the Department's conclusion that the proposed requirements that are more stringent than the EPA's 2016 O&G CTG "are reasonably necessary" to achieve or maintain the NAAQS. Commentators question the need to exceed the 2016 O&G CTG when this Commonwealth is near universal compliance with the 1997, 2008 and 2015 ozone standards. IRRC further notes that the commentators explain that the state is not required to rely on the recommendations of the 2016 O&G CTG to establish the proposed rulemaking. Instead, it could make RACT determinations for a particular source on a case-by-case basis considering the technological and economic feasibility of the individual source.

In response, the Board agrees that the ambient air ozone monitoring data demonstrates that this Commonwealth is in near universal compliance with the 1997, 2008 and 2015 ozone NAAQS. The Department's analysis of the 2020 ambient air ozone season monitoring data shows that all ozone samplers in this Commonwealth are monitoring attainment of the 2015 8-hour ozone NAAQS except three: the Bristol sampler in Bucks County, the Philadelphia Air Management Services Northeast Airport and Northeast Waste samplers in Philadelphia County. Ambient air ozone samplers in this Commonwealth are projected to monitor attainment of the 1997 and 2008 8-hour ozone NAAQS. However, the Department must ensure that the 1997, 2008 and 2015 8-hour ozone NAAQS continue to be attained and maintained by implementing permanent and Federally enforceable control measures.

Additionally, section 182(b)(2) of the CAA requires states with moderate ozone nonattainment areas to revise their SIPs to include RACT for sources of VOC emissions covered by 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 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, since this Commonwealth is not designated by the EPA as in attainment with the 2015 ozone NAAQS and is not monitoring compliance Statewide with the 2015 ozone NAAQS, 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. These sources were selected by the EPA because data and information has indicated that they are significant sources of VOC emissions.

The Department is obligated under the CAA to analyze the source sector, as defined in the 2016 O&G CTG, and regulate sources that have control techniques or equipment that is "reasonably available." 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 a product or source category in ozone nonattainment areas. In other words, the 2016 O&G CTG has no legally binding effects. While the EPA provided information and RACT recommendations through the 2016 O&G CTG for VOC emissions, it is up to the Department to determine what is RACT for each source category of VOC emissions. As explicitly stated by the EPA in the 2016 O&G CTG, state air pollution control agencies are free to implement other technically-sound approaches that are consistent with the CAA and the EPA's regulations. See 81 FR 74798, 74799 (October 27, 2016). The EPA also further clarified that "the information contained in the CTG document is provided only as guidance" and "this guidance does not change, or substitute for, requirements specified in applicable sections of the CAA or the EPA's regulations; nor is it a regulation itself." Id. While the EPA will ultimately need to approve the Department's RACT determinations by reviewing and approving the revision to the Commonwealth's SIP, the Department has made the initial RACT determinations in this final-omitted rulemaking based on the entirety of information available to the Department, including the 2016 O&G CTG.

The Department's obligation is to affirmatively determine what constitutes RACT for the source group identified in the 2016 O&G CTG and the EPA's provision of guidance and data in the 2016 O&G CTG does not obliviate that legal requirement. In the time since the 2016 O&G CTG was issued by the EPA, the Department acquired additional information and current emissions data specific to this Commonwealth that it analyzed to determine the RACT emission limitations and requirements established in this final-omitted rulemaking.

The Department determined that the recommendations provided in the 2016 O&G CTG for natural gas-driven continuous bleed pneumatic controllers, natural gas driven-diaphragm pumps and centrifugal compressors are RACT for sources in this Commonwealth. The EPA recommendations in the 2016 O&G CTG for storage vessels, reciprocating compressors, and fugitive emissions components were determined not to be RACT in this Commonwealth. The Department conducted a reanalysis to determine RACT for these three categories of sources: storage vessels, reciprocating compressor rod packing and fugitive emissions components. The information used in the Department's analysis was obtained from the Department's Air Emission Inventory, Oil and Gas Production Database, and information provided by industry trade associations from the public comment period for the proposed combined rulemaking.

The quarterly LDAR inspection requirement for conventional well sites with a well that produces, on average, 15 BOE per well per day is reasonably necessary to achieve and maintain the NAAQS for ozone and is technically and economically feasible. For applicable conventional well sites with at least one well that is less than 15 BOE per day and equal to or greater than 5 BOE per day, the owner or operator must perform annual instrument based LDAR inspections. The Department determined that this is also reasonably necessary to achieve and maintain the NAAQS for ozone and is technically and economically feasible. Additionally, the Department notes that the leak rate-based LDAR stepdown provision is removed in this final-omitted rulemaking.

To address the comment about case-by-case RACT determinations, the Board was incorrect in suggesting in the preamble for the proposed combined rulemaking that a case-by-case RACT determination is available for this

CTG-based rule. The Board decided not to exercise its discretion to conduct case-by-case RACT analysis for this final-omitted rulemaking. The process for submitting RACT determinations on a case-by-case basis to the EPA is administratively burdensome, particularly given the larger number of regulated facilities. Instead, for this final-omitted rulemaking, the Department modified the EPA's "presumptive norm" RACT recommendations. As stated by the EPA in 44 FR 53761 (September 17, 1979) titled, "State Implementation Plans; General Preamble for Proposed Rulemaking on Approval of Plan Revisions for Nonattainment Areas—Supplement (on Control Techniques Guidelines):" "Along with information, each CTG contains recommendations to the States of what EPA calls the "presumptive norm" for RACT, based on EPA's current evaluation of the capabilities and problems general to the industry. Where the States finds the presumptive norm applicable to an individual source or group of sources, EPA recommends that the State adopt requirements consistent with the presumptive norm level in order to include RACT limitations in the SIP."

g. *This final-omitted rulemaking will not negatively impact small businesses.*

IRRC noted that section 5(a)(12.1) of the RRA requires promulgating agencies to provide a regulatory flexibility analysis and to consider various methods of reducing the impact of the proposed regulation on small business. IRRC does not believe that the Board has met its statutory requirement of providing a regulatory flexibility analysis or considering various methods of reducing the impact the proposed regulation will have on small business in its responses to various sections and questions in the RAF. It is unclear from the RAF whether the 303 conventional wells subject to LDAR inspections are owned by small businesses. However, commentators believe most, if not all, are small businesses and strongly disagree that they will incur minimal costs as a result of the proposed rulemaking. In Section 15 of the RAF, the Board states that "further analysis is required to determine if any of the affected sources are owned or operated by small businesses." IRRC asked how the Board determined that costs would be minimal if it is unknown whether any of the affected sources are owned by small businesses. IRRC agreed with the commentators that further analysis is needed to determine the financial impact on small businesses and asked the Board to provide the required regulatory flexibility analysis when it submits the final-omitted rulemaking.

In response, the Board notes that as stated in the RAF for the proposed combined rulemaking, of the 71,229 conventional wells reporting production, only 303 were found to be above the 15 BOE/day production threshold as reported in the Department's 2017 oil and gas production database and would have fugitive emissions component requirements. Upon further analysis by the Board, it seems that only 199 of the previously identified 303 conventional wells were potentially subject to the proposed LDAR requirements for fugitive emissions. In the analysis for the proposed combined rulemaking, the Board examined individual wells, not well sites. It is difficult to determine at the individual well level how many are owned or operated by small businesses as there may be several wells per well site. However, the costs to the owners or operators of those 199 conventional wells would have been minimal, because the Board's cost analysis for quarterly LDAR was based on hiring a contractor, not purchasing equipment, hiring and training personnel, and conducting quarterly surveys.

The Board identified 4,719 client ID numbers for potentially affected owners or operators of facilities in this Commonwealth using the Department's eFACTS and AIMS databases and the North American Industry Classification System (NAICS) codes covered by the 2016 O&G CTG. These facilities include approximately 27,260 conventional well sites, 486 gathering and boosting stations, and 15 natural gas processing facilities in this Commonwealth. Of these potential 4,719 conventional owners or operators, approximately 3,704 may meet the definition of small business as defined in section 3 of the RRA. However, it is possible that far fewer than the 4,719 conventional owners or operators will be subject to the control measures of this final-omitted rulemaking, depending on the amount of VOC emissions that are emitted by the affected sources they own or operate or if they are subject to other regulations in Chapter 129. While many of the anticipated costs are due to new regulatory requirements, many of the costs associated with this final-omitted rulemaking are from what the Board believes are best management practices and controls that affected owners or operators may already be implementing. Additionally, the Board notes that the EPA did not distinguish between unconventional and conventional sources of emissions in the 2016 O&G CTG, and the Board does not have the authority to exempt sources from Federal requirements.

In this final-omitted rulemaking, the Board estimates that there are 27,260 conventional well sites with 68,519 producing conventional wells. Based on comments, the Board estimates there is approximately one storage vessel per well site; of these, only six are estimated to have VOC emissions that would require control, for a cost of approximately $185,453 (2021 dollars) and reducing 71 TPY VOC yielding $2,612 per ton reduced. For natural gas continuous bleed pneumatic controllers, based on comments and assuming those that are subject to Federal regulation are in compliance, the Board estimates there are 26,284 natural gas-driven continuous bleed pneumatic controllers that would require replacement. The cost to replace these natural gas-driven continuous bleed pneumatic controllers is estimated to be $9.1 million (2021 dollars). This would result in a VOC emission reduction of 8,336 TPY at a cost of $1,093 per ton reduced and an estimated savings in natural gas of $14.3 million (2021 dollars), or $546 in savings per natural gas-driven continuous bleed pneumatic controller replaced.

Of the 27,260 conventional well sites, the Board estimates that 64 well sites with 289 wells would be required to implement quarterly instrument-based LDAR and 31 well sites with 970 wells would be required to implement annual instrument-based LDAR. This would cost an estimated $482,408 (2021 dollars) and result in approximately 797 TPY VOC emissions reduction or $605 per ton reduced. The Board estimates that implementation of LDAR at these well sites would result in an estimated savings in natural gas of approximately $1.4 million (2021 dollars), or $14,447 in savings per facility conducting LDAR. These cost and savings figures represent a net benefit to the conventional industry of $889,129 which implies a financial benefit, not an impact, to the conventional industry. Therefore, the Board estimates total industry costs for conventional operators will be $9.8 million (in 2021 dollars), the total industry savings will be $15.7 million, for a total net benefit of $5.9 million.

In addition, those well sites all have one or more high producing wells. High producing wells generate the most oil, which leads to higher revenue and profits. In other words, for the conventional O&G industry, only the 95 highest producing well sites out of 27,260 well sites will be subject to the LDAR requirements. To the extent that the regulated well sites, which represent the 0.3% highest producing well sites, are small businesses, the economic burden will be small because these are among the very highest revenue generating well sites. Additional details on small businesses and the effects of this final-omitted rulemaking on small businesses can be found in Sections 15, 24 and 27 of the RAF.

2. Act 52 of 2016 does not apply to this final-omitted rulemaking.

IRRC commented that section 7(b) of Act 52 of 2016 (58 P.S. § 1207(b)), requires any rulemaking concerning conventional oil and gas wells that is considered by the Board must "be undertaken separately and independently of unconventional wells or other subjects and shall include a regulatory analysis form submitted to the Independent Regulatory Review Commission that is restricted to the subject of conventional oil and gas wells." IRRC noted that lawmakers and commentators state that the Board has violated clear legislative directives by proposing a VOC emissions rule that includes requirements for conventional oil and gas well owners and operators along with, not "separately and independently" from, requirements for unconventional well operations. IRRC further noted that the Board has not prepared or submitted an RAF restricted to the need and impact of the rulemaking on the conventional oil and gas industry. IRRC highlights that lawmakers request that the provisions that apply to the conventional oil and gas industry be withdrawn from the rulemaking. IRRC asked the Board to explain how it has and will comply with the legislative directives of Act 52 of 2016.

In response, the Board explains that this final-omitted rulemaking establishes control measures that are only applicable to conventional sources of VOC emissions installed at conventional well sites, gathering and boosting stations and natural gas processing plants.

On March 15, 2022, the Board adopted the combined rulemaking (both conventional and unconventional sources) as a final-form rulemaking. Also, on March 15, 2022, the Board submitted the final-form combined rulemaking to IRRC for its consideration. On April 26, 2022, the House ERE Committee sent a letter to IRRC indicating their disapproval of the combined rulemaking due to their interpretation of language in Act 52 of 2016. The letter stated the House ERE Committee's position that Act 52 of 2016 requires the Board to submit two rulemaking packages—one that applies to unconventional oil and natural gas sources and one that applies to conventional oil and natural gas sources. The House ERE Committee's letter to IRRC initiated the concurrent resolution process under section 7(d) of the RRA which allows the General Assembly to adopt a resolution that disapproves and permanently bars a final regulation from taking effect.

While the Board disagrees with the House ERE Committee's interpretation of Act 52 of 2016, to address their concerns and avoid further delay, on May 4, 2022, the Board withdrew the combined rulemaking from IRRC's consideration. The Board then revised the combined rulemaking to apply only to unconventional oil and natural gas sources. On June 14, 2022, the Board adopted the revised Control of VOC Emissions from Unconventional Oil and Natural Gas Sources final-form rulemaking (referred to as the unconventional rulemaking). On July 21, 2022, IRRC unanimously approved the unconventional rulemaking.

Given the concerns expressed by the House ERE Committee and other commentators during the regulatory process for the combined rulemaking, the Department developed this separate rulemaking, including a separate Regulatory Analysis Form, to control VOC emissions from conventional oil and natural gas sources of VOC emissions.

IRRC also commented that commentators representing the conventional oil and gas industry are uncertain whether the proposed regulation applies to conventional oil and gas operations in this Commonwealth. IRRC commented that these industry representatives claim that the regulation would apply to some equipment utilized in conventional oil and gas operations but were informed that this regulation would not apply to their sector of the industry. IRRC asked the Board to clarify which provisions, if any, apply to the conventional oil and gas industry.

In response, the Board explains that given the concerns expressed by the commentators during the regulatory process for the combined rulemaking, the Department developed this separate final-omitted rulemaking, including a separate Regulatory Analysis Form, to control VOC emissions from conventional oil and natural gas sources.

The Department estimates that approximately 95 of the 27,193 conventional well sites may need to implement a new LDAR program because those well sites produce at least 15 BOE per day with at least one well producing a minimum of 5 BOE. Based on the Department's record of when conventional well sites were drilled, the Department assumes that 67 conventional well sites are subject to Subpart OOOOa, which applies to oil and natural gas facilities constructed, modified or reconstructed after September 18, 2015. Of the approximately 95 conventional well sites that may be required to implement a new LDAR program under this final-omitted rulemaking, 31 would have to meet the annual instrument-based inspection requirement and the remaining 64 would have to meet the quarterly instrument-based inspection requirement.

3. The EPA is no longer withdrawing the 2016 O&G CTG.

IRRC notes that the Board states in Section 9 of the RAF that "[e]ven though a finalized withdrawal of the 2016 O&G CTG would relieve the state of the requirement to address RACT for existing oil and gas sources, the Department is still obligated to reduce ozone and VOC emissions to ensure that the NAAQS is attained and maintained under section 110 of the CAA. 42 U.S.C.A. § 7410." Commentators have asked the Board to consider another public comment period should the Federal regulations or guidelines be significantly changed before promulgation of this final-omitted rulemaking. IRRC asked the Board to explain how it will proceed if there are significant changes made to 2016 O&G CTG or 40 CFR Part 60, Subparts OOOO (relating to standards of performance for crude oil and natural gas facilities for which construction, modification, or reconstruction commenced after August 23, 2011, and on or before September 18, 2015) and OOOOa prior to the promulgation of this final-omitted rulemaking.

In response, the Board explains that the relevant Federal regulations and the 2016 O&G CTG have not significantly changed and will not change prior to promulgation of this final-omitted rulemaking. In March of 2020, the Department received notice that the EPA had decided not to proceed with the withdrawal of the 2016 O&G

CTG. The EPA announced in the OMB's Spring 2020 Unified Agenda and Regulatory Plan that the CTG will remain in place as published on October 27, 2016. On November 16, 2020, the EPA issued a Final Rule entitled "Findings of Failure To Submit State Implementation Plan Revisions in Response to the 2016 Oil and Natural Gas Industry Control Techniques Guidelines for the 2008 Ozone NAAQS and for States in the Ozone Transport Region (OTR)." 85 FR 72963 (November 16, 2020). This Commonwealth was one of the five states issued a finding of failure to submit a SIP revision incorporating the 2016 O&G CTG RACT requirements by October 27, 2018. The EPA's finding triggers the sanction clock under the CAA. The Commonwealth must submit this final-omitted rulemaking, along with the unconventional rulemaking, as a SIP revision and the EPA must determine that the submittal is complete within 18 months of the effective date (December 16, 2020) of the EPA's finding, that is, by June 16, 2022, or sanctions may be imposed. The offset ratio sanctions went into effect on June 16, 2022, and the Commonwealth now has until December 16, 2022, to submit the SIP revision or highway funding sanctions will be imposed.

4. Provisions of this final-omitted rulemaking were amended for clarity.

IRRC noted that § 129.121(a) provides that the proposed rulemaking would apply to the owners or operators of storage vessels in all segments except natural gas distribution; natural gas-driven continuous bleed pneumatic controllers; natural gas driven diaphragm pumps; reciprocating compressors; centrifugal compressors; or fugitive emissions component which were in existence on or before the effective date of this final-omitted rulemaking. Commentators ask how "existing" will be interpreted under this rulemaking since there may be facilities that have initiated construction but are not yet operational on the effective date of the rulemaking. IRRC asked the Board to explain, in the preamble to the final-omitted rulemaking, how "existing" will be interpreted under this chapter.

In response, the Board revises the applicability section, § 129.131(a), of this final-omitted rulemaking by removing the phrase "in existence" and replacing it with "constructed" to clarify that the requirements apply to sources constructed on or before the effective date of this final-omitted rulemaking. Sources constructed after the effective date will not be subject to this final-omitted rulemaking. However, new sources are subject to best available technology requirements, so it is likely that the requirements for new sources will be equivalent to or more stringent than the RACT requirements of this final-omitted rulemaking.

IRRC mentioned that subparagraph (iii) of the definition of "deviation" includes a failure to meet an emission limit, operating limit, or work practice standard during start-up, shutdown or malfunction as a "deviation" regardless of whether a failure is permitted by these rules. IRRC requested that the Board clarify this definition because commentators have asked the Board to make clear that failure to meet a limit or standard should not be considered a "deviation" if permit conditions are met.

In response, the Board explains that a deviation under subparagraph (iii) is not considered to be a violation of this final-omitted rulemaking or a permit and deviations must be recorded and reported as required under § 129.140. A facility that has a permit must evaluate the terms and conditions of the permit and the requirements of this final-omitted rulemaking and comply with the most stringent requirement. The deviation must be evaluated against the most stringent requirement. The Board will evaluate these instances for compliance with the applicable requirements and standards. Additionally, the definition of "deviation" is consistent with the EPA's guidance in the 2016 O&G CTG.

IRRC suggested that for consistency, the definition of "first attempt at repair" should be revised to replace "organic material" with "VOCs."

In response, the Board explains that in the proposed rulemaking it used the definition of "first attempt at repair" from the EPA's regulations at 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). While the term "first attempt at repair" is used in Sections A, D and G in the 2016 O&G CTG, it was not defined. After the EPA's Reconsideration of the NSPS, a definition that differed slightly from that in Subpart VVa was added to Subpart OOOOa. As the definition of "first attempt at repair" from Subpart OOOOa is closer in-line with the usage in the 2016 O&G CTG, the Board revises the definition in this final-omitted rulemaking. The Board removes the proposed definition which stated, "action taken for the purpose of stopping or reducing leakage of organic material to the atmosphere using best practices" and replaces it with "for purposes of § 129.127 (relating to fugitive emissions components): an action using best practices taken to stop or reduce fugitive emissions to the atmosphere." The Board also clarifies that the term includes tightening bonnet bolts, replacing bonnet bolts, tightening packing gland nuts and injecting lubricant into lubricated packing. This change accommodates the revision suggested by the commentators.

IRRC asked what the Board means by the phrase "an engineering judgment" in the definition of "in-house engineer" and suggested that the Board define this term or explain why it is unnecessary to do so.

In response, the Board removes the phrase "an engineering judgment" and makes further revisions to the definition of "in-house engineer" in this final-omitted rulemaking. Instead of the phrase "an engineering judgment," the Board revises the definition of "in-house engineer" in this final-omitted rulemaking to require the engineer to be qualified by having expertise in the design and operation of a natural gas-driven diaphragm pump or closed vent system.

IRRC noted that subparagraph (i) in the definition of "leak" reads "A positive indication, whether audible, visual or odorous, determined during an AVO inspection." IRRC also agreed with commentators who have suggested that this subparagraph be amended for clarity to state "A positive indication of a leak. . ."

In response, the Board revises subparagraph (i) of the definition of "leak" in this final-omitted rulemaking by removing "A positive indication, whether audible, visual or odorous, determined" and replacing it with "Through audible, visual or odorous evidence." The Board further clarifies the definition of "leak" by adding that it is "an emission detected" and providing for methods for detecting the emission. Additionally, the Board did not add "A positive indication of a leak. . ." to the definition as suggested by the commentators in accordance with § 2.11(h) (relating to definitions) of the *Pennsylvania*

Code and Bulletin Style Manual. Section 2.11(h) states that "the term being defined may not be included as part of the definition."

IRRC suggested that the phrase "For purposes of this section, §§ 129.121 and 129.123—129.130" in the definition of "TOC—total organic compounds" is unnecessary and should be deleted from the definition. In response, the Board agrees that the phrase "For purposes of this section, §§ 129.121 and 129.123—129.130" is redundant and removes that phrase from the definition in this final-omitted rulemaking.

IRRC questioned the need for the provision in subparagraph (ii) of the definition of "qualified professional engineer" providing that "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." In response, the Board explains that the EPA defined "qualified professional engineer" in the 2016 O&G CTG as "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 specific technical certifications required under this subpart. Professional engineers making these certifications must be currently licensed in at least one state in which the certifying official is located." Therefore, the requirement that the "qualified professional engineer" be licensed in one of the states where the responsible official does business is part of the EPA's RACT recommendation. The Board adds the requirement for reciprocity due to requirements that an engineer be legally qualified to engage in the practice of engineering and that the standards of the other state or territory be at least equal to the standards of this Commonwealth.

IRRC recommended that the definitions of "conventional well" and "unconventional well" as defined in §§ 78.1 and 78a.1 (relating to definitions) be included by reference in § 129.122(a).

In response, the Board adds definitions for "conventional well," "conventional well site," "unconventional formation," "unconventional well," and "unconventional well site" in this final-omitted rulemaking, since the applicability section is amended to clarify that this final-omitted rulemaking only applies to conventional sources installed at a "conventional well site." The definitions of "unconventional formation" and "unconventional well" in this final-omitted rulemaking are identical to the definitions in § 78a.1. The definition of "conventional well" in this final-omitted rulemaking is identical to the definition in § 78.1.

IRRC noted that § 129.123(a)(2)(i) requires that potential VOC emissions for conventional, unconventional, gathering and boosting station and at a facility in the natural gas transmission and storage segment use a generally accepted model or calculation methodology, based on the maximum average daily throughput prior to the effective date of this final-omitted rulemaking. Commentators asked the Department to revise this section to allow all generally accepted models or calculation methodologies and request the language referencing historical data be deleted. However, commentators stated that use of past maximum averages that are no longer representative of the facilities throughputs will not provide an accurate emissions profile to justify the proposed compliance requirements. IRRC requested that the Board explain its rationale for and the reasonableness of the provision relating to historical data.

In response, the Board revises § 129.133(a)(2)(i) in this final-omitted rulemaking to add that the maximum average daily throughput is as defined in § 129.132 and to extend the calculation requirement from the date of publication to 60 days after. This revision was made to provide clarity, to be more representative of the facility operations and to provide a more accurate emissions profile.

IRRC noted that § 129.123(a)(2)(ii) provides that 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. IRRC requested that the Board explain in the preamble to this final-omitted rulemaking whether State-permitting programs such as GP-5, GP-5A and Exemption 38 of the Air Quality Permit Exemptions list will be considered satisfactory for this requirement.

In response, the Board explains that when calculating the potential VOC emissions for this final-omitted rulemaking, an owner or operator must ensure that they are complying with existing VOC limits in an operating permit or plan approval. Section 129.133(a)(2)(ii) is revised to replace "must" with "may" to read "The determination of potential VOC emissions may consider requirements under a legally and practically enforceable limit established in an operating permit or plan approval approved by the Department." It was not the EPA's recommendation, nor the Board's intent, to require that legally and practically enforceable limits be considered when calculating potential VOC emissions to determine applicability to the rule. GP-5, GP-5A and Exemption 38 are not applicable for sources at conventional well sites, so this provision has no effect on the calculation of potential emissions for storage vessels at conventional well sites.

IRRC noted that § 129.123(b)(1)(iii) requires routing emissions to a control device or process that meets the applicable requirements of § 129.129. Commentators noted that § 129.129 contains requirements specific only to "control devices" and not to "processes." IRRC requested that the Board explain the intent of the proposed language and revise it if necessary. IRRC also noted that similar language appears in §§ 129.125(b)(1)(ii), 129.126(c)(2), 129.128(a)(2)(ii) and 129.128(b)(1).

In response, the Board explains that the requirements for "processes" can be found in § 129.139(d) of this final-omitted rulemaking. In particular, § 129.139(d)(1)(iv), regarding compliance requirements for an enclosed combustion device, establishes the requirements for the use of a boiler or process heater—a "process"—to control the VOC emissions. VOC emissions routed to a boiler or process heater are considered controlled if the vent stream containing the VOC emissions is injected into the flame zone of the boiler or process heater.

IRRC noted that § 129.124(d) requires the owner or operator to tag each affected natural gas-driven pneumatic controller with the date the controller is required to comply with the requirements of this section and an identification number that ensures traceability to the records for that controller. IRRC asked the Board to explain the rationale for this requirement, including why it believes it is reasonable.

In response, the Board explains that the requirement is based on the EPA's recommendation from the 2016 O&G

CTG, and the Department determines that the tagging would facilitate the determination that the owners or operators are in compliance with this final-omitted rulemaking, and is not overly burdensome.

IRRC asked the Board to specify a timeframe in § 129.127(a) that will be used to determine per-day average production figures for the 15 BOE per day applicability threshold or explain why it is unnecessary to do so.

In response, the Board adds a calculation procedure to estimate the average production of a conventional well site in § 129.137(b) of this final-omitted rulemaking. The owner or operator of a conventional well site shall calculate the average production in BOE per day of the well site using the previous 12 calendar months of operation as reported to the Department.

IRRC asked the Board to clarify whether the adjustments to the LDAR inspection intervals in proposed § 129.127(b) are required under proposed § 129.127(e).

In response, the Board explains that the LDAR inspection frequency reductions under § 129.137(c)(4)(i) of this final-omitted rulemaking do not require an owner or operator to request an extension of the LDAR inspection frequency under § 129.137(f) of this final-omitted rulemaking.

IRRC noted that § 129.127(e) permits the owner or operator of an affected facility to request, in writing, an extension of the LDAR inspection interval. IRRC asked the Board to explain the need for an extension, including under what conditions or circumstances an owner or operator may request an extension. IRRC also asked whether certain conditions or requirements are needed to request an extension, how owners or operators will be informed about those conditions or requirements and what the maximum amount of time is that an extension may be granted.

In response, the Board explains that the flexibility granted to an owner or operator by allowing them to request an extension of the LDAR inspection interval may be for any reason. Examples for requesting an extension of the inspection frequency could include that the owner or operator's inspection equipment requires repair and will be unavailable when the inspection is due, the owner or operator has numerous facilities and it will take longer than the time allowed under this final-omitted rulemaking to determine applicability, plan, and perform the initial inspections, or it is not possible to have a contractor perform the required inspection when it is due because there are no contractors available by that date. However, the conditions required for and the duration of the extension will be determined on a case-by-case basis by the Air Program Manager of the appropriate Department Regional Office when approving the extension request.

IRRC noted that § 129.129(b)(5)(ii) refers to an "inspection and maintenance plan" in § 129.129(b)(1) that does not exist. IRRC asked the Board to clarify the intent of this subparagraph and revise, if necessary.

In response, the Board removes the reference to an "inspection and maintenance plan" and instead requires the use of the best combustion engineering practice applicable to the control device if the manufacturer's repair instructions are not available.

IRRC asked the Board to delete the reference to subsection (c)(l)(ii) in § 129.129(k)(5) since subsection (c)(l)(ii) does not require or refer to a weight-percent VOC emission reduction requirement.

In response, the Board does not remove the reference to subsection (c)(l)(ii) and adds a weight-percent VOC emission reduction requirement to § 129.139(c)(1)(ii).

IRRC noted that §§ 129.129(j)(1)(v)(D) and 129.129 (j)(1)(vi)(B) provide for requests for extension of initial performance test reports and asked the Board to refer to IRRC's comments regarding the LDAR inspection interval extension requests in § 129.127(e) as the questions apply also to this subsection.

In response, the Board explains that the allowance for an owner or operator to request an extension of the initial performance test requirements provides flexibility to the owner or operator. The owner or operator may request an extension for any reason. For example, it is possible that an operator could request an extension due to scheduling issues with source testing contractors. However, the conditions required for and the duration of the extension will be determined on a case-by-case basis by the Air Program Manager of the appropriate Department Regional Office when reviewing and approving/denying the extension request.

IRRC noted that § 129.130(d)(l) requires the records for each natural gas-driven diaphragm pump to include the date, location and manufacturer specifications for each pump. IRRC requested that the Board revise this section to clarify the date referenced.

In response, the Board clarifies that the date in § 129.140(d)(1) is the "required compliance" date.

IRRC noted that § 129.130(g)(2)(ii)(G)(II) requires the "instrument reading of each fugitive emission component" that meets the definition of a leak under the rulemaking. IRRC asked if this subsection should be revised for consistency to account for leaks that are detected with OGI equipment.

In response, the Board does not make a revision and explains that the instrument reading for OGI equipment is a visible leak.

IRRC noted that Section 15 of the RAF indicates that the table in Section 23 provides a breakdown of the cost data for the industry. The figures provided in the table in Section 23 of the RAF represent industry-wide cost and savings estimates. IRRC recommended that the Board either include in the chart as described in the RAF for this final-omitted rulemaking or remove this statement if one does not exist.

In response, the Board explains that the response to Question 15 of the RAF details the breakdown of cost data for the conventional industry on a per owner or operator and a per facility basis. The response to Question 19 of the RAF details the individual source costs, including the total conventional industry cost based on the estimated number of affected sources in each category. The response to Question 23 provides a breakdown of the total costs to the industry. Additionally, the Board does not include a reference in the response to Question 15 to the table in the response to Question 23 as suggested.

IRRC recommended that in § 121.1, under the term "responsible official" subparagraph (iv) clause (B) after "or Chapter 129," the Board should include parentheses containing a description of what the chapter is relating to. In response, the Board explains that § 121.1 is not included in this final-omitted rulemaking.

IRRC noted that § 129.122(a) states that "the following words and terms, when used in this section, §§ 129.121 and 129.123—120.130, have the following meaning..." IRRC suggested inserting "shall" before "have" and revising "section" to "chapter." Additionally, IRRC recommended deleting "section" replacing it with "chapter" in the definitions for "deviation" and "TOC—total organic compounds."

In response, the Board respectfully disagrees with these recommendations and does not add the word "shall" as suggested as the phrasing used in § 129.132(a) is consistent with other sections in Chapter 129 as well as the phrasing used in § 121.1. This is also consistent with § 6.7(a) (relating to use of "shall," "will," "must" and "may") of the *Pennsylvania Code and Bulletin Style Manual*. Section 6.7(a) states that the term "shall" "expresses a duty or obligation. The subject of the sentence must be a person, committee or other nongovernmental entity that is required to or has the power to make a decision or take an action." Additionally, the definitions in § 129.132(a) apply only to §§ 129.131—129.140, not the entirety of Chapter 129; therefore, the Board does not revise "section" to read "chapter" as recommended.

IRRC noted that the following terms and definitions appear in § 129.122(a) but are not used in the text of the Annex: "completion combustion device," "fuel gas," "fuel gas system," "natural gas and oil production segment," "natural gas processing segment," "transmission compression station" and "underground storage vessel." IRRC suggested that these terms and definitions be deleted. In response, the Board agrees with this suggestion and does not include these terms in this final-omitted rulemaking.

IRRC recommended that for consistency the Board include a reference to the recordkeeping and reporting requirements found in § 129.130(i)(2) in § 129.128(d). In response, the Board notes that the recordkeeping and reporting requirements for closed vent systems in § 129.140(i)(2) are found in § 129.138(b)(6). The provisions of § 129.138(d) specify the procedures for the no detectable emissions inspection required in § 129.138(b)(2)(ii).

IRRC recommended amending § 129.130(k) to replace "can" with "may" so that the statement reads "The due date of the initial report may be extended with the written approval of the Air Program Manager of the appropriate Department Regional Office." In response, the Board agrees with this recommendation and § 129.140(k)(1)(ii) uses the word "may."

5. The Board has fulfilled its duties as a trustee as set forth in Article I, Section 27 of the Pennsylvania Constitution.

Commentators, including members of the General Assembly, referenced the Commonwealth's Environmental Rights Amendment in Article I, Section 27 of the Pennsylvania Constitution, Pa.Const. Art. I, § 27, and note that it states, "The people have a right to clean air, pure water, and to the preservation of the natural, scenic, historic and esthetic values of the environment." The commentators commented that the Board and the Department must satisfy their constitutional responsibilities.

In response, the Board fulfills its duties as a trustee of the environment, set forth in Article I, Section 27 of the Pennsylvania Constitution and the Pennsylvania Supreme Court Ruling on the Environmental Rights Amendment in *Pennsylvania Environmental Defense Foundation v. Commonwealth of Pennsylvania*, 161 A.3d 911 (Pa. 2017) during the development of this final-omitted rulemaking. This final-omitted rulemaking was developed under the authority of sections 5(a)(1) and (8) of the APCA. The APCA is built on a precautionary principle to protect the air resources of this Commonwealth for the protection of public health and welfare and the environment, including plant and animal life and recreational resources, as well as development, attraction and expansion of industry, commerce and agriculture. Implementation of the VOC emission control measures in this final-omitted rulemaking will help the Department protect the air resources of this Commonwealth as well as public health and welfare by reducing harmful VOC and methane emissions from the conventional oil and gas industry. The Department recognizes the rights of this Commonwealth's residents and the Commonwealth's obligations under the Pennsylvania Constitution and must meet those obligations in every action the agency takes. Because this final-omitted rulemaking simultaneously reduces VOC and methane emissions, resulting in considerable health and other benefits, the Department is satisfied that its Article I, Section 27 obligations have been met with development of this final-omitted rulemaking.

G. *Benefits, Costs and Compliance*

Benefits

The Department estimates that implementation of the control measures could reduce VOC emissions by as much as 9,204 TPY. Approximately 304 TPY of these VOC emission reductions are due to the RACT determinations by the Department that reduce emissions over and above the EPA's RACT recommendations. 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.

Adoption of the VOC emission control measures and other requirements in this final-omitted 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 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. Achieving and maintaining the ground-level ozone NAAQS provides healthful air quality which attracts and retains residents and industry, supports healthy environmental conditions for agriculture and the ecosystems of this Commonwealth, and reduces transport of VOC emissions and ground-level ozone to downwind states.

While this final-omitted rulemaking requires VOC emission reductions, methane emissions are also reduced as a cobenefit, 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. The control measures implemented for VOC emissions simultaneously control methane emissions and could reduce methane emissions by as much as 175,788 TPY with 8 TPY from the installation of controls for storage vessels, 160,430 TPY from pneumatic controllers, and 15,350 TPY from fugitive emissions components through the performance of LDAR inspections. Approximately 5,790 TPY of the methane emission reductions are due to the technically and economically feasible VOC RACT determination by the Department that is over and above the reductions from EPA's VOC RACT recommendations.

Additionally, as previously discussed, this final-omitted 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 GHG with a global warming potential more than 28 times that of CO_2 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 GHG 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 conventional oil and natural gas sources is essential to reducing global GHG emissions and protecting public health.

Adverse health and welfare effects of ground-level ozone on humans, animals and the environment

Exposure to high levels of ground-level ozone air pollution correlates to increased respiratory disease and higher mortality rates. Ozone can inflame and damage the lining of the lungs. Within a few days, the damaged cells are shed and replaced. Over a long time period, lung tissue may become permanently scarred, resulting in permanent loss of lung function and a lower quality of life. When ambient ozone levels are high, more people with asthma have attacks that require a doctor's attention or use of medication. Ozone also makes people more sensitive to allergens including pet dander, pollen and dust mites, all of which can trigger asthma attacks. The EPA has concluded that there is an association between high levels of ambient ozone and increased hospital admissions for respiratory ailments including asthma. While children, the elderly and those with respiratory problems are most at risk, even healthy individuals may experience increased respiratory ailments and other symptoms when they are exposed to high levels of ambient ozone while engaged in activities that involve physical exertion. High levels of ground-level ozone also affect animals including pets, livestock and wildlife, in ways similar to humans.

In addition to causing adverse human and animal health effects, the EPA has concluded that ground-level ozone affects vegetation and ecosystems, leading to reductions in agricultural crop and commercial forest yields. 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. Through deposition, ground-level ozone also contributes to pollution in the Chesapeake Bay. These effects can have adverse impacts including loss of species diversity and changes to habitat quality and water and nutrient cycles. The implementation of additional measures to address ground-level ozone precursor emissions impacts on air quality in this Commonwealth is necessary to protect the public health and welfare and the environment.

Adverse effects of ground-level ozone on this Commonwealth's economy

The economic value of the impacts of ground-level ozone on this Commonwealth's farm crops, fruit industries, forests, parks and timber due to high concentrations of ground-level ozone can be calculated, through things such as crop yield loss from both reduced growth and smaller, lower-quality seeds and tubers with less oil or protein. If ozone episodes last a few days, visible injury to some leaf crops, including lettuce, spinach and tobacco, as well as visible injury to the leaves of ornamental plants, including grass, flowers and shrubs, can appear. Other types of welfare loss may not be quantifiable, such as the reduced aesthetic value of trees growing in heavily visited parks.

Information about the economic benefit of the agricultural industry to this Commonwealth is provided by the Department of Agriculture. In 2019, this Commonwealth had more than 53,157 farms occupying more than 7.3 million acres of farmland which account for 75,475 direct jobs and $9.0 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 and beverage processing, marketing, transportation, farm equipment, forestry production and processing, and landscaping. In total, production agriculture and agribusiness support 232,463 direct jobs and contribute $59.7 billion to this Commonwealth's economy. The agriculture industry, including forestry, contributes 593,600 total direct, indirect and induced jobs and $132.5 billion in total direct, indirect and induced output. 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 16.6 million acres, which represents 58% of its 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 the state'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 $463 million in 2019, and over $1.1 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. Forestry production and processing account for 69,437 direct jobs and $21.8 billion in direct economic output and direct value added to this Commonwealth's economy. Reducing ground-level ozone concentrations will serve to protect the 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 State and out-of-State visitors. State forests, parks and game lands make up 3.9 million acres of forest land. This Commonwealth's 2.2 million-acre State forest system, found in 48 of this Commonwealth's 67 counties, comprises 13% of the forested area in this Commonwealth. The state forest represents one of the largest expanses of public forestland in the eastern United States, making it a priceless public asset. 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.

In sum, adoption and implementation of the VOC emission control measures in this final-omitted rulemaking for the owners or operators of certain sources in the oil and natural gas industry is reasonably necessary to allow the Commonwealth to continue its progress in attaining and maintaining the public health-based and welfare-based 8-hour ozone NAAQS and to satisfy related CAA requirements. The VOC emission reductions achieved through implementation of the regulatory requirements established in this final-omitted rulemaking and the associated decrease in formation of ground-level ozone will benefit the health and welfare of the residents of this Commonwealth as well as the health of tourists and visitors, with improved ambient air quality and healthier environments. The decrease in ground-level ozone formation will also benefit farmers, loggers, hunters and outdoor enthusiasts and the numerous animals, crops, vegetation and natural areas of this Commonwealth. The agriculture and timber industries and related businesses will benefit directly from reduced economic losses that result from ozone damage to crops and timber. Likewise, the natural areas and infrastructure within this Commonwealth and downwind states will benefit directly from reduced environmental damage and economic losses due to ground-level ozone.

Additionally, this final-omitted 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 or 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 final-omitted rulemaking, thereby creating an economic opportunity for the emissions monitoring industry.

Monetized public health benefits of attaining the 2015 ozone NAAQS

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 RACT measures, but the EPA estimates are indicative of the benefits to Commonwealth residents of attaining the 2015 8-hour ozone NAAQS through the implementation of a suite of measures to control VOC emissions in the aggregate from different source categories.

Compliance costs

Compliance costs will vary for each facility depending on which compliance option is chosen by the owner or operator. The costs were adjusted to 2021 dollars using the CPI adjustment using May as the reference month.

The annualized cost of $25,194 in 2012 dollars to control one storage vessel with a control device is based on the data in the 2016 O&G CTG, which is equivalent to $30,909 in 2021 dollars. The Department's additional analysis demonstrated that the annualized cost of routing emissions from a storage vessel to a control device ranges from $9,501 to $22,871 in 2021 dollars based on the data in the Department's Technical Support Document (TSD) for the General Plan Approval/General Operating Permit BAQ-GPA/BP-5 (GP-5) for natural gas compression stations, processing plants, and transmission stations and the General Plan Approval/General Operating Permit BAQ-GPA/GP-5A (GP-5A) for unconventional natural gas well site operations and remote pigging stations. The Department used the EPA's annualized cost estimate of $30,909 in 2021 dollars to be conservative when estimating the effect on the conventional oil and natural gas industry. The Department identified a total of 27,260 conventional well sites with storage vessels from the Department's databases. There are six conventional well sites with six storage vessels that emit 2.7 TPY or more of VOC with a total industry cost of $185,453 per year. The Department estimates that implementation of the final-omitted control measures could reduce VOC emissions by as much as 71 TPY from the installation of controls for storage vessels. This results in an average cost of approximately $2,612 per ton of VOC emissions reduced per year. Approximately 3 TPY of the VOC emissions reduction from this requirement is due to the technically and economically feasible RACT determination by the Department that is over and above the reductions from EPA's RACT recommendations.

The annualized cost of $296 in 2012 dollars to replace a continuous high-bleed pneumatic controller with a low-bleed pneumatic controller is based on the data in the 2016 O&G CTG, which is $347 per year in 2021 dollars. The Department identified a total of 26,284 conventional well sites with an estimated 26,284 affected pneumatic controllers. The total industry cost is $9,113,188 per year. Using the EPA's estimate of natural gas emissions per controller and this Commonwealth's average natural gas composition, the Department estimates that implementation of the final-omitted control measures could reduce VOC emissions by as much as 8,336 TPY from pneumatic controllers located at these facilities. This results in an average cost of approximately $1,093 per ton of VOC emissions reduced per year. The requirements for natural gas-driven continuous bleed pneumatic controllers are identical to the EPA's 2016 O&G CTG recommendation, which the EPA has determined to be cost-effective.

The annualized cost of $774 in 2012 dollars to control one natural gas-driven diaphragm pump is based on the data in the 2016 O&G CTG, which is $907 per year in 2021 dollars. The Department did not identify any conventional well sites with affected diaphragm pumps. If a conventional well site has an affected diaphragm pump, the owner or operator of the well site would be obligated to meet the requirements of § 129.135. The requirements for natural gas-driven diaphragm pumps are identical to the EPA's 2016 O&G CTG recommendation which the EPA has determined to be cost-effective.

The annualized cost of $782 in 2021 dollars to replace the rod packings for one reciprocating compressor at a conventional well site is based on the data in the Department's TSD for GP-5 and GP-5A. The Department did not identify any reciprocating compressors at conventional well sites. If a conventional well site has an affected reciprocating compressor, the owner or operator of the well site would be obligated to meet the requirements of § 129.136. The Department has determined this requirement to be cost-effective since the annualized cost, the sum of the annualized capital cost and the annual operating expenses is only $782 per year. Annualized cost is one of many factors that the Department can consider when determining the cost-effectiveness of a control device or control technique.

There are an estimated 423 gathering and boosting stations in this Commonwealth with at least 527 reciprocating compressors and an estimated 11 natural gas processing plants with at least 30 reciprocating compressors. The Department assumes that the owners or operators of these facilities are complying with the requirements of Subparts OOOO and OOOOa as none of these facilities were constructed prior to 2011. Therefore, they would have to do nothing further under this final-omitted rulemaking.

The annualized cost of $2,553 in 2012 dollars to control one wet seal degassing system for a centrifugal compressor is based on the data in the 2016 O&G CTG which is $2,990 in 2021 dollars. The Department did not identify any wet seal centrifugal compressors at conventional well sites. If a conventional well site has an affected wet seal centrifugal compressor, the owner or operator of the well site would not be obligated to meet the requirements of § 129.136 due to the exemption allowed under § 129.136(d). However, if conventional owners or operators have turbines driving wet seal centrifugal compressors at any gathering and boosting stations or processing plants, the owner or operator would be subject to the applicable wet seal degassing system VOC emission control requirements of this final-form rulemaking. VOC emissions would be reduced by 95% at a cost of $2,990 per year per wet seal degassing system in 2021 dollars. If the centrifugal compressors are dry seal centrifugal compressors, then the owners or operators of these sources would not have applicable VOC emission control requirements under this final-omitted rulemaking. The requirements for wet seal centrifugal compressor degassing systems are identical to the EPA's 2016 O&G CTG recommendation which the EPA has determined to be cost effective. In the 2016 O&G CTG, the annualized cost in 2012 dollars to conduct annual LDAR inspections at a well site is $1,318 and to conduct quarterly LDAR inspections at a conventional well site is $4,220, and to conduct quarterly LDAR inspections at a gathering and boosting station is $25,049. These costs are $1,554, $4,937, and $29,307 in 2021 dollars, respectively. The Department's TSD for GP-5 and GP-5A also contained cost data for implementing LDAR programs, which are more conservative than the annual costs in the EPA's 2016 O&G CTG as the costs in the TSD are based on a contractor's quote. The annual cost for implementing an annual LDAR inspection program is $1,681 in 2021 dollars at a conventional well site. The annual cost, in 2021 dollars, for implementing a quarterly LDAR inspection program is $6,723 at a conventional well site and $13,447 for a gathering and boosting station or natural gas processing plant. It should be noted that the estimates for conventional well sites assumed there are 1,000 components to monitor and that for gathering and boosting stations or natural gas processing plants there are 2,000 components to monitor. The EPA's assumptions for the number of components to monitor are between 127 and 671 for conventional well sites and 3,091 for gathering and boosting stations or processing plants.

The Department identified a total of 27,260 conventional well sites, 486 gathering and boosting stations and 15 natural gas processing plants. However, the Department does not know how many gathering and boosting stations and natural gas processing plants are associated with the conventional industry. The calculation of fugitive emissions before controls were based on estimates of the amount of natural gas leaked. The breakdown between the amounts of VOC and methane emissions is calculated using this Commonwealth's natural gas composition ratio of 4.47% VOC and 86.03% methane. The value of natural gas saved is calculated using the assumed cost of $1.70 per Mcf of natural gas in 2021 dollars.

There are approximately 27,193 conventional well sites with no LDAR program currently in place of which the Department assumes 31 will be required to implement an annual LDAR program. The total annualized cost is $52,107 reducing VOC emissions by approximately 135 TPY for a total cost per ton of VOC reduced of $386. The 135 TPY of the VOC emissions reduction from this requirement is due to the technically and economically feasible RACT determination by the Department that is over and above the reductions from the EPA's RACT recommendations.

There are approximately 27,193 conventional well sites with no LDAR program currently in place of which the Department assumes 64 will be required to implement a quarterly LDAR program. The total annualized cost is $430,301 reducing VOC emissions by approximately 662 TPY for a total cost per ton of VOC reduced of $650. Approximately 166 TPY of the VOC emissions reduction from this requirement is due to the technically and economically feasible RACT determination by the Department that is over and above the reductions from the EPA's RACT recommendations.

There are approximately 67 conventional well sites currently required to perform semiannual LDAR based on the applicability dates of 40 CFR Part 60, Subpart OOOOa that the Department assumes will not be required to implement a quarterly LDAR program. If the owner or operator of a conventional well site determines the well site would be obligated to meet the requirements of § 129.137(c)(3), the Department has determined this requirement to be cost-effective since the incremental annualized cost is only $3,362 per year.

As the Department does not have information and data on how many gathering and boosting stations and natural gas processing plants are used in the conventional industry, the following information is based on information and data for the entire oil and natural gas industry in this Commonwealth. The costs and emission reductions discussed here have been accounted for in the separate unconventional rulemaking. There are approximately 263 gathering and boosting stations with no LDAR program currently in place based on their construction date, that lack LDAR requirements in their permits or that have no reported fugitive emissions components. The Department assumes these facilities will be required to implement a quarterly LDAR program. The total annualized cost is $3,536,561. The requirements for quarterly LDAR at natural gas gathering and boosting stations are identical to the EPA's 2016 O&G CTG recommendation which the EPA has determined to be cost-effective.

There is one gathering and boosting station with an annual LDAR program currently in place in this Commonwealth that the Department assumes will be required to implement a quarterly program. The total annualized cost is $10,085. The requirements for quarterly LDAR at natural gas gathering and boosting stations are identical to the EPA's 2016 O&G CTG recommendation which the EPA has determined to be cost-effective.

There is one natural gas processing plant with no LDAR program currently in place in this Commonwealth that the Department assumes will be required to implement a quarterly LDAR program. The total annualized cost is $13,447 reducing VOC emissions by approximately 12 TPY for a total cost per ton of VOC reduced of $1,121.

The total conventional industry cost is approximately $482,408 in 2021 dollars. The Department estimates that the final-omitted control measures could reduce VOC emissions by 797 TPY or more from the subject fugitive emissions components due to implementation of the required LDAR inspection program at these facilities.

Based on the above compliance costs, and the number of applicable sources, the Department estimates that this final-omitted rulemaking will cost affected owners or operators approximately $9.8 million (based on 2021 dollars) per year without consideration of the economic benefit of the saved natural gas. The value of the saved natural gas, assuming a natural gas price of $1.70 per Mcf in 2021 dollars, yields a savings of approximately $15.7 million, resulting in a total net savings of approximately $5.9 million for this final-omitted rulemaking.

This estimate consists of two major categories of data. The first is the cost per year to control each piece of equipment or site affected, which came from either the 2016 O&G CTG or the Department's TSD for GP-5 and GP-5A, as detailed in the response to Question 17 of the RAF. The second is the number of potentially affected facilities, which were obtained from several data sources including the Department's Oil and Gas Production Report, eFACTS and AIMS. The cost per year to control each piece of equipment or site affected was multiplied by the number of each in this Commonwealth. The costs for each category of sources were added together to come up with a final estimated cost and savings.

The VOC RACT requirements established by this final-omitted rulemaking will not require the owner or operator to obtain an air operating permit. To the extent an owner or operator has an air operating permit, they will not be required to submit an application for amendments to an existing air operating permit. These requirements will be incorporated into the existing air operating permit when the permit is renewed, if less than 3 years remain in the permit term, as specified under § 127.463(c). 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 this final-omitted rulemaking, as required under § 127.463(b).

Compliance assistance plan

The Department will continue to educate and assist the public and the regulated community in understanding the requirements and how to comply with them throughout the rulemaking process. 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 final-omitted rulemaking are minimal because the records required align with existing Federal requirements. To minimize the burden of these requirements, the Department allows electronic submission of most planning, reporting and recordkeeping forms required by this final-omitted rulemaking.

H. *Pollution Prevention*

The Pollution Prevention Act (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 final-omitted rulemaking helps to ensure that the residents of this Commonwealth benefit from reduced emissions of VOC and methane from regulated sources. Reduced levels of VOC and methane promote healthful air quality and ensure the continued protection of the environment and public health and welfare.

I. *Sunset Review*

This Board is not establishing a sunset date for this final-omitted rulemaking because it is needed for the Department to carry out its statutory authority. If published as a final-omitted rulemaking in the *Pennsylvania Bulletin*, the Department will closely monitor its effectiveness and recommend updates to the Board as necessary.

J. *Regulatory Review*

Under section 5.1(c) of the RRA (71 P.S. § 745.5a(c)), on November 30, 2022, the Department submitted a copy of this emergency certified final-omitted rulemaking and a copy of a Regulatory Analysis Form to IRRC and to the Chairpersons of the House and Senate Environmental Resources and Energy Committees. On the same date, the final-omitted rulemaking was submitted to the Office of Attorney General for review and approval under the Commonwealth Attorneys Act (71 P.S. §§ 732-101—732-506).

Under section 6(d) of the RRA (71 P.S. § 745.6(d)), the Governor has certified that this final-omitted rulemaking is required to meet an emergency condition that could result in the need for supplemental or deficiency appropriations of greater than $1 million if not addressed. As such, this emergency certified final-omitted regulation is effective upon publication in the *Pennsylvania Bulletin*.

K. *Findings of the Board*

The Board finds that:

(1) This emergency certified final-omitted rulemaking is authorized by section 204(3) of the act of July 31, 1968

(P.L. 769, No. 240) (45 P.S. § 1204(3)) referred to as the Commonwealth Documents Law (CDL), and section 6(d) of the RRA.

(2) Use of the omission of notice of proposed rulemaking procedure is appropriate because the proposed rulemaking procedures in sections 201 and 202 of the CDL (45 P.S. §§ 1201 and 1202) are, in this instance, unnecessary and contrary to the public interest.

(3) Use of the emergency-certified rulemaking procedure provided in section 6(d) of the RRA is appropriate because this regulation is required to prevent the need for supplemental or deficiency appropriations of greater than $1 million based on Governor Tom Wolf's Certification of Need for Emergency Regulation dated November 30, 2022.

(4) The amendments are appropriate to implement RACT requirements to control VOC emissions from conventional oil and natural gas sources.

(5) These regulations are reasonably necessary and appropriate for administration and enforcement of the authorizing acts identified in section C of this final-omitted rulemaking.

(6) These regulations are reasonably necessary to attain and maintain the ozone NAAQS and to satisfy related CAA requirements.

L. *Order of the Board*

The Board, acting under the authorizing statutes, orders that:

(a) The regulations of the Department, 25 Pa. Code Chapter 129, are amended by adding §§ 129.131—129.140 to read as set forth in Annex A.

(b) The Chairperson of the Board shall submit this emergency certified final-omitted rulemaking to the Office of General Counsel and the Office of Attorney General for review and approval as to legality and form, as required by law.

(c) The Chairperson of the Board shall submit this emergency certified final-omitted rulemaking to IRRC and the House and Senate Committees as required by the Regulatory Review Act.

(d) The Chairperson of the Board shall certify this emergency certified final-omitted rulemaking and deposit it with the Legislative Reference Bureau as required by law.

(e) This emergency certified final-omitted rulemaking will be submitted to the EPA as a revision to the Commonwealth's SIP.

(f) This emergency certified final-omitted rulemaking shall take effect immediately upon notice or publication in the *Pennsylvania Bulletin*.

RAMEZ ZIADEH, P.E.,
Acting Chairperson

Fiscal Note: 7-580. No fiscal impact; (8) recommends adoption.

GOVERNOR'S OFFICE

Certification of Need for Emergency Regulation

Whereas, the General Assembly has created the Environmental Quality Board in this Commonwealth (71 P.S. § 1340.502); and

Whereas, the power and duty of the Environmental Quality Board under Pennsylvania's Air Pollution Control Act (35 P.S. § 4001 et seq.) shall be to adopt rules and regulations to implement the provisions of the Clean Air Act (CAA) (42 U.S.C.A. §§ 7401—7671q) that shall be consistent with the requirements of the CAA and the regulations adopted thereunder (35 P.S. § 4005(a)(8)); and

Whereas, section 110(a) of the CAA (42 U.S.C.A. § 7410(a)) requires that states demonstrate compliance with the CAA by adopting and submitting to the U.S. Environmental Protection Agency (EPA) a state implementation plan (SIP) for implementation, maintenance and enforcement of the National Ambient Air Quality Standards; and

Whereas, Pennsylvania was and is required to submit a revised SIP under the CAA showing that it has developed and implemented a program establishing Reasonably Available Control Technology (RACT) requirements for sources identified by the EPA in the 2016 Oil and Gas Industry Control Techniques Guidelines requiring oil and natural gas industry equipment and processes to reduce volatile organic compound (VOC) emissions; and

Whereas, section 179 of the CAA (42 U.S.C.A. § 7509) requires a state to submit a SIP and approvable SIP revisions to comply with all aspects of the CAA by certain dates or else face sanctions; and

Whereas, section 179 of the CAA (42 U.S.C.A. § 7509) requires the EPA to impose two types of sanctions if Pennsylvania fails to submit an approvable SIP by its deadlines: "2:1 offsets" on new or modified sources of emissions, and withholding of certain Federal highway funds; and

Whereas, Federal highway sanctions will apply if a revised SIP is not completed by December 16, 2022; and

Whereas, the Environmental Quality Board proposed a rulemaking (#7-544) to meet Pennsylvania's SIP requirements by requiring oil and natural gas sources to develop and implement an emission reduction program; and

Whereas, rulemaking #7-544 provided a public comment period of 66 days; and

Whereas, although rulemaking #7-544 would meet EPA's SIP requirements, the Pennsylvania House Environmental Resources & Energy Committee disapproved the proposed rulemaking on purported technical grounds that it violated Pennsylvania's Act 52 of 2016, (58 P.S. §§ 1201—1208) which requires that rulemakings concerning conventional oil and gas wells be undertaken separately and independently of rulemakings involving unconventional wells or other subjects; and

Whereas, the Environmental Quality Board separated what was originally submitted as rulemaking #7-544 into two rulemakings—one for conventional sources and one for unconventional sources—that impose the same requirements as the original rulemaking; and

Whereas, only one of those rulemakings could be submitted to the Independent Regulatory Review Commission (IRRC) on final-form as a continuation of the rulemaking process for #7-544; and

Whereas, the Environmental Quality Board submitted the rulemaking regarding unconventional sources to IRRC on final-form under regulation #7-544; and

Whereas, the Environmental Quality Board created a separate rulemaking (Regulation #7-579) to address conventional sources, which it adopted on October 12, 2022; and

Whereas, on November 14, 2022, the Pennsylvania House Environmental Resources & Energy Committee notified IRRC of the Committee's disapproval of Regulation #7-579 triggering the 14-calendar day legislative review period under section 7(d) of the Regulatory Review Act, (71 P.S. § 745.7(d)); and

Whereas, due to the Pennsylvania House Environmental Resources & Energy Committee's disapproval, the rulemaking process for the conventional rulemaking (Regulation #7-579) cannot be completed by December 16, 2022, in time to prevent an emergency which would create conditions causing the need for supplemental or deficiency appropriations of at least $1,000,000; and

Whereas, Section 6(d) of the Regulatory Review Act, (71 P.S. § 745.6(d)), prohibits IRRC from issuing an order barring an agency from promulgating a final-form or final-omitted regulation if the Governor certifies that the final-form or final-omitted regulation is required to meet an emergency which includes conditions which may threaten the public health, safety or welfare; cause a budget deficit; or create the need for supplemental or deficiency appropriations of greater than $1,000,000; and

Whereas, if the Governor so certifies, the final-form or final-omitted regulation may take effect prior to review by the commission and committees under Section 6(d) of the Regulatory Review Act (71 P.S. § 745.6(d)); and

Whereas, an immediate amendment to the regulations is necessary to prevent an emergency because the absence of a completed regulation and corresponding, complete SIP is a condition that will risk sanctions that will affect approximately $800 million in Federal highway funds and grants and will create the need for supplemental or deficiency appropriations greater than $1,000,000 to direct state funding to previously Federalized projects so as to carry out planned projects that have been selected to meet the needs of the motoring public; and

Whereas, the Environmental Quality Board adopted a separate rulemaking on November 30, 2022, identical to Regulation #7-579 (Regulation #7-580) that the Governor may certify under 71 P.S. § 745.6(d) to ensure completion of the regulation by December 16, 2022.

Now Therefore, I do hereby certify that the regulatory amendment (Regulation #7-580) to add conventional sources to the Department's regulations in Title 25 (25 Pa. Code §§ 129.131—129.140) to adopt RACT requirements and RACT emission limitations for oil and natural gas sources of VOC emissions as required under the CAA, following this certification as Annex A, is required to meet the emergency conditions enumerated in the recitals above and to avoid an emergency as described therein.

Further, I hereby authorize the Chairperson of the Environmental Quality Board to publish this amendment in the *Pennsylvania Bulletin* as an Emergency Certified Final-Omitted Rulemaking consistent with the provisions of Section 6(d) of the Regulatory Review Act, as amended, 71 P.S. § 745.6(d).

Further, this Emergency Certified Final-Omitted Rulemaking shall take effect immediately upon notice or publication in the *Pennsylvania Bulletin*.

Given under my hand and the Seal of the Governor, at the City of Harrisburg, on this 30th day of November in the year of our Lord two thousand and twenty two, and of the Commonwealth the two hundred and forty seventh.

Governor

Tom Wolf

Annex A

TITLE 25. ENVIRONMENTAL PROTECTION

PART I. DEPARTMENT OF ENVIRONMENTAL PROTECTION

Subpart C. PROTECTION OF NATURAL RESOURCES

ARTICLE III. AIR RESOURCES

CHAPTER 129. STANDARDS FOR SOURCES

CONTROL OF VOC EMISSIONS FROM CONVENTIONAL OIL AND NATURAL GAS SOURCES

Sec.
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129.136. Compressors.
129.137. Fugitive emissions components.
129.138. Covers and closed vent systems.
129.139. Control devices.
129.140. Recordkeeping and reporting.

§ 129.131. General provisions and applicability.

(a) *Applicability.* Beginning December 2, 2022, this section and §§ 129.132—129.140 (relating to control of VOC emissions from conventional oil and natural gas sources) apply to an owner or operator of one or more of the following conventional oil and natural gas sources of VOC emissions installed at a conventional well site, a gathering and boosting station or a natural gas processing plant in this Commonwealth which were constructed on or before December 2, 2022:

(1) Storage vessels at:

(i) A conventional well site.

(ii) A gathering and boosting station.

(iii) A natural gas processing plant.

(iv) The natural gas transmission and storage segment.

(2) Natural gas-driven continuous bleed 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 §§ 129.132—129.140 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 December 2, 2022, 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.

§ 129.132. Definitions, acronyms and EPA methods.

(a) *Definitions and acronyms.* The following words and terms, when used in this section, §§ 129.131 (relating to general provisions and applicability) and 129.133—129.140, 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 natural gas-driven continuous bleed 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.

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

Connector—

(i) A flanged fitting, screwed fitting or other joined fitting used to connect two pipes or a pipe 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.

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

Conventional well—

(i) A bore hole drilled or being drilled for the purpose of or to be used for construction of a well regulated under 58 Pa.C.S. §§ 3201—3274 (relating to development) that is not an unconventional well, irrespective of technology or design.

(ii) The term includes, but is not limited to:

(A) Wells drilled to produce oil.

(B) Wells drilled to produce natural gas from formations other than shale formations.

(C) Wells drilled to produce natural gas from shale formations located above the base of the Elk Group or its stratigraphic equivalent.

(D) Wells drilled to produce natural gas from shale formations located below the base of the Elk Group where natural gas can be produced at economic flow rates or in economic volumes without the use of vertical or nonvertical well bores stimulated by hydraulic fracture treatments or multilateral well bores or other techniques to expose more of the formation to the well bore.

(E) Irrespective of formation, wells drilled for collateral purposes, such as monitoring, geologic logging, secondary and tertiary recovery or disposal injection.

Conventional well site—A location with exclusively one or more conventional wells. A location with both unconventional and conventional wells is considered to be an unconventional well site.

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, §§ 129.131 and 129.133—129.140 fails to meet one or more of the following:

(i) A requirement or an obligation established in this section, § 129.131 or §§ 129.133—129.140, 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, § 129.131 or §§ 129.133—129.140 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, § 129.131 or §§ 129.133—129.140 during startup, shutdown or malfunction, regardless of whether a failure is permitted by this section, § 129.131 or §§ 129.133—129.140.

FID—Flame ionization detector.

First attempt at repair—For purposes of § 129.137 (relating to fugitive emissions components):

(i) An action using best practices taken to stop or reduce fugitive emissions to the atmosphere.

(ii) The term includes:

(A) Tightening bonnet bolts.

(B) Replacing bonnet bolts.

(C) Tightening packing gland nuts.

(D) Injecting lubricant into lubricated packing.

Flare—

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

(ii) The term does not include a horizontally or vertically installed ignition device or pit flare used to combust otherwise vented emissions from completions.

Flow line—A pipeline used to transport oil or gas, or both, to processing equipment, compression equipment, storage vessel or other collection system for further handling or to a mainline pipeline.

Fugitive emissions component—

(i) A piece of equipment that has the potential to emit fugitive emissions of VOC at a well site, 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 § 129.138 (relating to covers and closed vent systems).

(J) A thief hatch or other opening on a controlled storage vessel not subject to § 129.133 (relating to storage vessels).

(ii) The term does not include a device, such as a natural gas-driven continuous bleed 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 both of the following:

(i) Employed by the same owner or operator as the responsible official that signs the certification required under § 129.140(k) (relating to recordkeeping and reporting).

(ii) Qualified by education, technical knowledge and expertise in the design and operation of a natural gas-driven diaphragm pump or closed vent system to make the technical certification required under § 129.135(c)(3)(ii) (relating to natural gas driven diaphragm pumps) or § 129.138(c)(3), or both, as applicable.

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

LDAR—Leak detection and repair.

Leak—An emission detected using one or more of the following methods:

(i) Through audible, visual or odorous evidence during an AVO inspection.

(ii) By OGI equipment calibrated according to § 129.137(h).

(iii) With a concentration of 500 ppm or greater as methane or equivalent by a gas leak detector calibrated according to § 129.137(i).

(iv) Using an alternative leak detection method approved by the Department in § 129.137(c)(2)(ii)(C), (c)(3)(ii)(C) or (e)(2)(iii).

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

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

Natural gas processing 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 transmission and storage segment—The term includes the following:

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

(ii) The natural gas transmission stations which include the following:

(A) The land, mains, valves, meters, boosters, regulators, storage vessels, dehydrators and compressors.

(B) The driving units and appurtenances associated with the items listed in clause (A).

(C) The 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.

(iii) The 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—The results of EPA Method 25A.

UIC—Underground injection control.

UIC Class I oilfield disposal well—A well with a UIC Class I permit that meets the definition in 40 CFR 144.6(a)(2) (relating to classification of wells) and receives eligible fluids from oil and natural gas exploration and production operations.

UIC Class II oilfield disposal well—A well with a UIC Class II permit where wastewater resulting from oil and natural gas production operations is injected into underground porous rock formations not productive of oil or gas and sealed above and below by unbroken, impermeable strata.

Unconventional formation—A geological shale formation existing below the base of the Elk Sandstone or its geologic equivalent stratigraphic interval where natural gas generally cannot be produced at economic flow rates or in economic volumes except by vertical or horizontal well bores stimulated by hydraulic fracture treatments or by using multilateral well bores or other techniques to expose more of the formation to the well bore.

Unconventional well—A bore hole drilled or being drilled for the purpose of or to be used for the production of natural gas from an unconventional formation.

Unconventional well site—A location with one or more unconventional wells.

VRU—vapor recovery unit—A device used to recover vapor and route it to a process, flow line or other equipment.

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 a conventional well or injection well.

(ii) For purposes of the fugitive emissions standards in § 129.137, 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.

(iii) For purposes of the fugitive emissions standards in § 129.137, the term does not include:

(A) A UIC Class I oilfield disposal well.

(B) A UIC Class II oilfield disposal well and disposal facility.

(C) The flange immediately upstream of the custody meter assembly.

(D) Equipment, including fugitive emissions components, located downstream of the flange in clause (C).

(b) *EPA methods*. The EPA methods referenced in this section and §§ 129.133—129.140 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.

§ 129.133. 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 § 129.131(a)(1) (relating to general provisions and applicability) that 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 as defined in § 129.132 (relating to definitions, acronyms and EPA methods) prior to January 31, 2023, for an existing storage vessel.

(ii) The determination of potential VOC emissions may 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 § 129.138(a) (relating to covers and closed vent systems).

(B) The closed vent system requirements in § 129.138(b).

(iv) If the apparatus that recovers and routes vapor to a process is removed from operation or is operated inconsistently with § 129.138, 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 December 2, 2023, 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 § 129.138(a).

(ii) Connect the storage vessel to a control device or process through a closed vent system that meets the requirements of § 129.138(b).

(iii) Route the emissions from the storage vessel to a control device or a process that meets the applicable requirements of § 129.139 (relating to control devices).

(iv) Demonstrate that the VOC emissions are reduced as specified in § 129.139(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 maintains actual VOC emissions less than 2.7 TPY determined as a 12-month rolling sum. 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) Beginning on or before January 1, 2023, calculate the actual VOC emissions once per calendar month 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 45 calendar days.

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

(ii) Comply with subsection (b) within 1 year of the date of the monthly calculation showing that actual VOC emissions from the storage vessel have increased to 2.7 TPY VOC or greater.

(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 § 129.140(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 § 129.140(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 § 129.140(b) and submit the reports under § 129.140(k)(3)(i).

§ 129.134. Natural gas-driven continuous bleed pneumatic controllers.

(a) *Applicability.* This section applies to the owner or operator of a natural gas-driven continuous bleed pneumatic controller subject to § 129.131(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 continuous bleed 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 December 2, 2023, the owner or operator of a natural gas-driven continuous bleed pneumatic controller subject to this section shall do the following:

(1) Ensure each natural gas-driven continuous bleed pneumatic controller with a natural gas bleed rate greater than 6.0 standard cubic feet per hour, at a location other than a natural gas processing plant, maintains a natural gas bleed rate of less than or equal to 6.0 standard cubic feet per hour.

(2) Ensure each natural gas-driven continuous bleed pneumatic controller maintains a natural gas bleed rate of zero standard cubic feet per hour, if located at a natural gas processing plant.

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

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

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

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

(e) *Recordkeeping and reporting requirements.* The owner or operator of a natural gas-driven continuous bleed pneumatic controller affected under subsection (c) shall maintain the records under § 129.140(c) (relating to recordkeeping and reporting) and submit the reports under § 129.140(k)(3)(ii).

§ 129.135. Natural gas-driven diaphragm pumps.

(a) *Applicability.* This section applies to the owner or operator of a natural gas-driven diaphragm pump subject to § 129.131(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 December 2, 2023, the owner or operator of a natural gas-driven diaphragm pump subject to this section shall comply with the following:

(1) *Conventional well site.* The owner or operator of a natural gas-driven diaphragm pump located at a conventional well site shall reduce the VOC emissions by 95.0% by weight or greater. The owner or operator 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 § 129.138(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 § 129.139 (relating to control devices).

(iii) Demonstrate that the VOC emissions are reduced as specified in § 129.139(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. An owner or operator that claims this exception shall do the following:

(i) Maintain the records under § 129.140(d)(4) (relating to recordkeeping and reporting).

(ii) Connect the natural gas-driven diaphragm pump to the control device through a closed vent system that meets the requirements of § 129.138(b).

(iii) Demonstrate the percentage by which the VOC emissions are reduced as specified in § 129.139(k).

(2) Has no available control device or process. An owner or operator that claims this exception shall do the following:

(i) Maintain the records under § 129.140(d)(5).

(ii) Certify that there is no available control device or process in the next annual report required by § 129.140(k)(1).

(iii) 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 subparagraph (ii) 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. An owner or operator that claims this exception shall do the following:

(i) Maintain the records under § 129.140(d)(6).

(ii) Perform an assessment of technical infeasibility which must meet 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 § 129.135(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 § 129.140(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 § 129.140(d) and submit the reports under § 129.140(k)(3)(iii).

§ 129.136. Compressors.

(a) *Applicability.* This section applies to the owner or operator of a reciprocating compressor or centrifugal compressor subject to § 129.131(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.* Beginning December 2, 2023, 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) December 2, 2022, 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) December 2, 2025, for a reciprocating compressor rod packing that has not yet been replaced.

(2) Route the VOC emissions to a control device or a process that meets § 129.139 (relating to control devices) by using a reciprocating compressor rod packing emissions collection system that operates under negative pressure and meets the cover requirements of § 129.138(a) (relating to covers and closed vent systems) and the closed vent system requirements of § 129.138(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 § 129.138(a) through a closed vent system that meets the requirements of § 129.138(b) to a control device or a process that meets the applicable requirements of § 129.139.

(3) Demonstrate that the VOC emissions are reduced as specified in § 129.139(k).

(d) *Exemptions.* Subsection (c) does not apply to the owner or operator of 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 § 129.140(e) (relating to recordkeeping and reporting) and submit the reports under § 129.140(k)(3)(iv).

(2) For a centrifugal compressor, maintain the records under § 129.140(f) and submit the reports under § 129.140(k)(3)(v).

§ 129.137. Fugitive emissions components.

(a) *Applicability.* This section applies to the owner or operator of a fugitive emissions component subject to § 129.131(a)(5) (relating to general provisions and applicability), located at one or more of the following:

(1) A conventional well site.

(2) A natural gas gathering and boosting station.

(3) A natural gas processing plant.

(b) *Average production calculation procedure for a well site.* Beginning on or before January 1, 2023:

(1) The owner or operator of a well site subject to subsection (a)(1) shall calculate the average production in barrels of oil equivalent per day of the well site using the previous 12 calendar months of operation as reported to the Department and thereafter as specified in subsection (c)(4) for the previous calendar year. The owner or operator shall do the following:

(i) For each well at the well site with production reported to the Department:

(A) Record the barrels of oil produced for each active well.

(B) Convert the natural gas production for each active well to equivalent barrels of oil by dividing the standard cubic feet of natural gas produced by 6,000 standard cubic feet per barrel of oil equivalent.

(C) Convert the condensate production for each active well to equivalent barrels of oil by multiplying the barrels of condensate by 0.9 barrels of oil equivalent per barrel of condensate.

(ii) Calculate the total production for each active well, in barrels of oil equivalent, by adding the results of subparagraph (i)(A)—(C) for each active well.

(iii) Sum the results of subparagraph (ii) for all active wells at the well site and divide by 365 or 366 days for the previous 12 calendar months or the previous calendar year, as applicable.

(2) If the owner or operator does not know the production of an individual well at the well site, the owner or operator shall comply with subsection (c)(2).

(c) *Requirements for a conventional well site.*

(1) For a well site consisting of only oil wells, the owner or operator shall:

(i) Determine the GOR of the oil well site using generally accepted methods.

(ii) If the GOR of the oil well site is less than 300 standard cubic feet of gas per barrel of oil produced, maintain the records under § 129.140(g)(1) (relating to recordkeeping and reporting).

(iii) If the GOR of the oil well site is equal to or greater than 300 standard cubic feet of gas per barrel of oil produced, meet the requirements of paragraph (2) or paragraph (3) based on the results of subsection (b)(1).

(2) For a well site producing, on average, equal to or greater than 15 barrels of oil equivalent per day, with at least one well producing, on average, equal to or greater than 15 barrels of oil equivalent per day, the owner or operator shall:

(i) Conduct an initial AVO inspection on or before January 31, 2023, with monthly inspections thereafter separated by at least 15 calendar days but not more than 45 calendar days.

(ii) Conduct an initial LDAR inspection program on or before January 31, 2023, with quarterly inspections thereafter separated by at least 60 calendar days but not more than 120 calendar days using one or more of the following:

(A) OGI equipment.

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

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

(3) For a well site producing, on average, equal to or greater than 15 barrels of oil equivalent per day, and at least one well producing, on average, equal to or greater than 5 barrels of oil equivalent per day but less than 15 barrels of oil equivalent per day, the owner or operator shall:

(i) Conduct an initial AVO inspection on or before January 31, 2023, with monthly inspections thereafter separated by at least 15 calendar days but not more than 45 calendar days.

(ii) Conduct an initial LDAR inspection program on or before May 1, 2023, with annual inspections thereafter separated by at least 335 calendar days but not more than 395 calendar days using one or more of the following:

(A) OGI equipment.

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

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

(4) The owner or operator of a producing well site shall calculate the average production of the well site under subsection (b) for the previous calendar year not later than February 15 and may adjust the frequency of the required LDAR inspection as follows:

(i) If two consecutive calculations show reduced production, the owner or operator may adopt the requirements applicable to the reduced production level.

(ii) If a calculation shows higher production, the owner or operator shall adopt the requirements applicable to the higher production level immediately.

(5) The owner or operator of a well site subject to paragraph (3) may submit to the appropriate Department Regional Office a request, in writing, for an exemption from the requirements of paragraph (3)(ii).

(i) The written request must include the following:

(A) Name and location of the well site.

(B) A demonstration that the requirements of paragraph (3)(ii) are not technically or economically feasible for the well site.

(C) Sufficient methods for demonstrating compliance with all applicable standards or regulations promulgated under the Clean Air Act or the Act.

(D) Sufficient methods for demonstrating compliance with this section, §§ 129.131—129.136 and 129.138—129.140.

(ii) The Department will review the complete written request submitted in accordance with subparagraph (i) and approve or deny the request in writing.

(iii) The Department will submit each exemption determination approved under subparagraph (ii) to the Administrator of the EPA for approval as a revision to the SIP. The owner or operator shall bear the costs of public hearings and notifications, including newspaper notices, required for the SIP submittal.

(iv) The owner or operator of the well site identified in subparagraph (i)(A) shall remain subject to the requirements of paragraphs (1), (3)(i) and (4).

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

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

(2) The date of the next required LDAR inspection after the conventional well site is put into production.

(e) *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 initial AVO inspection on or before January 31, 2023, with monthly inspections thereafter separated by at least 15 calendar days but not more than 45 calendar days.

(2) An initial LDAR inspection program on or before January 31, 2023, with quarterly inspections thereafter separated by at least 60 calendar days but not more than 120 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.

(f) *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.

(g) *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 (h).

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

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

(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 13 months apart.

(h) *Verification procedures for OGI equipment.* An owner or operator that identifies OGI equipment in the fugitive emissions monitoring plan in subsection (g)(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 verification check each day prior to use.

(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 by using the following procedures:

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

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

(iii) Dealing with interferences, such as steam.

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

(i) *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 (g)(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.

(j) *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.

(k) *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.

(l) *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 is no visible leak image when using OGI equipment calibrated according to subsection (h).

(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 (i).

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

(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.

(m) *Recordkeeping and reporting requirements.* The owner or operator of a fugitive emissions component subject to this section shall maintain the records under § 129.140(g) and submit the reports under § 129.140(k)(3)(vi).

§ 129.138. 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 § 129.133(b)(1)(i) or § 129.136(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 § 129.139 (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 initial AVO inspection on or before January 31, 2023, with monthly inspections thereafter separated by at least 15 calendar days but not more than 45 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 § 129.137(l) (relating to fugitive emissions components).

(7) Maintain the records under § 129.140(h) (relating to recordkeeping and reporting) and submit the report under § 129.140(k)(3)(vii).

(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 § 129.133(b)(1)(ii), § 129.135(b)(1)(i) or (c)(1)(ii) (relating to natural gas-driven diaphragm pumps) or § 129.136(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 § 129.139.

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

(i) Conduct an initial AVO inspection on or before January 31, 2023, with monthly inspections thereafter separated by at least 15 calendar days but not more than 45 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) during the facility's scheduled LDAR inspection in accordance with § 129.137(c)(2)(ii) and (c)(3)(ii) or (e)(2).

(3) Repair a detected leak or defect as specified in § 129.137(l).

(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 on or before January 31, 2023, with monthly inspections separated by at least 15 calendar days but not more than 45 calendar days.

(C) Maintaining the records under § 129.140(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 § 129.140(i) and submit the reports under § 129.140(k)(3)(viii).

(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 § 129.138(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 inspection required under subsection (b)(2)(ii) by performing one of the following:

(1) Use OGI equipment that meets § 129.137(h).

(2) Use a gas leak detection instrument that meets § 129.137(i). The owner or operator may adjust the gas leak detection instrument readings as specified in § 129.137(k).

(3) Use another leak detection method approved by the Department.

(4) 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 § 129.132(a) (relating to definitions, acronyms and EPA methods).

§ 129.139. 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 § 129.133(b)(1)(iii), § 129.135(b)(1)(ii) or (c)(1), or § 129.136(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 § 129.140(j) (relating to recordkeeping and reporting) and submit the reports under § 129.140(k)(3)(ix).

(2) The owner or operator may route the liquid, gas, vapor or fume from more than one source subject to § 129.133(b)(1)(iii), § 129.135(b)(1)(ii) or (c)(1), or § 129.136(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 45 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 45 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 subparagraph (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 applicable to the control device if the manufacturer's repair instructions are not available.

(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 to demonstrate that the mass content of VOC in the gases vented to the device is reduced by 95.0% by weight or greater.

(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 under 40 CFR Part 270 (relating to EPA administered permit programs: the hazardous waste permit program) that implements the requirements of 40 CFR Part 264, Subpart X (relating to miscellaneous units).

(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 under 40 CFR Part 270 that implements the requirements of 40 CFR Part 266, Subpart H (relating to hazardous waste burned in boilers and industrial furnaces).

(C) An industrial furnace designed and operated in accordance with the interim status requirements of 40 CFR Part 266, Subpart H.

(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 45 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 120 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 120 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) The owner or operator shall do the following, as applicable:

(i) Except as specified in subparagraph (iii), conduct an initial performance test within 180 days after installation of a control device.

(ii) Except as specified in subparagraph (iii), conduct a performance test of an existing control device on or before July 30, 2023, unless the owner or operator of the control device is complying with an established performance test interval, in which case the current schedule should be maintained.

(iii) The performance test in subparagraph (i) or subparagraph (ii) is not required if the owner or operator meets one or more of the following:

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

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

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

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

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

(I) 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.

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

(III) 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.

(IV) 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.

(F) 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):

(I) Was submitted to the Department.

(II) 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.

(G) 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)(iii)(A)—(G).

(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 § 129.131(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.

§ 129.140. Recordkeeping and reporting.

(a) *Recordkeeping.* The owner or operator of a source subject to §§ 129.131—129.139 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 § 129.133 (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 § 129.133.

(3) The identity of each storage vessel removed from service under § 129.133(e) and the date on which it was removed from service.

(4) The identity of each storage vessel returned to service under § 129.133(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 § 129.133(a)(2).

(6) The identity of each storage vessel and the actual VOC emission calculation under § 129.133(c)(2)(i) including the following information:

(i) The date of each monthly calculation performed under § 129.133(c)(2)(i).

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

(iii) The calculation demonstrating that the actual VOC emissions are less than 2.7 TPY determined as a 12-month rolling sum.

(7) The records documenting the time the skid-mounted or mobile storage vessel under § 129.133(d)(1) 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 § 129.133(b)(1) and the demonstration under § 129.133(b)(1)(iv).

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

(1) The required compliance date, identification, location and manufacturer specifications for each natural gas-driven continuous bleed pneumatic controller subject to § 129.134(c) (relating to natural gas-driven continuous bleed pneumatic controllers).

(2) Each deviation when the natural gas-driven continuous bleed pneumatic controller was not operated in compliance with the requirements specified in § 129.134(c).

(3) If the natural gas-driven continuous bleed 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 continuous bleed pneumatic controller under § 129.134(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 required compliance date, location and manufacturer specifications for each natural gas-driven diaphragm pump subject to § 129.135 (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 § 129.135.

(3) For a natural gas-driven diaphragm pump under § 129.135(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 § 129.135(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 § 129.139(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 § 129.135(c)(2), maintain a copy of the certification submitted under subsection (k)(3)(iii)(B)(II).

(6) The engineering assessment substantiating a claim under § 129.135(c)(3), including the certification under § 129.135(c)(3)(ii)(C).

(7) For a natural gas-driven diaphragm pump required to reduce VOC emissions under § 129.135(b)(1), the demonstration under § 129.135(b)(1)(iii).

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

(1) For a reciprocating compressor under § 129.136(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 § 129.136(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 § 129.136(b)(2), the following records:

(i) A statement that emissions from the rod packing are being routed to a control device or 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 § 129.136(b)(2).

(4) Each deviation when the reciprocating compressor was not operated in compliance with § 129.136(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 § 129.136(c).

(2) Each deviation when the centrifugal compressor was not operated in compliance with § 129.136(c).

(3) For a centrifugal compressor required to reduce VOC emissions under § 129.136(c)(1), the demonstration under § 129.136(c)(3).

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

(1) For an oil well site subject to § 129.137(c)(1)(ii) (relating to fugitive emissions components):

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

(ii) The analysis documenting a GOR of less than 300 standard cubic feet of gas per 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 each well site, the average production calculations required under § 129.137(b)(1) and § 129.137(c)(4).

(3) For a well site subject to § 129.137(c)(2) or (c)(3), a natural gas gathering and boosting station or a natural gas processing plant:

(i) The fugitive emissions monitoring plan under § 129.137(g).

(ii) The records of each monitoring survey conducted under § 129.137(c)(2)(ii), (c)(3)(ii) or (e)(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 § 129.132(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.

(h) *Covers.* The records for each cover include the results of each cover inspection under § 129.138(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 § 129.138(b)(2).

(2) For the no detectable emissions inspections of § 129.138(d), a record of the monitoring survey as specified under subsection (g)(3)(ii).

(3) The engineering assessment under § 129.138(c), including the certification under § 129.138(c)(3).

(4) If the closed vent system includes a bypass device subject to § 129.138(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 § 129.138(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 § 129.139(b):

(i) The manufacturer's written operating instructions, procedures and maintenance schedule to ensure good air pollution control practices for minimizing emissions under § 129.139(b)(1).

(ii) The results of each monthly physical integrity check performed under § 129.139(b)(2).

(iii) The CPMS data which indicates the presence of a pilot flame during the device's operation under § 129.139(b)(3).

(iv) The results of the visible emissions test under § 129.139(b)(4) using Figure 22-1 in EPA Method 22 or a form which includes the following:

(A) The name of the company that owns or operates the control device.

(B) The location of the control device.

(C) The name and affiliation 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 § 129.139(b)(6) under subparagraph (iv) following a return to operation from a maintenance or repair activity performed under § 129.139(b)(5).

(vi) The maintenance and repair log under § 129.139(b)(7).

(6) For a manufacturer-tested combustion control device under § 129.139(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 § 129.139(c)(1)(i).

(iv) The results of each performance test conducted under § 129.139(c)(1)(ii) as performed under § 129.139(k).

(7) For an enclosed combustion device in § 129.139(d):

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

(ii) The results of each performance test conducted under § 129.139(d)(1)(i) as performed under § 129.139(k).

(iii) The results of each performance test conducted under § 129.139(d)(1)(ii) as performed under § 129.139(l).

(iv) The data and calculations for the CPMS installed, operated or maintained under § 129.139(d)(2).

(8) For a flare in § 129.139(e), the records specified in paragraph (5)(iii)—(vi).

(9) For a regenerative carbon adsorption device in § 129.139(g):

(i) The records specified in paragraph (5)(i) and (ii).

(ii) The results of the performance test conducted under § 129.139(f)(1)(i) as performed under § 129.139(k).

(iii) The results of the performance test conducted under § 129.139(f)(1)(ii) as performed under § 129.139(l).

(iv) The control device design analysis, if one is performed under § 129.139(g)(6).

(v) The data and calculations for a CPMS installed, operated or maintained under § 129.139(g)(1)—(5).

(vi) The schedule for carbon replacement, as determined by § 129.139(f)(2) or the design analysis requirements of § 129.139(g)(6) and records of each carbon replacement under § 129.139(f)(3) and (4).

(10) For a nonregenerative carbon adsorption device in § 129.139(h):

(i) The records specified in paragraph (5)(i) and (ii).

(ii) The results of the performance test conducted under § 129.139(f)(1)(i) as performed under § 129.139(k).

(iii) The results of the performance test conducted under § 129.139(f)(1)(ii) as performed under § 129.139(l).

(iv) The control device design analysis, if one is performed under § 129.139(h)(2).

(v) The schedule for carbon replacement, as determined by § 129.139(f)(2) or the design analysis requirements of § 129.139(h)(2) and records of each carbon replacement under § 129.139(f)(3) and (4).

(11) For a condenser or other nondestructive control device in § 129.139(i):

(i) The records specified in paragraph (5)(i) and (ii).

(ii) The results of the performance test conducted under § 129.139(i)(1)(i) as performed under § 129.139(k).

(iii) The results of the performance test conducted under § 129.139(i)(1)(ii) as performed under § 129.139(l).

(iv) The control device design analysis, if one is performed under § 129.139(i)(7).

(v) The site-specific monitoring plan under § 129.139(i)(2).

(vi) The data and calculations for a CPMS installed, operated or maintained under § 129.139(i)(3)—(5).

(k) *Reporting.* The owner or operator of a source subject to § 129.131(a) (relating to general provisions and applicability) shall do the following:

(1) Submit an initial annual report to the Air Program Manager of the appropriate Department Regional Office by December 2, 2023, and annually thereafter on or before June 1.

(i) The responsible official must sign, date and certify compliance and include the certification in the initial report and each subsequent annual report.

(ii) The due date of the initial report may be extended with the written approval of the Air Program Manager of the appropriate Department Regional Office.

(2) Submit the reports under paragraph (3) in a manner prescribed by the Department.

(3) Submit the information specified in subparagraphs (i)—(ix) for each report as applicable:

(i) *Storage vessels.* The report for each storage vessel must include the information specified in subsection (b)(1)—(4) for the reporting period, as applicable.

(ii) *Natural gas-driven continuous bleed pneumatic controllers.* The initial report for each natural gas-driven continuous bleed pneumatic controller must include the information specified in subsection (c), as applicable. Subsequent reports must include the following:

(A) The information specified in subsection (c)(1) and (2) for each natural gas-driven continuous bleed pneumatic controller.

(B) The information specified in subsection (c)(3) and (4) for each natural gas-driven continuous bleed pneumatic controller installed during the reporting period.

(iii) *Natural gas-driven diaphragm pumps.* The report for each natural gas-driven diaphragm pump must include the following:

(A) The information specified in subsection (d)(1) and (2) for the reporting period, as applicable.

(B) A certification of the compliance status of each natural gas-driven diaphragm pump during the reporting period using one of the following:

(I) A certification that the emissions from the natural gas-driven diaphragm pump are routed to a control device or process under § 129.135(b)(1)(ii) or (c)(1). If the control device is installed during the reporting period under § 129.135(c)(2)(iii), include the information specified in subsection (d)(4).

(II) A certification under § 129.135(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.

(III) A certification according to § 129.135(c)(3)(ii)(C) that it is technically infeasible to capture and route emissions from:

(-a-) A natural gas-driven diaphragm pump installed during the reporting period to an existing control device or process.

(-b-) An existing natural gas-driven diaphragm pump to a control device or process installed during the reporting period.

(-c-) 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.

(iv) *Reciprocating compressors.* The report for each reciprocating compressor must include the information specified in subsection (e) for the reporting period, as applicable.

(v) *Centrifugal compressors.* The report for each centrifugal compressor must include the information specified in subsection (f) for the reporting period, as applicable.

(vi) *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)(3)(ii).

(vii) *Covers.* The report for each cover must include the information specified in subsection (h) for the reporting period, as applicable.

(viii) *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 for the initial report or if the closed vent system was installed during the reporting period.

(ix) *Control devices.* The report for each control device must include the information specified in subsection (j), as applicable.

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Title 49—PROFESSIONAL AND VOCATIONAL STANDARDS

STATE BOARD OF AUCTIONEER EXAMINERS

[49 PA. CODE CH. 1]

Fees

The State Board of Auctioneer Examiners (Board) and the Acting Commissioner of the Bureau of Professional and Occupational Affairs (Acting Commissioner) amends Chapter 1 (relating to State Board of Auctioneer Examiners) by amending § 1.41 (relating to schedule of fees) to read as set forth in Annex A.

This final-form rulemaking increases application fees to reflect updated costs of processing applications and increases all the Board's biennial renewal fees to ensure its revenue meets or exceeds the Board's current and projected expenses. This final-form rulemaking increases the following application fees on a graduated basis: auctioneer, apprentice auctioneer, auction company, trading assistant, trading assistant company, special license and course of study. Approximately 141 applicants are impacted annually by the increased application fees.

The Board is also increasing the graduated biennial renewal fees for the following licenses and registrations: auctioneer, apprentice auctioneer, auction company, trading assistant and trading assistant company. There are approximately 2,437 individuals who possess current licenses and registrations issued by the Board who are required to pay more to renew their licenses or registrations.

Effective Date

This final-form rulemaking is effective upon final-form publication in the *Pennsylvania Bulletin*. The initial increase for application fees will be implemented immediately upon publication. Thereafter, the subsequent graduated increases for application fees are implemented on a 2-fiscal-year basis on July 1, 2025, and July 1, 2027.

The increased biennial renewal fees are implemented for the March 1, 2023—February 28, 2025, biennial renewal period. Thereafter, the subsequent graduated increases are implemented for the March 1, 2025—February 28, 2027, biennial renewal period and then again for the March 1, 2027—February 28, 2029, biennial renewal period, and thereafter.

Statutory Authority

Under section 6(a) and (b) of the Auctioneer Licensing and Trading Assistant Registration Act (act) (63 P.S. § 734.6(a) and (b)), the license and examination fees and all other fees imposed under the provisions of this act shall be fixed by the Board by regulation and shall be subject to review in accordance with the Regulatory Review Act (71 P.S. §§ 745.1—745.14). If the revenues generated by fees, fines and civil penalties imposed in accordance with the provisions of this act are not sufficient to match expenditures over a 2-year period, the Board shall increase these fees by regulation, subject to review in accordance with the Regulatory Review Act, that the projected revenues will meet or exceed projected expenditures. If the Bureau of Professional and Occupational Affairs (Bureau) determines that the fees established by the Board are inadequate to meet the minimum enforcement efforts required, then the Bureau, after consultation with the Board, shall increase the fees by regulation, subject to review in accordance with the Regulatory Review Act, that adequate revenues are raised to meet the required enforcement effort. In addition to the previous cited authority, other sections of the act support the Board's authority to amend its fees by regulation when necessary.

Section 32 of the act (63 P.S. § 734.32) provides that "[t]he board may adopt rules and regulations necessary for the proper administration and enforcement of this act." Section 33(a) of the act (63 P.S. § 734.33(a)) provides that "[a]ll fees fixed pursuant to section 203 of the act of July 1, 1978 (P.L. 700, No. 124), known as the Bureau of Professional and Occupational Affairs Fee Act, shall continue in full force and effect until changed by the board." Regarding fees for trading assistant registration, the act of October 8, 2008 (P.L. 1080, No. 89) (Act 89 of 2008) established trading assistant registration by adding section 10.1. Section 10.1(c) specifically required that a registration fee of $100 be included with each application for registration. When the act was amended by the act of July 20, 2016 (P.L. 789, No. 88) (Act 88 of 2016), it added section 5.1 requiring trading assistants and trading assistant companies to register with the Board and repealed section 10.1. Section 5.1(c) of the act (63 P.S. § 734.5.1(c)) established an initial $100 registration fee for trading assistants and trading assistant companies and expressly added the new language of allowing the Board to establish this fee by regulation. According to the fiscal notes for Act 88 of 2016 from the House and Senate Appropriations Committees, the statutory fee of $100 for the registration and renewal of trading assistants established by section 10.1 was deleted and section 5.1(c) provided language giving the Board the authority to increase this fee for both trading assistants and trading assistant companies when needed to increase its revenue. Here, section 5.1 expressly provides the authority for the Board to establish this fee by regulation and with the other sections of the act cited previously provides the Board with the authority to amend this initial fee by regulation when necessary.

The Commissioner is appointed by the Governor and has a number of powers and duties. Specifically, under section 810(a)(7) of The Administrative Code of 1929 (71 P.S. § 279.1(a)(7)), the Commissioner has the power and duty, "[u]nless otherwise provided by law, to fix the fees to be charged by the several professional and occupational examining boards within the department."

Background and Purpose

Under section 6(a) of the act, the Board is required to support its operations from the revenue it generates from fees, fines and civil penalties. The act further provides that the Board shall increase fees when expenditures outpace revenue. Most of the general operating expenses of the Board are borne by the licensee population through revenue generated by the biennial renewal of licenses. A small percentage of its revenue comes from application fees, fines and civil penalties.

In January of 2021, the Board voted to increase its renewal and application fees based on its review of incoming revenue and biennial expenses. The Board's Fee Increase Report showed summaries of the Board's revenue and expenses for Fiscal Years (FY) 2018-2019 and 2019-2020 and the projected revenue and expenses through FY 2023-2024. During FYs 2018-2019 through 2019-2020, the Board received biennial revenue of $589,612.09, incurred expenses of $651,142.11 and ended with a deficit of $276,136.32. For FYs 2020-2021 and 2021-2022, the Board anticipates receiving biennial revenue of $571,000 and anticipates incurring expenses of $667,000. At the end of FY 2020-2021, the Department of State's Bureau of Finance and Operations (BFO) anticipates a deficit balance of $372,136.22. For FYs 2022-2023 and 2023-2024, with the implementation of this fee increase, the Board projects receiving biennial revenue of $890,000 and projects incurring expenses of $687,000, ending with a deficit of $169,136.32. The BFO's data demonstrated that the Board was not able to meet expenditures over a 2-year period and recommended a fee increase.

The proposed rulemaking for the fee increase was published at 52 Pa.B. 1736 (March 26, 2022) for review and comment. Publication was followed by a 30-day public comment period during which the Board received no public comments. The Senate Consumer Protection/Professional Licensure Committee (SCP/PLC) did not submit any comments. The House Professional Licensure Committee (HPLC) and the Independent Regulatory Review Commission (IRRC) submitted comments as detailed as follows.

Since the proposed rulemaking was published, the Board continues to be in a deficit, and it continues to increase as anticipated by the BFO.

Summary of Comments and the Board and Commissioner's Response

In preparing this final-form rulemaking, the Board considered all comments submitted by the HPLC and IRRC.

HPLC comment regarding potential impact of the fee increase

The HPLC questioned the Board regarding the potential impact the regulation could have on this Commonwealth's ability to compete with other states because the proposed increase to the fees for initial licensure and renewal for auctioneers are significantly higher than surrounding states that license auctioneers. IRRC shared the same concern.

The Board and the Acting Commissioner find that the increases in fees for initial licensure and renewal for auctioneers are necessary to equate for the rising costs associated with reviewing and processing the initial applications and to help continue the Board's mission of providing public protection through licensure of the profession and the enforcement of the act. As described in detail as follows, the increase in the initial application fees will not deter applicants from applying for licensure in this Commonwealth or put this Commonwealth at a competitive disadvantage. Also, increasing initial application fees to cover the cost of processing those applications will lessen the burden on existing licensees regarding biennial fee increases. Adjusting the initial application fees to cover the costs of applications is a fair and equitable approach because existing licensees will not have to bear all of the burden of initial applicant costs through higher biennial licensure fee increases. Unfortunately, the increases to the initial application fees are not sufficient to alleviate the Board's financial deficit so the Board's decision to increase the renewal fees for licensure, albeit at a lower amount than if the initial application fees were not increased, is also needed. The Board does not believe that the increase of these fees will put the Commonwealth at a competitive disadvantage as outlined as follows.

In comparing professional licensing in this Commonwealth to states in the Northeast Region (Connecticut, Delaware, Maine, Maryland, Massachusetts, New Hampshire, New Jersey, New York, Ohio, Rhode Island, Vermont and West Virginia), about half of the states regulate auctioneers to varying degrees. Some only require them to register as a business for tax purposes; others require auctioneers to be licensed. Pennsylvania, Maine, Massachusetts, New Hampshire, Ohio, Vermont and West Virginia are the only states in the Northeast Region that license auctioneers. In comparing this Commonwealth's current application fee of $50 to the other states, it is well below what the other states currently charge. For the new initial application fee of $180, that fee is still lower than some of the other states and well within the range of fees among states. Maine has a license period of 1 year and requires an application fee of $271; Massachusetts and West Virginia each have a license period of 1 year and require an application fee of $100. New Hampshire and Ohio each have a license period of 2 years like the Commonwealth and require an application fee of $200; Vermont has a license period of 2 years and requires an application fee of $100. Therefore, while the initial application fee increase from $50 to $180 represents an increase for the Commonwealth, the increase itself is actually just bringing the Commonwealth closer to the average application fees for auctioneers being charged by the surrounding states. Thus, the Board does not believe the application fee increase will put the Commonwealth at a competitive disadvantage.

In addition to being a fair and necessary increase in fees, professional licensure provides assurance to the consumers that the auction being conducted is being done so in accordance with the law. This is important and works as a competitive advantage for the Commonwealth over the states that do not license the profession. Furthermore, the Commonwealth is the fifth largest state by population based on the 2020 United States Census so there is more opportunity here for auctioneers to conduct a profitable business. As such, the Board finds that an increase in fees would not put the Commonwealth at a competitive disadvantage.

In comparing this Commonwealth's biennial renewal fee for auctioneers of $400 (effective with the 2023—2025 biennial renewal), Maine has an annual renewal of $200, Massachusetts has an annual renewal of $100 and West Virginia has an annual renewal of $50. New Hampshire and Ohio each have biennial renewals of $200 and Vermont's fee is $240. While the Board's biennial renewal fee for auctioneers is higher than other states, the Board does not believe it will make this Commonwealth less competitive as compared to other states. As stated earlier, because of the large population size and the fact that this Commonwealth conducts more auctions per year than the smaller surrounding states, the Board does not believe an increase of $140 (equating to $70 per year over 2 years) will deter licensees from practicing in this Commonwealth or put this Commonwealth at a competitive disadvantage.

IRRC comments

IRRC asked the Board to explain how the proposed application and biennial renewal fees were calculated and how it determined that the proposed fee increases to be implemented during the first phase, including those for applications and renewals for the five categories of licenses, are both appropriate and reasonable. IRRC also asked the Board to explain how the implementation schedule, particularly the first phase, is reasonable. IRRC also asked the Board to provide in this final-form rulemaking additional information and updates in the Regulatory Analysis Form (RAF).

Calculation of application and renewal fees; reasonableness of fee increases

IRRC asked the Board to detail how the proposed application fees, to be implemented during the first phase, were calculated. Boards and commissions under the Bureau calculate and design initial application fees to cover the cost to process applications. Application fees are based on time study reports created within the Bureau that lay out each step in processing an application and the amount of time it takes to complete each step. That amount of time per application is multiplied by the total number of anticipated application requests for 1 year to get the total number of minutes per year necessary to process applications. (The number of minutes per year is multiplied by two since the increases are biennial.) Initial application fees are based on a formula that multiplies the number of minutes to perform the processing function by the pay rate for the classification of the personnel performing the function and adding a proportionate share of administrative overhead. The corresponding fee report forms for each application fee describe in detail how the fees are calculated. For example, the application fee for an auctioneer license is calculated by taking the cost of 1 hour of clerical staff time to review the application and 1 hour of the clerical supervisor's time for review and sign off and then finally 1 hour of the Board's administrator's time to process the application along with standard administrative overhead costs to achieve a total cost. The Board finds that the fee increases are reasonable based on the fees charged by the neighboring states and are appropriate based on the fee report forms that outline the costs to the Board to review and process the applications.

As reflected in Annex A, the application fees would increase on a graduated level for the licenses and registrations for auctioneer, apprentice auctioneer, auction company, trading assistant and trading assistant company. The application fees will be increased on a graduated basis so that the application fees collected during each biennium reflect the anticipated costs of processing applications for that biennium. These fees are designed to cover the cost to process applications and are borne by individual applicants. Application fees for FY 2021-2022 are based on the time study reports created within the Bureau giving each step in the process and the amount of time it takes to process one application. That amount is multiplied by the anticipated application requests for 1 year (times two since the increases are biennial). Increases effective July 1, 2025, and July 1, 2027, are calculated at a 9.5% increase based upon raises under current Commonwealth union contracts. Application fees are almost entirely dependent upon personnel-related costs.

IRRC also asked the Board to explain how it calculated the fee increases for biennial renewal of licenses for auctioneer, apprentice auctioneer, auction company, trading assistant and trading assistant company which will take effect beginning with the March 1, 2023, March 1, 2025, and March 1, 2027 biennium renewal periods. Biennial renewal fees were calculated by the BFO using the Board's revenues and expenses while using past histories of prior fee increases as well as changes in the licensee population as a guide in determining the graduated fee increases. The Board last increased its fees in 2015 and based on those fees if left unchanged the Board's current deficit would continue to grow. The biennial fee increases are calculated to ensure that the projected revenues will meet or exceed projected expenditures, as required by the act. In calculating the new renewal fees, the BFO considered the licensure population and adjusted the current biennial renewal fees upward to an amount that would put the Board back on stable financial footing by the end of the 2027 renewal cycle.

IRRC asked the Board to explain how it determined that the proposed fee increases to be implemented during the first phase, including those for applications and renewals for these five categories of licenses, are both appropriate and reasonable. As indicated previously, the first fee increase for application fees are calculated to cover the cost to process applications. This initial increase brings the application fee in line with the cost to process the applications. Because application fees are almost entirely dependent upon personnel-related costs, the subsequent increases effective July 1, 2025, and July 1, 2027, are calculated at a 9.5% increase based upon raises under current Commonwealth union contracts. Thus, moving forward, the Board anticipates that the subsequent increases will cover future costs to process applications. In determining the biennial renewal fees, the BFO calculated the increase needed to allow the Board to meet its operational costs while also reducing the accumulated deficit in the most efficient manner. Most of the Board's operational costs are personnel-related, and much of those costs are not within the Board's control. Staff are generally employees of the Commonwealth, most of whom are civil service personnel; many are in union positions. For these employees, the Board is bound by the negotiated contract. Personnel costs associated with investigation and enforcement depend largely on the number of complaints received that need to be investigated, and the number of those matters that result in disciplinary action. The Board has no control over the number of complaints that are filed against licensees and unlicensed individuals, nor may they control which matters are, or are not, prosecuted. The BFO also considered and incorporated the projected increases in initial application fees that could be used to help reduce the deficit by bringing those costs into alignment with the actual costs required to process the applications. Furthermore, it was noted that increases in expenses have steadily rose over the last few years. Some of the increase in expenses is simply due to personnel cost of living increases over time. However, over the last few fiscal years, the Board has had some sizable increases to expenses for a variety of reasons.

One of the largest financial impacts for the Board was the incorporation of The Pennsylvania Justice Network (JNET), due in part to the enactment of the act of February 15, 2018 (P.L. 14, No. 6) (Act 6 of 2018), which requires mandatory self-reporting of criminal convictions. The Board uses JNET to identify criminal convictions of licensees and to verify compliance with Act 6 of 2018's mandatory reporting requirement. There was a sizable increase in the number of complaints being processed and opened for prosecution. The additional complaints resulted in increased expenses due to higher prosecutions, investigations, expert witness usage and hearings. Since incorporation of JNET, expenses have increased steadily in all of these cost categories.

In addition to the legal expense increases, the 29 boards and commissions under the Bureau have undergone an information technology transformation upgrade with the incorporation of the Pennsylvania Licensing System (PALS). Expenses associated with PALS, including the initial build as well as ongoing maintenance, are proportionately spread across all entities based on licensee population to effectively share costs per licensee. While the initial build is in the past, it has contributed to higher administrative expenses for all boards during the last few fiscal years. Due to PALS' high functioning database with enhanced features over the Bureau's previous License 2000 platform, maintenance for this system requires a larger financial commitment from all boards and commissions than the previous system. As detailed in the BFO's Fee Increase Report, these costs were also considered in calculating the renewal fee increase.

As noted previously in answering the comment received from the HPLC, because the application fees were calculated based on the current rates for processing auctioneer applications and they are in line with the other states' application fees, the Board finds them to be reasonable. The same applies to the renewal fees for auctioneers.

For apprentice auctioneers, the Commonwealth, Ohio and West Virginia are the only states in the Northeast Region that license apprentice auctioneers. In comparing the Commonwealth's application fee of $145, Ohio and West Virginia each have an application fee of $100. The Commonwealth's biennial renewal fee of $200 (effective with the 2023—2025 biennial renewal) is comparable to annual rates for Ohio at $100 and West Virginia at $100.

The Commonwealth is the only state in the Northeast Region that licenses an auction company. Ohio licenses an auction corporation, partnership or association but not a company. The Commonwealth's application fee of $120 in 2023, $135 in 2025 and $150 in 2027 is comparatively lower than Ohio's application fee of $200 for an auction corporation. The Commonwealth's biennial renewal fee of $400 (effective with the 2023—2025 biennial renewal) is comparatively higher than Ohio's biennial renewal fee for an auction corporation at $200, but the Board does not believe that this would put the Commonwealth at a competitive disadvantage because the Commonwealth is the only state in the region that licenses auction companies. Ohio's licensure differs from the Commonwealth's in that it requires that at least 50% of the owners of an auction corporation, partnership or association also have an auctioneer's license. The Commonwealth's auction company license does not require this and as such, holds an advantage over Ohio's due to the lack of that ownership element. The Commonwealth's license only requires that an auctioneer of record be on file with the auction company and that person does not have to be an owner. Thus, it is easier for more auction type companies to do business in this Commonwealth as opposed to the neighboring states which is a competitive advantage. Thus, charging a higher fee than Ohio should not put the Commonwealth at a competitive disadvantage.

A license is not required by any other comparison state in the Northeast Region for trading assistants and trading assistant companies. Trading assistants and trading assistant companies are licenses granted to those individuals looking to sell other people's property using only an online auction format and not an in-person auction. Having a licensure requirement to conduct online only auctions without having to have a full auctioneer's license is a competitive advantage for the Commonwealth because it allows more individuals to engage in this business, while providing the security of accountability that is provided through the licensure of professionals. The Commonwealth is the only state in the region that issues these types of licenses; therefore, the Board does not anticipate that the fee increase will put the Commonwealth at a competitive disadvantage.

Reasonableness of the implementation schedule

IRRC asked the Board to explain how the implementation schedule, particularly the first phase, is reasonable. The Board and the Acting Commissioner submit that the graduated application fee increases are appropriate and reasonable because the increased fees are projected to cover the cost to process the applications for that biennial period. The Board carefully considered the best way to implement an increase in application fees and determined that a graduated fee schedule is favorable because it aligns the actual cost to process applications in each biennial period with the fee for that period. While the Board is reluctant to put additional fiscal burdens on its applicants, the increased fees are not significant when looking at the total increase in dollars. Moreover, even with the implementation of the graduated application fee increase, the Board's fees are still comparable with other states.

The Board and the Acting Commissioner further submit that the graduated increases to the biennial renewal fees are also appropriate and reasonable based on the BFO's calculations. Significantly, the Board has not increased its fees since 2015. These needed increases are appropriate because they are necessary to ensure revenues meet or exceed expenses, as required by the act. Currently the Board has had a steady increase in its expenses, while its revenues have remained stagnant which has created a sizable deficit. The biennial renewal fee increases were calculated to reduce the deficit as quickly as possible. Therefore, the initial increase had to be higher. However, because the initial fee increase would not totally eliminate the Board's deficit, there was a need to implement additional smaller increases for the following renewal cycles. The needed biennial renewal fee increases are reasonable because they are made on a graduated basis to reduce the impact to the licensee population, while also allowing the Board to meet or exceed its projected expenditures to put the Board back on firm financial ground in the most efficient manner possible.

The Board submits that the implementation schedule is reasonable based on the current financial circumstances of the Board. Currently, the Board's expenses are exceeding its revenues and while the Board can continue to do business through its reliance on dollars from the Professional Licensure Augmentation Account (PLAA), where the 26 licensing boards under the Department of State deposit revenue; the Board cannot rely on PLAA funds to address its growing deficit. Thus, the Board has implemented a graduated fee schedule to reduce its deficit in the most efficient manner while lessening the immediate burden to applicants and the licensee population that would occur with a flat fee increase. While applicants and licensed individuals will be impacted economically, the graduated increases, as opposed to a flat fee increase, will ensure that fees charged coincide more closely with the projected expenses for each biennium.

The Board finds that the implementation schedule for the application fees is reasonable and fair because the graduated application fee increases are designed to reflect the anticipated costs of processing applications for that biennium.

Additionally, the Board finds that the implementation schedule for the biennial renewal fees is also reasonable. As noted previously, the need for the increased revenue through biennial renewal fees is necessary because the Board's expenses have increased based on the increase in complaints being filed because of the Board's use of JNET and the resulting increase in expenses due to higher prosecutions, investigations, expert witness usage and hearings. More than likely, this new level of legal workload will be part of the financial picture for the Board going forward so any delays in implementing new fees will push the Board into a larger deficit. Furthermore, the Board continues to pay for the administrative expenses involving the upgrade to PALS and will continue to pay ongoing expenses in the form of yearly maintenance costs for the foreseeable future. Thus, the Board's decision to implement the graduated biennial renewal fee schedule is reasonable based on its current financial position and the need to implement the higher fees in a manner to reduce its deficit in a quick and efficient manner to return the Board to a financially stable environment.

Updates to the RAF

Finally, IRRC asked the Board to update the RAF to include a dollar estimate in its response to RAF question # 21 for the cost to implement the regulation or explain why it is not possible to do so; to elaborate on any alternative regulatory provisions in response to RAF question # 26, which the Board considered and rejected; to provide fee report forms provisions in response to RAF question # 28 for the fees described herein; and to delete any meeting dates provisions in response to RAF question # 30 that have passed. The Board has updated the RAF as requested.

Regarding RAF question # 21, to implement this final-form rulemaking, paper and online applications will have to be revised to reflect the new fees. Paper documents will be revised by Board administrative staff, who will change the fee amounts on an electronic copy of the paper document; this process will take about 15 minutes of staff time to complete the revisions per renewal year to revise the documents, as well as 15 minutes for the Bureau Business Licensing Division Chief, Bureau Deputy Commissioner and Board Counsel to each review and sign-off on the revisions. Online applications will be revised in PALS by Board administrative staff; this process will take about 1 hour of staff time to complete the revisions per renewal year, as well as 15 minutes for the Bureau Business Licensing Division Chief, Bureau Deputy Commissioner and Board Counsel to each review and sign-off on the revisions. The total estimated cost to revise paper and online documents is $381; $127 in FY 2022-2023, $127 in FY 2024-2025 and $127 in FY 2026-2027.

Regarding RAF question # 26, the Board considered an alternative fee increase that did not include a graduated fee schedule but decided to not move forward with that version because the Board believes that the graduated application fee and graduated biennial renewal fee increases are more beneficial to the Board and to the licensees. The application fee increases on a graduated basis are reflective of the actual costs to process applications over time, which is more beneficial to the licensees to spread the needed increase in fees over time and not try to reduce the deficit all at once with higher fees. A nongraduated fee increase would have been much larger and may have put the Commonwealth at a competitive disadvantage to the other states in the region based on those higher fees. The same is true for the graduated increase to the biennial renewal fees because increasing fees in this manner coincides more closely with the projected expenses for each biennium. This is less impactful on the licensee population by spreading the needed fee increase out over several renewal cycles instead of implementing a higher fee all at once.

Regarding RAF question # 28, when calculating the new application fees, the Board relied on fee report forms which were inadvertently not included with the RAF in its prior submission. This error has been corrected as noted previously and those reports are attached to the RAF in this final-form rulemaking.

Fees for biennial license renewal, however, are not determined in the same way as fees for initial applications. Renewing a license is an online process through PALS where a licensee answers several questions and pays the appropriate fee. Generally, PALS automatically renews the license. Thus, there are no fee report forms for the biennial renewal fees. As noted previously, unlike initial application fees, biennial renewal fees are designed to cover the operational costs of the Board. These costs include salaries for administrative and legal staff as well as the cost for investigation of complaints, enforcement of statutory and regulatory requirements, hearing expenses and board member expenses. The biennial fees are calculated to ensure that the Board can meet or exceed its operational costs. Since biennial renewal fees are based on operating expenses and do not reflect the cost to process a renewal application, fee report forms are not utilized for biennial renewal fees.

Miscellaneous amendments for clarity

The Board and the Acting Commissioner made minor amendments to the effective dates to clarify that the increase is applicable to each renewal period, and thereafter. In doing so, the effective dates of the biennial fee increases were amended to clarify that the first renewal fee increase will be implemented for the March 1, 2023—February 28, 2025, biennial renewal period. Thereafter, the subsequent graduated increases will be implemented for the March 1, 2025—February 28, 2027, biennial renewal period and then again for the March 1, 2027—February 28, 2029, biennial renewal period, and thereafter.

Fiscal Impact and Paperwork Requirements

When the Board voted to increase the renewal and application fees, the Board was deficit spending and the BFO noted that if the Board did not increase its fees that deficit would continue to increase. The new fee structure approved by the Board will eliminate the deficit spending and decrease the current deficit balance. This will allow the Board to meet or exceed its projected expenditures in the coming biennial renewal cycles and will eventually put the Board back on firm financial ground.

To accomplish this goal, the amendments will increase application and biennial renewal fees. Applicants, licensees and registrants will be required to comply with the regulation. The fees may be paid by applicants, licensees or registrants or may be paid by their employers, should their employers choose to pay these fees. This final-form rulemaking should have no other fiscal impact on the private sector, the general public or political subdivisions of the Commonwealth.

Approximately 141 applicants will be impacted annually by the increased application fees. Specifically, the number of applicants affected are as follows: 25 auctioneers, 40 apprentice auctioneers, 1 course of study, 45 auction companies, 10 special licenses, 10 trading assistants and 10 trading assistant companies.

Based upon the graduated application fee increases, the total economic impact per fiscal year is as follows:

FY 2021-2022:	$10,735
FY 2022-2023:	$10,735
FY 2023-2024:	$ 2,245
FY 2024-2025:	$ 2,245
FY 2025-2026:	$ 2,245
FY 2026-2027:	$ 2,245
Total:	$30,450

There are approximately 2,437 individuals who possess current licenses and registrations issued by the Board who will be required to pay more to renew their licenses and registrations.

Based upon the above biennial renewal fee increases, the economic impact is as follows:

FY 2021—2023:	$321,340
FY 2023—2025:	$175,025
FY 2025—2027:	$ 68,675
Total:	$565,040

Thus, the total economic impact to applicants, licensees, registrants, or employers, if employers choose to pay application or licensing fees, is $595,490. This amount reflects the economic impact that will occur between FY 2021-2022 through FY 2026-2027.

This final-form rulemaking will require the Board to revise its printed and online application forms. The amendments will not create additional paperwork for the regulated community or for the private sector.

Sunset Date

The Board continuously monitors the effectiveness of its regulations. Therefore, no sunset date has been assigned. Additionally, the BFO provides the Board with an Annual Board Budget Report detailing the Board's financial condition. In this way, the Board continuously monitors the adequacy of its fee schedule.

Regulatory Review

Under section 5(a) of the Regulatory Review Act (71 P.S. § 745.5(a)), on March 10, 2022, the Board submitted a copy of the notice of proposed rulemaking published at 52 Pa.B. 1736 and a copy of an RAF to IRRC and to the Chairpersons of the SCP/PLC and the HPLC, for review and comment. Publication was followed by a 30-day public comment period during which the Board received no public comments.

Under section 5(c) of the Regulatory Review Act, the Board is required to submit to IRRC, the HPLC and the SCP/PLC copies of comments received during the public comment period, as well as other documents when requested. The SCP/PLC did not submit comments. In preparing the final-form rulemaking, the Board and the Acting Commissioner have considered all comments from IRRC and the HPLC.

Under section 5.1(g)(3) and (j.2) of the Regulatory Review Act (71 P.S. § 745.5a(g)(3) and (j.2)), on October 19, 2022, the final-form rulemaking was deemed approved by the HPLC and the SCP/PLC. Under section 5.1(e) of the Regulatory Review Act, IRRC met on October 20, 2022, and approved the final-form rulemaking.

Additional Information

Additional information may be obtained by writing to Terri Kocher, Board Administrator, State Board of Auctioneer Examiners, P.O. Box 2649, Harrisburg, PA 17105-2649, RA-AUCTIONEER@pa.gov.

Findings

The State Board of Auctioneer Examiners and the Acting Commissioner find that:

(1) Public notice of intention to adopt a regulation at 49 Pa. Code, Chapter 1, was given under sections 201 and 202 of the act of July 31, 1968 (P.L. 769, No. 240) (45 P.S. §§ 1201 and 1202), referred to as the Commonwealth Documents Law and the regulations promulgated under those sections at 1 Pa. Code §§ 7.1 and 7.2 (relating to notice of proposed rulemaking required; and adoption of regulations).

(2) A public comment period was provided as required by law and all comments were considered in drafting this final-form rulemaking.

(3) The amendments to this final-form rulemaking do not enlarge the original purpose for the proposed regulation published at 52 Pa.B. 1736.

(4) These amendments to the regulations of the State Board of Auctioneer Examiners are necessary and appropriate for the regulation of the practice of auctioneering in the Commonwealth.

Order

The Board therefore orders that:

(A) The regulations of the State Board of Auctioneer Examiners, 49 Pa. Code, Chapter 1, are amended by amending § 1.41 to read as set forth in Annex A.

(B) The Board shall submit a copy of this final-form rulemaking to the Office of the Attorney General and the Office of General Counsel for approval as required by law.

(C) The Board shall submit this final-form rulemaking to IRRC, the HPLC and the SCP/PLC as required by law.

(D) The Board shall certify this final-form rulemaking and shall deposit it with the Legislative Reference Bureau as required by law.

(E) This final-form rulemaking shall take effect immediately upon publication in the *Pennsylvania Bulletin*.

NEVIN B. RENTZEL,
Chairperson, State Board of Auctioneer Examiners

ARION CLAGGETT,
Acting Commissioner, Bureau of Professional and Occupational Affairs

(*Editor's Note*: See 52 Pa.B. 6941 (November 5, 2022) for IRRC's approval order.)

Fiscal Note: Fiscal Note 16A-6411 remains valid for the final adoption of the subject regulation.

Annex A

TITLE 49. PROFESSIONAL AND VOCATIONAL STANDARDS

PART I. DEPARTMENT OF STATE

Subpart A. PROFESSIONAL AND OCCUPATIONAL AFFAIRS

CHAPTER 1. STATE BOARD OF AUCTIONEER EXAMINERS

FEES

§ 1.41. Schedule of fees.

(a) An applicant for a license, certificate, registration or service shall pay the following fees at the time of application:

		Effective December 10, 2022	*Effective July 1, 2025*	*Effective July 1, 2027*
(1) *Auctioneer*	Application for license to practice as an auctioneer	$180	$200	$220
(2) *Apprentice auctioneer*	Application for license to practice as an apprentice auctioneer	$145	$160	$175
	Application fee to change sponsor	$15	$15	$15
(3) *Auction company*	Application for license to practice as an auction company	$120	$135	$150
	Application fee to change auction company license	$15	$15	$15
(4) *Trading assistant*	Application for registration to practice as a trading assistant	$120	$135	$150
(5) *Trading assistant company*	Application for registration to practice as a trading assistant company	$120	$135	$150
(6) *Miscellaneous*				
	Special license to conduct auction	$120	$135	$150
	Application fee to approve course	$180	$200	$220
	Certification of scores, permit or registration	$25	$25	$25
	Verification of license, registration, permit or approval	$15	$15	$15

(b) An applicant for biennial renewal of a license, certificate or registration shall pay the following fees:

		March 1, 2023—February 28, 2025 biennial renewal	*March 1, 2025—February 28, 2027 biennial renewal*	*March 1, 2027—February 28, 2029 biennial renewal and thereafter*
(1) *Auctioneer*	Biennial renewal	$400	$475	$500
(2) *Apprentice auctioneer*	Biennial renewal	$200	$250	$300
(3) *Auction company*	Biennial renewal	$400	$475	$500
(4) *Trading assistant*	Biennial renewal	$200	$250	$300
(5) *Trading assistant company*	Biennial renewal	$200	$250	$300

[Pa.B. Doc. No. 22-1926. Filed for public inspection Decemeber 9, 2022, 9:00 a.m.]