MARCELLUS
SHALE COALITION™

July 27, 2020

The Honorable Patrick McDonnell, Chairman
Environmental Quality Board
16th Floor Rachel Carson State Office Building
400 Market Street
P.O. Box 8477
Harrisburg, PA 17105-8477

Re: Proposed Rulemaking – 25 Pa. Code § 121.1 and §§ 129.121 to §129.130 - Control of VOC Emissions from Existing Oil and Natural Gas Sources (#7-544); submitted electronically via https://www.ahs.dep.pa.gov/eComment/ and RegComments@pa.gov

Dear Chairman McDonnell:

The Marcellus Shale Coalition (MSC), a regional trade association with a national membership, hereby submits the following comments to the Pennsylvania Department of Environmental Protection (PADEP or Department) regarding PADEP's proposed Existing Source Regulations affecting the Oil & gas Industry titled "Control of VOC Emissions from Oil and Natural Gas Sources." The MSC was formed in 2008 and is comprised of approximately 150 producing, midstream, transmission and supply chain members who are fully committed to working with local, county, state and federal government officials and regulators to facilitate the development of the natural gas resources in the Marcellus, Utica and related geological formations. Our members represent many of the largest and most active companies in natural gas production, gathering, processing and transmission, in the country, as well as the suppliers and contractors who work with the industry.

The MSC understands that this rulemaking is a response to the Control Technique Guidelines (CTGs) issued by the United States Environmental Protection Agency (USEPA) on October 27, 2016. However, the MSC is concerned that PADEP is exceeding the scope of the CTG's by drafting regulations that more closely align with permit requirements using Best Available Technology (BAT) determinations rather than the Reasonably Available Control Technology (RACT) determinations required by this type of rulemaking. In addition, it is the opinion of MSC that existing source regulations should not be more stringent than those for new and modified sources due to the difficulty and cost-prohibitive nature of implementing more stringent control requirements, designed for newer sources, on existing equipment.

As noted in USEPA's Memorandum of October 20, 2016 regarding Implementing Reasonably Available Control Technology Requirements for Sources Covered by the 20 I 6 Control Techniques Guidelines for the Oil and Natural Gas Industry, the USEPA has defined 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. The General Preamble Supplement (September 17, 1979, 44 FR 53761) goes on to indicate that RACT for a particular source is determined on a case-by-case basis, considering the technological and economic circumstances of the individual source. In evaluating economic feasibility for RACT determinations, the USEPA gives significant weight to economic efficiency and relative cost effectiveness. The USEPA has not established universal decision criteria for technological and economic feasibility that would apply in every case and did not establish decision rules that would have restricted the cost consideration in determining whether a emissions control is considered "cost effective." Therefore, all RACT determinations are considered case-by-case determinations.

The Oil and Gas CTG contains recommended controls that States may readily adopt, subject to USEPA approval, for groups of covered sources. However, a state may also consider the uniqueness of a specific source's operations in evaluating whether the recommended controls are RACT for that source. The air agency should provide USEPA with the information supporting the source-specific determination of RACT for each source. This demonstration should consider cost effectiveness. Where the USEPA determines that the air agency has shown that an alternative to the controls recommended in the CTG satisfies the requirements for RACT, the USEPA will propose to approve the RACT demonstration.

PADEP's RACT evaluations for the control recommendations, which are more restrictive than the CTG recommendations, do not provide a clear economic analysis supporting these recommendations. The recommendations also do not provide the additional Volatile Organic Compound (VOC) reductions for these sources as a result of the controls.

The benefits of the proposed rulemaking are described in terms of total statewide reductions. Additional detail is needed on a control basis. One significant portion of the evaluation should detail how the significant variation of VOC concentrations in the natural gas in different areas and market sectors impact these evaluations.

Additionally, the MSC is concerned that the stated benefits to the oil and gas industry are overstated. Specifically, in calculating approximately $9.9 million in benefits from the value of natural gas that is saved during the production and processing phases, the Department acknowledges that this benefit is based upon the value of natural gas in 2012. This is an inappropriate dollar figure upon which to base the value of natural gas in 2020, and it is unclear why the Department chose this figure. Indeed, the value of natural gas has plummeted in recent years in Pennsylvania and across the nation. For example, in 2012 the NYMEX price of natural gas averaged $2.79/MCF; however, in 2020 the NYMEX average price to date is $1.79, or approximately 35% lower. Moreover, due to constrained markets and the lack of pipeline capacity to reach market, many Pennsylvania producers receive on average only 70% - 80% of the national NYMEX price of natural gas. The MSC requests that the Department recalculate the cost of compliance and value of benefits of saved natural gas based on more relevant dollar figures than those included in the current Regulatory Analysis Form.

The MSC is concerned that PADEP has not considered in its RACT evaluation that many of the potential sources operate in areas where the VOC concentration of the gas is extremely low. In some regions this concentration may be less than 1 percent by weight (wt%) and will have a significant impact on the economic feasibility of the proposed VOC controls. The MSC welcomes the opportunity to discuss this concern in greater detail so that its implications are fully understood by the Department.

In the preamble, PADEP indicates the RACT determination was developed to maintain consistency with the requirements of the General Permit 5 and 5a, as well as preventing backsliding from Best Available Technology (BAT). However, no specific evaluation was completed to determine whether those controls are "reasonably available", or "technically and economically feasible" compared to the requirements of the CTG.

PADEP has noted the anticipated reduction in VOC emissions and the co-benefit related to the reduction of methane emissions. However, it has failed to elaborate on the significance of those reductions as they relate to location or industry sector. For example, the transmission sector is being treated the same as similar sources in high VOC gas areas.

The MSC notes that the lack of this information makes it difficult to provide complete comments on the control requirements that exceed those required by the CTG's, especially in locations where the VOC content of the gas is less than 1% by weight and for sectors with low VOC emissions, specifically from storage vessels, pneumatic controllers, pneumatic pumps and/or fugitive components. The MSC has attached more specific comments and suggestions from its review of the proposed existing source regulation for the oil and gas industry.

The MSC remains committed to working with the Department to ensure a reasonable and predictable permitting and compliance process is in place that meets the needs of both the industry and the Department, while ensuring protection of the Commonwealth's air resources.

Thank you for your consideration of these comments. Please do not hesitate to contact me if you have any questions or desire additional clarification.

Sincerely,

Jim Welty
Vice President, Government Affairs

Marcellus Shale Coalition
Comments on
Proposed Rulemaking – 25 Pa. Code § 121.1 and §§ 129.121 to §129.130 - Control of VOC Emissions from Existing Oil and Natural Gas Sources (#7-544)

July 27, 2020

Preamble

1) The support document for the rule has not been made available to the public; as such, there is no way to comment on how compliance requirements were determined for various sources. MSC requested via email on June 9th and June 30th, 2020 for the Department to provide the support document but never received a response. Additionally, the Department's own Air Quality Technical Advisory Committee (AQTAC) also made this same request, without receiving the requested document or justification data. In a related note, on page 2636 of the preamble to the proposed rule the Department states "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." This contention is inconsistent with the way that RACT is intended to be applied to emissions sources; the stated purpose of the rule on page 2633 is to reduce VOC emission, and the Department is clearly stating that in many cases, specific VOC emissions rates are not considered prior to assigning control requirements to a source category (and thus no cost analyses in terms of $/ton of VOC removed). If compliance requirements which are more stringent than what USEPA has proposed in the CTGs are being considered, the Department needs to show justification in terms of cost analysis for those requirements; the "Compliance Costs" section of the preamble includes some information on equipment costs but nothing on how they correspond to VOC emissions rate reductions. Otherwise, many operators will be forced into costly compliance requirements with minimal VOC related environmental benefit (i.e. negligible reduction of VOCs). The MSC requests an extension to the comment period that would extend 30 days following the release of the technical support document.

General Provisions

1) § 129.121(a) – Since this is an "existing" source rule, it should apply to sources not covered by other rules and regulations that cover "new" sources. The fact that the effective date is proposed to be the date the final rule is published in the PA Bulletin (as also stated on page 2633) means that any source listed in § 129.121(a)(1)-(5) that is in existence on or before the publication date of this rulemaking will be subject to the rule. This would result in facilities being subject to these existing source rules as well as other authorization mechanisms such as the GP5, GP5A, and Exemption #38, resulting in inconsistent and/or potentially conflicting requirements. The MSC requests that PADEP remove applicability for facilities and sources constructed after August 23, 2011, the applicability date for the NSPS OOOO. In addition, the MSC recommends clarification for how "existing" vs "new" will be determined for facilities that have initiated construction, but are not yet in operation on the effective date of the rule (i.e. what does "in existence on or before" the effective date of the rule mean).

   Also, the MSC requests that the effective date of the rule be at least 60 days from the date of publication of the final rule, to allow for an appropriate transition period, since there may still be changes between the proposed rule and the final rule. Facilities should not be required to immediately implement new requirements which they may not have seen in final form until the publication date.

2) §129.121(a)(2) – This rule should only be applied to continuous high-bleed natural gas driven pneumatic controllers as recommended in the CTG and should specifically state that the requirements are not applicable to low-bleed and intermittent controllers. Of note is that OOOOa requires natural gas continuous bleed pneumatic controllers to be "low-bleed" controllers with a bleed rate not to exceed 6 standard cubic feet per hour (scf/hr)) or, for natural gas processing plants, 0 scf/hr. That is, for natural gas processing plants, pneumatic controllers are to operate by a means other than natural gas, such as, compressed instrument air.

3) §129.121(b) – Many facilities have recently completed case by case RACT evaluations. This section provides them relief from proposed requirements only where they are subject to "more stringent requirements". Additional relief should be added to permit demonstration of equivalency of the requirements and/or an opportunity to demonstrate technical or economic feasibility based upon their current permit which is based upon the case by case RACT evaluation. Where the proposed controls are required, PADEP should consider additional time for these facilities to meet the final requirements.

Definitions

1) "*Completion combustion device*" definition

   a. The term "completion combustion device" is not used anywhere in sections § 129.121 or § 129.123 to § 129.130 of the proposed rule, so this definition is not necessary for purposes of this rulemaking and should be deleted. The only other place where the term is used is in the definition of "Flare," but that reference is also unnecessary in the context of this rule and should be deleted.

      However, if retained:

   b. Subparagraph (ii) of this definition specifically includes "pit flares," but the definition of "Flare" specifically excludes a "completion combustion device," which appears to be a conflict between those two definitions. Also, subparagraph (i) of this definition would seem to include any type of flare, but again, the definition of "Flare" specifically excludes a "completion combustion device," which appears to be a potential conflict between those two definitions.

      In addition, subparagraph (i) of this definition uses the terms "exploration," "production," and "completions," none of which are defined terms for purposes of this rule. Because "completions" is generally considered a separate phase in the life of a well from "exploration" or "production," if the defined term "completion combustion device" is retained in this rule, suggest that subparagraph (i) be revised to read:

      i. *"(i) An ignition device, installed horizontally or vertically, used ~~in exploration and production operations~~ to combust otherwise vented emissions from the* *completions phase of a well."*

2) "*Compressor station*" definition – It is not clear whether there is an intentional distinction between the defined term "Compressor Station" and the defined term "Gathering and Boosting Station." The definitions of those two terms are similar, but not identical. The only place in these rules where the term "compressor station" is used is in the definition of "natural gas transmission and storage segment," which is, by definition, limited to transportation between natural gas processing plants and the distribution segment. As such, it is unclear why "gathering" is included in the "compressor station" definition since that term is only used in these rules in the context of the "natural gas transmission and storage segment" definition. The MSC urges the Department to clarify these definitions and determine if each definition is needed in the rulemaking.

3) "*Connector*" definition – The reference to "pipeline(s)" in subparagraph (i) of the proposed definition would seem to be more appropriately referred to as "pipe(s)" as shown below:

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

4) "*Deviation*" definition – Subparagraph (iii) of this definition includes failing 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 Failure to meet a limit or standard should not be considered a deviation if it is in compliance with the rules.

5) "*First attempt at repair*" definition – It is not clear why this definition refers broadly to "organic material" when this rule is specifically applicable to "VOC's." Suggest replacing "organic material" in this definition with "VOCs" as shown below:

    a. *"First attempt at repair—Action taken for the purpose of stopping or reducing leakage of VOC's ~~organic material~~ to the atmosphere using best practices."*

6) "*Flare*" definition – Consistent with the comment above at the definition of "Completion Combustion Device," suggest deleting subparagraph (ii) of the "Flare" definition which refers to a "completion combustion device." The term "completion combustion device" is not used anywhere in sections § 129.121 or § 129.123 to § 129.130 of these rules, so it is unnecessary to refer to that term in the "Flare" definition for purposes of this rule.

7) "*Flow line*" definition – The only place in these rules where the term "flow line" is used is in the definition of "Wellhead," to help define the limits of what constitutes the wellhead. Within this definition, the reference to a pipeline used to transport oil or gas to a "processing facility" is somewhat unclear, since what constitutes a "processing facility" is not defined, and flow lines could transport to other equipment such as storage or compression as well. Suggest that the terminology "processing facility" in this definition be revised as shown below:

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

8) "*Fuel gas*" definition - The term "fuel gas" is not used anywhere in sections § 129.121 or § 129.123 to § 129.130 of these rules, so this definition is not necessary for purposes of this rulemaking and should be deleted.

9) "*Fuel gas system*" definition - The term "fuel gas system" is not used anywhere in sections § 129.121 or § 129.123 to § 129.130 of these rules, so this definition is not necessary for purposes of this rulemaking and should be deleted.

10) "*GOR – Gas-to-oil ratio*" definition – **The definition does not provide sufficient clarity as to its purpose in the rule as to applicability of fugitive monitoring and recordkeeping requirements. PADEP should provide clarifications and/or allow existing sources the option to perform these requirements as described in Exemption 38(b).**

11) "*In-house engineer*" definition – The proposed definition worded as "an individual who is qualified by education, technical knowledge and experience …." does not specifically require that the engineer be an "in-house" individual. Any engineer, whether in-house or not, who is "qualified by education, technical knowledge and experience" should be eligible to perform the associated duties, so the defined term here, and in §§ 129.125(c)(3)(ii)(A) and 129.128(c)(1) where that term is used, should be changed from "in-house engineer" to "qualified engineer," as shown below:

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

12) "*Natural gas and oil production segment*" definition – This term is not used anywhere in the proposed regulations, so it should be deleted as unnecessary.

13) *"Natural gas-driven pneumatic controller" definition* – The definition does not include any mention of intermittent controllers. This needs to be included and be consistent with the GP's and the NSPS OOOOa.

14) *"Natural gas processing plant or gas plant" definition – The term "gas plant" is not used anywhere in the proposed regulations, so it should be deleted from the defined term, as shown below:*

    a. *"Natural gas processing plant"*

15) *"Natural gas processing segment" definition* – This term is not used anywhere in the proposed regulations, so it should be deleted as unnecessary.

16) *"Produced Water"* definition – The wording in this definition refers to "water that is extracted… from an oil or natural gas production well…" That wording is not entirely clear as to whether or not the definition is intended to include flowback water or any other water recovered from the well prior to the well being put into production, but as drafted would appear to exclude those pre-production waters. PADEP should clarify this definition. For consistency with federal rulemaking, the MSC recommends that PADEP utilize the same definition of "Produced Water" as USEPA utilizes:

> "Produced water means the fluid brought up from the hydrocarbon-bearing strata during the extraction of oil and gas, and includes, where present, formation water, injection water, and any chemicals added downhole or during the oil/water separation process."
>
> 40 CFR §435.33 (v)

17) *"Storage vessel"* definition – Subparagraph (iii)(C) would exclude from the definition of a storage vessel containers/tanks with a capacity greater than 100,000 gallons used to recycle water that has been passed through two-stage separation, but there is no explanation or rationale provided as to why that proposed exclusion is limited only to containers/tanks greater than 100,000 gallons capacity. As long as the contained water meets the stated condition that it has been passed through two-stage separation, there should not be a size threshold limit to the exclusion, and subparagraph (iii)(C) should be revised as shown below:

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

18) *"Transmission compression station"* definition – The term "transmission compression station" is not used anywhere in the proposed regulations. The term "transmission compressor station" is used once in the proposed regulations, in the definition of "natural gas transmission and storage segment," but nowhere else, so it is unclear this definition is even needed. However, if retained, the word "compression" in the defined term should be changed to "compressor," and subparagraph (i) of the definition related to pipelines should be deleted since the pipelines are not part of the compressor station, as shown below:

a. *"Transmission compressor ~~compression~~ station—*
~~(i) The pipelines used for the long-distance transport of natural gas, excluding processing.~~
~~(ii)~~ The term includes the land, mains, valves, meters, boosters, regulators, storage vessels, dehydrators, compressors, and their driving units and appurtenances, and equipment used for transporting gas from a production plant, delivery point of purchased gas, gathering system, storage area or other wholesale source of gas to one or more distribution areas."

19) *"VRU - Vapor recovery unit"* definition – VRU's do not route vapor back into a storage vessel, nor do they typically route vapor into a liquids line. MSC recommends replacing the definition with the following: "a device used to recover vapor and route it to a process, flow line or similar equipment".

20) *"Underground storage vessel"* definition - This term is not used anywhere in the proposed regulations, so it should be deleted.

21) *"Well"* definition – The definition of "well" includes "a hole…into which fluid is injected," which would appear to potentially include all Underground Injection Control (UIC) wells, however, the applicability language at § 129.121(a) for purposes of this rule limits applicability only to "oil and natural gas sources of VOC emissions." It is not clear whether DEP intends these rules to apply to UIC wells, and if so, whether the applicability would be limited only to UIC wells directly associated with oil and natural gas operations, such as Class II UIC wells. The applicability or non-applicability to UIC wells should be made clearer.

22) *"Wellhead"* definition – In subparagraph (iii) of this definition, the words "at the wellhead" should be inserted following "conveyance" to properly clarify and limit the scope to the actual wellhead equipment, as shown below:

    a. *"(iii) The term does not include other equipment at the well site except for a conveyance <u>at the wellhead</u> through which gas is vented to the atmosphere."*

23) *"Well site"* definition – Regarding the reference to "injection well" in subparagraph (i) of this definition, the same comment as shown above at the "well" definition calling for clarification with regard to which injection wells are considered within scope would also apply here.

Storage Vessels

1) § 129.123(a)(1)(i) – (iii) – The terms "conventional well" and "unconventional well" are not defined in § 129.122(a) or elsewhere for purposes of this rule. Suggest that definitions of each of those terms, as defined in 25 Pa. Code 78.1 and 78a.1, be included by reference in § 129.122(a).

2) § 129.123(b)(1)(iii) – This paragraph requires routing emissions to a "control device or process that meets the applicable requirements of § 129.129." While § 129.129 contains requirements specific to "control devices" it is unclear what "processes" are addressed by §129.129 or what requirements may apply to them. A clearer reference to the specific processes in §129.129 should be provided Note that this same comment/question would apply to the similar wording in § 129.125(b)(1)(ii), § 129.126(c)(2), § 129.128(a)(2)(ii), and § 129.128(b)(1).

3) §129.123(a)(2)(i) – A more accurate emissions profile could be determined by using actual storage vessel monthly throughputs for VOC potential to emit calculations. If PADEP ultimately decides to continue with this methodology, this condition must provide a time frame for maximum average daily throughput evaluations. Without a limitation on how far back an operator is required to go, the calculations would result in inaccurate emissions profiles for tanks that have been in place for a significant period of time (many of these tanks may have begun production as far back as 2012, or earlier). Ideally the maximum daily average throughput should be based on recent data (i.e. the prior twelve months), not outdated throughputs prior to well decline or other operational changes that would cause inaccurate results.

4) §129.123(a)(2)(ii) - The potential to emit calculations should include the emissions reductions required under Exemption 38, not just those in Plan Approvals and/or Operating Permits.

5) §129.123(b) – The one-year deadline for control device installation will be difficult to comply with due to the problematic nature of retrofitting older sites with new controls and controller availability from manufacturers. Additional time may also be necessary to receive authorization to construct an air cleaning device and accommodate any additional Erosion and Sediment (E & S) permits necessary for the expansion of the site to accommodate any new equipment. For example, in some regional offices it can take over 200 days to obtain an erosion and sediment control permit from the Department.

6) §129.123(c) – The exemption provisions will not apply to any storage vessels since a limit cannot be obtained without approval from the department. The language needs to be revised to be applicable to existing sources with VOC emissions at, or above, thresholds for applicability.

7) 7) §129.123(c)(2)(i) – To accurately estimate actual tank emissions, monthly VOC emissions estimates should be based on the actual monthly tank throughputs, not the highest average daily throughput. Using the highest average daily throughput will result in an overly-conservative (i.e. incorrect) monthly throughput volume and inaccurate actual emission estimates. In addition, it is not necessary to separate calculations by a certain number of days. However, as long as the data used in the calculations is correct, the timing of the calculation is irrelevant. If the maximum interval concept is retained, it should be changed to "not more than 45 days" to avoid forcing the calculations to be performed earlier in months as time goes on.§ 129.123(c)(2)(i)(A) – The maximum timeframe between calculations should be extended from 30 days to 45 days. Setting an arbitrary 30-day standard will ultimately lead to unmanageable scheduling and duplicate compliance activities being performed in the same month.

8) §129.123(c)(2)(iii) – Fracturing, or refracturing, a well should not, by itself, result in control requirement applicability. Fracturing and refracturing does not automatically cause storage vessel throughputs and/or emissions to increase beyond those determined during the original facility design. Control requirements should only be applicable if a facility undergoes a significant modification that results in emissions increases above the original potential to emit determination.

Pneumatic Controllers

1) §129.124(c) – PADEP should consider the varying regional VOC content of the gas across the Commonwealth to determine appropriate and accurate cost and efficiency associated with emissions reductions.

2) §129.124(d) – This requirement reads that all pneumatic controllers (possibly thousands per operator) must be tagged; however, tagging requirements for natural gas driven pneumatic controllers should be limited to continuous high-bleed natural gas driven pneumatics. Tagging of low-bleed and/or intermittent pneumatic controllers will not provide any environmental benefit and will be cost-prohibitive. It's not entirely clear whether the reference to each "affected" pneumatic controller in this paragraph means all natural-gas driven pneumatic controller regardless of emission rates, or only those that have not yet met the emission limitations in paragraph (c). Since the primary purpose of paragraph (d) is to tag controllers with the date that it is required to comply, it would be appropriate to only

require tagging of those existing controllers that do not yet meet the paragraph (c) requirements consistent with the requirements of the NSPS OOOO and OOOOa.

3) §129.124(e) - Reporting should be limited to continuous bleed natural gas-driven pneumatic controllers that do not comply with the applicable standard of 6 scfh.

Pumps

1) § 129.125(b)(1)(ii) – This paragraph requires routing emissions to a "control device or process that meets the applicable requirements of § 129.129." However § 129.129 only appears to contain requirements specific to "control devices" and nothing specific to "processes," so it is unclear whether "processes" must somehow meet certain § 129.129 "control device" requirements, or if the proper reading of this paragraph is simply that are no "applicable" § 129.129 requirements for "processes." Please refer to the recommendation on "processes" included in the comments to § 129.123(b)(1)(iii).

Compressors

1) §129.126(a)(1) – To ensure consistency with the CTG's, this section should state that any reciprocating compressor located at a well site and servicing more than one well site is not a source subject to VOC requirements under this rule.

2) §129.126(b)(1)(i)(B) – MSC understands that this section implies that rod packing must be replaced prior to the effective date of the rule. However, for practical implementation, the rule should incorporate typical requirements that allow for sufficient time following the effective date of a regulation for its implementation, that is, for replacement of rod packing.

3) § 129.126(b)(2) – As proposed, this paragraph would only allow routing emissions from a reciprocating compressor to a "process" and would not allow routing to a "control device." Routing to a "control device" should be an allowable option here, the same as is allowed for centrifugal compressors, storage vessels, and natural gas-driven diaphragm pumps, and for consistency with § 129.129(a) which includes this paragraph § 129.126(b)(2) in the applicability for control devices and in the § 129.129(a)(2) language. The suggested revision to § 129.126(b)(2) is shown below:

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

4) § 129.126(c)(2) – This paragraph requires routing emissions to a "control device or process that meets the applicable requirements of § 129.129." However § 129.129 only appears to contain requirements specific to "control devices" and nothing specific to "processes," so it's unclear whether "processes" must somehow meet certain § 129.129 "control device" requirements, or if the proper reading of this paragraph is simply that are no "applicable" § 129.129 requirements for "processes." Please refer to the recommendation on "processes" included in the comments to § 129.123(b)(1)(iii).

Fugitive Emission Components

Stakeholders never received a copy the technical support document to review during comment development. The reduction and cost numbers referenced in the preamble are inconsistent with those determined in the CTGs, and in many cases, simply do not make sense. Without a thorough understanding of the calculations and where the numbers came from, it is impossible to effectively comment on this proposal. As stated previously, both the AQTAC and MSC requested this document in May and June but received no response from the PADEP.

This is not the first time the Department has proposed a comprehensive air quality rulemaking yet failed to provide the technical support document during the public comment period. This document provides the calculations, methodology and other detailed information that form the foundation for and justification of the PADEP rulemaking. This information should be provided to all stakeholders, as well as the Independent Regulatory Review Commission and legislative committees, during the public comment period so that stakeholders in the rulemaking process can provide informed feedback on the proposal.

1) § 129.127(a)(1) – This paragraph contains an applicability threshold of 15 barrels of oil equivalent per day, "on average," but it isn't clear over what period of time the "average" must be determined. Is that per day average production figure to be determined over a month, a year, or what timeframe?

2) §129.127(b)(1)(ii)(A) – Monthly AVO inspections for existing sources is beyond the scope of the current CTG, and PADEP has not demonstrated economic feasibility of such controls in reducing VOC emissions from existing sources. This should be eliminated.

   Furthermore, placing an arbitrary 30-day maximum separation deadline for any compliance activity is inconsistent with the New Source Performance Standard (NSPS) OOOOa and will create a scenario that will lead to unmanageable scheduling with a greater likelihood of non-compliance. MSC's goal remains compliance with all regulatory requirements and is seeking the Department's assistance with achieving this goal by not setting an arbitrary, unobtainable deadline.

   Setting an arbitrary 30-day standard will lead to duplicate compliance activities being performed in the same month in order to demonstrate compliance. MSC supports a minimum deadline of generally about 50% longer than the defined period (such as, 45-days for monthly, 9-months for semi-annual requirements, 18_months for annual requirement, etc.). Any monthly inspections required by this rule should be required to be separated by at least 15 calendar days, but no more than 45 days. **This comment is applicable throughout the rule: all compliance timelines must be revised consistently in order for operators be able to comply with them in a reasonable manner.**

3) §129.127(b)(1)(ii)(B) – Quarterly Leak Detection and Repair (LDAR) inspections for existing producing well sites is beyond the scope of the current CTG. Furthermore, PADEP has not shown it to be technically feasible, and therefore it should be eliminated from this rulemaking. MSC operators have submitted data to the Department which demonstrates conclusively that annual LDAR surveys are effective in reducing leaks well below proposed off-ramp thresholds, and there will not be any significant emissions reductions resulting from the implementation of quarterly, or even semi-annual frequency. In addition, quarterly inspections are significantly more restrictive than what was

recommended in the USEPA CTGs and the off-ramps provide little if any relief for most operators as they create scheduling conflicts and overwhelming recordkeeping burdens.

The MSC believes that the LDAR requirements from Exemption #38b should be the template for the existing source rule as they will offer an environmentally beneficial and practical option for leak detection. The benefits of LDAR survey frequencies more stringent than annual have not been proven and are not economically feasible for sources constructed prior to August 10, 2013. The MSC has provided data to PADEP on two occasions demonstrating annual leak rates from existing sources are well below the step-down thresholds provided in the draft rule. Furthermore, the initial compliance period should be longer than 60 days. We recommend the initial compliance period be extended to 120 days. There are numerous sites already required to perform LDAR inspections on a periodic basis and these initial existing source surveys will interfere with those facilities already on the schedule.

Any required quarterly LDAR surveys should be separated by at least 60 days, but no more than 120 days. Any required semi-annual LDAR surveys should be separated by at least 120 days, but no more than 240 days.

4) § 129.127(b)(2)(i) – Consistent with the comment above to change the quarterly LDAR monitoring to annual, the reduced frequency allowed by this paragraph should be changed from annual to every two years, as shown below:

   a. *"(i) If the percentage of leaking components is less than 2% for two consecutive ~~quarterly~~ <u>annual</u> inspections, the owner or operator may reduce the LDAR inspection frequency to biennially ~~semiannually~~ with inspections separated by at least <u>15 months</u> ~~120 calendar days~~ but not more than <u>27 months</u> ~~180 calendar days~~."*

5) § 129.127(b)(2)(i) – DEP should clarify that the allowance under this paragraph to reduce the inspection frequency when the leak rate is less than 2% for two consecutive inspections <u>does not require the owner or operator to request that extended inspection interval under paragraph § 129.127(e)</u>.

6) § 129.127(c)(2) – The requirement in this paragraph to perform an LDAR inspection on a shut in well by the date of the next required LDAR inspection would seemingly require LDAR inspections of wells even while they are shut in. This section needs to be amended to read, *"The date of the next required LDAR inspection <u>after the well is put into production</u>,"* similar to the wording in §129.127(c)(1).

7) § 129.127(d)(1) – Monthly AVO inspections should not be required, and we suggest removing this paragraph entirely.

   However, it if is retained, the maximum timeframe between inspections should be extended from 30 days to 45 days. Setting an arbitrary 30-day standard will ultimately lead to unmanageable scheduling and duplicate compliance activities being performed in the same month.

8) § 129.127(d)(2) – Consistent with comments above, the maximum timeframe between inspections here should be extended from 90 days to 120 days. Setting a 90-day standard will ultimately lead to

unmanageable scheduling and duplicate compliance activities being performed in the same quarter.

9) § 129.127(d)(2) – There should be an allowable step-down provision for reducing the frequency of LDAR inspections at gathering and boosting stations (in this case from quarterly to semi-annually) for leak rates less than 2%, similar to the provisions in § 129.127(b)(2) for well sites. This should be accomplished by inserting a new paragraph § 129.127(d)(3) with those step-down provisions for leak rates less than 2%, and then returning to the original frequency if leak rates exceed 2%.

10) §129.127(f) – The MSC believes it would be beneficial to streamline the fugitive monitoring plan. MSC is aware that this is being reconsidered at the federal level and many of these components are overly burdensome with no additional environmental benefit.

11) §129.127(f)(10)(iii) – See comment 2 in this section concerning compliance "deadlines." Consistent with comments above that the maximum timeframe between inspections should be generally 50% longer than the defined period, the maximum of "12 months apart" in this paragraph should be changed to "18 months apart"

12) §129.127(g)(2) – Daily verification checks on Optical Gas Imaging (OGI) and/or Method 21 analyzers is only practical if the equipment is being used daily. Per manufacturer recommendation, verification checks should be performed prior to use, not necessarily daily.

13) §129.127(g)(3) – Maximum viewing distance is variable and will change based on ambient conditions, location and operator. MSC requests that this requirement be removed.

14) §129.127(g)(4) – OGI camera operators are trained to operate the camera when leaks can be detected. Furthermore, increased wind speed may or may not affect the accuracy of the readings depending on the operator, distance from the component, other ambient conditions and the spatial relationship of the component being observed to other nearby equipment. The camera operators are trained to understand these variables and to take appropriate action. MSC requests that this requirement be removed.

15) § 129.127(g)(5) – The wording in this paragraph that refers to "conducting the survey that determines…" is unclear and confusing. What "survey" is that referring to and how would it be performed? It would seem clearer, and more consistent with the language used in paragraphs (g)(4) and (5). if that sentence were revised as shown below:

   a. *"(5) ~~Conducting the survey that determines~~ <u>Determining</u> how the equipment operator will perform the following:"*

16) General – operators will have in many cases been performing LDAR (including annual, semi-annual or even quarterly) on these sources for years at the point that the proposed rule becomes effective. The rule currently and reasonably includes a step-down provision from well site facilities which show a low fraction of leaking components, yet there is currently no provision to utilize historical LDAR data (which would have likely been performed in accordance with the Department's own requirements, such as Exemption 38). MSC requests that the Department include a provision to allow the utilization of historical LDAR data to immediately utilize the step-down provision to a semi-annual or annual frequency. Otherwise, operators will be burdened with completing thousands of additional LDAR

surveys on facilities with a history of minimal leaks at no environmental benefit but at great cost and effort.

Covers and Closed Vent Systems

1) § 129.128(a)(2)(ii) – This paragraph refers to routing emissions to a "control device or process that meets the applicable requirements of § 129.129." However § 129.129 only appears to contain requirements specific to "control devices" and nothing specific to "processes," so it's unclear whether "processes" must somehow meet certain § 129.129 "control device" requirements, or if the proper reading of this paragraph is simply that are no "applicable" § 129.129 requirements for "processes." Please refer to the recommendation on "processes" included in the comments to § 129.123(b)(1)(iii).

2) § 129.128(a)(4) – The maximum timeframe between inspections should be extended from 30 days to 45 days. Setting an arbitrary 30-day standard will ultimately lead to unmanageable scheduling and duplicate compliance activities being performed in the same month.

3) § 129.128(b)(1) – This paragraph refers to routing emissions to a "control device or process that meets the applicable requirements of § 129.129." However § 129.129 only appears to contain requirements specific to "control devices" and nothing specific to "processes," so it's unclear whether "processes" must somehow meet certain § 129.129 "control device" requirements, or if the proper reading of this paragraph is simply that are no "applicable" § 129.129 requirements for "processes." Please refer to the recommendation on "processes" included in the comments to § 129.123(b)(1)(iii).

4) §129.128(b)(2)(ii) & §129.128(d) – The "no detectable emissions" requirements should allow for OGI technology to be used and should also have a consistent monitoring schedule with the facility's normal LDAR program. Different survey schedules for these very similar activities can create scheduling difficulties, which will lead to significant economic impacts with no foreseeable environmental benefit. In many cases, these components are already included in the normal OOOOa LDAR program, which allows the use of OGI technology. Furthermore, Method 21 may not be practical, safe, or even possible, in some locations where these requirements are applicable due to height and inaccessibility (for example, across the tops of large storage tanks).

   Any required quarterly LDAR surveys should be separated by at least 60 days, but no more than 120 days. Any required semi-annual LDAR surveys should be separated by at least 120 days, but no more than 240 days.

   The inspections for closed vent systems should be changed from quarterly to annual, consistent with the comment above regarding LDAR inspection intervals for well sites.

   "(ii) Conducting a no detectable emissions <u>or no visible leak</u> inspection as specified in subsection (d) within 30 days after _____ (Editor's Note: The blank refers to the effective date of this rulemaking, when published as a final-form rulemaking.), with ~~quarterly~~ <u>annual</u> inspections separated by at least <u>9 months</u> ~~60 calendar days~~ but not more than <u>18 months</u> ~~90 calendar days~~."

5) § 129.128(b)(4)(ii)(B) - The maximum timeframe between inspections should be extended from 30 days to 45 days. Setting an arbitrary 30-day standard will ultimately lead to unmanageable scheduling and duplicate compliance activities being performed in the same month.

6) §129.128(c) – The closed vent system design and capacity assessments are unnecessary. MSC believes that issues with design and capacity will be revealed during the leak surveys and/or control equipment manufacturer design specifications and that this requirement can be met via these alternative methods.

7) § 129.128(d) – Consistent with the comment above at § 129.128(b)(2)(ii), this paragraph (d) should also allow for and address OGI procedures by amending the introductory paragraph of (d) and (d)(1) as shown below:

   a. *"(d) No detectable emissions and no visible leak procedures. The owner or operator shall conduct the no detectable emissions test procedure under Section 8.3.2 of EPA Method 21 or no visible leak test procedure using OGI equipment.*

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

      (i) Use a gas leak detection instrument that meets § 129.127(h) or OGI equipment that meets § 129.127(g).

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

Control Devices

This section should not contain requirements more restrictive than those found in the NSPS OOOOa.

1) § 129.129(b)(2) – The maximum timeframe between inspections should be extended from 30 days to 45 days. Setting an arbitrary 30-day standard will ultimately lead to unmanageable scheduling and duplicate compliance activities being performed in the same month.

2) § 129.129(b)(3) – Not all control devices operate with a pilot flame, so this paragraph should be modified by wording such as "where applicable" at the beginning, as shown below:

   a. *(3) Where applicable, ~~M~~maintain a pilot flame while operating the control device and monitor the pilot flame by installing a heat sensing CPMS as specified under subsection (m)(3)."*

3) §129.129(b)(4) – This section should incorporate an exemption for facilities that utilize combustors that only operate intermittently based on pressure switches that are activated by pressure buildups. Once the set point is reached the combustor will ignite only long enough to burn off enough pressure to lower the tank pressure to below the set point. These combustor design systems will rarely, if ever, operate continuously for a 15-minute period.

4) § 129.129(b)(4)(i) – The maximum timeframe between tests should be extended from 30 days to 45 days. Setting an arbitrary 30-day standard will ultimately lead to unmanageable scheduling and duplicate compliance activities being performed in the same month.

5) § 129.129(b)(5)(ii) – The reference to an "inspection and maintenance plan of paragraph (1)" in this paragraph should be deleted, as shown below, because paragraph (1) does not require or refer to an "inspection and maintenance plan:"

   a. **a.** *(ii) The best combustion engineering practice* <u>*applicable to*</u> ~~*outlined in*~~ *the control device* ~~*inspection and maintenance plan of paragraph (1)*~~*."*

6) §129.129(c)(1)(i) – A Continuous Parameter Monitoring System (CPMS) requirement is far too restrictive for existing sources. Engineering calculations performed during the equipment/facility design phase should satisfy concerns relating to inlet flow. Requirements such as this could mean extensive design and retrofitting for existing older equipment, which is more difficult to implement than when designing and building a new facility, as well as the installation of complex data acquisition systems and other technically complex and cost-prohibitive equipment.

7) §129.129(c)(2) – submitting a copy of the performance test to USEPA is something that is completed by the device manufacturer, for devices that are manufacturer-tested. Having the owner or operator re-submit the report is duplicative and serves no purpose. If a device has been approved by USEPA, the test report will have already been submitted and if approved, USEPA will publish the make and model on their continually updated list of devices (https://www.epa.gov/stationary-sources-air-pollution/performance-testing-combustion-control-devices-manufacturers).

8) §129.129(d)(3) – requiring an arbitrary temperature for a combustion device is not appropriate; if this requirement is to remain included it should be revised to state something like "at a minimum temperature to ensure proper combustion as demonstrated in the performance test".

9) § 129.129(f)(4)(i)(A) – The requirement in this paragraph that a thermal treatment unit have a permit or authorization by the "Department's Bureau of Waste Management" should only apply if the thermal treatment unit is located in Pennsylvania. For thermal treatment units located outside of Pennsylvania, any permit or authorization should be by the state in which the unit is located, as shown below:

   a. *"(A) A thermal treatment unit for which the owner or operator has been issued a permit or authorization by the Department's Bureau of Waste Management* <u>*if located in Pennsylvania, or if located outside of Pennsylvania, by the state in which the unit is located, in accordance with any applicable requirements of that state*</u>*."*

10) § 129.129(f)(4)(ii)(B) – The requirement in this paragraph that an industrial furnace have a permit or authorization by the "Department's Bureau of Waste Management" should only apply if the industrial furnace is located in Pennsylvania. For industrial furnaces located outside of Pennsylvania, any permit or authorization should be by the state in which the unit is located, as shown below:

a. *"(B) An industrial furnace for which the owner or operator has been issued a permit or authorization by the Department's Bureau of Waste Management if located in Pennsylvania, or if located outside of Pennsylvania, by the state in which the unit is located, in accordance with any applicable requirements of that state."*

11) § 129.129(g)(1)(i)(A) – The maximum timeframe between inspections should be extended from 30 days to 45 days. Setting an arbitrary 30-day standard will ultimately lead to unmanageable scheduling and duplicate compliance activities being performed in the same month.

12) § 129.129(g)(1)(i)(B) and (C) – The maximum timeframe between inspections in these two paragraphs should be extended from 90 days to 120 days. Setting a 90-day standard will ultimately lead to unmanageable scheduling and duplicate compliance activities being performed in the same quarter.

13) §129.129(j) – See comment 1 of this section regarding the exemption of combustors that operate intermittently.

Conducting stack tests on all non-manufacturer tested control devices within 180 days of rule promulgation will be difficult, expensive, and often impractical. Often field combustors are not equipped or designed for stack testing. Protocol approval and scheduling will require more time to avoid unnecessary and unintended compliance issues. Currently, Department stack testing protocol approval can be excessive, often taking over six months. Because of design differences, a standard protocol is not practical. MSC requests that this requirement be removed.

14) § 129.129(k) – In the introductory paragraph of (k), the reference to "(c)(1)(ii)" should be deleted since "(c)(1)(ii)" does not require or refer to a weight-percent VOC emission reduction requirement, as shown below:

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

15) § 129.129(k)(5) – The reference to "(c)(1)(ii)" in this paragraph should be deleted since "(c)(1)(ii)" does not require or refer to a weight-percent VOC emission reduction requirement, as shown below:

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

Recordkeeping and Reporting

The MSC strongly recommends that this section not contain requirements more restrictive than or inconsistent with those found in the NSPS OOOOa.

1) §129.130(b)(1) – Requiring a unique set of coordinates for individual tanks within a multi-tank battery is overly burdensome and does not provide any environmental benefit. MSC is proposing that a single latitude and longitude for a tank battery be supplied to the department to meet this requirement.

2) §129.130(b)(6)(i) –MSC believes that the date the calculation was performed provides no environmental benefit and has no bearing on compliance, therefore, MSC requests that this requirement be removed.

3) § 129.130(b)(7) – The reference in the first sentence of this paragraph to "§ 129.123(d)(3)" should be changed to "§ 129.123(d)(1)" since that is the paragraph that addresses skid-mounted or mobile storage vessels, as shown below:

   a. *"(7) The records documenting the time the skid-mounted or mobile storage vessel under § 129.123(d)(1)~~(3)~~ is located on site."*

4) §129.130(c) – In line with comments provided in the above sections, recordkeeping and reporting requirements for natural gas-driven driven pneumatic controllers should be limited to high-bleed pneumatics and not include low-bleed or intermittent natural gas-driven driven pneumatic devices. MSC requests that this requirement be modified to include only high-bleed natural gas-driven pneumatic controllers. Please verify the "date" stated in (c)(1) refers to the compliance "date" stated in129.124(d)(1).

5) § 129.130(c)(1) – As drafted, it is unclear what "date" is required to be recorded. For consistency with § 129.124(d)(1), the date should be clarified to refer to the required compliance date for the controller, as suggested below:

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

6) § 129.130(d)(1) – As drafted, it is unclear what "date" is required to be recorded. The required "date" for purposes of this paragraph should be specified, or the reference to "date" should be deleted from this paragraph.

7) § 129.130(d)(7) – The reference in this paragraph to "§ 129.125(c)(1)(iii)" does not exist. It appears the intended reference here should be "§ 129.125(c)(1)(i)(C)," as shown below:

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

8) § 129.130(e)(3)(i) – For consistency with the comment above at § 129.126(b)(2) that reciprocating compressors should be allowed to also be routed to a control device, not just to a process, this paragraph should include the corresponding revision shown below:

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

9) §129.130(g)(1)(ii) – Since gas to oil ratio (GOR) will not change significantly over time, MSC believes that an annual review and updating of this data will not materially change the result of a one-time analysis. Additionally, there should be no need for this type of analysis to require certification by a responsible official; therefore, MSC requests that this requirement be removed. While we are not sure of the intent in this condition, requiring samples to be collected and analyzed from every site is overly burdensome and ultimately unnecessary.

10) 129.130(g)(1)(ii) – For consistency with the language in referenced § 129.127(b)(1)(i), the wording "stock barrel" in the first sentence of this paragraph should be changed to just "barrel" since the word "stock" isn't used in § 129.127(b)(1)(i), as shown below:

   a. *"(ii) The annual analysis documenting a GOR of less than 300 standard cubic feet of gas per ~~stock~~ barrel of oil produced, conducted using generally accepted methods."*

11) § 129.130(g)(2) – It would appear that the reference in this paragraph to "§ 129.127(b)(2)" may have been intended to refer instead to "§ 129.127(b)(1)(ii)," as shown below:

   a. *"(2) For a well site subject to § 129.127(b)(1)(ii)~~(2)~~, a natural gas gathering and boosting station and a natural gas processing plant:"*

12) § 129.130(g)(2)(ii) – It would appear that the reference in the first sentence of this paragraph to "§ 129.127(b)(1)(ii)" should be modified to "§ 129.127(b)(1)(ii)(B)" for consistency with the reference to "§ 129.127(d)(2)," as shown below:

   a. *"(ii) The records of each monitoring survey conducted under § 129.127(b)(1)(ii)(B) or § 129.127(d)(2)."*

13) § 129.130(g)(2)(ii)(G)(II) – As drafted, this paragraph requires "the instrument reading" to be recorded for each leak, but what does that mean for leaks detected with OGI equipment? What "instrument reading" from the OGI would satisfy this requirement? That should be clarified.

14) § 129.130(i)(2) – For consistency with the comments above at § 129.128(b)(2)(ii) and § 129.128(d), this paragraph should also allow for and address OGI procedures by amending the wording as shown below:

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

15) §129.130(j)(2) & §129.130(j)(3) – Records of the date of purchase and a copy of the purchase order for a control device are wholly irrelevant for compliance with this rule; the installation date of a control device prior to the applicable compliance date is the pertinent concern. MSC requests that this requirement be removed.

16) § 129.130(j)(5)(iv)(A) – In this paragraph, it's not clear if the "name of the company" is referring to the company that performed the test or the company that owns or operates the control device. That should be clarified.

17) §129.130(k) – This condition does not specify the duration of the initial compliance period, only the date that the initial report is due by. MSC requests that the Department include clarification on the compliance period duration and report due date, for example: that the initial compliance period is one year following the effective date of the rule, the initial report is due within 90 days of the initial compliance period, and subsequent reports are due annually following the due date of the initial report.