FINAL-FORM RULEMAKING
ENVIRONMENTAL QUALITY BOARD
[25 PA. CODE CHS. 121 AND 129]

Control of VOC Emissions from Oil and Natural Gas Sources

The Environmental Quality Board (Board) 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—129.131 to adopt reasonably available control technology (RACT) requirements and RACT emission limitations for 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 in all segments except natural gas distribution. 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 of the final-form regulation.

This final-form rulemaking was adopted by the Board at its meeting on DATE, 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 DATE, 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 (35 P.S. § 4005(a)(8)), 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 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 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 National Ambient Air Quality Standards (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) 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 (42 U.S.C.A. § 7502(c)(1)) 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 the 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 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 U.S. 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, https://www.reginfo.gov/public/do/eAgendaViewRule?pubId=202004&RIN=2060-AT76.

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. 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. 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 submit this final-form rulemaking as a SIP revision and the EPA must determine 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 SIP Revisions for the 2016 O&G CTG for the 2015 Ozone NAAQS and for states in the OTR," with an effective date of January 18, 2022. 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 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.

This final-form rulemaking will address both the December 2021 and the November 2020 findings of failure to submit SIP revisions by addressing the RACT requirements associated with the 2016 O&G CTG. 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. The Department is working toward completing the submittal by June 16, 2022, to avoid any 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 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 the 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 the 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 at both conventional and unconventional well sites. 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 in all segments except natural gas distribution. The tiered emissions thresholds 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 a 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 three years for reciprocating compressors located at 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, 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 a 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 a 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 a 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 a 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 EPA as a revision to the Pennsylvania 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 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 in the oil and natural gas industry emitted 24,619 TPY VOC and that implementation of the control measures in this final-form rulemaking could reduce VOC emissions by as much as 12,068 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 co-benefit, 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 the oil and natural gas industry emitted 467,400 TPY methane in 2020, and that the co-benefit methane emissions reduction from this final-form rulemaking may be as much as 221,066 TPY.

Furthermore, the technically and economically feasible RACT determinations in this final-form 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 714 TPY of VOC and 11,913 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 oil and natural gas sources of VOC emissions which were constructed on or before the effective date of this final-form rulemaking: storage vessels in all segments except natural gas distribution, natural gas-driven continuous bleed pneumatic controllers, natural gas-driven diaphragm pumps, centrifugal compressors, reciprocating compressors and fugitive emission components.

The Department identified 5,039 owners or operators of approximately 31,149 facilities in this Commonwealth that may be affected by this final-form rulemaking. Approximately 3,834 of the 5,039 owners or operators may meet the definition of small business as defined in section 3 of the Regulatory Review Act (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 30,648 well sites, 486 gathering and boosting stations, 15 processing plants, and 121 transmission stations. The Department estimates that these owners or operators have at least 51 storage vessels at 18 facilities, 34,856 pneumatic controllers at 31,134 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 2,711 of 30,648 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 263 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 industry-wide cost of complying with this final-form rulemaking will be about $31.7 million per year. However, implementation of the control measures will also potentially save owners or operators in the oil and natural gas industry about $20.3 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 facilities in the oil and natural gas 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-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 minimal cost as a result of this final-form rulemaking; net costs of approximately $366 per facility or, on average, $2,263 per owner or operator. Overall, the Department does not anticipate that this final-form rulemaking will result in any significant adverse impact on small oil and gas operators.

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 (CDAC) 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 proposed amendments to Chapter 129.

No change is made to this section from proposed to 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: a storage vessel in all segments except natural gas distribution; natural gas-driven continuous bleed pneumatic controller; natural gas-driven diaphragm pump; reciprocating compressor; centrifugal compressor; or fugitive emissions component.

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)(2) is also 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.

No change is made to subsection (b) from proposed to 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 remove 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" and "UIC class II oilfield disposal well."

Subsection (b) lists the EPA methods referenced in this final-form rulemaking. No change is made to subsection (b) from proposed to 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, then the cover and closed vent systems must meet the requirements in § 129.128 (relating to covers and closed vent systems).

No change is made to subsection (b) from the proposed to the 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) was removed in this final-form rulemaking.

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

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

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

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

Subsection (g) references the recordkeeping and reporting requirements under § 129.130(b) (relating to recordkeeping and reporting) and § 129.130(k)(1) for owners or operators of storage vessels subject to this section. No change is made to subsection (g) from the proposed to the final-form rulemaking.

§ 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 NSPS requirements. Subsections (d) and (e) are also 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).

§ 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. No change is made to subsection (a) from the proposed to the 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 a well site, the owner or operator shall reduce VOC emissions by connecting the natural gas-driven diaphragm pump to a control device through a closed vent system that meets the requirements of § 129.128(b) and routing the emissions to a control device or process that meets the requirements of § 129.129 (relating to control devices). For natural gas-driven diaphragm pumps located at a natural gas processing plant, the owner or operator shall reduce VOC emissions by maintaining an emission rate of zero standard cubic feet per hour.

Subsection (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 (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.

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.

No changes are made to subsections (d)—(f) from the proposed to the final-form rulemaking.

§ 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.

No change is made to subsection (a) from the proposed to the 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 "[e]xcept as specified in subsection (d)" from subsection (b) and to add further clarifying language to subsection 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)(4) for owners or operators of reciprocating compressors and under § 129.130(f) and (k)(5) for owners or operators of centrifugal compressors.

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

§ 129.127. Fugitive emissions components

This section was 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. This subsection also establishes that a fugitive emissions component at a well site with a well that produces less than 15 barrels of oil equivalent per day is not subject to this section.

Subsection (a) is amended in this final-form rulemaking to remove the phrase "with a well that produces, on average, greater than 15 barrels of oil equivalent per day" from subsection (a)(1).

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) on proposed, establishes the compliance requirements for well sites based on the gas to oil ratio (GOR) of the well.

Subsection (c) is amended in this final-form rulemaking to renumber due to formatting changes, remove the word "producing" from "requirements for a producing well site" and to remove "the owner or operator of a producing well site shall perform the following." The Board also removed "determine the GOR of the well using generally accepted methods" and replaced it with "for a well site consisting of only oil wells, the owner or operator shall" in paragraph (1). The Board added new language to paragraph (1)(i) and added "of the oil well site" and removed "the owner or operator shall" in paragraph (1)(ii). The Board also added "of the oil well site," removed "the owner or operator shall perform the following:" and added "meet the requirements of paragraph (2) or paragraph (3) based on the results of subsection (b)(1)" in paragraph (1)(iii). The Board also added new language in paragraph (2). The Board added the word" initial" before AVO inspection and removed "within 60 days after" and replaced it with "on or before" 60 days after final publication in paragraph (2)(i). The Board also added "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 in paragraph (2)(i). Additionally, the Board added 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)(ii). The Board also added "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 in paragraph (2)(ii).

Under subsection (c)(3), the Board also added 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) on proposed, the Board removed "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;" added "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;" added the word "required" before LDAR inspection; and removed "required under paragraph (1)(ii)(B)."

Under subsection (c)(4)(i), the Board also removed "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 replaced 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 removed "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 replaced 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 added subsection (c)(5) at final-form to include an option for the owner or operator of 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 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 well sites.

Subsection (d), formerly subsection (c) in the proposed rulemaking, is amended in this final-form rulemaking to add the word "site" after "well" to clarify that the LDAR inspection requirements are for the well site as a whole and not an individual well. The Board also added "after the 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 added "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 in paragraph (1). Additionally, the Board added 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 added "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 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. No change is made to subsection (f) from the proposed to the 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 increased 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 removed the word "daily" and added "each day prior to use" in paragraph (2). Additionally, the Board removed "that determines how the equipment operator will perform the" and added "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. No change is made to subsection (j) from the proposed to the 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. No change is made to subsection (k) from the proposed to the 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 new source performance standards (NSPS). Since the LDAR inspection program is recognized as AMEL for the 2016 NSPS, and the requirements of the 2016 NSPS and the 2016 O&G CTG are identical, the EPA should also accept the Commonwealth's LDAR inspection program in this proposed rulemaking as AMEL. By establishing consistent LDAR inspection requirements for both new and existing sources, the Department is providing owners and operators with the ability to merge both types of sources into one LDAR inspection program.

Subsection (1) is amended in the 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 corrected a cross reference in paragraph (4)(ii). Additionally, the Board removed "there is no visible leak image when using OGI equipment calibrated according to subsection (g)" and replaced 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)(6). No change is made to subsection (m) from the proposed to the final-form rulemaking.

§ 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 added "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 in paragraph (4). Additionally, the Board corrected a cross reference in paragraph (6).

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 also added “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 in paragraph (2)(i). The Board also removed “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 replaced 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 also removed “within 30 days after” and replaced 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 in paragraph (4)(ii)(B).

Additionally, the Board also corrected a cross reference in subsection (b) and paragraph (3).

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. No change is made to subsection (c) from the proposed to the 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 removed “the owner or operator shall perform the following:” and replaced it with “use OGI equipment that meets § 129.127(h)” in paragraph (1). The Board also corrected a cross reference and added “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) on proposed. The Board also added 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 the final-form rulemaking. The Board also removed 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)(9). No change is made to subsection (a) from the proposed to the final-form rulemaking.

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 the final-form rulemaking. The Board also amended 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 amended 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. No change is made to subsection (d) from the proposed to the 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). No change is made to subsection (e) from the proposed to the 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 removed "or authorization by the Department's Bureau of Waste Management" and replaced 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 removed 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 to 45, and in paragraph (1)(i)(B) and (C) from 90 to 120.

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

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

Subsection (j) identifies the general performance test requirements.

Subsection (j) is amended in this final-form 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 added 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). No change is made to subsection (k) from the proposed to the 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). No change is made to subsection (1) from the proposed to the final-form rulemaking.

Subsection (m) lists the continuous parameter monitoring system requirements (CPMS) for control devices that are required to install CPMS. No change is made to subsection (m) from the proposed to the 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. No change is made to subsection (a) from the proposed to the 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 corrected 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 amended subsection (c) to add “required compliance” before “date” in paragraph 1. The Board also clarified 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. No change is made to subsection (f) from the proposed to the 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 added 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 deleted 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 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 added 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 website.

IRRC states that section 2 of the Regulatory Review Act (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 proposal, 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 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-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 this 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 notes that this final-form rulemaking does not apply to conventional oil and gas wells. Instead, 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. Additionally, the 2016 O&G CTG does not provide definitions of conventional and unconventional wells and the EPA does not establish definitions of conventional and unconventional wells in the NSPS codified at 40 CFR Part 60, Subpart 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) or 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). Rather, the recommendations of the 2016 O&G CTG are applicable to the control of VOC emissions from certain categories of sources used by owners or operators at both conventional and unconventional well sites in the onshore production and processing segments of the oil and natural gas industry and are not specific to the operation of a conventional well or an unconventional well.

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 website.

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 the final-form regulation 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 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 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. The implementation of the VOC emission control measures in this final-form rulemaking are 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-form rulemaking, when implemented, are expected to provide VOC emission reductions of approximately 12,068 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 221,066 TPY of methane as a co-benefit. Methane is a potent greenhouse gas (GHG) with a higher global warming potential than carbon dioxide (CO_2).

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 regulation 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. In order for IRRC to determine whether this rulemaking is in the public interest, the Board must submit a revised estimate of the costs and/or savings 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 $31.7 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 $20.3 million (2021 dollars). This results in a total net cost of $11.4 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-form rulemaking, the impact on industry is a net benefit. 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 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" 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 Subpart OOOOa 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 revised the definition of "*In-house engineer*" from proposed to 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 "Engineer, Land Surveyor and Geologist Registration Law" (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 152 of the Registration Law, 63 P.S. § 152 (relating to exemption from licensure and registration). Clause (i) of the definition in this final-form rulemaking recognizes that in accordance with sections 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 sections 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 sections 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 regulation 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 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 the 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 will be 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 this 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 the 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 the 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 the 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 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 asks the Board to explain the need for each provision and how determinations were made, as well 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 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 removed 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 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 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 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 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 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, and the Philadelphia Air

Management Services Northeast Airport and Northeast Waste samplers in Philadelphia County. All 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. 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 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 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 modified 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 submits the 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.

The Board identified 5,039 client ID numbers for potentially affected owners or operators of facilities in this Commonwealth using the Department's eFACTS and AIMS databases and the NAICS codes covered by the 2016 O&G CTG. These facilities include approximately 30,648 well sites, 486 gathering and boosting stations, and 15 natural gas processing facilities in this Commonwealth. Of these potential 5,039 owners or operators, approximately 3,834 may meet the definition of small business as defined in section 3 of the RRA. However, it is possible that far fewer than the 5,039 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. 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-form 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 1 storage vessel per well site; of these, only 6 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-form 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-form rulemaking.

IRRC comments that section 1207(b) of the Pennsylvania Grade Crude Development Act, the act of June 23, 2016 (P.L. 375, No. 52) (58 P.S. §§ 1201—1207), known as Act 52, 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.

In response, the Board clarifies that Act 52 does not apply to this final-form rulemaking and therefore, the Board is not required to develop a separate rulemaking and regulatory analysis form for the requirements for conventional oil and gas wells.

Section 1207(b) of Act 52 (58 P.S. § 1207(b)) states that "any rulemaking concerning conventional oil and gas wells that the Environmental Quality Board undertakes after the effective date of this act shall 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." Looking at section 1207(b) outside of the context of Act 52, it is not clear what the term "concerning conventional oil and gas wells" means or how to determine whether a rulemaking undertaken by the Board must comply with this requirement. It is not clear if this term is limited to regulation of (1) the well bore itself; (2) the well bore and the activities on the well site related to drilling, operation, plugging and restoration; or (3) the well bore, activities on the well site and all of the activities related to the development of conventional operations, including but not limited to residual waste processing, waste/water storage, well development pipelines, gathering pipelines, transmission pipelines, distribution pipelines, compressor stations, processing plants/facilities and all the equipment associated with these activities. Based on the plain language of this section, it is also not clear what "any rulemaking" means, especially relative to "concerning conventional oil and gas wells." The plain language of section 1207(b) provides no bounds on what activities are controlled by this requirement and how the Board determines whether "any rulemaking" must comply with this section.

However, Act 52 outlines the duties for both the Pennsylvania Grade Crude Development Advisory Council (CDAC) and the Department. Under section 1204(a)(5) (58 P.S. § 1204(a)(5)), CDAC has a duty to "[r]eview and comment on the formulation and drafting of all technical regulations proposed under 58 Pa.C.S." Under section 1205(1) (58 P.S. § 1205(1)), the Department is required to "consult with [CDAC] on all policies and technical regulations promulgated under Title 58 Pa.C.S. (relating to oil and gas)."

Given the vagueness in the plain language of section 1207(b), it is consistent with the Rules of Statutory Construction to look at the entirety of the statute and the consequences of a particular interpretation among other factors. See 1 Pa.C.S. §§ 1921—1922. Applying those factors here, sections 1204(a)(5) and 1205(1) provide the General Assembly's intent that the scope of Act 52 is regulations promulgated under Title 58. Again, applying those factors, this scope provides a reasonable and appropriate limit on the applicability of section 1207(b) as Title 58 contains the statutory framework for regulating the activities associated with conventional development and contains applicable cross references and exemptions to other applicable statutes.

For this reason, Act 52 does not apply to this final-form rulemaking because it is being promulgated under the APCA in Title 35 — not Title 58. Where Title 58 contains the statutory framework for the oil and gas industry, Title 35 provides the statutory framework for air quality across all industry sectors.

In addition to IRRC's comment related to Act 52, commentators claimed that the Department failed to comply with sections 1204 and 1205 of Act 52 because the Department did not consult with CDAC in the development of this final-form rulemaking. As discussed above, CDAC's duty to review and comment and the Department's duty to consult with CDAC applies to policies and regulations promulgated under the authority of Title 58. See 58 P.S. §§ 1204(a)(5), 1205(1). Unlike section 1207(b), it is clear from the plain language of Act 52 that CDAC's and the Department's duties apply to policies and regulations promulgated under Title 58. This final-form rulemaking is not being promulgated under Title 58. It is being promulgated under the authority of the APCA in Title 35. Therefore, the language in Act 52 does not provide CDAC with the authority to review the Department's air quality regulations promulgated under Title 35 or obligate the Department to consult with CDAC in the development of air quality regulations promulgated under Title 35.

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 asks the Board to clarify which provisions, if any, apply to the conventional oil and gas industry.

In response, the Board explains that this final-form rulemaking controls harmful VOC emissions from five specific categories of air emission sources as required by the EPA. These source categories include storage vessels in all segments of oil and gas operations except natural gas distribution, natural gas-driven continuous bleed pneumatic controllers, natural gas-driven diaphragm pumps, reciprocating and centrifugal compressors, and fugitive emissions components. These sources are the same pieces of equipment irrespective of whether they are used by owners or operators in the unconventional or conventional oil and natural gas industry. Some conventional owners or operators may need to implement control measures if they own or operate regulated sources emitting above the VOC emission threshold. The EPA did not distinguish between unconventional and conventional sources of emissions in the 2016 O&G CTG, and the Department does not have the authority to exempt sources from Federal requirements.

To clarify regarding the conventional industry's understanding of the applicability of this final-form rulemaking, while not required to consult with CDAC, at the January 24, 2019 CDAC meeting, the Department reported to CDAC that this rulemaking was in the proposed stage. The Department also noted that most of the potentially regulated sources used by owners or operators in the conventional oil and gas industry would likely be exempted from implementing the proposed rulemaking control measures, because these sources tend to emit VOC emissions at levels well below the proposed thresholds requiring VOC emission controls. However, the Department did not state that this rulemaking would not apply to sources used in the conventional oil and gas industry.

In terms of whether this final-form rulemaking applies to the conventional industry, based on information from the Department's oil and gas production database, 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-form 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.

To the extent that this final-form rulemaking applies to the conventional industry, the owners or operators are required to confirm this applicability determination.

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 the final-form rulemaking. IRRC asks the Board to explain how it will proceed if there are significant changes made to 2016 O&G CTG or Subparts OOOO 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 the final-form 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 asks the Board to explain, in the Preamble to the final-form regulation, how "existing" will be interpreted under this chapter.

In response, the Board revised 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 proposed to 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 replaced 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 clarified 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 removed 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 revised 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 **<u>of a leak</u>**…”

In response, the Board revised subparagraph (i) of the definition of “*Leak*” from proposed to 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 clarified 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 **<u>of a leak</u>**…” to the definition as suggested by the commentators in accordance with section 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 removed 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 added 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 be included by reference in § 129.122(a). In response, the Board removed the references to "conventional well" and "unconventional well" from § 129.123(a) from proposed to final-form rulemaking. Section 129.123(a) was the only section that included the terms "conventional well" and "unconventional well" in the proposed rulemaking. Since the terms were removed, the Board determined that there was no need to add the reference to the definitions in 25 Pa. Code §§ 78.1 and 78a.1. As explained in other responses, the Board is not regulating conventional or unconventional wells in this final-form rulemaking. Additionally, the Board revised § 129.123(a) to reflect the Department's analysis which shows that it is cost-effective for the owner or operator of a storage vessel to control by 95% those storage vessels with a potential to emit 2.7 TPY or greater VOC emissions and that it is not necessary to include requirements based on where that storage vessel is installed.

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 revised § 129.123(a)(2)(i) at 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 was 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 the final-form regulation 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% 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 retained 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 added 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 subparagraph (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) on proposed.

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 subparagraph and revise, if necessary. In response, the Board has revised the language of § 129.129(b)(5)(ii) from proposed to 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 revised the language of § 129.129(c)(1)(ii) from proposed to 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 revised the language of § 129.130(d)(1) from proposed to 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 the final-form regulation or remove this statement if one does not exist.

In response, the Board revised 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 removed 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 section 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 deleted 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 revised § 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 5(a)(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 proposed control measures could reduce VOC emissions by as much as 12,068 TPY. Approximately 714 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 proposed VOC emission reduction measures would also assist the Commonwealth in reducing the levels of ozone precursor emissions that contribute to potential nonattainment of the 2015 ozone NAAQS. As a result, the VOC emission control measures are reasonably necessary to attain and maintain the health-based and welfare-based 8-hour ozone NAAQS in this Commonwealth and to satisfy related CAA requirements. 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 co-benefit, 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 221,066 TPY with 41 TPY from the installation of controls for storage vessels, 175,171 TPY from pneumatic controllers, 135 TPY from pneumatic pumps, 1,172 TPY from replacement of reciprocating compressor rod packings at well sites, and 44,547 TPY from fugitive emissions components through the performance of LDAR inspections. Approximately 11,913 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 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 Pennsylvania 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 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 31,270 facilities with storage vessels from the Department's databases. There are 18 facilities with 51 storage vessels that emit 2.7 TPY or more of VOC with a total industry cost of $556,359 per year. The Department estimates that implementation of the final-form control measures could reduce VOC emissions by as much as 282 TPY from the installation of controls for storage vessels. This results in an average cost of approximately $1,973 per ton of VOC emissions reduced per year. Approximately 18 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 31,134 facilities with an estimated 34,856 affected pneumatic controllers. The total industry cost is $12,085,272 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 9,102 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% 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 a 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 3 gathering and boosting stations reporting at least 7 turbines and 2 processing plants reporting at least 2 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% 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 a well site is $1,318, to conduct quarterly LDAR inspections at a 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 well site. The annual cost, in 2021 dollars, for implementing a quarterly LDAR inspection program is $6,723 at a well site and $13,447 for a gathering and boosting station or natural gas processing plant. It should be noted that the estimates for 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 31,149 facilities including 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 37 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 $62,192 reducing VOC emissions by approximately 136 TPY for a total cost per ton of VOC reduced of $457. The 136 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 1,525 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 $10,253,276 reducing VOC emissions by approximately 1,163 TPY. The Department has determined this requirement to be cost-effective since the annualized cost is only $6,723 per year. Approximately 291 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 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 $5,042 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 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 $3,361 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 $18,576,941 in 2021 dollars. The Department estimates that the final-form control measures could reduce VOC emissions by 2,616 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-form rulemaking will cost affected owners or operators approximately $31.7 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 $20.3 million, resulting in a total net cost of approximately $11.4 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. 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 25 Pa. Code § 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. If published as a final-form 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(a) of the Regulatory Review Act (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 Regulatory Review Act, 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(j.2) of the Regulatory Review Act (71 P.S. § 745.5a(j.2)), on DATE, 2022, this final-form rulemaking was deemed approved by the House and Senate Committees. Under section 5.1(e) of the Regulatory Review Act, IRRC met on DATE, 2022, and approved this final-form rulemaking.

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), known 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—129.131 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.)

(b) The Chairperson of the Board shall submit this final-form regulation 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 regulation to IRRC and the House and Senate Committees as required by the Regulatory Review Act (71 P.S. §§ 745.1—745.14).

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

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

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

PATRICK McDONNELL,
Chairperson