Commonwealth of Pennsylvania

Comment and Response Document

For the General Plan Approval and/or General Operating Permit for Unconventional Natural Gas Well Site Operations and Remote Pigging Stations (BAQ-GPA/GP-5A)

And the Revisions to the General Plan Approval and/or General Operating Permit for Natural Gas Compressor Stations, Processing Plants, and Transmission Stations (BAQ-GPA/GP-5)

And the Revisions to the Air Quality Permit Exemptions (275-2101-003)

Part 2 of 2

FINAL
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Introduction

On March 31, 2018, the Pennsylvania Department of Environmental Protection (Department or DEP) published notice in the Pennsylvania Bulletin of the availability of the draft-final General Plan Approval and/or General Operating Permit for Unconventional Natural Gas Well Site Operations and Remote Pigging Stations (BAQ-GPA/GP-5A or GP-5A), and draft-final revisions to the General Plan Approval and/or General Operating Permit for Natural Gas Compressor Stations, Processing Plants, and Transmission Stations (BAQ-GPA/GP-5 or GP-5) and the Air Quality Permit Exemptions document (275-2101-003 or Exemptions List) for public review and comment. (47 Pa.B. 733)

This Comment and Response Document summarizes the comments submitted to DEP by 32 commentators on the draft-final GP-5A and draft-final revisions to GP-5 and the Exemptions List and provides the Department's responses to those comments. Generally, this document is organized such that each comment and response is grouped according to the relevant document and section. Each public comment is listed with an identifying number for each commentator that provided comments to the Department. A list of commentators, including names and affiliations (if applicable) is provided below:

ID	Name	Affiliation
1	Suzanne Almeida	League of Women Voters
2	Robert Altenburg	PennFuture
3	Bruce Baizel	Earthworks
4	Scott Blauvelt	JKLM Energy, LLC
5	Harry Brownfield	
6	Jill Brownfield	
7	Delma Burns	
8	Steve Deiker	Kairos Aerospace
9	Steve Dussault	GE Power
10	Chad Eisenman	Chevron Appalachia, LLC
11	Lesley Fleischman	Clean Air Task Force
12	Timothy French	Truck and Engine Manufacturer's Association
13	Douglas Frisco	Energy Transfer
14	Sharon Furlong	Bucks Environmental Action Group
15	Meleah Geertsma	Natural Resources Defense Council
16	Patrick Henderson	Marcellus Shale Coalition
17	Deborah Hunter	
18	Leann Leiter	Earthworks
19	David McCabe	Clean Air Task Force
20	James McCarthy	Innovative Environmental Solutions
21	Joseph Otis Minott	Clean Air Council
22	Rachael Neffshade	ISO (International Socialist Organization)
23	Elizabeth Paranhos	Environmental Defense Fund
24	Andres Restrepo	Sierra Club
25	James Rosenberg	Fayette Marcellus Watch
26	Robert Routh	Clean Air Council
27	Michael Sherman	Range Resources - Appalachia, LLC
28	Christopher Trejchel	Seneca Resources Corporation

ID	Name	Affiliation
29	Dan Weaver	Pennsylvania Independent Oil and Gas Association
30	Andrew Williams	Environmental Defense Fund
31	Tonya Williams	SWEPI, LP
32	Stephanie Wissman	Associated Petroleum Industries of Pennsylvania

Abbreviations and Acronyms

A/F	Air-to-Fuel
AVO	Auditory, Visual, and Olfactory Inspections
BAT	Best Available Technology
bhp	Brake Horsepower
BMP	Best Management Practices
BTEX	Benzene, Toluene, Ethylbenzene, and Xylene
CFR	Code of Federal Regulations
CO	Carbon Monoxide
CO_2	Carbon Dioxide
CPI	Consumer Price Index
DI&M	Direct Inspection and Maintenance
DEA	Diethanolamine
DEP	Pennsylvania Department of Environmental Protection
EGR	Exhaust Gas Recirculation
EPA	U.S. Environmental Protection Agency
g/bhp-h	Grams per Break Horsepower-Hour
GHG	Greenhouse Gas(es)
GP	General Plan Approval/General Operating Permit
GP-5	General Plan Approval/General Operating Permit for Natural Gas Compressor Stations, Processing Plants, and Transmission Stations
GP-5A	General Plan Approval/General Operating Permit for Unconventional Natural Gas Well Site Operations and Remote Pigging Stations
H_2O	Water
H_2S	Hydrogen Sulfide
HAP	Hazardous Air Pollutant
HCHO	Formaldehyde
GPU	Gas Production Unit
MEA	Monoethanolamine
Mcf	Thousand Cubic Feet
MMBtu	Million British Thermal Units
MMBtu/h	Million British Thermal Units per Hour
N2	Molecular Nitrogen
NAAQS	National Ambient Air Quality Standard
NESHAP	National Emission Standards for Hazardous Air Pollutants
NGL	Natural Gas Liquids
NGStar	The Natural Gas Star Program
NMNEHC	Non-Methane, Non-Ethane Hydrocarbon
NO	Nitric Oxide
NO_2	Nitrogen Dioxide
NO_X	Oxides of Nitrogen
NSCR	Non-Selective Catalytic Reduction
NSPS	New Source Performance Standards
OGI	Optical Gas Imaging Camera
PennDOT	Pennsylvania Department of Transportation
PM	Particulate Matter

Abbreviations and Acronyms (cont.)

PM2.5	Particulate Matter with an Aerodynamic Diameter Less Than 2.5 Microns
PM10	Particulate Matter with an Aerodynamic Diameter Less Than 10 Microns
ppmvd	Parts Per Million, Dry, by Volume
ppmv	Parts Per Million by Volume
PRO	Partner Reported Opportunities
PTE	Potential to Emit
RACT	Reasonably Available Control Technology
RBLC	RACT/BACT/LAER Clearinghouse
REC	Reduced Emission Completion
RFD	Request for Determination
scf	Standard Cubic Feet
SCR	Selective Catalytic Reduction
SI RICE	Spark Ignition Reciprocating Internal Combustion Engine
SO_2	Sulfur Dioxide
SO_X	Oxides of Sulfur
THC	Total Hydrocarbons
tpy	Tons Per Year
TSD	Technical Support Document
VOC	Volatile Organic Compound

General Comments

Comment 1: The commentators appreciated DEP's action to reduce methane and volatile organic compound (VOC) leaks and urge DEP to adopt the strongest GP possible. They commended DEP for introducing standards for air pollution sources such as pigging and liquids unloading as well. They recommend that PA take the following additional steps.

- Increase the frequency of leak detection and repair from quarterly to monthly.
- Remove the provision that rewards operators who don't find leaks with lowered leak detection requirements.
- Lower the threshold for acceptable methane leaks from tanks, dehydrators, and pigging operations.

Lastly, they comment that the new GPs do not cover existing facilities and request that DEP introduce its plan to reduce emissions from existing sources by this summer. (5, 6)

Response: DEP appreciates the acknowledgment of DEP's efforts to reduce methane emissions from oil and gas operations. DEP evaluated the feasibility of other frequencies for the leak detection and repair (LDAR) program. The Department has determined that in addition to monthly audio, visual, and olfactory (AVO) inspections, a quarterly LDAR program is most appropriate. The determination is more fully documented in the Department's Technical Support Document (TSD). The recently promulgated federal New Source Performance Standards (NSPS) require semiannual LDAR for wellsites.

On October 27, 2016, the Environmental Protection Agency (EPA) issued Control Techniques Guidelines (CTG) for VOC emissions from existing oil and gas sources that identify the Reasonably Available Control Technology (RACT) requirements. The Department is required to develop regulations to implement the CTG for existing sources. The Department's rulemaking for existing sources will be proposed for public comment prior to its promulgation.

Comment 2: The commentator raised concerns about the environmental and climate damage from methane emissions from natural gas wells. It recommended DEP thoroughly inspect wells and shut them down when any leaks are found and ban fracking as it is a net negative economically and environmentally due to current and future damage caused by extreme weather. (17)

Response: DEP appreciates the commentator's concern regarding the impact of methane emissions from well site operations. The Department believes that the final criteria of conditional Exemption 38 along with GP-5A are protective of public health and allow for the development of the natural gas industry in a safe and effective manner.

Comment 3: The commentator recommends allowable emissions should be next to nil and if that is not possible, then natural gas extraction in PA should end for climate and health reasons. (22)

The commentator recommends that fossil fuel production in PA be halted due to its air pollution and contribution to climate change. (14)

Response: DEP appreciates the commentator's concern regarding the impact of methane emissions from well site operations. The Department believes that the final criteria of conditional Exemption 38 along with GP-5A are protective of public health and allow for the development of the natural gas industry in a safe and effective manner.

Comment 4: The commentator noted the positive aspects of the requirement of air permits for new unconventional wells. The commentator also noted the negative aspects of the changes made to the earlier version of GP-5A, such as the elimination of specific measures to address fugitive particulate emissions, reduction of control efficiency from 98% to 95%, elimination of hi-flow monitors and failure to address annual toxic exposure. (7)

Response: Regarding fugitive particulate emissions, the proposed Section B was removed from the final general permits and replaced with Section A, Condition 10(c)(iii) which cites 25 Pa. Code § 123.1 (prohibition of certain fugitive emissions) and § 123.2 (fugitive particulate emissions).

The Department revised the control efficiency from 98% to 95% in the final GPs based on the public comments received. While manufacturer-tested models typically achieve significantly greater than 95% control in practice, the control requirement was revised to allow operators to continue to benefit from the manufacturer-tested models in accordance with the federal regulations. This revision avoids additional source testing to demonstrate 98% efficiency, instead relying on the manufacturer's certification list maintained by EPA to demonstrate and maintain compliance under the federal regulations.

Due to the non-availability of reliable high flow samplers, the final GP-5A does not contain any instrument-based quantification requirements.

GP-5A is protective of public health and allows for the development of the natural gas industry in a safe and effective manner.

Comment 5: The commentator is appreciative of the following improvements in the last draft (31)

- Greatly improving the clarity through an extensive incorporation by reference with limited large-scale duplication of OOOOa and other regulatory text.
- Reducing operational delays and redundancy by maintain the consistency with previous versions of the Exemption and GP-5 without the inclusion of temporary sources such as drilling and completion activities.
- Concurring with the change to sections covering Enclosed Flares and Other Emission Control Devices to eliminate the need for Professional Engineer certification.
- Good corrections and improvements to the pneumatics requirements.
- Elimination of hi-vol sampler testing of fugitive equipment leaks.
- Good corrections and improvements to the natural gas-driven pneumatic diaphragm pump ("Pumps") section.

Response: The Department appreciates the acknowledgment.

Comment 6: The commentator appreciates the following changes

- Adding flexibility for Transfer of Ownership.
- Reinforcing the use of the current Malfunction Reporting Guidance.

- Adding flexibility for de minimis emission increases.
- Clarifying that only natural gas driven pneumatic diaphragm pumps are subject to control requirements.
- Allowing flexibility on testing intervals based upon performance.
- Changing requirements to allow for the industry accepted 95% control efficiency.
- Clarifying the exemption threshold for control of Truck Loading.
- Clarifying the applicability of Best Management Practices and Control Requirements on Pigging Operations.
- Updating the definition for delay or repair to match the current federal requirements. (10, 16, 28)

Response: The Department appreciates the comments.

Comments 7: The commentator suggests re-instating the provisions of exemption #16 of physical changes that qualify for exemption under Section 127.14(a)(9) on the list and adhering to the regulatory definitions for modification. This provision has appeared in the Exemption List since at least 2003 and provides much-needed flexibility for the regulated community. (10, 28, 32, 4, 16, 31, 27)

Response: The Department disagrees. Category 38 of the Exemptions list provides conditional exemption from both a plan approval and an operating permit. Therefore, there is no need for an exemption category under "Physical Changes Qualifying for Exemption Under Section 127.14(a)(9)."

Comment 8: The commentator recommends DEP revise the language at the beginning of Exemption 38(c) to ensure clarity and improve consistency with triggering a modification as addressed by the general permit/plan approval process. (10, 28, 32)

Response: The Department believes that the applicability description of Exemption 38(c) is self-explanatory.

Comment 9: The commentator requests clarification that the monitoring plans only need to meet the requirements of OOOOa for those facilities subject to OOOOa. (10, 16, 28)

Response: Exemption 38c requires the owner/operator to comply with 40 CFR part 60 subpart OOOOa requirements as applicable.

Comment 10: The commentator suggests that GP-5 and GP-5A be linked to associated provisions of Subpart OOOOa so that regulatory revisions associated with Subpart OOOOa are "automatically" reflected in GP-5 and GP-5A, without a permit revision process. (29)

Response: GP-5 and GP-5A incorporate federal requirements including OOOOa by reference unless additional requirements are warranted by Best Available Technology (BAT) determinations.

Comment 11: The commentator suggests revising the proposed Exemption No. 38b, last paragraph on page 8, the first sentence to "If the source does not meet the exemption criteria under 38(c), or cannot qualify for GP-5A, or has not otherwise been determined to be exempt by the department (e.g., no RFD approval) ...." (29)

Response: Since Exemption No. 38b is only applicable to existing oil and gas exploration, development, and production facilities and associated equipment and operations already authorized to operate under exemption criteria dated August 10, 2013, prior to August 8, 2018 no changes are warranted.

Comment 12: The commentator suggests that Exemption No. 38(c), item (v) on page 10, a new condition to limit ammonia slip to 5 ppmvd @ 15% oxygen from units that rely on nitrogen oxides (NO_x) control using ammonia or urea injection be eliminated. The commentator suggests that a provision be included allowing "manufacturer's information" as a compliance mechanism, or that the new condition be removed due to the lack of an enforceable compliance mechanism. (29)

Response: Based on the comments received, the Department has revised Ammonia slip to 10 ppmvd in the final general permits and the Exemptions List, Category 38(c). The owner and operator may rely on manufacturers' information to comply with the requirement.

Comment 13: The commentator recommends that the two general permits encourage innovation in technology for alternative monitoring requirements which would reduce costs for the regulated community, and improve environmental outcomes. (8)

Response: GP-5 and GP-5A allow the owner/operator to request alternative monitoring technologies provided such technologies are equivalent or better than the prescribed monitoring requirements in the permits.

Comment 14: The commentator recommends that DEP, at a minimum, take action to ensure that non-oil & gas operators in the state have been made adequately aware of the proposed changes to the Exemption List. (10, 28, 32)

Response: The Department published a notice in 48 Pa.B. 1902 (March 31, 2018) and in six newspapers which opened a public comment period for the proposed revisions to Categories Nos. 35 and 38 under Section 127.14(a)(8) provision; Category No. 16 under Section 127.14(a)(9) provision; and under the Trivial Activities provision, Category No. 40.

Comment 15: The commentator supports DEP's updates to the existing general permit process, GP-5 and GP-5A, as useful actions to limit unchecked fugitive methane emissions across the state. The commentator also urges DEP to immediately move ahead in drawing up parallel regulations for existing unconventional gas facilities as it has previously indicated it would do. Furthermore, the commentator urges DEP to move quickly to promulgate methane regulations for conventional oil and gas facilities as well. (1)

Response: On October 27, 2016, EPA issued Control Techniques Guidelines (CTG) for VOC emissions from existing oil and gas sources that identify the Reasonably Available Control Technology (RACT) requirements. The Department is required to develop regulations to implement the CTG for existing sources. The Department's rulemaking for existing sources will be proposed for public comment prior to its promulgation.

Comment 16: The commentator specifies:

- Removal of new Unconventional Oil & Gas wells from coverage under Exemption 38 is commendable.

- Prohibition of use of GP-5/GP-5A for circumvention (Section A5(d)) is commendable. (25)

Response: Thank you for the comment.

Comment 17: DEP has failed in its duty to the public by neglecting to publish a Comment Response Document for the previous Public Comment Period (closed 6/5/2017) for these three documents. (25)

Response: A separate Comment and Response Document for the first comment period (Part 1 of 2) was made available when the Department published the final general permits.

Comment 18: A requirement for new or modified Unconventional Oil & Gas wells to obtain a General Plan Approval under BAQ-GPA/GP-5A must be made mandatory. DEP must take an additional step and delete Exemption 38(b). (25)

Response: The Department maintains an exemption for temporary activities and insignificant emissions sources. Existing sources are covered under either Exemption 38(a) or Exemption 38(b) unless they trigger a modification by installing a new source, drilling or fracturing a new well, or fracturing or refracturing an existing well.

Although a source may be exempt from the plan approval and operating permit requirements of 25 Pa. Code Chapter 127, the source is subject to all other applicable air quality regulations. The Exemption List does not exempt sources from compliance with emission limitations, work practice standards, and other applicable requirements contained in Title 25 of the Pa. Code. This requirement can be found in Section D(4) of the Exemptions List under "Further Qualifications Regarding Plan Approval Exempted Sources."

The Department believes that the final criteria of the conditional Exemption 38 are protective of public health and allow for the development of the natural gas industry in a safe and effective manner.

Comment 19: There is no public comment on minor source determination under GP-5/GP-5A. More generally, there is no public comment on eligibility for the use of GP-5/GP-5A. (25)

Response: The Department followed the requirements to propose and finalize a general permit under 25 Pa. Code § 127.611 and § 127.612, including a 45-day comment period on the draft-final permits. The Department offered an initial 120-day comment period on the proposed terms and conditions. The Department also offered a second comment period on the revised general permits beginning March 31, 2018. The Department has also published its Technical Support Document (TSD) to support the determinations used to establish the terms and conditions of the general permits. In addition, the Department has issued Comment and Response Documents for both public comment periods.

Furthermore, the Department met with numerous stakeholders before, during, and after the comment period while developing the general permits.

Comment 20: Handling of Synthetic Minor Sources under GP-5/GP-5A is seriously deficient and operators should be required to declare the list of potential to emit (PTE) if the special measures were not taken, and to indicate in detail what the operating provisions will be to ensure that only minor source emission levels happen. Where actual emission amounts exceed PTE, these actuals must be fed back into calculation of potential from that point forward. (25)

Response: The Department disagrees. Stationary sources are considered major or minor facilities based on the emissions of criteria and hazardous air pollutants. Any facility that does not meet the emissions thresholds specified in the definition of the term “major facility” codified in 25 Pa. Code § 121.1 and 40 CFR § 52.2020(c) is treated as a minor facility.

The Department has prohibited the use of the final GP-5 for Title V facilities. Section A, Condition 10(a) of the final general permits requires the emissions from all sources and associated air pollution control equipment located at a facility to be less than the major source thresholds on a 12-month rolling sum basis. Section A, Condition 12(b) of the final general permits requires the owner or operator of the facility to maintain records that clearly demonstrate to the Department that the facility is not a Title V facility. Furthermore, Section A, Condition 10(h) of the final general permits requires the owner or operator of the facility to annually submit to the DEP a certification of compliance with the terms and conditions in the final general permits, for the previous year, including the emission limitations, standards or work practices.

The final general permits include emission limits for specific emission units, facility emission limits, and adequate testing, monitoring, and recordkeeping requirements. Therefore, the emission limits established in the general permits are federally enforceable. In addition, Section A, Condition 13(d) of the final general permits requires the owner or operator of facilities to submit to the Department, by March 1st each year, a source report for the preceding calendar year for all sources controlled under the general permit. The report includes all emissions information for all previously reported sources and new sources which were first operated during the preceding calendar year. The Department may revoke the authorization to use the general permit if actual emissions are found to exceed any major source threshold. Furthermore, 25 Pa. Code § 127.203(e)(2) specifies that if a particular source or modification becomes a major facility or major modification solely by virtue of a relaxation of an enforcement limitation which was established after August 7, 1980 on the capacity of the source or modification to emit a pollutant including a restriction on hours of operation, the requirements of Subchapter E also apply to the source or modification as though construction had not yet commenced on the source or modification.

Comment 21: There is no requirement under GP-5/GP-5A for facility operators to estimate the risk of exposure to doses of air emission chemicals capable of causing harmful health effects. DEP must remedy this problem by requiring compressor station operators to submit a dispersion study providing a forecast probability of exposure to toxic air pollutants — including under adverse weather conditions. (25)

Response: Forecasting risk and exposure is generally only done for major facilities subject to Prevention of Significant Deterioration of Air Quality (PSD), which requires modeling and risk determinations. Minor sources, which are the only sources eligible to apply for the general permits, are typically not required to perform the expensive modeling. The applicants are required to submit actual emission reports, measured in tons per year on a 12-month rolling basis, to ensure the facility is a minor source.

Comment 22: We applaud the Department’s continued efforts to refine the documents and address questions and concerns raised by industry. (4)

Response: The Department appreciates the comment.

Comment 23: The commentator recommends that the Exemptions List, Category 38(c) reference a spud date similar to 38(b). (4)

Response: The final Exemptions list, Category 38(c) has been revised as recommended.

Comment 24: The commentator states that VOC emissions threshold of 2.7 tpy should not account for the controlled emissions from storage tanks, sources subject to LDAR and flares similar to the Exemption List, Category 38(b). (4)

Response: The final exemption Category 38(c) does not include the term "uncontrolled" for emission thresholds encouraging the use of such controls. The final GP-5A addressed emissions from storage tanks, sources subject to LDAR, and flares.

Comment 25: The commentator requests the DEP to provide a clarification regarding the meaning of changes to a wellsite. The Department has not adequately defined "modified" for purposes of assessing Exemption 38 applicability. (4)

Response: "Modification" is defined at 25 Pa. Code Section 121.1.

Comment 26: In addition to the revisions to Exemption 38, the Department is proposing two other significant revisions to the Exemption List. First, the Department intends to remove methane from the list of inert gases described in Exemption 35 and Trivial Activity 40. Please explain the basis for this proposed change. The commentator questions whether this revision may have unintended consequences, especially for sources in other industries. (4)

Response: Methane emissions from the oil and gas industries are addressed in the Exemptions list and general permits. Methane emissions from landfills are addressed in the state-only operating permits. Methane emissions from other industries will be addressed on a case-by-case basis.

Comment 27: The commentator supports the quarterly LDAR inspection frequency in GP-5 for compressor stations and processing plants and also supports the proposed baseline quarterly inspection frequency in GP-5A for well sites. (26, 3)

Response: Thank you for the comment.

Comment 28: The commentator states by incorporating OOOOa requirements by reference in GP-5 and GP-5A, there will be significant confusion for industry operators and the public in Pennsylvania about which requirements apply to which sources and when. To mitigate the effects of this uncertainty, the commentator suggested the following:

40 CFR Part 60, Subpart OOOOa, as finalized on June 3, 2016, not including any later amendments – Standards of Performance for Crude Oil and Natural Gas Facilities for which Construction, Modification, or Reconstruction Commenced after September 18, 2015.

Applicable federal regulations include, but are not limited to, the following NSPS, codified at 40 CFR Part 60 and incorporated by reference in 25 Pa. Code § 122.3, except as set forth below**,** and National

Emission Standards for Hazardous Air Pollutants (NESHAP), codified at 40 CFR Part 63 and incorporated by reference in 25 Pa. Code § 127.35. (26)

Response: EPA finalized 40 CFR Part 60 Subpart OOOOa on June 3, 2016. EPA has proposed a stay of certain provisions of OOOOa while they are being reconsidered. The Department has either incorporated the respective citations by reference or established state BAT requirements for these sources within the final general permits. If EPA finally revises any of the federal NSPS provisions that were directly referenced, the Department will re-evaluate the general permit conditions at that time.

Comment 29: Since the initial publication of the draft general permits and the 120-day public comment period that closed on June 5, 2017, DEP has removed several requirements from the current permit drafts, thereby resulting in less stringent, less protective control standards in many instances. Many of these revisions were publicly announced by DEP at the AQTAC meeting. The commentator suggests restoring following requirements:

Allowance for alternative LDAR technologies.

- Removal of the step-down provision in the draft GP-5A.
- Restoration of provisions contained in earlier drafts of the GP-5 and GP-5Apermits, including requirements that:
- Operators be present during manual liquids unloading, a procedure that can cause significant emissions and impact the health and safety of workers.
- Electric emission controls be used whenever possible.
- Operators notify DEP within 24 hours of a scheduled blowdown or venting event.
- Emission sources be controlled at a 98% destruction efficiency level.

The commentator supports DEP's proposed standards for detecting and repairing leaks from sources not covered in most states, including pigging operations and liquids unloading. The commentator also supports the new requirement that operators must obtain air permits for well pads prior to drilling. (3)

Response: DEP appreciates the commentator's concern regarding the impact of emissions from well site operations. The Department believes that the revisions to GP-5A are protective of public health and allow for the efficient oversight of the industry.

The final general permits do not discourage the use of any potentially advanced LDAR and DI&M program. Section G Condition 1(b) of the final general permits state that "…the owner or operator shall conduct an LDAR program using… leak detection methods approved by the Division of Source Testing and Monitoring." At minimum, the alternative LDAR method would have to be at equivalent or better than OGI and Method 21.

The stepdown provision provides some relief to smaller operators by allowing them to track the percentage of leaking components and, by maintaining less than 2% leaking components, reduce frequency. This allows smaller operators to reduce the number of times per year they must hire a contractor to perform this service. If at any time the percentage of leaking components exceeds 2%, the facility must resume quarterly LDAR inspections. The Department expects that larger operators will typically have in-house personnel to perform LDAR inspections and would rather maintain a consistent frequency than be burdened by the additional recordkeeping to receive a stepdown frequency.

Based on the comments received, the 98% control requirement for methane, VOCs, and hazardous air pollutants (HAPs) was revised to a 95% control requirement in the final general permits. While manufacturer-tested models typically achieve significantly greater than 95% control in practice, the control requirement was revised to allow operators to continue to benefit from the manufacturer-tested models in accordance with the federal regulations. This revision avoids additional source testing to demonstrate 98% efficiency, instead relying on the manufacturer's certification list maintained by EPA to demonstrate and maintain compliance under the federal regulations.

Comment 30: The commentator recommends that the largest facilities should be subject to a monthly LDAR inspection frequency. This is already implemented in Colorado, which requires well sites with storage tanks and compressor stations that emit more than 50 tpy VOC and well sites without storage tanks that emit more than 20 tpy VOC to perform monthly LDAR. (3)

Response: The monthly frequency proposed by the commentators for larger facilities is based on Colorado's requirement for major facilities to perform LDAR monthly. The final general permits cannot be used at major facilities. In Pennsylvania, major facilities would be required to determine LDAR frequency on a case-by-case basis during the individual permitting process.

<u>The Department Should Maintain the Current Exemption 38 and the Existing GP-5</u>

Comment 31: The Department should maintain the current Exemption 38 and the existing GP-5. The commentator suggests that the current air quality regulatory structure (e.g., Exemption No. 38 and reliance on 40 CFR 60 Subpart OOOOa) be retained and that the final draft versions of GP-5A, GP-5, and the proposed modifications to the Air Quality Permit Exemption List (275-2101-003) be withdrawn. (10, 28, 32, 29)

Response: The Department is moving to a general permit from Exemption 38 to reduce confusion, improve compliance with the regulatory requirements and provide more transparency and assurance to the public. In addition, some operators have expressed a preference for the certainty that a general permit provides as opposed to the permit exemption in place now.

Through the implementation of Exemption 38, the Department discovered a high non-compliance rate. For example, between August 2013 and February 2017, over 3,000 wells were drilled and 28% owners or operators of these well sites failed to comply with all conditions of exemption criteria. This was unexpected considering the outreach conducted for the use of Exemption 38. The conditions for eligibility under Exemption 38 are significantly more stringent than other categories in the Permit Exemption List. It is likely that these numerous conditions contributed to the confusion over the compliance requirements for Exemption 38. Additionally, operators have underreported the emissions from remote pigging operations which has led DEP to include these operations in GP-5A.

The development of general permits for these sources in Pennsylvania is not unique. Several states, including Alaska, Louisiana, Texas, Ohio, West Virginia, and Colorado, have general permits for oil and gas production facilities in place. Operators of well pads in Pennsylvania who operate in these states have been authorized through general permits.

The Department has included a conditional permit exemption in revised Category No. 38 [38(c)] for certain activities at conventional and unconventional sites, including temporary activities such as site preparation, well drilling, hydraulic fracturing, completion, work-over activities and associated temporary flaring operations.

Comment 32: The commentator recommends the department to maintain Exemption 38, while addressing remote pigging facilities directly either through a general permit specific to these operations via a trimmed down version of GP-5A or by including in GP-5. (10, 28, 32)

Response: The Department designates the facility a remote pigging station if the facility emissions exceed the 200 tons per year (tpy) methane, 2.7 tpy VOC, 0.5 tpy single HAP, or 1.0 tpy total HAP (control thresholds) and the activity does not take place at unconventional natural gas well sites, midstream compressor stations, natural gas processing plants, or transmission stations. Because remote pigging stations are generally small, disparate facilities like unconventional natural gas well sites, the Department included those in the applicability for the final GP-5A.

The Department Lacks the Authority to Regulate Methane

Comment 33: The Commentator believes that establishing an emission threshold that must be achieved in order to maintain compliance with the law is a regulation and goes above and beyond the statutory and legal authority as well as the scope of a general permit. Even if the Department had the requisite statutory authority to regulate methane in this manner, it must first go through the appropriate rulemaking process to establish those limits, which it did not. The main function of any permitting program is to implement lawfully established compliance obligations, not establish them.

Another commentator stated that DEP does not have the authority to extend the scope and breadth of federal regulations via the permit process without following the formal rulemaking requirements of the Regulatory Review Act (RRA). An important requirement of the RRA process that is lacking here is a thorough analysis of the economic impacts of these regulations on operators. *See generally*, 71 P.S. § 745.5(a) and 1 Pa. Code § 305.1 and 307.2. (10, 16, 28, 32)

Response: The Department disagrees with the commentators' contention that the Department lacks the authority to regulate methane emissions from oil and gas facilities because they do not "cause" "air pollution" as that term is defined under the Air Pollution Control Act (APCA). Methane, as a greenhouse gas, is regulated under the federal Clean Air Act (CAA) as well as the APCA. The commentators fail to point to any specific language in the APCA that limits the Department's ability to regulate conventional pollutants only. To the contrary, the definitions of "air contamination" and "air pollution" do not limit the Department's legal authority in the way described by the commentators. The General Assembly was concerned with air pollution generally and that it be remedied no matter what the source. *See* 35 P.S. § 4002. Pennsylvania courts have found that the regulation of air pollution has long been a valid public interest. *See e.g., Bortz Coal Co., v. Commonwealth,* 279 A.2d 388, 391 (Pa. Cmwlth. 1971); *DER v. Pennsylvania Power Co.,* 384 A.2d 273, 284 (Pa. Cmwlth. 1978); *Commonwealth v. Bethlehem Steel Corporation*, 367 A.2d 222, 225 (Pa. 1976). Moreover, the Commonwealth Court has endorsed the Department's position that the General Assembly, through the APCA, gave the agency the authority to reduce greenhouse gases (GHG) emissions. *Wolf v. Funk,* 144 A.3d 228, 250 (Pa. Cmwlth. 2016).

Because methane is a gas, it falls within the definition of "air contaminant," and "air contamination" under the APCA. "Air contaminant" is defined as "smoke, dust, fume, gas, odor, mist, radioactive substance, vapor, pollen or any combination thereof." 35 P.S. § 4003. While "air contamination" is defined as "the presence in the outdoor atmosphere of an air contaminant which contributes to any condition of air pollution." Id. Because the sources controlled under GP-5 and GP--5A emit methane they fall within the definition of "air contamination source" under the APCA which is "any place, facility or equipment, stationary or mobile, at, from or by reason of which there is emitted into the outdoor atmosphere any air contaminant." 35 P.S. § 4003.

Methane also meets the definition of "air pollution" as that term is defined under the APCA. "Air pollution" is defined as "[t]he presence in the outdoor atmosphere of any form of contaminant … in such place, manner or concentration inimical or which may be inimical to the public health, safety or welfare or which is or may be injurious to human, plant or animal life or to property or which unreasonably interferes with the comfortable enjoyment of life or property." 35 P.S. § 4003.

In 2009, based on a large body of scientific evidence, U.S. EPA issued an "Endangerment Finding" under CAA section 202(a)(1), 42 U.S.C. § 7521(a)(1), related to GHGs.[1] EPA found that six well-mixed GHGs — carbon dioxide, methane, nitrous oxide, hydrofluorocarbons, perfluorocarbons, and sulfur hexafluoride — endanger both the public health and the public welfare of current and future generations by causing or contributing to climate change. *Id.* New scientific assessments and observations strengthen the conclusions of this Endangerment Finding that GHGs endanger public health and the environment.[2] Methane traps 86 times more heat in the atmosphere than carbon dioxide in the short-term, increasing the consequences of climate change. Additionally, methane is often accompanied by toxic air pollutants such as benzene, formaldehyde and ethylbenzene.

Methane is also a precursor to ground level ozone, which can cause a number of harmful effects on public health and the environment. *Id.* Exposure to ozone can cause respiratory system effects such as difficulty breathing and airway inflammation. *Id.* In addition, long-term exposure to ozone is likely to result in harmful respiratory effects, including respiratory symptoms and the development of asthma. *Id.*

There are also independent peer-reviewed studies which indicate that shale gas development is associated with the production of secondary pollutants such as tropospheric (ground-level) ozone, which is formed through the interaction of methane, volatile organic compounds ("VOCs"), and nitrogen oxides (NOx") in the presence of sunlight. Shonoff, Hays, Finkel, *Environmental Health Dimensions of Shale and Tight Gas*, Environ Health Perspect., 2014 Aug; 122(8): 787-795. *See also* Jerrett M, Burnett RT, Pope CA III, Ito K, Thurston G, Krewski D, *et al*. *Long-term ozone exposure and mortality,* N Engl J Med 360:1085–1095, 2009 and *U.S. EPA Integrated Science Assessment for Ozone and Related Photochemical Oxidants* (EPA 600/R-10/076F) available at: http://www.epa.gov/ncea/isa/ozone.htm (accessed on May 9, 2018).

Tropospheric ozone is a strong respiratory irritant associated with increased respiratory and cardiovascular morbidity and mortality. Jerrett *et al*. Although toxicological data suggest that pure methane is not by itself health damaging (excluding its role as an asphyxiant and an explosive), it is a precursor to global tropospheric ozone. *See* Smith KR, Jerrett M, Anderson HR, Burnett RT, Stone V, Derwent R, *et al. Public health benefits of strategies to reduce greenhouse-gas emissions: health implications of short-lived greenhouse pollutants*. Lancet 374:2091–2103, 2009.

[1] "Endangerment and Cause or Contribute Findings for Greenhouse Gases Under Section 202(a) of the Clean Air Act," 74 Fed. Reg. 66496 (December 15, 2009) ("Endangerment Finding").

[2] "Oil and Natural Gas Sector: Emission Standards for New, Reconstructed, and Modified Sources," 81 Fed. Reg. 35824 (June 3, 2016).

Based on all the information reviewed by the Department above, which the Department agrees with, adopts as its own, and incorporates by reference into this General Permit package, methane meets the definition of air pollution under the APCA, because as a GHG and ozone precursor, it is, among other things, inimical or may be inimical to the public health, safety or welfare.

In addition, the requirements of the Regulatory Review Act do not apply to General Permits because they are not regulations. Specifically, the methane control threshold specified in GP-5, GP-5A, and Exemption 38(c) are established under PA's BAT requirements and the APCA's General Permit Program. The economic analysis related to the methane control threshold is in the TSD.

The Department is authorized to issue a plan approval and operating permit to facilities that emit air contaminants under the APCA. The Department has developed these general permits to reduce the administrative burden on both industry and the Department by offering an alternative to the case-by-case determinations of the standard plan approval and operating permit program. The Department may opt to create a general plan approval and general operating permit for categories of sources that "…can be adequately regulated using standardized specifications and conditions." The final general permits detail these specifications and conditions. Owners and operators may, at their discretion, opt to undergo a case-by-case determination if these specifications and conditions may not be met for their individual facility.

The Department's authority to issue general permits is Section 6.1(f) of the APCA, 35 P.S. § 4006.1(f) and 25 Pa. Code Chapter 127, Subchapter H (relating to general plan approvals and general operating permits). In the case of the air contamination sources identified under GP-5 and GP-5A, and as required under Section 6.1(f), the Department determined that the sources are similar in nature and can be adequately regulated using standardized specifications and conditions through the general permit process. Both GP-5 and GP-5A control, among other things, methane emissions from natural gas compressor and processing facilities, and natural gas wellhead facilities.

The APCA specifically provides that "the Department is authorized to require that new sources demonstrate in the plan approval application that the source will reduce or control emissions of air pollutants, including hazardous air pollutants, by using the best available technology." 35 P.S. § 4006.6(c). Because general permits apply to new or modified air contamination sources, they establish BAT requirements and authorize the construction or modification of a source that meets the BAT requirements established under 25 Pa. Code §§ 127.1 and 127.12(a)(5). This requirement also extends to greenhouse gases like methane. *See Snyder v. DEP*, 2015 EHB 027. Both GP-5 and GP-5A establish BAT requirements to control methane emissions.

The Department is currently controlling methane emissions under Air Quality Permits Exemption List Exemptions 33 and 38. The Department is also controlling GHGs under Prevention of Significant Deterioration and Title V Greenhouse Gas Tailoring Rule which controls GHG emissions from new and modified air contamination sources. 75 Fed. Reg. 31514. Pennsylvania implements these GHG requirements through its PSD program under 25 Pa. Code Chapter 127, Subchapter D and Title V Operating Permits program under 25 Pa. Code Chapter 127, Subchapter G.

Comment 34: The Department's action to control methane emissions through GPs-5 and -5A is unjustified, because it singles out a specific industry. (16, 32).

Response: To the extent that any legal challenge asserts that the GPs amount to "special legislation" unfairly classifying the oil and gas industry in violation of Article III, Section 32, of the Pennsylvania

Constitution, the Department has a strong argument, that reduction of methane emissions from unconventional natural gas facilities is: (1) a legitimate state interest; (2) based upon a reasonable difference between classes; and (3) achieves the objectives of the General Assembly. *See Robinson Township v. Commonwealth*, 147 A.3d 536, 581 (Pa. 2016); *see also Pennsylvania Turnpike Commission v. Commonwealth*, 899 A.2d 1085, 1095 (Pa. 2006).

First, there is a legitimate state interest in reducing methane emissions. Methane is both a GHG and ozone precursor that is or may be inimical to public health or welfare. Methane emissions from the natural gas industry in 2015 amounted to approximately 123,081 tons in Pennsylvania, which makes it the largest single industry for that pollutant. Furthermore, as previously noted, Pennsylvania courts have found that the regulation of air pollution has long been a valid public interest. *Bortz Coal Co.*, 279 A.2d at 391; *Pennsylvania Power Co.*, 384 A.2d at 284; and *Bethlehem Steel*, 367 A.2d at 225.

Second, the reduction of methane from the natural gas sector is based upon a reasonable difference between classes. The largest key sources of anthropogenic methane emissions include natural gas and oil systems (30.5 percent), coal mining (30.3 percent), landfills (21.1 percent), enteric fermentation from domestic livestock (9.9 percent), wastewater (3.9 percent), and manure management (2.3 percent). Of these major categories, natural gas and oil systems are the only areas that show significant growth, increasing threefold from the 1990s. The other major categories are either flat or slightly down from the 1990s.

Additionally, methane reduction technologies from coal mining have complicating factors relating to widespread use of these technologies, like low gas concentration, the presence of other contaminants, and risk to miners. State landfill methane emission limits are more stringent than federal requirements. Because there are no CAA requirements regulating methane emissions from agricultural sources, section 4.1 of the APCA, 35 P.S. § 4004.1, prohibits the Department from enacting its own requirements. Current regulatory approaches related to waste water treatment do not address methane emissions, and only relate to sewage sludge incineration and not to the emissions from the water treatment tanks, weirs, or digesters which are the primary sources of methane emissions.

Third, the regulation of methane from the oil and gas industry achieves the objectives of the General Assembly under the APCA, which is to protect public health and the environment. *See* 35 P.S. § 4001. *See also* Bethlehem Steel, 367 A.2d at 225. (The adoption of the APCA makes the preservation of the quality of our air resources a matter of the highest public importance).

The Department Lacks Justification for Requirements Exceeding Federal Requirements Which Should Be Incorporated By Reference

Comment 35: The commentator recommends that DEP limit requirements in the proposed GP-5 and GP-5A to those found in federal regulations unless justification is provided that additional regulation is cost-effective and necessary for the protection of public health, safety and the environment. (10, 28, 32)

Response: Title 25 of the Pa. Code requires that all new sources control the emissions to the maximum extent, consistent with the BAT as determined by the Department at the time of issuance of a plan approval. BAT is an evolving standard and is defined as equipment, devices, methods or techniques as determined by the Department which will prevent, reduce or control emissions of air contaminants to the maximum degree possible and which are available or may be made available. The Department has evaluated various control technologies and determined BAT for specific sources emitting respective pollutants above certain thresholds when a technology was found to be technically and economically feasible.

BAT is in addition to, and independent of, and not a substitution for the limits established under the NSPS. The NSPS establishes the minimum emission limitation that a permittee must meet. BAT establishes the maximum control that is required to be met as determined by the Department. The permitting requirements are authorized under the APCA and as required under 25 Pa. Code § 127.1. The detailed analysis for BAT determinations can be found in the TSD.

Comment 36: The commentator recommends that recordkeeping be made consistent with federal regulations for sources regulated by an existing federal rule. For sources not regulated by federal requirements, DEP should consider and justify the burden and benefits associated with the data being requested. The annual reporting provisions should be removed from both the GP-5 and GP-5A; especially regarding the obligation to submit annual emissions. Any records not already in DEP's possession can be made available if/when requested by DEP. (10, 28, 32)

Response: In response to comments, the Department reevaluated and simplified these requirements by removing redundancies. The notification, recordkeeping, and reporting requirements in the final General Permits were determined to satisfy 25 Pa. Code § 127.12b and § 127.441, which include all federal notification, recordkeeping, and reporting requirements.

Implementation Schedule for the General Permits

Comment 37: The commentators are concerned about the 60-day transition period and recommends lengthening it to 120 days. (31, 10, 28, 32)

Response: The Department appreciates the concern for the demand of Department resources for timely review of authorization requests. The Department has developed an electronic application system (e-Permitting) to expedite review of applications. This electronic application system will be implemented on June 6, 2018, and will enable Department personnel to authorize the use of the general permits in a timely fashion. The Department believes 60 days is adequate for a smooth transition.

Comment 38: The commentator believes that an updated TSD should be available along with the revised proposed GP-5 and 5A in order to comment on the proposal adequately. (10, 16, 28)

Response: The draft TSD was available to the public along with the proposed general permits. The final TSD has been made available to the public along with the publication of the final general permits.

Comment 39: The commentator believes that a follow-up notification should be published and a second comment period be considered due to inconsistencies between the information published in the Pennsylvania Bulletin notice of March 31, 2018. (10, 16, 28)

Response: The Department disagrees. Since inconsistencies are minor and the draft-final general permits were made available to the public prior to the commencement of the public comment period, no additional comment period is warranted.

Comment 40: The commentator requests a 3-month phase-in period allowing for a 1-month application period and 60 days for the Department to review. The longer period will ensure the Department's transition to e-permitting will be successful. (10, 16, 28)

Response: The Department disagrees. The Department is providing a delayed implementation period which will accommodate an adequate transition to e-permitting. The effective date for Exemption 38 and the final permits is August 8, 2018.

Streamlined Review and Issuance of General Permits

Comment 41: The commentator recommends that DEP evaluate the review process in regions that are consistently issuing permits within 30 days, and consider a "checklist-type" review of general permit applications rather than a full review. (10, 16, 28)

The commentator suggests that DEP prepare and distribute a "Fact Sheet" and/or develop a formal outreach program to present and explain the revised GPs and exemptions to affected operators. (29)

The commentator recommends that the GP-5A permitting program be designed to allow balancing of the permit review workload among the PADEP Regional Offices where upstream oil and gas operations occur. The commentator is also concerned about the regional offices' ability to process the applications for authorizations in the statutorily mandated 30-day timeframe. (27)

DEP should simplify the application process for both the draft GP-5 and draft GP-5A as recommended throughout these comments to reduce burden to the Department, while still maintaining the intended environmental benefit. It is also recommended that DEP develop a staffing and funding plan to address the anticipated permit application demand so that industry needs for timely permit approval can be met. (10, 28, 32)

Response: The Department appreciates the concern for the demand of Department resources for timely review of authorization requests. The Department has developed an electronic application system (e-Permitting) to expedite review of applications. This electronic application system will be implemented on June 6, 2018, and will enable Department personnel to authorize the use of the general permits in a timely fashion. This system will also allow the Department to track processing metrics and respond to temporary resource issues. Training, including a webinar, will be offered and the Department will follow-up with additional tools like fact sheets or FAQs.

Comment 42: The commentator suggests that GP-5 and 5A include provisions that allow operators to proceed if a general permit application has not been acted on in 30 days. (29)

The commentator recommends the 30-day approval requirement of the former permit guarantee program should be reinstated and applications not processed within that 30-day period should be deemed approved to assure that the needs of the regulated industry can be met. It is recommended that the DEP staff involved in the permitting and inspection of emission sources subject to GP-5 and GP-5A be provided with electric commerce capabilities similar to those in use and under development in the Oil and Gas Program. (10, 28, 32)

Response: The Department is developing e-permitting for GP-5A and GP-5 that will expedite the review process and enable the Department to authorize the use of general permits in a timely fashion.

Malfunction Reporting Requirements

Comment 43: The commentator strongly supports the requirement for operators to notify DEP within 24 hours when malfunctions occur. As in our previous comments, we request that DEP require operators to report any malfunction within an even shorter timeframe (such as one hour) and not allow for reporting delays due to weekends and holidays. (3)

GP-5 Activity Notifications (Section A.11(b)) and Malfunction Notifications (Section A11(c)) must be published for the public on the Internet. (25)

Response: The GP-5 and GP-5A Malfunction Reporting Instructions clearly state that malfunctions that may cause imminent danger are required to be reported within one hour and malfunctions that do not create imminent danger are required to be reported within 24 hours. The Department does not publish these notifications on an internet web page, however, they are publicly available documents that can be provided on request.

Methane Control

Comment 44: The Commentator indicates that the data analysis and reasoning behind the 200 tpy methane threshold is deficient. Specifically, the commentator called out the averaging used, the sparse data set, and the rational for conclusions. (31)

DEP has not provided a detailed explanation of how it arrived at 200 tpy as an appropriate threshold for methane. (28)

The commentator requests clarification on the establishment of 200 tons per year of methane as a de minimis source level. (10, 16, 28)

Response: EPA used the social cost for methane of $1,000 per metric ton (in 2012 dollars) at a discount rate of 3% in the rulemaking of NSPS Subpart OOOOa for the oil and gas industry. EPA’s social cost for methane ranges from $1,000 to $2,800 at various discount rates. The estimate of $2,800 is the 95th percentile of the social cost for methane. EPA’s conclusion is largely based on its use of a model called the Social Cost of Methane. EPA used this model to place a present-dollar value on projected future benefits to the climate from reducing methane emissions. Based on the model and the three percent discount rate that EPA used in the cost effectiveness analysis, EPA determined that every ton of methane emission that this rule prevents was worth $1,100 in 2015.

The Department used a conservative measure of $1,000/ton of methane reduced, as cost effectiveness threshold for the feasibility of methane reduction measures. The 200 tpy methane control threshold is one of four tests; others are 2.7 tpy VOC, 0.5 tpy of a single HAP, and 1.0 tpy of total HAP; to determine if glycol dehydration units, storage vessels, pumps, and pigging operations require the installation of control. Emissions greater than or equal to any one of the limits requires that the source be controlled. The Department’s BAT is applicable to each source, not to an entire facility, which is why the 200 tpy threshold is a source-specific and not a facility-wide control threshold.

The Department originally proposed a methane control threshold of 200 tpy based on calculating the amount of methane based on the VOC control threshold and an average gas composition. To calculate the methane control threshold, the Department used a standard mass-balance calculation; the general methodology for determining the methane control threshold was to calculate the amount of methane in a natural gas release relative to the amount of VOC that reaches the VOC control threshold. Using twelve different gas samples, the methane control thresholds ranged from a minimum of 21.2 tpy to a maximum of 1,615.3 tpy. The average of the twelve calculated control thresholds is 714.9 tpy, which is 17,872 tpy of CO2e. This value is nearly 25% of the 75,000 tpy of CO2e major modification facility threshold for greenhouse gases.

Therefore, the Department calculated an average gas composition from the twelve samples and followed the same methodology for determining the methane control threshold with a result of 191.6 tpy. The Department conservatively used 200 tpy methane to account for the scientific uncertainty due to the limited number of gas samples used in the calculation, which is equivalent to 5,000 tpy CO2e. This is approximately 7% of the facility greenhouse gas threshold.

Several commentators stated that the Department's calculated average gas composition was not representative of natural gas in Pennsylvania because of its small sample size and limited geographic scope. To improve the average gas composition calculation, the Department decided to expand the scope of the analysis; for every county with wells displayed on eMapPA, the Department attempted to obtain at least five reasonable representative gas analyses, two from compressor stations or processing plants, and three from unconventional natural gas well sites. The Department then calculated a county average gas composition for each county, and a state average gas composition by averaging the county average gas compositions.

The same process was followed as in the previous analysis, where methane emissions were calculated based on a standard mass-balance and the VOC control threshold of 2.7 tpy for each county. The methane control thresholds ranged from 5.8 tpy for Mercer County and 1,474.8 tpy for Somerset County with an average methane control threshold of 444.0 tpy. While this value is lower than the 714.9 tpy value of the previous analysis, the Department determined that it is unreasonable to be used as a control threshold; this is because it is approximately 15% of the major modification facility threshold for GHG. For the calculated state average composition, the methane control threshold is calculated at 51.9 tpy; this is lower than in the previous calculation because there were more representative gas analyses with VOC weight percentages higher than 2%.

The average gas composition determined in the second analysis is comparable to other sources such as E C/R Incorporated's memorandum to EPA, which was used in establishing the requirements of 40 CFR Part 60 Subparts OOOO and OOOOa. In most cases the cost-effectiveness threshold for methane control was determined to be $1,000/ton of methane reduced, which is based on an analysis of EPA's technical support document for Subpart OOOOa where the cost-effectiveness threshold appeared to be $1,000/ton based on which methane control techniques were implemented and which were not. The $1,000/ton of methane reduced also coincides with the central estimate of the Social Cost of Methane as determined by EPA in 2012.

Definitions

Comment 45: In draft final GP-5A, Section A, Condition 3 – Definitions, the commentator suggests the following revisions: "Remote Pigging Station" definition - The reference to "the exemption criteria in Category 38(b)" should be corrected to read "the exemption criteria in Category 38(c)". (29)

Response: This typographical error has been corrected in the final GP-5A.

Comment 46: The definition of modification as it is used for the revised exemption 38 criteria and the requirements of GP-5 and GP-5A is not consistent with the regulatory definition of 25 PA Code 127.1, the NSPS provisions of Part 60, and the criteria that triggers the need to conduct LDAR for the collection of fugitive emission components under 40 CFR 60.5364(i)(3) and (j). (16, 27, 31,)

Response: 25 Pa. Code § 121.1 defines a modification as it relates to a source. A source is defined as an air contamination source, which in turn is defined as "any place, facility or equipment, stationary or mobile, at, from or by reason of which there is emitted into the outdoor atmosphere any air contaminant." Under § 121.1, installing a new source (piece of equipment) at a source (facility) constitutes a modification because a physical change in a source (facility) increases the amount of an air contaminant emitted by the source (facility). This is consistent with § 60.5365a(i) and (j).

Comment 47: The commentator requests the Department define "operational design analyses". (10, 16, 28)

Response: The operational design analysis is defined in 40 CFR part 60 Subpart OOOO and OOOOa.

Comment 48: For better consistency with the corresponding definitions in the Oil and Gas Act, the definition of "Unconventional Natural Gas Well" should be revised as follows: "A well drilled to produce natural gas from shale formations below the base of the Elk Sandstone Group or its geologic equivalent stratigraphic interval, where recovery of the natural gas resource is generally not economic without the well bores being stimulated by hydraulic fracturing, multilateral well bores, or other techniques to expose more of the formation to the well bore." (29)

Response: The definition included in the proposed GP-5A was consistent with the definition from the Oil and Gas Act; however, in the final GP-5A suggested changes have been made.

Transfer of Ownership

Comment 49: There appears to be a missing word in the second sentence of paragraph 6(d) between the words "submit" and "appropriate" which should be corrected, as suggested below: "Within 30 calendar days after a transfer of ownership of the facility, the new owner or operator shall submit an appropriate form or application to the Air Program Manager of the appropriate Regional Office. (29)

Response: This typographical error has been corrected in the final GP-5A.

Comment 50: The commentator recommends that the process be simplified for the benefit of both the Department staff and operator. The commentator recommends defining "change of ownership" in the permit to mean a change in the employer ID number (Federal IRS No.) of the permittee, per the existing DEP policy. (10, 16, 28)

Response: The Department agrees. The Department has developed a simplified form for a Transfer of Ownership form. The final GPs are amended to allow the use of a change in the employer ID number (Federal IRS No.) of the permittee for the transfer of ownership.

Comment 51: The commentator requests clarification on what would satisfy the clause "...when the change of ownership is demonstrated to the satisfaction of the Department..." and what documentation would be required in a Transfer of Ownership request. The commentator recommends that the Department develop a checklist outlining the required documentation.

The commentator requests guidance on how the Department will handle a Transfer of Ownership in the event that a facility is authorized under the current GP-5 approved for use prior to the effective date of the new, revised GP-5. (10, 16, 28)

Response: The final GPs have been updated to indicate that a change in the employer I.D. number will be used to define a transfer of ownership. The Department has finalized a "Transfer of Ownership form" with a check list and instructions. The Transfer of Ownership form, checklist and instructions are available with the issued general permits.

Applicability/Scope

Comment 52: The applicability of the new GP-5 to sources is noted as "constructed" after the effective date of the revised GP-5. The commentator recommends that applicability be clarified to ensure that sources which are constructed within the allowable window of an existing and already-approved GP-5, but after the effective date of the revised GP-5, be permissible. The commentator recommends the change in language is needed to avoid confusion upon renewal of a GP-5 permit from the existing to the revised version. (10, 16, 28)

Response: The sources which are already authorized by GP-5 prior to the effective date of the final GP-5 may continue to comply with all terms and conditions of the authorized GP-5. There is no need to apply for new authorization to use the final GP-5 provided there are no modifications to a source or construction of a new source. The BAT emission limits will be unchanged during the reauthorization.

Comment 53: The commentator requests clarification on the requirement to submit an application in the event that "there is equipment or activities located on the same site or on sites that share equipment and are within 1/4 mile of each other." (10, 16, 28)

Response: Single source determinations arise when air contamination sources under common control are located on one or more contiguous or adjacent properties. These determinations will continue to be made on a fact-specific and case-by-case basis. Single source determinations are made by the Department to ensure that GP-5 and GP-5A are not authorized for sources located at major facilities.

Comment 54: In draft final GP-5A, Section A, Condition 4 - Applicability/Scope, the commentator suggests the following revisions: Paragraph 4(a) - To avoid an interpretation that an approved GP-5A must be obtained before construction of a well site or pigging station can begin, and for consistency with the wording in Condition 6(a) that refers to "sources," the first sentence of paragraph 4(a) should be revised as follows: "This General Permit authorizes the construction, modification, and/or operation of sources listed below at an unconventional natural gas well site or remote pigging station." (29)

Response: The final GP-5A was amended as requested.

Prohibited Use of the General Permit

Comment 55: Paragraph 5(c) refers to a "facility that produces or processes sour gas" (the same as the wording in the corresponding section of GP-5A) but since "production" facilities are covered by GP-5A, and this GP-5 covers "compressor stations and processing plants" it seems more appropriate that this 5(c) wording in GP-5 be changed to something like "a facility that compresses or processes sour gas". (29)

Response: The Department believes the current statement in 5(c) is sufficient.

Administrative Update

Comment 56: The commentator recommends removing the reference of 25 PA Code, § 127.450 for Condition No. A(6)(e). Additionally, the commentator recommends replacing "General Permit" with "General Permit Authorization. (10, 16, 28)

The additional conditions for administrative changes will allow for timely and efficient authorizations to be executed; however, the condition should not reference the regulation for administrative operating permit amendments [25 Pa. Code 127.450]. The commentator suggests removing the reference. We also suggest including the term General Permit Authorization where the term General Permit is used, since the modification of a General Permit requires that the Department follow the procedures codified under 25 PA Code 127.611. (27)

Response: The final general permits do not reference 25 PA Code, § 127.450 when addressing administrative amendments.

Comment 57: Paragraph 6(e) – The reference to "Condition 7(d)" in this paragraph should be corrected to read "Condition 7(e)." (29)

Response: The typographical error has been corrected in the final GP-5A.

Comment 58: Paragraph 6(f)(ii) – The reference to "unconventional natural gas well site" in this paragraph should be revised to read "unconventional natural gas well site operations" for better consistency with the defined terms and the wording in Section A, paragraph 1. Paragraph 6(f)(ii) should be revised as follows: "This General Permit may be modified, suspended, or revoked if the Department determines that the unconventional natural gas well site operations or remote pigging station cannot be adequately regulated under this General Permit." (29)

Response: The final permit has been amended as requested.

General Permit Fees

Comment 59: The commentator recommends revising the wording of section A.7(c-d) (relating to fees) to state that the fee is payable as part of the application and also payable annually on March 1st. The commentator also claims that the fee schedule is inconsistent with the fees authorized under 25 PA Code 127, Subchapter l. (10, 16, 28)

The fee schedule of Section 7 of GP-5A is not consistent with the fees authorized under 25 PA Code 127 Subchapter I. The General Plan Approval application fee with new single source determination under paragraph (b) is not specified in the regulation. 25 PA Code 127.702(i) limits the general plan approval application fees to those established via regulation.

The annual Operating permit administrative fee is required as part of the application under 127.703(a). The commentator suggests revising the wording to state that it is payable as part of the application and annually thereafter on March 1st of each year. (27)

Response: The Department disagrees. The fee of $375 is payable for the general operating permit application fee, as well as an annual operating permit administration fee. The annual operating permit administration fee is payable by March 1st for the previous calendar year. These are two separate fees and are consistent with § 127.703 (relating to operating permit fees under Subchapter F).

Comment 60: The commentator requests clarification that the fee listed in 7(b) only applies to a Transfer of Ownership where a new Single Source Determination is submitted to the Department. If this is not the case, then the commentator requests overall clarification on this section, as one could infer that the required fee for a GP-5 application for a new facility would be greater than the fees authorized by 25 Pa. Code § 127.702. The commentator also requests clarification on the required fee for a Transfer of Ownership where a new Single Source Determination is not required to be submitted to the Department. (10, 16, 28)

Under proposed GP-5 and GP-5A, there is a proposed $1,000 fee associated with making a single source determination (see Section A.7). The commentator is requesting clarification that the fee listed in 7(b) only applies to a Transfer of Ownership where a new Single Source Determination is submitted to the Department. (10, 28, 32)

Response: If the owner or operator is not modifying any existing source, not adding a new source, or not subject to a new Single Source Determination based on the transfer of ownership, the owner or operator shall submit a Transfer of Ownership form with a $300 fee. However, if the single source determination is required due to equipment or activities located on the same site or on sites that share equipment and are within 1/4 mile of each other during the transfer of ownership, the required fee is $1,000 for a new general plan approval authorization in accordance with 25 Pa. Code § 127.702(b). It should be noted that the Compliance Review needs to be conducted by the Department for any request for a Transfer of Ownership.

Compliance Requirements and Compliance Certification

Comment 61: The commentator requests clarification of the alternate procedure and process described in Condition 10(c)(ii) to replace manufacturer's requirements with an alternate procedure approved by the Department that achieves equal or greater emissions reductions in accordance with 25 Pa. Code § 127.12b. (10, 16, 28, 27)

Response: The owner or operator must demonstrate that the alternate procedure achieves equal or greater emission reductions when compared to the manufacturer's requirements.

Comment 62: The commentator requests clarification of the alternate procedure and process Paragraph 10(c)(iii) refers broadly to 25 Pa. Code 123.1 for fugitive emission requirements, but there are many temporary type activities addressed in § 123.1(a) that are not specifically covered by this GP-5 permit (such as construction, grading, clearing of land, etc.). DEP should clarify that with regard to this GP-5 permit, the 10(c)(iii) provisions only apply to the GP-5 covered sources identified in Sec. A.4. (a). (29)

Response: 25 Pa. Code 123.1 is applicable to all sources addressing fugitive emission requirements.

Notification Requirements

Comment 63: In draft final GP-5A, Section A, Condition 11 – Notification Requirements, the commentator suggests the following revisions: Paragraph 11(c)(i), related to malfunction reporting, requires use of guidance in the "GP-5 Malfunction Reporting Instructions" document. Since this is the GP-5A permit, it seems inappropriate to require use of a "GP-5" instructions document, which is written only from the GP-5 perspective. It appears that document should either be more broadly referred to as the "GP-5 & GP-5A Malfunction Reporting Instructions" and modified accordingly, or a separate set of instructions should be developed for GP-5A. (29)

Response: The final general permits refer to the "GP-5 & GP-5A Malfunction Reporting Instructions."

Comment 64: Paragraph 11(c)(i) – In the last sentence of this paragraph, the reference to "(iv)" should be corrected to "(iii)" since paragraph (iii) contains the written notification details in this latest Draft of the permit. As such, the last sentence of paragraph 11(c)(i) should be revised as follows: "Following the telephone or email notification, a written notice as specified in (iii) (iv) below shall be submitted to DEP within five business days." (29)

Response: The typographical errors have been corrected in the final general permits.

Comment 65: Section A.11(c)(i) changes the requirement from contacting the DEP regional office to contacting the DEP 24-hour emergency hotline. The rationale for this change is unclear, and the commentator recommends maintaining the current protocol. (10, 16, 28)

Response: The regional office is not staffed 24 hours a day. The 24-hour emergency hotline personnel know the appropriate people to contact in the event of an emergency.

Comment 66: DEP should also restore the 24-hour notification for scheduled blowdowns and venting events. (3)

Response: The operator is required to notify the Department no more than 24 hours after a scheduled blowdown if it results in an exceedance of an emission limit. In addition, the emissions from all scheduled blowdowns are to be included in the emission inventory report.

Comment 67: In no circumstances should DEP leave it up to operators to judge whether the malfunction and resulting emissions event poses "imminent danger" to health and safety. (3)

Response: According to the GP-5 and GP-5A Malfunction Reporting Instructions, events that pose imminent danger include fire, explosion, or an explosive or other condition with impacts outside the fence-line or require evacuation.

Comment 68: Municipal notification requirements do not provide sufficient basis for local governments to determine impact and should include PTE amounts to be listed. (25)

Response: The final general permits require the facility owner or operator to notify the local municipality and county where the air pollution source is to be located and clearly describe the proposed sources and/or modifications.

Recordkeeping Requirements

Comment 69: Section A.12(c) requires that the owner or operator of the facility shall keep records of all notifications made to the Department. "All notifications" seems overly broad, and the commentator recommends that this be clarified to reference formal notifications required under the permit conditions, and not routine inquiries or contact. (10, 16, 28)

Response: The Department has clarified in the final general permits that the owner or operator of the facility is required to keep records of all formal notifications required under the permit conditions.

Comment 70: We recommend to further reduce the burden associated with recordkeeping and reporting, specifically to eliminate duplication of already-submitted data or detailed back-up information that may be provided upon request rather than as a matter of routine. (10)

Response: In response to various public comments, the Department re-evaluated and simplified these requirements by removing redundancies. The notification, recordkeeping, and reporting requirements in the final general permits were determined to satisfy 25 Pa. Code § 127.12b and § 127.441, which include all federal notification, recordkeeping, and reporting requirements.

Comment 71: It is unclear what recordkeeping requirements exist for unloading systems that do not contribute to any air emissions. The commentator recommends that record keeping and reporting requirements under GP-5A apply to unloading methods that result in emissions to atmosphere. (10, 16, 28)

Response: The final GP-5A requires the owner or operator to maintain records of each unloading operation that result in emissions to the atmosphere.

Reporting Requirements

Comment 72: The annual reporting timing is not sufficient and we need 60 days to prepare the report. The Department should allow GP-5A permit holders the flexibility to elect to shorten their annual compliance period to comfortably align their reporting due-dates as they see best. We suggest that the Department (1) define the annual compliance period as the anniversary of the permit issuance date, and (2) require annual reporting within 60-days of the end of this reporting period. (31)

Response: The final general permits require that the reporting period specified by the owner/operator shall be no later than one year from the start of operations of the facility, unless and otherwise approved by the Department. The initial and subsequent annual reports shall be submitted within 60 days of the end of the reporting periods.

Comment 73: The commentator requests clarification as to what communications required by GP-5A must be submitted to PA DEP, U.S. Environmental Protection Agency (U.S. EPA), or both. The commentator also recommends distinguishing the annual report required by NSPS or National Emission Standards for Hazardous Air Pollutants (NESHAP) rules from the annual report required by GP-5A. (10, 16, 28)

Response: The Department is the delegated administrator of the federal regulations and is aware that operators submit reports to the Department to comply with those regulations. However, the Department finds the manner in which this information is submitted to be unmanageable and desires to streamline the requirements to reduce the administrative burden on both the operator and the Department. Rather than file separate reports in accordance with the many applicable federal regulations, some of which are required more frequently than once each year, the Department opted to consolidate them into a single report. The submission of records as part of the annual report is consistent with the federal regulations, and only apply to the records collected for the term of the annual period contained in the report.

Comment 74: The commentator requests that the annual report required under section A13(C) has a specified compliance period and a due date that is at least 60 days following the end of the compliance period. The specific date may be chosen by the permittee or include several options for timeframes from which the permittee could choose (e.g., report April from March (due by July 1); report July through June (due October 1)). If the permittee is allowed to choose the initial compliance period, the commentator requests flexibility to file an initial report with less than a full year's data in order to group multiple facilities on the same schedule, which is permissible under standards such as NSPS OOOOa. (10, 16, 28)

Response: The final general permits require that the reporting period specified by the owner/operator shall be no later than one year from the start of operations of the facility, unless and otherwise approved by the Department. The initial and subsequent annual reports shall be submitted within 60 days of the end of the reporting periods.

Comment 75: The commentator requests flexibility to file an initial report with less than a full year's data in order to group multiple facilities on the same schedule, which is permissible under standards such as NSPS OOOOa if the permittee is allowed to choose the initial compliance period. (10, 16, 28)

Response: The final general permits have been revised to allow the flexibility to submit a report on an alternate schedule approved by the Department.

Comment 76: The commentator recommends using the NSPS OOOOa concept of "certifying official" (rather than "certifying Responsible Official") to authorize operations personnel to sign annual reports required by the general permits. (10, 16, 28)

Response: The term "Responsible Official" is defined at 25 Pa. Code Section 121.1. The term allows any individual in charge of a principal business function, or another person who performs similar policy or decision-making functions for the corporation, or an authorized representative of the person if the representative is responsible for the overall operation of the facility.

EPA certifying official provisions of NSPS, Subpart OOOO regulations deal only with notification, reporting and record-keeping requirements, whereas the responsible official provisions of the general permits deal with certifying compliance with all terms and conditions. Therefore, the final general permits must retain the annual compliance certification requirement for responsible officials.

Comment 77: A.13(c)(viii) requires the submission of the background information. The Department has not provided justification for this additional reporting requirement, and the commentator requests that it be removed from the general permits. (10, 16, 28)

Response: Condition A.13(c)(viii) of the final general permits requires the identification of each permit term or condition that is the basis of the certification, the compliance status, and the methods used for determining the compliance status of the source, currently and over the reporting period as identified in Sections B through N of the general permits.

Comment 78: Under section A.13(c)(ix), the permittee is required to maintain records demonstrating compliance with the permit emissions limits. Additionally, each facility submits annual emissions data to DEP. Requiring additional submittals of emissions data is duplicative, and the language is unclear regarding what to submit (i.e., does the permittee need to submit 12-month rolling total values for the compliance period?). This condition should be removed.

Response: The monthly recordkeeping is necessary to demonstrate that the facility is not a Title V facility and that the facility is in compliance with facility-wide emission limits. The facility-wide emission limits are determined on a 12-month rolling basis.

Comment 79: The commentator requests condition A.13(c)(x) of GP-5A be removed due to its unclear and duplicative nature. (10, 16, 28)

Response: Section A Condition 13 addresses the annual reporting requirements. Condition 13(c)(x) requires the operator to submit the records of Section A Condition 12(b) for the reporting period in the annual report. It is not a duplicative requirement.

Comment 80: The intent of the language in A.13(d), "The inventory report shall include all emissions information for all sources operated during the preceding calendar year from the annual report required in (c) above," is unclear and should be clarified to delineate what is meant by "all emissions information" as this phrase seems overly broad. Also, the commentator recommends deleting "from the annual report required in (c) above" because it is confusing and unnecessary. (10, 16, 28)

Section A.l3(d). Reporting Requirements, Subpart (d) includes a statement that "Emissions data including, but not limited, to the following shall be reported (emphasis added) We recommend modifying the sentence to read "Emissions data for the following shall be reported." If an emission is not expressly listed in the permit, then the operator shouldn't be required to report on it. (28)

Response: The final general permit Condition No. 13(d) is a requirement under 25 Pa. Code § 135.3 that requires the owner or operator of a facility to submit to the Department by March 1st of each year, a facility inventory report for the preceding calendar year for all sources controlled under the general permit. This condition provides flexibility for the owner or operator to report any additional pollutant emitted from the facility. Therefore, the condition has been retained.

Comment 81: The commentator recommends that the annual report timing be updated to provide more flexibility. (10, 28, 32)

Response: The final general permits require that the reporting period specified by the owner/operator shall be no later than one year from the start of operations of the facility, unless and otherwise approved by the Department. The initial and subsequent annual reports shall be submitted within 60 days of the end of the reporting periods.

Comment 82: Reporting requirements must disclose which wells are connected to which compressor stations. (25)

Response: Single source determinations arise when air contamination sources under common control are located on one or more contiguous or adjacent properties. These determinations will continue to be made on a fact-specific and case-by-case basis. The applications for the general permits require owners and operators to disclose all sources within 1/4 mile of the facility seeking authorization.

Source Testing Requirements

Comment 83: Stack testing should not be required for engines under 500 hp. (31)

Response: Testing requirements for engines under 500 hp are consistent with 40 CFR Part 60 Subpart JJJJ.

Comment 84: Testing protocols should not be required 60 days prior to the test date. 30 days should be sufficient. Also, the operator should be able to submit one master testing protocol to cover future testing. The commentator suggested the following wording. "An Operator may request the use of a single Test Protocol that covers testing of all currently operated and future natural gas-fired compressor engines in service at that Operator's various facilities. In such a request, the Operator will submit the Test Protocol in accordance (d) above for review and approval, and include a list of currently permitted engines (to be updated as necessary when engines are installed or removed)." (31)

Response: The final general permits require the owner or operator to submit a test protocol at least 60 calendar days prior to commencing an emission testing program to demonstrate compliance required by this General Permit.

The Department may develop a standardized test protocol for performance testing and will provide a public comment period prior to finalizing the test protocol.

The final general permits allow that an operator may request an approval from the Department for a test protocol that covers testing of all currently operated and future sources in service at that operator's various facilities. In such a request, the operator will submit the test protocol for review and approval and include a list of currently permitted engines (to be updated as necessary when engines are installed or removed). If the owner or operator has a test protocol, previously approved by the Department, a new test protocol does not need to be submitted for review/approval, provided that there are no changes, including the testing contractor, and the owner/operator agrees to comply with all conditions of acceptance in the letter approving the protocol.

Comment 85: A.14(f) — The commentator requests that testing protocol submittal for Department review should be required 60 days prior to test date reflecting requirements in the approved Department's Source Testing Manual. (10, 16, 28)

Response: The final general permits require the owner or operator to submit a test protocol at least 60 calendar days prior to commencing an emission testing program to demonstrate compliance required by this General Permit.

Comment 86: The commentator recommends creating a stakeholder group consisting of DEP source testing, industry representatives and the air quality source testing industry in order to prepare standardized protocols for performance and periodic testing. (10, 16, 28, 20)

Response: The Department may develop a standardized test protocol for performance testing and will provide a public comment period prior to finalizing the test protocol.

Comment 87: A.14(f) In lieu of a separate protocol for each test and for each engine, the commentators recommend that the Operator have the option to submit one ‘master" protocol to cover future testing. The commentator recommends the wording:

"An Operator may request the use of a single Test Protocol that covers testing of all currently operated and future natural gas-fired compressor engines in service at that Operator's various facilities. In such a request, the Operator will submit the Test Protocol in accordance (d) above for review and approval. and include a list of currently permitted engines (to be updated as necessary when engines are installed or removed)."

or

"An Operator may request the use of a single Test Protocol that covers testing of all currently operated and future natural gas-fired compressor engines in service at that Operator's various facilities. In such a request, the Operator will submit the Test Protocol in accordance (d) above for review and approval and include a list of currently permitted engines (to be updated as necessary when engines are installed or removed)." (10, 16, 28, 32)

Response: The final general permits state that an operator may request an approval from the Department for a test protocol that covers testing of all currently operated and future sources in service at that operator's various facilities. In such a request, the operator must submit the test protocol for review and approval and include a list of currently permitted engines (to be updated as necessary when engines are installed or removed). If the owner or operator has a test protocol, previously approved by the Department, a new test protocol does not need to be submitted for review/approval; provided that there are no changes, including the testing contractor, and the owner/operator agrees to comply with all conditions of acceptance in the letter approving the protocol.

Comment 88: Under Section A.14(f), the time for notification of a stack test date and time has increased from 30 to 45 days. The commentator recommends that the 30-day timeframe be retained, as notification so far out (45 days) leads to inaccuracies that may be beyond the operator's control. (10, 16, 28, 32)

Response: The final general permits require at least 30 calendar days prior to commencing an emission testing program to notify the Department, in writing of the date and time of testing so that an observer may be present.

Comment 89: In the draft final GP-5A and GP-5, Section A General Requirements, condition 14(b) was added that allows DEP to "alter" the frequency of performance testing. The commentator suggests that this provision be revised to replace the term *"alter"* with the term *"reduce"* because the provisions should already reflect the maximum level of performance testing for affected sources. (29)

Response: The Department disagrees with the commentator that the frequency of performance testing in the general permits reflect the maximum level of performance testing. The frequency of performance testing may also be altered upon request of the owner or operator with written Departmental approval if the test results are consistently below allowable emission limits, unless required by federal regulation.

Comment 90: In the draft final GP-5A, Section A, Condition 14 – Source Testing Requirements, the commentator suggests the following revisions:

Paragraph 14(e) – In the first sentence of this paragraph, the word "through" should be deleted.

Paragraph 14(f) – The reference to "(d)" in this paragraph should be corrected to "(e)".

Paragraph 14(h) – The wording associated with how to submit this electronic notification should be revised as shown below, to avoid confusion with the referenced paragraph (d) [which appears intended to refer to (e)], which would also require two copies to be submitted by either hand-delivery, courier, or certified mails, which does not appear to be intended here. This paragraph should be revised as follows: "Within 15 calendar days after completion of the on-site testing portion of an emission test program to demonstrate compliance required by this General Permit, if a complete test report has not yet been submitted, an electronic notification shall be submitted to the Air Program Manager of the appropriate DEP Regional Office in accordance with (d) above indicating the completion date of the on-site testing."

Paragraph 14(i) – The reference to "(d)" in the first sentence of this paragraph should be corrected to "(e)". (29)

Response: The typographical errors noted above have been corrected in the final general permits.

Comment 91: The commentators request that DEP incorporate test methods approved by U.S. EPA for the measurement of volatile organic compounds ("NMNEHC") and formaldehyde ("HCHO"). Including U.S. EPA methods 18, 320, 25A, and ASTM 6348-03 (9, 12)

Response: The owner or operator should use the ALT-106 method to measure the NMNEHC concentration, as propane, excluding formaldehyde and Method 320 to measure formaldehyde to obtain more accurate results. All testing, with the exception of periodic monitoring, shall be performed in accordance with any applicable federal regulations, 25 Pa. Code, Chapter 139, and the current version of the Department's Source Testing Manual, or an alternative test method as approved by the Department.

Comment 92: In section A.14(d), related to Source Testing Requirements, DEP requests that in addition to electronic copies, two hard copies of all reports, protocols, and notifications must be submitted. The provision of multiple hard copies is redundant and not necessary. (28)

Response: The final general permits require "one electronic copy and one printed copy of all reports, protocols, and test completion notifications, with the exception of periodic monitoring data, shall be submitted either by hand-delivery, courier, or sent by certified mail, return receipt requested, to the Air

Program Manager of the appropriate DEP Regional Office and to the PSIMS Administrator for the Source Testing Section in DEP's Central Office."

De Minimis Requirements

Comment 93: A.15(a)(i) The commentator requests confirmation that when a like-kind replacement is being considered under the de minimis provisions, the emissions decrease from the equipment being removed can be accounted for, such that the change in emissions resulting from the replacement is what is compared against the de minimis thresholds. (10, 16, 28)

Response: In accordance with 25 Pa. Code Chapter 127, the Department considers the installation of "in-kind" replacement of sources as new sources subject to BAT requirements. The final general permits allow replacement of equipment at the facility with identical equipment without additional authorization provided that the owner or operator complies with the requirements of 25 Pa. Code § 127.449(a), (b), and (d) through (i), and the equipment being replaced meets the current applicable BAT compliance requirements and other conditions of the permits.

Comment 94: A.15(a)(i) requires replacement with the current BAT requirements detailed in the GP-5. The commentator requests the Department consider the option for the operator to present situations where replacement of equipment, due to catastrophic failure, may demonstrate that replacement with more restrictive BAT limitations is not technically or economically feasible. Examples would be where insufficient space is available for new equipment needed to meet BAT requirements or where significant costs for support equipment, such as cooling capacity for an engine, are in excess of the cost presented in the final TSD. (10, 16, 28)

Response: In the event of a catastrophic failure, the owner or operator may submit a Request for Determination (RFD) form for a temporary installation. For a permanent installation, the owner or operator may submit a GP application or a plan approval application for a case-by-case BAT determination.

Comment 95: Under A.15(a)(iii)(A), for certain processes multiple pieces of equipment are integrated. As such, there is no specific serial number for the emission unit. The commentator recommends that this requirement be changed to read "The manufacturer, model, rated capacity, and serial number of the equipment as appropriate." (10, 16, 28)

Response: In the final general permits, the owner or operator is required to provide a written notification to include the manufacturer, model, rated capacity, and serial number of the equipment. If multiple pieces of equipment are integrated, a specific serial number for such an integrated source can be included in the notification.

Comment 96: A.15(a)(iii)(B) & (C) are redundant to the requirements for using the GP-5, therefore the annual compliance certification and should be removed. (10, 16, 28)

Response: The notification and annual reporting requirements are not redundant since the GP-5 and GP-5A require a single report satisfying both applicable federal and state requirements. In addition, the annual emissions inventory report is required under 25 Pa. Code § 135.3 (related to reporting). The compliance certification requirement in GP-5 provides a means to certify compliance with the terms and conditions in the general permit.

Comment 97: It appears that the reference in paragraph 15(b) to "GP-5A" in this GP-5 Condition should be corrected to read "GP-5". (29)

Response: The typographical error has been corrected in the final GP-5.

Comment 98: In draft final GP-5A, Section A, Condition 15 – De Minimis Emissions Increases, the commentator suggests the following revisions: Paragraph 15(b) – The end of the sentence in Condition 15(b) refers to "Section M Condition 1(c)," but there is no "Section M" in this GP-5A permit. The reference to "Section M" appears to possibly be an incorrect carry-over from the GP-5 permit where a Section M does appear for turbines. The reference to "Section M Condition 1(c)" in this paragraph appears to be erroneous and should be deleted. (29)

Response: The typographical error has been corrected in the final GP-5A.

Comments on the Technical Support Document

Comment 99: The commentator states that the cost evaluation for combustion control devices in section D of the TSD is flawed. The Department relies on one Vendor quote of $25,102 Total Purchased Equipment Cost where the commentator's investigation of controls in 2013 with a vendor were more than $50,000 purchase cost. Also, the US EPA has determined it is not appropriate to conduct "multipollutant cost-effectiveness." In Table 24, the reductions of VOC and HAP are added when calculating the cost per ton reduced, but is likely double-counting because these HAPs are typically also VOCs. The USEPA has a precedent for the cost-effective threshold of VOC for ozone non-attainment areas at $5,700 per ton. (31)

Response: The Department believes that if a control technology controls more than one pollutant, then it is appropriate to conduct a multi-pollutant cost-effectiveness analysis. The Department has used actual quotes from the vendors to perform the cost-effectiveness analysis and determined that it is cost-effective to control a source with combustion control technology when uncontrolled emissions exceed methane, VOC, and HAP control thresholds.

Comment 100: The commentators state that one of many errors in the methane control threshold analysis is the assumption that there is a direct relationship between VOC, an ozone precursor, and methane, a non-VOC and GHG. Another is establishing emission rates above which control is required using BAT and below which are de minimis. Another error is the assumption that the concentrations of methane and VOC in natural gas extracted in Pennsylvania can be averaged to provide a statistically significant relationship even though the VOC content of the natural gas can range from less than 1% to 20%. Compounding this already flawed approach is the statistically insignificant number of natural gas samples used in the averaging. Therefore, the general methodology to calculate the methane in a natural gas release relative to the amount of VOC that reaches the 2.7 tpy de minimis level and the corresponding 200 tpy methane control threshold is severely flawed. (10, 16, 28)

Response: The commentators are incorrect about methane's role as a ozone precursor. In EPA's 2009 Endangerment Finding and the preamble to 40 CFR Part 60 Subpart OOOOa, EPA states that in addition to being a GHG, methane is also a precursor to ground level ozone, which can cause a number of harmful effects on public health and the environment. Exposure to ozone can cause respiratory system effects such as difficulty breathing and airway inflammation. In addition, long-term exposure to ozone is likely to result in harmful respiratory effects, including respiratory symptoms and the development of asthma.

There are also independent peer-reviewed studies which indicate that shale gas development is associated with the production of secondary pollutants such as tropospheric (ground-level) ozone, which is formed through the interaction of methane, VOC, and nitrogen oxides (NOx) in the presence of sunlight. Tropospheric ozone is a strong respiratory irritant associated with increased respiratory and cardiovascular morbidity and mortality. Although toxicological data suggest that pure methane is not by itself health damaging (excluding its role as an asphyxiant and an explosive), it is a precursor to global tropospheric ozone. See the final TSD for more information.

Pennsylvania Code Title 25 requires that all new sources control the emissions to the maximum extent, consistent with the BAT as determined by the Department at the time of issuance of a plan approval. BAT is an evolving standard and is defined as equipment, devices, methods or techniques as determined by the Department which will prevent, reduce or control emissions of air contaminants to the maximum degree possible and which are available or may be made available. The Department has evaluated various control technologies and determined BAT for specific sources emitting respective pollutants above certain thresholds when a technology was found to be technically and economically feasible. These determinations are available in the final TSD.

The Department is required to issue a General Permit that must have standardized terms and conditions for all sources within the state of Pennsylvania. To that end, the Department averaged natural gas compositions to use in establishing BAT. See Appendix A of the final TSD. The Department conducted an expanded analysis, as suggested by commentators in the first comment period, to determine a more representative state average gas composition using nearly five times the previous sample size with a wider geographic distribution and varying VOC content. The re-analysis can be found in the final TSD, see Appendix A. The result is a control threshold of 51.9 tpy of methane. However, that is only one part of a BAT determination and the cost analysis shows that a control threshold of 51.9 tpy is not economically feasible. The 200 tpy control threshold is economically feasible, however at only half of the cost-effectiveness threshold. The linear interpolation at the EPA's Social Cost of Methane is a control threshold of 158 tpy of methane. However, due to the scientific uncertainty in the gas analysis, and site-specific uncertainty of control costs, the Department conservatively maintained the 200 tpy methane control threshold.

Comment 101: Based on a review of DEP's analyses presented in the TSD that accompanied the draft general permits, it was determined that certain controls do not appear to be justified by an adequate cost-effectiveness analysis and certain controls were determined to represent BAT based on incomplete or inaccurate data. The following cost analysis for control of emissions from pigging operations and pneumatic pumps are missing. (10, 28, 32)

Response: The cost analysis for pigging operations and pneumatic pumps are detailed in Appendix D of the TSD. The Department calculates the cost-effectiveness and establishes BAT for sources that have emissions above the control thresholds such as glycol dehydrators, storage tanks, pneumatic pumps, and pigging operations.

Comment 102: The commentator states that the Department's LDAR cost analysis was flawed as it is illogical to base estimated emissions on a super-emitter leak rate that is based upon a value that an instrument is capable of measuring. These extremely high leak rates drive the cost effectiveness evaluations presented in the TSD, which is based on costs and component counts provided from LDAR contractors and not from operator data from actual program implementation. Also, the Department did not consider the cost for repair of identified leaks despite noting that such costs can vary significantly. Therefore, the Department has severely underestimated the costs. The commentator states that costs to control methane are 9 to 31 times higher at a semi-annual frequency and 5 to 28 times higher at a quarterly monitoring frequency when compared to the EDF and ONE Future studies cited in the TSD. (32, 10, 16, 28)

Response: The Department has performed independent cost-analysis for LDAR requirements and determined that quarterly monitoring using OGI is cost-effective. The detailed cost-analysis can be found in the TSD.

NATURAL GAS-FIRED COMBUSTION UNITS – Section C of GP-5 and Section E of GP-5A

Comment 103: In the TSD published February 4, 2017, DEP does not address BAT for heaters in any fashion, including showing that this limit is technically feasible and cost-effective in reducing NO_x emissions. The commentator requests that the technical support and BAT determination be provided. The commentator also requests that for heaters installed after the effective date of the GP-5, Section L.1(b)(i) read similar to the GP-5 permit with a NO_x limit of 30 ppmvd @ 3% O_2. (10, 16, 28)

PA DEP has proposed emission limitations in the table of Section L.l(b)(i) that are rated between 10 mmbtu/hr and 50 mmbtu/hr. The commentator does not believe that the Department has met its burden that these limitations meet the definition for BAT. The commentator believes that the new requirement of 15 ppmvd for NO_x is not practicable and does not fall within BAT guidelines. (10, 16, 28)

Response: The Department has found that there are few vendors that offer natural gas-fired combustion units with a NOx emission rate of lower than 30 ppmvd corrected at 3% oxygen. These units are typically used in production facilities for producing steam. GP-5 includes combustion units including, but not limited to, heated flash separator units, evaporator units, fractionation column heaters, and glycol dehydrator reboilers. Typically, these combustion units are rated at less than 10 MMBtu/hr, which are exempted from permitting. Due to the availability of limited emissions data for units operating at natural gas production, compression and transmission facilities, the Department has established a NOx emission limit for natural gas-fired combustion units at 30 ppmvd corrected @3% oxygen. The Department will continue to evaluate NOx emissions data from these units.

Comment 104: In draft final GP-5, the commentator suggests deletion of Section L, Condition 4(b)(iv)(C) filterable and condensable particulate matter (PM) testing requirements for natural gas fired combustion units. PM emissions testing of small combustion units is overly burdensome with no resulting environmental benefit. Natural gas is an inherently clean burning fuel and accurate emissions factors are available for combustion units fired by natural gas. (29)

Response: The final GP-5 does not require PM emissions testing for a combustion unit.

Comment 105: With respect to sections L.4(b)(i), L.4(c), & L.5(b)(i) the commentator requests the language related to performance testing load requirements be revised to be consistent with the federal regulations (ex. NSPS Subpart JJJJ): “within 10 percent of 100 percent peak (or the highest achievable) load”. The current language is confusing and may lead to various interpretations. (10, 16, 28)

Response: Conditions 4(b)(i) and 5(b)(i) of the final GP-5 have been amended to read that performance testing and periodic monitoring should be conducted within 10% of 100% peak (or the highest achievable) load.

GLYCOL DEHYDRATION UNITS – Section D of GP-5 and Section F of GP-5A

Comment 106: The commentator requests confirmation that the Glycol Dehydrator's flash tank is still a piece of process equipment as stated in the 12/11/2015 FAQ. (31)

Response: A flash tank is included as part of the glycol dehydrator's emissions. The flash tank emissions are typically routed to the reboiler for fuel and are controlled in accordance with 40 CFR Part 60 Subparts OOOO and OOOOa and 40 CFR Part 63 Subpart HH.

Comment 107: Dehydrator PTE calculations are determined by modeling based on assumed and constant gas composition. This assumption is invalid since gas composition can vary widely. DEP must require PTE amounts for dehydrators to be periodically recalculated based on measured gas analysis from the wells that feed that dehydrator. DEP must require up-to-date gas analysis reporting in GP-5A. (25)

Response: The Department agrees that the gas composition can vary and that it is critical for estimation of emissions. The final general permits require the operator to submit representative gas analyses with their application. Emissions calculations are required to be performed for glycol dehydration units using software such as GRI-GlyCalc. Section A, Condition 10(a) of the final general permits requires the emissions from all sources and associated air pollution control equipment located at a facility to be less than the major source thresholds on a 12-month rolling sum basis. Section A, Condition 12(b) of the final general permits requires the owner or operator of the facility to maintain records that clearly demonstrate to the Department that the facility is not a Title V facility.

Comment 108: The commentator recommends that references to Section J in sections B(1)(a) and B.1.b categories be removed — options include either removing the phrase "that meets the applicable requirements in Section J" or to remove testing requirements for control devices already installed and approved under existing GP-5 permits, Exemption 38, or other authorization. (10, 16, 28)

Response: The final general permit Condition 1(a)(iii) has been revised as follows: "The owner or operator must conduct performance tests in accordance with Condition 4 within 180 days of each reauthorization **unless**: The combustion control device is a manufacturer-tested model tested in accordance with 40 CFR § 60.5413(d) or § 60.5413a(d); A performance test conducted on a device of the same make and model in similar service at another facility within the Commonwealth upon approval by the Department may be used to satisfy this requirement. The Department may use EPA's National Stack Testing Guidance for stack test waivers; **or** the combustion control device established a correlation between the outlet TOC performance level and the firebox or combustion chamber temperature during the initial performance test."

Comment 109: In the draft final GP-5A, Section B(1)(a) Glycol Dehydration Units, it's not clear why this Condition is referring to glycol dehydration units constructed and operated under "GP-5." Are there glycol dehydration units that have previously been authorized under GP-5 that will now be covered by this GP-5A, or is this reference to "GP-5" incorrect here in GP-5A? (29)

Response: Prior to February 2, 2013, GP-5 was applicable for dehydrator use at natural gas production facilities. Therefore, the previous GP-5 condition is referenced in the final GP-5A.

Comment 110: GP-5, section B.1(d) should refer to "natural gas driven pneumatic diaphragm pumps" to maintain consistency with GP-5A which was previously corrected. (31)

The commentator requests that similar language in the GP-5A concerning pneumatic pumps be used in Section B.l(d). Specifically replacing the language in the issued draft with the following. "Associated equipment, such as controllers (Section H), natural gas driven pneumatic diaphragm pumps (Section l), and fugitive emissions components (Section G) are subject to the requirements of their respective Sections." (10, 16, 28)

Response: The final GP-5 and GP-5A remove the reference to natural gas driven pneumatic diaphragm pumps (Section I). It is understood that natural gas driven pneumatic diaphragm pumps are not installed at dehydrators.

Comment 111: The replication of 40 CFR Part 63 Subpart HH in Section B, Glycol Dehydration Units, should be deleted. Refer to draft requirements Section B.1(e), (2), and (3)(a). (31)

Response: These requirements were incorporated by reference in the final general permits.

Comment 112: It appears that the reference to "40 CFR § 63.764(d)(2)(iii)" in section 1(e)(v) should be corrected to read "40 CFR § 63.764(d)(2)(ii)". (29)

Response: The final general permits have been corrected as recommended.

STATIONARY NATURAL GAS-FIRED SPARK IGNITION INTERNAL COMBUSTION ENGINES – Section C of GP-5 and GP-5A

Comment 113: The commentator states that in the draft final GP-5A, Condition 1(b) should be changed from "GP-5" to "GP-5A". (29)

Response: The suggested edit was not made, as it incorporates the standards for engines that are installed at well sites under the previous version of GP-5 issued February 2, 3013.

Comment 114: The commentator states that the proposed limits of CO for rich burn engines rated at 30 hp or less are not achievable. (27)

The commentator requests that emission limitations on 1-100 hp rich burn engines be kept at the current GP-5 levels. (10, 16, 28)

Response: The emission limitations for rich burn engines less than 100 hp included in the final general permits are consistent with the emission limitations for engines in 40 CFR Part 60 Subpart JJJJ.

Comment 115: The commentators state that Condition 1(c)(i) includes emissions limitations on engines which categorically are exempt (<100 hp) or that qualify for the NO_x emission limit exemption (6.6 tpy, etc.). To avoid confusion, the GP-5 requirements should be consistent with the existing list of exemptions. (10, 16, 28)

Response: The emission limitations for engines less than 100 hp included in the final general permits are consistent with the emission limitations for engines in 40 CFR Part 60 Subpart JJJJ.

Comment 116: The commentator believes that the Department should make three alterations to the final general permits in order to ensure that lean burn engines are properly classified according to their relative power categories and that the effective date for larger lean-burn engines more appropriately reflects the time period in which new technology for larger engines can become widely available. First, the DEP should modify the proposed "mid-size" lean-burn power range category of greater than or equal to 500 hp but less than 2,370 hp to a narrower range of greater than or equal to 500 hp but less than 1,750 hp. Next, the Department should make a conforming change to the highest power range category (i.e., all engines rated greater than or equal to 1,750 hp). Finally, the DEP should include an effective date for the highest power range category for lean burn engines of January 1, 2021. (9)

The commentators believe that the 0.5 g/bhp-h NO_x emission limit be maintained for lean burn engines rated greater than or equal to 1,875 hp, as per the commentators previously submitted comments. (10, 16, 28)

The commentators state that the emission limits for natural gas-fired lean burn engines rated at 2,370 bhp and above are too stringent. The current TSD fails to justify the $10,000/ton of NOx reduced cost threshold, the issue of technical feasibility for SCR, or whether the proposed standards have been achieved in practice for similar units. Therefore, the commentator recommends that the DEP retain the NOx standard of 0.5 g/bhp-h for lean burn engines or delay implementation of the more stringent NOx limits for 2 years to ensure product availability as currently only one manufacturer offers 0.3 g/bhp-h lean burn engines. However, if DEP is going to assign a specific emission rate, then only a single emission rate should be defined and not two different values, as shown by the "controlled" and "uncontrolled" emission rates provided in the general permits for larger reciprocating engines and larger turbines. (12, IES, 10, 28, 32)

Response: New sources are required to control the emission of air pollutants to the maximum extent, consistent with the BAT as determined by the Department. BAT is defined in 25 Pa. Code § 121.1 as equipment, devices, methods or techniques as determined by the Department which will prevent, reduce or control emissions of air contaminants to the maximum degree possible and which are available or may be made available. The resources utilized in the determination of BAT include BAT included in the plan approvals which are determined on a case-by-case basis, general permits, and other permits issued by other states, for similar sources. The Department also evaluated vendors' guaranteed emission limits, available stack test data, and stakeholders' submitted data for the applicable sources. The emission limitations included in the GP-5 must be technically and economically achievable. In addition, these emission limitations must be sustainable during the life of the unit. The Department has determined that the emission limitations in the final GP-5 and GP-5A constitute BAT. Details of the technical and economic feasibility can be found in the TSD.

The Department has established a NOx emission limit of 0.5 g/bhp-h for lean-burn engines rated greater than 500 and less than 2,370 bhp. The Department has determined that SCR technology is technically and economically feasible for engines rated at or above 2,370 bhp unless the uncontrolled NOx emission rate is 0.3 g/bhp-h.

The emission limits included in the final general permits for lean-burn engines are currently achievable and therefore, delayed compliance for the highest power range category for lean burn engines until January 1, 2021 is not necessary.

Comment 117: The commentator states that attaining the present NMNEHC (excluding HCHO) standard of 0.25 g/bhp-h as proposed for new natural gas-fired lean-burn engines rated at 500 bhp and above would require the use of high-quality natural gas. The commentator recommends that a 0.7 g/bhp-h NMNEHC standard be allowed for engines operating on non-typical fuels along with either the 0.3 or 0.05 g/bhp-h standard for NOx. (12)

Response: The 0.25 g NMNEHC/bhp-h emission limit is BAT for lean-burn engines rated greater than or equal to 500 hp established February 2, 2013, in the previous version of GP-5. The limit was established based on engineering calculations and corroborated by stack test results. The owner or operator may apply for a case-by-case BAT determination through a Plan Approval using unique site-specific factors.

Comment 118: The commentator maintains that Selective Catalytic Reduction (SCR) is not technically or economically feasible based on the supporting data. The commentator provided a detailed economic evaluation regarding the use of SCR on engines in previous comments; with the evaluation showing SCR is not economically feasible. Therefore, the commentator believes that the requirement for SCR should be removed; since SCRs are complex and that general permits are to regulate using “standardized specifications and conditions”. (10, 16, 28)

Response: The Department has determined that SCR technology is technically and economically feasible for engines rated at or above 2,370 bhp unless the uncontrolled NO_x emission rate is 0.3 g/bhp-h. Details of the technical and economic feasibility can be found in the TSD.

Comment 119: The commentators state that Condition l(d)(v) includes periodic monitoring (stack testing for NO_x and CO) for engines in the two ranges of “< 100 hp” and “100 hp – 500 hp” which has not been supported by the Department and should be deleted. (10, 16, 28)

Response: Testing and Monitoring requirements for engines in the two ranges of < 100 hp and 100 hp – 500 hp are consistent with the federal requirements.

Comment 120: The commentator states that Condition 1(d)(v) should be modified from “…as detailed in Condition 5...” to “…as detailed in Conditions 4 and 5...” since performance tests are addressed in Condition 4 and periodic monitoring is addressed in Condition 5. (29)

The commentator states that in the table of Condition 1(d)(v) the second row of the Engine Size column should be changed from “≤100 - ≤500” to “≥100 - ≤500.” (29)

The commentator states that the reference to “Section A Condition 14(h)” in Condition 2(g) should be corrected to “Section A Condition 14(i)”. (29)

The commentator states that the references to “Section A Condition 14(e)” in Condition 4(a) should be corrected to “Section A Condition 14(f).” (29)

Response: The typographical errors discussed above have been corrected in the final GPs.

Comment 121: The commentator suggests that Condition 1(d)(v)(C) of the draft final GP-5A be revised from “The Department may alter the frequency of periodic monitoring” to “The Department may reduce the frequency of periodic monitoring” The proposed periodic monitoring interval should already reflect the maximum level of performance testing for affected sources. (29)

Response: The Department disagrees with the commentator that the frequency of periodic monitoring in the general permits reflect the maximum level of performance testing. If the periodic monitoring test results warrant, the Department may require the owner or operator to perform a reference method test prior to the next scheduled periodic monitoring test required by the general permits. The frequency of periodic monitoring may also be altered upon request of the owner or operator with written Departmental approval if the periodic monitoring test results are consistently below allowable NO_x and CO emission limits.

Comment 122: The commentator states that the final GP-5 and GP-5A requirements should assure that all US EPA-approved test methods are allowed for the measurement of volatile organic compounds (NMNEHC). (See 40 C.F.R. Pan 60, Subpart JJJJ, Table 2). (12)

Response: The owner or operator should use the ALT-106 method to measure the NMNEHC concentration, as propane, excluding formaldehyde and Method 320 to measure formaldehyde to obtain more accurate results. All testing, with the exception of periodic monitoring, shall be performed in accordance with any applicable federal regulations, 25 Pa. Code, Chapter 139, and the current version of the Department’s Source Testing Manual, or an alternative test method as approved by the Department.

Comment 123: The commentator requests that US EPA Method 320 be added as an accepted test method in Condition 4(b)(iv)(C) & (D). (10, 16, 28)

Response: Operators can use any valid method described in a test protocol and approved by the Department. The methods listed are preferred methods, and are not required to be used. All performance tests must submit a test protocol in accordance with Section A Condition 14(f).

Comment 124: The commentator states that Condition 4(b)(iv) refers to “…the determination of the O2 concentration in (iii)(B) above” However, Condition 4(b)(iii)(B) does not appear to require an O2 determination. There is an O2 determination requirement in (iii)(A), so should the first sentence on this Condition should be revised to “Simultaneous to the determination of the O2 concentration in (iii)(A)(B) above, determine:”. (29)

Response: Method 3A of 40 CFR Part 60, Appendix A-2 is used to determine the O2 concentration of the exhaust. Both Condition 4(b)(iii)(A) and 4(b)(iii)(B) require Method 3A to be used, so Condition 4(b)(iv) will be revised to “Simultaneous to the determination of the O2 concentration in (iii)(A) or (B) above, determine:”

Comment 125: The commentator requests that the language of Condition 4(c) related to performance testing load requirements be revised to be consistent with the federal regulations (i.e., within 10 percent of 100 percent peak (or the highest achievable) load). (10, 16, 28)

Response: The condition cannot be amended as recommended because it establishes a requirement that an owner or operator that operates the engine in excess of the highest achievable load plus 10% must perform a stack test within 180 days from the anomalous operation.

Comment 126: The commentator requests the language of Condition 5(b)(i) be revised to be consistent with the federal regulations (i.e, within 10 percent of 100 percent peak (or the highest achievable) load). (10, 16, 28)

Response: Condition 5(b)(i) of the final general permits have been amended to read that performance testing and periodic monitoring should be conducted within 10% of 100% peak (or the highest achievable) load.

Comment 127: The commentator states that Condition 5(c) should be removed. (10, 16, 28)

Response: The Department disagrees with the commentator. The requirement for resetting the 2,500 hours of operation count after any performance test performed is to streamline the recordkeeping to determine when the next periodic monitoring test is required.

STATIONARY NATURAL GAS-FIRED COMBUSTION TURBINES – Section M of GP-5

Comment 128: With respect to the option to control turbines with an SCR, DEP has not provided any additional technical or economic information that highlights the reasoning for the designation of SCR as BAT for these sources. Further, the commentator has been unable to identify even one turbine in the country that is subject to or meeting an emission rate of 1.5 ppm NO_x. Thus, the commentator does not understand how DEP can justify that the level of emissions is achievable in this service when it has not been demonstrated in practice. The use of oxidation catalyst for large turbines does not appear to meet the BAT threshold for economic feasibility. (10, 16, 28)

Response: BAT is defined broadly in 25 Pa. Code § 121.1 as equipment, devices, methods or techniques as determined by the Department which will prevent, reduce or control emissions of air contaminants to the maximum degree possible and which are available or may be made available. The 9 ppm NO_x limit from an uncontrolled turbine is an option for the operator to avoid the installation of an SCR system for gas turbine rating greater than or equal to 15,900 bhp. Most SCR vendors guarantee NO_x emission reduction of 90% or more and therefore the 1.5 ppm NO_x limit with even an uncontrolled baseline NOx emission of 15 ppm is achievable. Also, the Department has permitted several turbines equipped with SCR with 2 ppm NOx limit. The stack test results for these turbines show NOx emissions lower than 1.5 ppm. Therefore, the 1.5 ppm NOx limit is determined to be a BAT for a turbine rated greater than or equal to 15,900 hp. The detailed cost analysis is in the TSD.

Comment 129: NO_x emission limits for smaller turbines should be consistent with Subpart KKKK or the units will be precluded from the market. (20)

The commentator recognizes that in previous versions of the GP-5 that it failed to comment that the Solar Saturn Taurus 1,600 horsepower unit cannot meet the 25 ppmvd NOx @15% 02. It currently is offered with a warranty of 100 ppmvd NOx, which meets the current NSPS KKKK requirements. At the current limitations the, low horsepower turbine cannot be permitted under the GP-5. (10, 16, 28)

Response: Since 2013 the previous GP-5 has required turbines rated greater than or equal to 1,000 hp but less than 5,000 hp to meet 25 ppm NO_x.

Comment 130: The Department should review its BAT determination for larger reciprocating engines and turbines in order to ensure the BAT values established are in fact technically feasible and achieved in practice for similar units. (10, 28, 32)

BAT should be based on the technology (e.g. clean burn dry low-NO_x combustion technology) and not a specific value that only a limited number of vendors are currently guaranteeing. However, if DEP is going to assign a specific emission rate, then only a single emission rate should be defined and not two different values, as shown by the "controlled" and "uncontrolled" emission rates provided in the general permits for larger reciprocating engines and larger turbines. (10, 28, 32)

Response: The resources the Department has utilized in the determination of BAT include BAT included in the plan approvals which are determined on a case-by-case basis, general permits, and other permits issued by other states, for similar sources. The Department also evaluated vendors' guaranteed emission limits, available stack test data, and stakeholders' submitted data for the applicable sources. The emission limitations included in the GP-5 must be technically and economically achievable. In addition, these emission limitations must be sustainable during the life of the unit. The Department has determined that the emission limitations in the final GP-5 and GP-5A constitute BAT. Details of the technical and economic feasibility can be found in the TSD.

Comment 131: The commentator comments on the use of SCR on combustion turbines to control NOx is almost identical to those for engines. Similar to the requirements for larger lean burn engines, PA DEP has identified an emission rate (9 ppm NO_x for turbines > 15,900 hp) that is only recently been met - and only by one manufacturer. (10, 16, 28)

Response: There is precedent in establishing BAT limitations specific to a source based on fuel, technology, or other factors. BAT is defined broadly in 25 Pa. Code § 121.1 as equipment, devices, methods or techniques as determined by the Department which will prevent, reduce or control emissions of air contaminants to the maximum degree possible and which are available or may be made available. The 9 ppm NO_x limit from an uncontrolled turbine is an option for the operator to avoid the installation of an SCR system and does not negatively impact the competitiveness of manufacturers. Over time, more manufacturers will develop turbine models capable of meeting the proposed limit.

Comment 132: In draft final GP-5, Section M, Condition 1(d)(v), the commentator suggests that this provision be revised to replace the term *"alter"* with the term *"reduce"* because the provisions should already reflect the maximum level of performance testing for affected sources. (29)

Response: The Department disagrees with the commentator that the frequency of performance testing in the general permits reflect the maximum level of performance testing. The frequency of performance testing may also be altered upon request of the owner or operator with written Departmental approval, if the test results are consistently below allowable emission limits, unless required by federal regulation.

Comment 133: The commentator appreciates the Department providing the regions flexibility in M.1(d)(v) regarding the frequency of testing. (10, 16, 28)

Response: The Department appreciates the comment.

Comment 134: The commentator also appreciates the language concerning turbine operations at or below 0^0 F. However, the commentator requests the language match that of the federal requirements. (10, 16, 28)

Response: The general permits require operators to operate and maintain stationary combustion turbines, air pollution control equipment, and monitoring equipment in a manner consistent with good air pollution control practices for minimizing emissions at all times, in accordance with 40 CFR § 60.4333(a).

Comment 135: In draft final GP-5, Section M Stationary Natural Gas-Fired Combustion Turbines, the commentator suggests the following revisions: The reference to "Section A Condition 14(h)" should be corrected to read "Section A Condition 14(i)". (29)

Response: The typographical error has been corrected in the final GP-5.

Comment 136: In draft final GP-5, Section M Stationary Natural Gas-Fired Combustion Turbines, the commentator suggests the following revisions: The two references to "Section A Condition 14(e)" in this paragraph should be corrected to read "Section A Condition 14(f)" (29)

Response: The typographical error has been corrected in the final GP-5.

Comment 137: M(4)(c)—The commentator requests the language related to performance testing load requirements be revised to be consistent with the federal regulations (ex. NSPS Subpart JJJJ): "within 10 percent of 100 percent peak (or the highest achievable) load". (10, 16, 28)

Response: The condition cannot be amended as recommended because it establishes a requirement that an owner or operator that operates the engine in excess of the highest achievable load plus 10% must perform a stack test within 180 days from the anomalous operation.

Comment 138: M.5(b)(i) —The commentator requests the language related to performance testing load requirements be revised to be consistent with the federal regulations (ex. NSPS Subpart JJJJ): "within 10 percent of 100 percent peak (or the highest achievable) load". (10, 16, 28)

Response: Condition 5(b)(i) of the final GP-5 have been amended to require periodic monitoring be conducted within 25% of 100% peak or at the highest achievable load point.

Comment 139: The commentator recommends that core changes be allowed for combustion turbines as long as defined criteria are met. (20)

Response: The final GP-5 includes requirements for turbine core changes. A turbine core must be done in accordance with the terms and conditions of the GP-5; these terms and conditions are consistent with turbine core replacement requirements established for landfill gas-fired turbines in GP-22.

RECIPROCATING COMPRESSORS – Section G of GP-5 and Section H of GP-5A

Comment 140: In draft final GP-5, Section D. 1(a) – Reciprocating Compressors, the commentator suggests the following revisions: The reference to "40 CFR 50.5385" in this Condition should be corrected to read "40 CFR 60.5385". (29)

Response: The typographical error has been corrected in the final GP-5 as requested.

Comment 141: In draft final GP-5A, Section D, Conditions 1 and 2 previously referenced Subpart OOOOa instead of identifying specific BAT and recordkeeping requirements. The commentator suggests that the BAT and recordkeeping requirements of Conditions 1 and 2 incorporate applicable Subpart OOOOa conditions by reference to be consistent with draft final GP-5 and to avoid regulatory uncertainty. (29)

Response: NSPS, Subpart OOOOa is not applicable to reciprocating compressors at well sites. GP-5A includes BAT requirements for such reciprocating engines.

STORAGE VESSELS – Section I of GP-5 and GP-5A

Comment 142: Please confirm that the Storage Vessel requirements in Section E are consistent between draft final GP-5A and GP-5 and that both reflect the applicable dates specified in Subpart OOOO and Subpart OOOOa, as applicable. (29)

Response: The requirements for storage vessels are identical in GP-5A and GP-5.

Comment 143: Section E, Storage Vessels-Section E.1(d) should be edited as follows: " Any storage vessel removed from service must meet the requirements of 40 CFR § 60.5395(f) § 60.5395a(c), as applicable." As removal from service does not trigger NSPS standards. (31, 32, 10, 16, 28)

Response: The Department agrees. Section E, Condition 1(c) in the final general permits has been amended accordingly.

TANKER TRUCK LOAD-OUT OPERATIONS – Section J of GP-5 and GP-5A

Comment 144: Please confirm that the Section F Tanker Truck Load-out Operation language and requirements in Section F are consistent between draft final GP-5A and GP-5. (29)

Response: The requirements for tanker truck load-out operations are identical in GP-5A and GP-5.

Comment 145: Tanker trucks are obviously not stationary sources under the Air Pollution Control Act. DEP needs to clarify its legal authority to establish regulations to control emissions from these mobile sources. (28)

Response: GP-5 does not regulate tanker trucks. However, GP-5 includes requirements to control emissions from load-out operations. Requirements on load-out operations have been implemented since August 10, 2013 through the Exemptions List, Category 38.

Comment 146: Oil and gas operators generally do not own and operate their own trucks; however, most of the record keeping requirements set forth in this Section require access to the records of the truck operator/owner. It is unduly burdensome to require operators to maintain records for truck fleets that are not owned, operated or maintained by the operator. (28)

Response: Though tanker truck testing requirements apply to truck carrier companies, it is the responsibility of the permittee to ensure that all trucks that perform loadout operations at their facility have passed one of the appropriate leak tests prior to allowing them to unload liquids from a storage vessel. While the leak test requirements are part of PennDOT and US DOT regulations, the Department maintains that verifying that a tanker is properly leak tested is necessary to control emissions from storage tanks that emit above the control thresholds.

The emissions records for each loadout operation will assist the inspector in verifying compliance with emissions control thresholds for VOC, HAP, and methane.

Comment 147: The commentator appreciates the clarification on the exemption threshold for control of truck loading. (10, 16, 28)

Response: The Department appreciates the comment.

Comment 148: The commentator recommends applying the emission threshold to the load-out source. Suggested lead-in language for the Department's consideration: "For all truck load-out operations of a given liquid type (ex. condensate) with a total uncontrolled methane emission rate of 200 tpy or greater, a total uncontrolled VOC emission rate of 2.7 tpy or greater an uncontrolled single HAP emission rate of 0.5 tpy or greater, or a total uncontrolled HAP emission rate of 1.0 tpv or greater, where the loading rack was constructed on or after (effective date of GP-5) the owner or operator shall": (10, 16, 28)

Response: The leading language in the final general permits is as follows: "For all truck load-out operations that service a storage vessel with a methane emission rate of 200 tpy or greater, a VOC emission rate of 2.7 tpy or greater, a single HAP emission rate of 0.5 tpy or greater, or a total HAP emission rate of 1.0 tpy or greater, where the loading rack was constructed on or after (effective date of GP-5)…"

Comment 149: The commentator recommends that F.l(a)(i) and F.l(b)(i) state that the captured portion of emissions from load-out operations be controlled at 95% or greater to allow for alternative means of control. The commentator further recommends for safety considerations that Section F.(1) allow the use of combustion control, vapor recovery in conjunction with oxygen elimination units in lieu of just vapor balancing. (10, 16, 28)

Response: The final general permits allow as an alternative measure that VOC emissions must be controlled with 95% or greater efficiency.

Comment 150: The requirement to utilize pressure-tested trucks in sections F(l)(a)(ii) (GP-5 & GP-5A) & F(l)(b)(ii) (GP-5A) has not demonstrated that the additional cost of vapor balancing is cost-effective at the proposed control threshold levels (e.g., 2.7 tpy). (10, 16, 28)

Response: The final GPs allow the owner/operator to use a vapor balancing system for tanker truck loadout operations instead of a vapor recovery unit or control emissions with greater than 95%

control efficiency. Conditional Exemption 38, finalized in 2013 required 95% control of any emission unit, including tanker-truck loadout operations exceeding emission thresholds of 2.7 tpy VOC, 0.5 tpy single HAP, and 1.0 tpy total HAP. Despite the requirement to install 95% VOC control on storage vessels and other equipment, no individual plan approval was submitted for an unconventional natural gas well site. This means either the installation of control is cost effective, or that the sources in question emit less than 2.7 tpy VOC, 0.5 tpy single HAP, and 1.0 tpy total HAP.

Comment 151: In draft final GP-5A, Section F, Condition 1(a) and 1(b), please clarify whether the emissions criteria apply to load-out operations or to the storage vessel. (29)

Response: The emission thresholds are applicable to truck load-out operations.

Comment 152: In draft final GP-5A, Section F, Condition 2(b), please clarify whether the affected source or the tanker truck operator is responsible for documenting the annual leak test. (29)

Response: Though tanker truck testing requirements apply to truck carrier companies, it is the responsibility of the permittee to ensure that all trucks that perform loadout operations at their facility have passed one of the appropriate leak tests prior to allowing them to unload liquids from a storage vessel. While the leak test requirements are part of PennDOT and US DOT regulations, the Department maintains that verifying that a tanker is properly leak tested is necessary to reduce emissions from storage tanks that emit above the control thresholds.

FUGITIVE EMISSIONS COMPONENTS – Section K of GP-5 and GP-5A

Comment 153: The commentators request the Department expressly state in GP-5A that fugitive emissions, after appropriate control (e.g. LDAR), are of minor significance with respect to causing air pollution and are not preventing or interfering with the attainment or maintenance of an ambient air quality standard, per 25 Pa Code § 123.1(a)(9). (10, 16, 28)

Response: "The Department determined that the VOC and methane emissions remaining after the implementation of BAT requirements, including LDAR, are of minor significance with regard to causing air pollution, and will not, on their own merits, be preventing or interfering with the attainment or maintenance of an ambient air quality standard." See Section G of the final GPs and the TSD.

Comment 154: The commentators recommend that the current GP-5 LDAR program remain in place for existing sources and non-OOOOa facilities and that OOOOa requirements be referenced as applicable. (10, 16, 28, 20)

Response: The final general permits have been amended as requested.

Comment 155: The commentator states that the applicability of LDAR has been narrowed from the facility as a whole to just fugitive emissions components. This excludes vents or exhausts which emit the wrong substance. (25)

Response: The previous version of GP-5 was not as clearly defined as the final GP-5. The LDAR program described in the final general permit is consistent with the Department's intent as indicated through responses to FAQs.

Comment 156: The commentator appreciates the removal of the leak quantification requirement. (31)

Response: The Department appreciates the comment.

Comment 157: Several commentators contends that its supplemental analysis to LDAR costs demonstrates that the Department considerably overestimated the calculated abatement cost for quarterly LDAR. However, this was based on the draft general permits which differed from those proposed on March 31, 2018. In the March 31 versions, the leak quantification requirement has been removed. Therefore, the commentators urge the Department to revisit the cost analysis and remove the costs associated with leak quantifications and determine if the stepdown provision is still necessary from an economic standpoint. (21).

Response: The stepdown provision provides some relief to smaller operators by allowing them to track the percentage of leaking components and, by maintaining less than 2% leaking components, reduce frequency. This allows smaller operators to reduce the number of times per year they must hire a contractor to perform this service. If at any time the percentage of leaking components exceeds 2%, the facility must resume quarterly LDAR inspections. Larger operators typically have in-house personnel to perform LDAR inspections and would rather maintain a consistent frequency than be burdened by the additional recordkeeping to receive a stepdown frequency.

Comment 158: The commentator states that the Department's LDAR cost analysis was flawed as it is illogical to base estimated emissions on a super-emitter leak rate that is based upon a value that an instrument is capable of measuring. These extremely high leak rates drive the cost effectiveness evaluations presented in the TSD, which is based on costs and component counts provided from LDAR contractors and not from operator data through actual program implementation. Also, the Department did not consider the cost for repair of identified leaks despite noting that such costs can vary significantly. Therefore, the Department has severely underestimated the costs. (10, 28, 32)

A recent cost analysis performed by the API, and cited by others in their own comments, state that costs to control methane are 9 to 31 times higher at a semi-annual frequency and 5 to 28 times higher at a quarterly monitoring frequency when compared to the EDF and ONE Future studies cited in the TSD. (32, 10, 16, 28)

Response: The Department has performed an independent cost-analysis for LDAR requirements and determined that quarterly monitoring using OGI is cost-effective. The detailed cost-analysis can be found in the final TSD.

Comment 159: The commentator supports the Department's proposed standards for detecting and repairing leaks from sources not covered in most states, including pigging operations and liquids unloading. (3)

Response: Thank you for your comment.

Comment 160: The commentator recommends that monthly AVOs begin on the same schedule as LDAR (i.e. "60 days after the start of production" for the GP-5A or "60 days after commencing operation" for the GP-5). (10, 16, 28)

Response: AVO does not require the use of any special equipment. Therefore, the requested change is not included in the final general permits.

Comment 161: Regarding determining the component count in Section G.l(b)(iv), the commentator suggests the following language: "The owner or operator shall estimate the total facility component count using appropriate methods such as 40 CFR 98 Subpart W, P&lDs. physical counts or other methods accepted by the Department." (10, 16, 28)

Response: The final GP-5 does not prohibit the use of recommended methods such as 40 CFR 98 Subpart W, P&lDs or physical counts to estimate the component.

Comment 162: The commentators state that methane leak detection technology is dynamic, with frequent innovation such as their own efforts changing the marketplace with different detection limits, frequencies, underlying science, and observation platforms. These technologies, used independently or in combination with each other, yield better and more cost-effective results. The commentators recommend that the Department establish its support for demonstration or pilot projects by establishing a list of approved devices, with the ability to add to the list of approved devices. (8, 18, 21)

Response: The monthly frequency proposed by the commentators is not cost-effective, and therefore is not BAT. Monthly LDAR might be appropriate for major facilities which are ineligible to use the general permits. Major facilities would be required to determine LDAR frequency on a case-by-case basis.

Comment 163: The commentator recommends focusing LDAR inspections on the highest volume leaks, realizing that by focusing on a larger leak definition, more frequent inspections would be required. The technology used by the commentator, aerial surveying, focuses on super-emitters, recognized as accounting for the majority of methane emissions. The commentator can identify and fix the small fraction of high-emitting sources, achieving better environmental and economic results while avoiding over-engineered instruments. The aerial survey service is capable of covering large areas in a short period of time; is methane-specific; produces images of methane plumes overlaid on optical imagery; quantifies methane emissions within ±25%; is offered as a service, meaning there is no capital expenditure or oncoming maintenance costs to an operator; is operated by trained engineers, meaning no training or labor costs to operators and reduced chance of operator error; offers proprietary data analysis that streamlines reporting and recordkeeping. (8)

Response: The monthly frequency proposed by the commentator is not cost-effective, and therefore is not BAT. Monthly LDAR might be appropriate for major facilities which are ineligible to use the general permits. Major facilities would be required to determine LDAR frequency on a case-by-case basis.

Comment 164: The commentator recommends that well pads should only be subject to annual LDAR requirements. (31)

Response: The LDAR requirement in 40 CFR Part 60 Subpart OOOOa requires a semi-annual inspection with no provision for reduction. Barring that, the Department determined BAT to be quarterly inspections, with the potential to step down to the federal semi-annual schedule based on the percentage of leaking components at unconventional natural gas well sites, coupled with monthly AVO inspections.

Comment 165: The commentator supports the quarterly LDAR inspection frequency in GP-5 and GP-5A. Multiple studies have shown that quarterly LDAR at both new and existing facilities is a highly cost-effective way to reduce emissions. Pennsylvania's proposal to adopt a baseline quarterly inspection frequency for well sites brings its requirements in line with those of other states that have also implemented quarterly inspection requirements. (21)

Response: Thank you for your comment.

Comment 166: The commentator recommends revising the reference to "Condition 3(a)" in Condition 1(b)(ii) of GP-5 and Condition 1(b)(iii) of GP-5A to "Condition 2(a)." (29)

Response: The typographical errors have been corrected in the final general permits**.**

Comment 167: The commentator suggests altering the language of Condition 1(b)(iv) of GP-5A to "The owner or operator shall estimate the total facility component count using appropriate methods such as 40 CFR Part 98 Subpart W, P&IDs, physical counts, or other methods accepted by the Department. (10, 16, 28)

Response: The final GP-5A does not prescribe any specific methodology to be used to determine facility component counts.

Comment 168: The commentator recommends increasing the LDAR inspection frequency to monthly as leaks would be found quickly and repaired as soon as possible, especially at facilities with emissions above 50 tpy of VOC for well sites with storage tanks and compressor stations or 20 tpy for well sites without storage tanks. (18)

Response: The monthly frequency proposed by the commentator is not cost-effective, and therefore is not BAT. Monthly LDAR may be appropriate for major facilities which are ineligible to use the general permits. Major facilities would be required to determine LDAR frequency on a case-by-case basis.

Comment 169: The commentators recommend removing the stepdown provision of Condition 1(b)(iv) that allows operators to reduce the frequency of LDAR inspections if less than 2% of components are found leaking. (18, 21)

Response: The stepdown provision provides some relief to smaller operators by allowing them to track percentage of leaking components and, by maintaining less than 2% leaking components, reduce the inspection frequency. This allows smaller operators to reduce the number of times per year they must hire a contractor to perform this service. If at any time the percentage of leaking components exceeds 2%, the facility must resume quarterly LDAR inspections. Larger operators typically have in-house personnel to perform LDAR inspections, and would rather maintain a consistent frequency than be burdened by the additional recordkeeping to utilize the stepdown frequency.

Comment 170: The commentator requests DEP incorporates the NSPS requirement in Section G.l(f)(ii) by reference only. The commentator recommends the following language: "The repair or replacement is technically infeasible, would require a vent blowdown, a well shutdown or well shut-in, or would be unsafe to repair during operation of the unit. the repair or replacement must be completed during the next scheduled well shutdown, planned well shut-in. after a planned vent blowdown or within 2 years, whichever is earlier." (10, 16, 28)

Response: The final general permits incorporate recently amended NSPS requirements. The final general permits include the following, "The repair or replacement is technically infeasible, would require a vent blowdown, a compressor station shutdown, or would be unsafe to repair during operation of the unit, the repair or replacement must be completed during the next scheduled compressor station shutdown, after a planned vent blowdown or within 2 years, whichever is earlier."

Comment 171: The commentator appreciates that the Department updated the definition for delay of repair in Condition 1(f)(ii) of GP-5 to match the current federal requirements; however, they request the Department incorporate those requirements by reference to avoid any future conflicting requirements. (10, 16, 28)

Response: EPA reconsidered the delay of repair issues and amended NSPS requirements on March 1, 2018. The final general permits include the identical requirements.

Comment 172: The commentators recommend the following language for Condition 1(f)(ii) of GP-5: "The repair or replacement is technically infeasible, would require a vent blowdown, a compressor station, processing plant, or transmission station shutdown, or would be unsafe to repair during operation of the unit, in which case the repair or replacement must be completed during the next scheduled compressor station, processing plant, or transmission station shutdown, after a planned vent blowdown or within 2 years, whichever is earlier." (29, 10, 16, 28)

Response: The final GP-5 has been amended as recommended.

Comment 173: The commentator recommends that the Department thoroughly inspect for methane leaks at wells and order immediate shutdowns when leaks are detected. (17)

Response: The final GP-5A includes comprehensive LDAR requirements such as quarterly inspections using OGI and monthly AVO inspections. Any leak detected from a fugitive emission component must be repaired by the owner or operator of the facility as expeditiously as practicable. A first attempt at repair must be attempted within 5 calendar days of detection, and the repair must be completed no later than 15 calendar days after the leak is detected. Once a fugitive emission component has been repaired or replaced, the owner or operator must resurvey the component as soon as practicable, but no later than 30 calendar days after the leak is repaired.

Comment 174: The commentator recommends that the Department revise the GP-5 and Exemption 38 FAQ document to ensure that leak repair confirmation requirements are consistent with the proposed general permits. Questions 10 and 11 in the FAQ guidance document are not consistent with leak repair confirmation criteria in the proposed general permits; they should be revised to clearly indicate that multiple methods are acceptable to confirm repair – i.e., Method 21 or optical gas imaging can be used for repair confirmation regardless of the method used to detect the leak. (20)

Response: GP-5 and GP-5A allow the owner or operator to use Method 21 or optical gas imaging for repair confirmation regardless of the method used to detect the leak. As necessary, the Department will develop Exemption 38, GP-5A, and GP-5 implementation instructions or an FAQ document that is applicable to the current versions of the permit and Exemption 38.

Comment 175: The commentator requests clarification that the monitoring plans only need to meet the requirements of OOOOa for those facilities subject to OOOOa. (10, 16, 28)

Response: The final general permits include appropriate monitoring requirements including applicable NSPS OOOOa requirements.

CONTROLLERS – Section L of GP-5 and GP-5A

Comment 176: The commentator requests that PADEP recognize that the emissions from gas driven pneumatic controllers, particularly in dry gas areas, are minor sources of emissions. (10, 16, 28)

Response: Devices that vent as part of their normal operation, such as pneumatic controllers and pneumatic pumps, are not fugitive emissions components unless there is a discharge from a place other than the vent.

Comment 177: In draft final GP-5A, Section H(1)(a), the commentator suggests the following revisions: The references to "40 CFR § 5390" and § 5390a" should be corrected to read "40 CFR § 60.5390" and § 60.5390a". (29)

Response: The typographical errors have been corrected in the final general permits.

PUMPS – Section M of GP-5 and GP-5A

Comment 178: The commentator appreciates that DEP clarified that only natural gas driven pneumatic diaphragm pumps are subject to control requirements. (10, 16, 28)

Response: Thank you for your comment.

ENCLOSED FLARES AND OTHER EMISSION CONTROL DEVICES – Section N of GP-5 and GP-5A

Comment 179: The commentator requests that the Department clarify whether candlestick or open flame flares can be used when such flares are more technically suitable for high pressure relief than enclosed units. Section J should contain an option to utilize traditional open flares, which would be most often utilized where high pressure blowdowns need to be controlled. These devices are necessary for safety purposes as the only technically feasible and cost-effective solution for vapor destruction at these facilities. Enclosed combustors that are able to handle high-pressure, high-volume blowdowns typical at these stations may be technically infeasible from a size perspective and economically infeasible due to the much greater cost (in excess of $1 to $2 million). In addition, the GP-5A does not appear to allow for the operation of existing open flame flares. The Department has not demonstrated that only enclosed combustors are BAT for these operational scenarios, or why open flame flares were not evaluated.

Excluding open flares for these operations would require facilities to apply for Plan Approvals for the sole reason of demonstrating that an enclosed combustor is not cost effective. (10, 16, 28)

Response: Since August 10, 2013, Exemption 38 requires an enclosed combustion device, including an enclosed flare to be used for all permanent flaring operations at a wellhead or facility. These flaring operations are to be designed and operated in accordance with the requirements of 40 CFR § 60.18. It was determined that if enclosed flares are required for permanent installations at well sites, it would also be appropriate for compressor stations, processing plants, and transmission stations.

However, due to infrequent natural operation at the remote pigging stations, enclosed flares are not mandated.

Comment 180: The commentator appreciates many of the changes made to the draft GP-5A and GP-5 and the accompanying Exemption #38b; specifically, changes to allow for the industry accepted 95% control efficiency. (10, 16, 28)

Response: Thank you for the comment.

Comment 181: The commentators ask why the Department reduced the required control efficiency from 98% to 95% for new glycol dehydration units, storage vessels, natural gas-driven pneumatic diaphragm pumps, wet seal centrifugal compressors, and pigging operations in the proposed general permits. The commentator urges the DEP to reconsider its approach and restore the 98% destruction efficiency that it previously required for new glycol dehydrators, storage tanks, pneumatic pumps, centrifugal compressors, and pigging operations. (21, 7)

Response: Based on the comments received, the 98% control requirement for methane, VOC, and HAP was revised to a 95% control requirement in the final general permits. While manufacturer-tested models typically achieve significantly greater than 95% control in practice, the control requirement was revised to allow operators to continue to benefit from the manufacturer-tested models in accordance with the federal regulations. This revision avoids additional source testing to demonstrate 98% efficiency, instead relying on the manufacturer's certification list maintained by EPA to demonstrate and maintain compliance under the federal regulations.

Comment 182: The commentators state that a review of DEP's analyses presented in the Technical Support Document that accompanied the draft General Permits, do not appear to justify certain controls with an adequate cost-effectiveness analysis and certain controls were determined to represent BAT based on incomplete or inaccurate data. Cost analyses for pigging operations and pneumatic pumps are missing. (10, 28, 32)

Response: In addition to compliance requirements for applicable federal requirements, 25 Pa. Code Chapter 127 requires that all new sources control the emissions to the maximum extent, consistent with the BAT as determined by the Department at the time of issuance of Plan Approval. The Department has provided the rationale in the TSD for BAT requiring methane, VOC and HAP control for pigging operations and pneumatic pumps.

Comment 183: The commentator states that Condition 1(a)(ii) requires that the owner/operator conduct a performance test on an enclosed combustion device within 180 days of initial startup unless the device is a manufacturer-tested model. The commentators request that the language be modified to "The owner or operator must conduct a performance test in accordance with Condition 4 within 180 days of the initial startup of the affected facility unless the combustion control device is a manufacturer-tested model testing accordance with 40 CFR § 60.5413(d) or § 60.6413a(d). A performance test conducted on a device of the same make and model in similar service at another facility within the Commonwealth may be used to satisfy this requirement." This is because many operators will use the same make and model enclosed combustion device at various facilities within the Commonwealth. Requiring each individual unit to be tested is costly and does not better prove compliance than testing only one unit. (10, 16, 28)

Response: The final general permit condition 1(a)(ii) has been revised as follows:

The owner or operator must conduct a performance test in accordance with Condition 4 within 180 days of initial startup of the affected facility **unless** the combustion control device is a manufacturer-tested model tested in accordance with 40 CFR § 60.5413(d) or § 60.6413a(d). A performance test conducted on a device of the same make and model in similar service at another facility within the Commonwealth upon approval by the Department may be used to satisfy this requirement.

Comment 184: The commentator states that Condition 1(a)(iii) requires further testing of each enclosed combustion device upon each reauthorization of the permit. The commentator recommends that an Condition 1(a)(iii)(C) be added to read as follows: "(C) A performance test conducted on a device of the same make and model in similar service at another facility within the Commonwealth that has been conducted within the previous five (5) years of the application for reauthorization may be used to satisfy this requirement." (10, 16, 28)

Response: The final general permit condition 1(a)(iii) has been revised as follows:

The owner or operator must conduct performance tests in accordance with Condition 4 within 180 days of each reauthorization **unless** the combustion control device is a manufacturer-tested model tested in accordance with 40 CFR § 60.5413(d) or § 60.5413a(d); A performance test conducted on a device of the same make and model in similar service at another facility within the Commonwealth upon approval by the Department may be used to satisfy this requirement.

Comment 185: The commentator recommends Condition J(1)(b)(ii) to be amended as follows: The owner or operator shall conduct a performance test in accordance with Condition 4 and 40 CFR § 60.5413a as applicable. If compression is used as the mechanism to recover vapor, the permittee shall track the vapor recovery unit downtime on a monthly basis using best available data, in lieu of performance testing. (10, 16, 28)

Response: The owner or operator must comply with 95% control requirements by using a vapor recovery device or a vapor recovery unit (VRU). If the enclosed combustion device is used as a backup for the VRU, the time period when the emissions are diverted to the control device shall also be recorded.

Comment 186: The commentator requests clarification that AVO inspections are to be conducted in accordance with 40 CFR § 60.5411 as applicable. (10, 16, 28)

Response: 40 CFR § 60.5411 does not include any methodology for conducting AVO inspections.

Comment 187: The commentator concurs with the change to sections covering Enclosed Flares and Other Emission Control Devices to eliminate the need for Professional Engineer certification. (31)

Response: Thank you for the comment.

PIGGING OPERATIONS – Section O of GP-5 and GP-5A

Comment 188: The March 2018 revisions to Exemption 38 include the addition of Category 38(c), which applies to facilities affected by the proposed revisions. However, the text in Category 38(c) of the Air Quality Permit Exemption List refer to, "Oil and gas exploration, development, and production facilities and associated equipment and operations." That terminology does not clearly indicate that *transmission pipelines* are included on the exempt list, and clarification is requested. The text in Category 38(c) should be revised as follows: "Oil and gas exploration, development, and production facilities and associated equipment and operations, and natural gas transmission pipelines, for which construction or reconstruction commenced on or after [the effective date] of this Exemption criteria meeting the following provisions:" (20)

Response: Exemptions Category 38(c) is applicable to sources located at well sites. The owner or operator may submit a RFD form for other facilities.

Comment 189: It appears the citation for Exemption 38 in GP-5A was not updated. In the definition of "Remote Pigging Station" in GP-5A, the citation should be revised from "Category 38(b)" to "Category 38(c)." (20)

Response: The typographical error has been corrected in the final GP-5A.

Comment 190: LDAR requirements for remote pigging sites are included in Exemption Category 38(c), subsection (c). It appears that those LDAR requirements only apply if the emissions thresholds in subsection (c)(ii) are exceeded. PA DEP should clarify that is the intent. If that is not the intent, then PA DEP should justify why LDAR is warranted at a location with minimal emissions. (20)

Response: In the final GP-5A and GP-5, the Department revised the condition to provide flexibility to the owner or operator in choosing BMPs to minimize the liquids present in the pig receiver chamber and to minimize emissions from pigging operations. The Department has provided the emissions thresholds, below which the owner or operator is not required to install a control for methane, VOC and HAP. The Department believes that the owner or operator must use a BMP to minimize the liquids present in the pig receiver chamber and to minimize emissions from pigging operations.

Comment 191: There is no cost analysis for emissions control from pigging operations (10, 28, 32)

Response: The cost analysis for control requirements are included in the TSD.

Comment 192: The commentator appreciates DEP's clarification of the applicability of Best Management Practices and Control Requirements on Pigging Operations. (10, 16, 28)

Response: Thank you for your comment.

Comment 193: The commentator requests that pigging operations that are exempt sources because they have emissions less than 200 tpy of methane, less than of 2.7 tpy of total VOC, less than 0.5 tpy of a single HAP, or less than 1.0 tpy of total HAP emissions be exempted from recordkeeping because their emissions are below these rates. (10, 16, 28)

Response: The adequate recordkeeping is necessary to ensure that emissions are below the applicable emission thresholds.

WELLBORE LIQUIDS UNLOADING OPERATIONS – Section P of GP-5A

Comment 194: The commentator recommends that the BAT requirements of the Well bore liquids unloading operations section be edited to read as follows "The owner or operator that conducts wellbore liquids unloading operations shall use best management practices including, but not limited to, plunger lift systems, soaping, swabbing, unless venting is necessary for safety to mitigate ~~emissions including those from the production annulus~~. In all cases, where technically feasible and safe, the owner or operator shall direct the gas to existing separator, storage vessel, or control device. The selection of the appropriate best management practice must be documented in the application." (29)

Another commentator recommended the deletion of reference to production annulus from liquid well bore, since a primary reason to vent to the atmosphere is to minimize the potential of stray gas migration within the subsurface. (10, 16, 28)

Response: The condition has been revised as follows "The owner or operator that conducts wellbore liquids unloading operations shall use best management practices including, but not limited to, plunger lift systems, soaping or swabbing, unless venting is necessary for safety to mitigate emissions during liquids unloading activities. In all cases, where technically feasible and safe, the owner or operator shall direct the gas generated during liquids unloading to a control device, a gas production line or existing separator or storage vessel which is controlled. The selection of the appropriate best management practices must be documented in the application."

Comment 195: Wellbore liquid unloading events are often automated and no record of the event should be required as they are environmentally unnecessary and difficult to obtain. The commentator suggests reporting situations where the plunger lift fails to work and must be operated manually. (31)

It is unclear what recordkeeping requirements exist for unloading systems that do not contribute to any air emissions. The commentator recommends that record keeping and reporting requirements under GP-5A apply to unloading methods that result in emissions to atmosphere. (10, 16, 28)

Response: GP-5A has been revised to require recordkeeping of each wellbore liquid unloading that result in emissions to atmosphere.