October 15, 2012

The Honorable Lisa P. Jackson, Administrator
U.S. Environmental Protection Agency
1200 Pennsylvania Ave., NW
Washington, D.C. 20460

RE: America's Natural Gas Alliance Request for Reconsideration -- Oil and Natural Gas Sector: New Source Performance Standards and National Emission Standards for Hazardous Air Pollutants Reviews; 77 Fed.Reg. 49490 (Aug. 16, 2012)

Dear Administrator Jackson:

Pursuant to Section 307(d)(7)(B) of the Clean Air Act ("CAA"), 42, U.S.C. § 7607(d)(7)(B), America's Natural Gas Alliance (ANGA) and the American Exploration and Petroleum Council (AXPC) respectfully request that the U.S. Environmental Protection Agency ("EPA" or the "Agency") reconsider certain specific aspects of the Final Rule entitled "Oil and Natural Gas Sector: New Source Performance Standards and National Emission Standards for Hazardous Air Pollutants Reviews," that was published on August 16, 2012, at 77 Fed. Reg. 49490 ("Final Rule"). Section 307(d)(7)(B) of the CAA authorizes reconsideration of issues where it is impracticable to raise an objection during the period of public comment or if the grounds for such an objection arise after the public comment period (but within the time specified for judicial review), and if such objections are of central relevance to the outcome of the rule.

ANGA and AXPC appreciate the Agency's efforts to develop this rulemaking, and in particular the outreach and dialogue on the many important issues that are embedded in the Final Rule. We believe that the Final Rule reflects important changes on many of the issues of importance to the natural gas industry; however, we also believe that there are several issues where the Final Rule remains problematic and where the Final Rule contains specific provisions or language that ANGA and AXPC did not have an adequate opportunity to address during the public comment period. To that end we list and discuss these issues below, and request that the Agency reconsider each of them pursuant to Section 307(d)(7)(B).

<u>Gas Well Completions</u>

1. While ANGA and AXPC appreciate EPA's efforts to encourage early action by exempting recompleted wells that comply with the reduced emission completion (REC) requirement from becoming an affected facility, the Final Rule, as drafted, requires that owner/operators of exempt recompleted wells comply with all of the notification, recordkeeping, and reporting requirements of §60.5375 that are associated with recompleted wells that are not exempt. We agree with EPA's policy decision to encourage early action to meet REC requirements, but the regulatory language as drafted does not encourage early action, as exempt recompletions are essentially treated the same as regulated recompletions. We request that EPA reconsider the requirements that it set forth in Section 60.5365(h)(1) of the Final Rule and develop a scheme that actually encourages early action

to meet REC requirements. For example, EPA could adopt language stating that recompletions are exempt if they meet the operational or work practice standard requirements of section 60.5375(a).

2. As described to EPA in previous submissions regarding this rulemaking, there are periods during normal completions operations when fluids are not able to be sent to the separator in order to be flared or captured without the use of a flaring pit. In the proposed rule, there was a provision that allowed owners/operators to use various methods, including venting, during the initial phase of the flowback operations. The Final Rule does not include any such provision, and because it was not anticipated that EPA would eliminate this provision in the Final Rule, ANGA and AXPC did not have the opportunity to provide information to EPA regarding the adverse impacts resulting from the elimination of the provision in the Final Rule during the comment period. We request that EPA reconsider the elimination of the proposed Section 60.5375(a)(2) and adopt provisions clarifying that, during periods when capture or flaring is not feasible, EPA does not intend to require fluids to be routed to a separator and subsequently captured or flared as long as emissions are minimized and resource recovery is maximized to the greatest extent possible.

3. In the Final Rule, EPA has included a provision (Section 60.5420(b)(2)(i)) that allows an alternative annual reporting option for well completions that involves a list of well completions and digital photographs. In the recordkeeping provisions of the Final Rule (Section 60.5420(c)(1)(v)), however, the regulatory language requires that records of digital photograph(s) be maintained regardless of whether the reporting entity is using the primary or alternative annual reporting option. ANGA and AXPC could not comment on the digital photograph requirement because it was not included in the proposed rule. EPA should only require digital photographs if the reporting entity is using the digital photograph alternative annual reporting option. We do not believe that EPA intended to require that digital photographs be taken and maintained for all well completions, but rather only when the alternative annual reporting option is being used. Therefore, we request that EPA reconsider the language in Section 60.5420(c)(1)(v), and revise the regulations with language specifically limiting the requirement to keep digital photographs to those reporting entities that are choosing to use the annual reporting option that requires digital photographs.

4. The rule does not include any provisions in either Section 60.5375(a)(3) or Section 60.5375(f)(2) exempting operations from the capture and combustion requirements where flaring is restricted or prohibited by local ordinance (e.g., DFW). Requiring flaring where local ordinance prohibits flaring creates conflicting regulatory requirements and will result in operators facing a dilemma -- noncompliance with the local ordinance or the NSPS requirements. The language does provide an exception for conditions that may result in a fire hazard or explosion, and it is our experience that local ordinances that prohibit or restrict flaring are in most cases based on safety-related concerns. As such, we believe that the regulatory language needs to include an exception similar to the exception currently in these two sections for fire/explosion conditions. We request that the Agency reconsider Sections 60.5375(a)(3) and Section 60.5375(f)(2) to add language that explicitly exempts operators that face a local ordinance or regulations that prohibits flaring from the otherwise applicable capture and combustion requirements.

Storage Vessels

EPA changed the applicability provisions in Section 60.5395 for storage vessels from a throughput-based limit in the proposed rule to an annual VOC emissions rate-based limit in the Final Rule. This change affects many of the provisions of the Final Rule that apply to storage tanks, in some cases with ramifications that ANGA and AXPC were not able to address during the comment period because we were not in a position to anticipate the direction that the Agency ultimately took. This is a critical issue in many respects, and we request that EPA reconsider the regulatory provisions discussed below.

1. For purposes of evaluating applicability (whether the vessel has VOC emissions equal to or greater than 6 tons per year), the Final Rule further requires that producers "determine the VOC emission rate for each storage vessel affected facility using any generally accepted model or calculation methodology." The regulation does not, however, include language that indicates that the applicability threshold in Section 60.5395(a) is to be based on post-control emissions similar to the requirements of §63.772(b)(2) for glycol dehydration units.

We believe that EPA intended that the VOC emissions calculation for threshold purposes be based on emissions post-control. It appears that EPA based both the standard and the compliance schedule (including the one-year phase-in period that is included to allow time for the development and implementation of compliance technology and testing resources) on an analysis that showed that approximately 300 tanks per year would be subject to the requirements. As discussed in detail in the "*Request for Administrative Reconsideration and an Administrative Stay*" submitted to the Agency by the American Petroleum Institute (dated August 16, 2012), if the Agency had intended that the threshold calculations be based on uncontrolled emissions, the universe of new vessels that would be subject to these requirements would be far in excess of the 300 that EPA used in its analysis. We support and reference the data and analysis set forth in API's Request for Reconsideration on this issue, and we believe it supports the presumption that EPA intended that the calculation of whether emissions from a vessel exceed the VOC emission applicability threshold of 6 tpy is to be based on calculation of post-control emissions. Unfortunately, the regulations do not contain language that explicitly sets this out, and there is language in the Response to Comments document that appears to suggest that the calculation should be performed on "potential" (uncontrolled) emissions.[1]

ANGA and AXPC did not have the opportunity to comment on the specific issue of the validity of the regulatory requirements and compliance schedule that depend almost entirely on the manner in which the Agency intended that the threshold be determined -- post-control or uncontrolled. In light of the lack of clarity around how this threshold determination is to be made and the ramifications that flow from the lack of clarity, we request that the Agency reconsider Section 60.5395 of the Final Rule and provide specific regulatory language that the determination is to be

[1] EPA, *Oil and Natural Gas Sector: New Source Performance Standards and National Emission Standards for Hazardous Air Pollutants Reviews 40 CFT Parts 60 and 63, Response to Public Comments on Proposed Rule August 23, 2011 (76 FR 52738)*. EPA-HQ-OAR-2010-0505-4546. p. 107.

based on emissions estimated after application of enforceable controls, and that it make clear that the statement in the Response to Comments document referenced above was in error.

2. ANGA and AXPC also request that EPA consider revising the rule to include provisions for reevaluating actual annual emissions and emissions control requirements on an annual basis. This is appropriate given the natural decline of liquid production from a well as well as the uncertainty in emission projections. If actual annual emissions from an affected facility are found to be below 6 tons per year for the reporting period and are projected to remain below 6 tons per year, ANGA and AXPC recommend allowing the removal of controls. This would ensure that additional combustion emissions are not produced from the use of supplemental fuel in order to control a small amount of VOC emissions. Again, because the proposed rule contained a throughput-based threshold determination, rather than an emissions-based threshold determination, ANGA and AXPC did not have the opportunity to submit comments on the need to include regulatory language authorizing such reevaluations.

3. New Section 60.5395(a)(2) requires that sources located at facilities where there are other wells in production calculate emissions and install any required controls upon start-up. In practice, however, this is infeasible in many cases. While it is true that there would be production data available for the existing well or wells, the age of the well, formation type, location within the formation, and characteristics of the well including lateral length, proppant used, and direction of fractures can lead to great variability and unpredictability in any compositional or production estimates. Not only does the lack of this consistency preclude operators from estimating emissions before start-up, but it also makes the design, installation, and operation of a control device upon startup very difficult. The applicability of the control requirements in the proposed rule for storage vessels was based on a throughput threshold, so the issue of having to calculate emissions before start-up and design/install/operate control devices upon start-up was not an issue, and ANGA and AXPC did not have the opportunity to raise these practical constraints on the new requirements in comments submitted during the comment period. We therefore request that the Agency reconsider these requirements, and consider providing the same allowance for emission determination and control installation for all wells (60 days and 120 days respectively), regardless of whether or not there are other collocated wells in production.

4. The revised definition of storage vessels at Section 60.5430 contains helpful language describing three categories of vessels that are not considered storage vessels for purposes of these regulations. We do not believe, however, that the Agency has adequately considered the complete universe of vessels that should not be covered by Subpart OOOO. The revised definition in Section 60.5430 could potentially apply to storage vessels storing liquids or other materials with limited or no VOC emissions, such as lube oil. ANGA and AXPC understand that EPA intends to regulate vessels that are storing three classes of liquids: (1) condensate, (2) crude oil, and (3) produced water. However, the definition of storage vessel does not make any distinction between these three classes of liquids and other liquids that are stored in tanks at natural gas exploration and development facilities. We therefore request that the Agency reconsider the scope of the definition of storage vessel, in light of the Agency's interpretation as to the liquids that it intends to be covered,

and amend the regulation by including language that makes the regulatory definition consistent with the Agency's interpretation.

The definition also appears to have the potential to include portable tanks that may be located onsite for more than 180 days but are not in use for that entire time, such as tanks holding new or recycled fracturing fluid (frac tanks). Frac tanks are frequently used to contain flowback fluids up to the point where the fluids can be safely routed to permanent and pressure rated tanks; this can include periods of time after the flowback is initially routed to the separator as discussed below. Notwithstanding Agency guidance or clarification regarding when certain liquids are subject to the requirements at Section 60.5375, the definition of storage vessel would clearly apply to portable tanks that do not meet one of the three enumerated exceptions in Section 60.5430. It would be infeasible to meet the VOC control and monitoring requirements for these types of tanks.

Industry has focused on reducing its overall environmental footprint over the last several years. Best Management Practices developed include: reducing surface disturbance, reduced use of flowback pits, reduced truck traffic and recycling of fracturing fluid. This has been accomplished in large part by utilizing temporary equipment to manage the high volumes of flowback water experienced during initial flowback. The requirements of Section 53.5375 and recent agency guidance require operators to direct recovered liquids (including produced water) to "storage tanks". Agency guidance states that "the initial flowback (prior to the recovery through separation) may be routed to temporary "fracture tanks" as long as the separation of water, condensate, crude oil and gas occurs as soon as practicable.." Unfortunately, when these gas wells are directed to separation they are usually producing up to 100 barrels (bbls) per hour of frac fluid for the first 7-14 days. In order comply with this requirement an operator would need to install dozens of permanent "storage vessels" to accommodate this short lived production rate. In addition, operators would be required to increase around the clock water hauling, translating to additional mobile source emissions. By limiting the use of temporary frac tanks to recovered flowback prior to separation, the agency prohibits the effective utilization of many of the best management practices recognize today.

We request that the Agency reconsider the definition of storage vessels to consider including an exemption for portable tanks such as frac tanks and well testing tanks that are used in the circumstances described above. In addition, we request that 60.5375 (a)(1) be revised to authorize the routing of flowback liquids to these temporary portable tanks where storage of the liquids in a storage vessel is infeasible or impractical due to safety or operational concerns.

5. Finally, Section 60.5420(b)(6)(ii) of the Final Rule requires that owners/operators include "documentation that the VOC emission rate is less than 6 tpy for meeting the requirements in §60.5395(a)" in the annual report -- this would apply to storage vessels that are below the threshold and therefore not subject to the rule of the control requirement. This reporting requirement is burdensome and unnecessary, and inconsistent with annual reporting requirements for other equipment that meets non-applicability criteria. Similarly, the annual reporting requirement should not apply to tanks that are below 6 tpy due to the presence of state-mandated

controls. Because the applicability criteria changed from throughput to emissions-based, ANGA and AXPC did not have the opportunity to address the inclusion of this annual reporting requirement in its comments on the proposed rule, and we therefore request that EPA reconsider including this requirement in the annual reporting provisions.

Control Device Requirements -- Combustion Control Devices

1. New Sections 60.5412(a)(1) and 60.5412(a)(3) include additional requirements for determining initial compliance with control devices that apply to two categories of combustion control devices that may be used to control storage vessels – enclosed combustion devices (60.5412(a)(1)) and flares (60.5412(a)(3)). As discussed in greater detail in comments submitted by ANGA and AXPC dated August 3, 2012, we believe that some combustion control devices such as enclosed combustors or ground flares that are commonly used in industry to control emissions from storage vessels may not be considered to be either "flares" or "enclosed combustion devices" as those terms are either defined in or contemplated by the regulations. For example, certain control devices utilize a burner (or a series of burners) and pilot flame that are open to atmosphere (in order to oxidize hydrocarbons and other combustibles emitted from the storage vessels) but that are often wrapped in steel shrouds for safety reasons. These devices meet the control efficiency requirements of the rule and are categorized by AP-42 as ground flares. However, it is not clear to us that these units would be considered either flares or enclosed combustion devices under the rule. This is a critical issue for regulated entities, as they need to be sure that the use of these devices to meet the applicable control requirements for storage vessels is authorized under section 60.5412; in addition, they need to be able to understand what their initial and continuous compliance demonstration and performance testing obligations are under Sections 60.5412(a), 60.5415, and 60.5413 respectively. All of these depend on how the units are classified.

We suggest that the Agency has two options with respect to these units. First, it could decide that these units should be considered to be flares and subject to the initial compliance demonstration, performance testing, and continuous compliance demonstration requirements for flares. As set forth in our August 3, 2012, submission to the Agency, ANGA and AXPC believe that these units are appropriately considered "flares" within the context of this regulation, and should be subject to all requirements applicable to flares.

As an alternative, the Agency could consider these devices to be neither flares nor enclosed combustion devices. In that event, ANGA and AXPC suggest that EPA needs to reconsider all of the following to account for this category of control devices: (a) Section 60.5412(a) to add a fourth category of "control devices specified" in that section and that would include the identification of appropriate design and operation criteria; (b) Section 60.5413 to establish appropriate performance testing procedures for these devices; and (c) Section 60.5415 to establish appropriate continuous compliance demonstration procedures. If EPA chooses to pursue this option, we suggest that the Agency revisit each of the proposed subsections of 40 CFR Part 60, Subpart OOOO, to ensure that all of the regulatory requirements that apply to storage vessels are modified to account for this fourth category of approved control devices.

ANGA and AXPC request that the Agency either reconsider the definition of "flare" at Section 60.5430 to incorporate language making it clear that these enclosed combustors or ground flares fall within the definition of flare (or otherwise indicate that they are deemed to qualify as flares), in either event rendering them subject to all requirements in Subpart OOOO that are applicable to flares, or reconsider the Subpart OOOO regulations as they relate to the control device requirements applicable for controlling storage vessels in the manner suggested in the paragraph immediately above.

2. The compliance requirements for enclosed combustion devices were derived from the NESHAP Subpart HH control requirements for major sources of HAP emissions and area sources that are located near an urban area. The wellpad facilities where the majority of the storage vessel affected facilities will be located are unmanned and are often very remote, do not have power, and are minor sources of VOC and HAP emissions. As a result, several of the compliance requirements applicable to enclosed combustion devices in the Final Rule cannot be logistically or economically achieved by these units, and there are alternative compliance requirements that would be feasible, achievable, and adequately demonstrate compliance:

- As the rule has recognized in other sections, exploration and development in some remote locations introduces several challenges to effective capture of continuous monitoring parameter data. Some remote locations do not have electricity to power logging systems, remote data acquisition systems, or the phone lines or bandwidth available to transmit data every hour.

- Due to the inherent variability of flow to the control device, hourly monitoring may not be indicative of the periodic flow events, and an alarm system may be more appropriate in order to ensure compliance with an operating limit.

- The flow monitors that are capable of measuring the widely variable flow rates are very expensive, and given the difficulty and cost of accurate flow measurement, as well as the direct relationship between inlet pressure and flow capacity, ANGA and AXPC believe that measurement of inlet pressure should serve as a surrogate monitoring parameter for the flow rate.

- Control devices (such as the ABUTEC medium temperature flare) -- which do not require a continuous pilot light and utilize an electronic ignition system to ignite vapors once a set point is reached (typically around 4 oz) and the solenoid valve opens to release the vapors -- -- are increasingly being used in the field. These devices eliminate the need for a continuous pilot light. Testing has proven that these devices are compliant with all of the requirements of the rule except that they do not require a continuous pilot light and thus require special monitoring provisions.

3. Section 60.5415(e)(2)(vii)(C) requires an operator to perform a 2 hour visible emissions test using Method 22 on a monthly basis. The proposed rule required performance of a Method 22 visible emission test as part of the initial compliance demonstration, but there was no requirement

for additional Method 22 testing. Conducting monthly Method 22 tests would require significant additional resources, and ANGA and AXPC believe that these requirements are unnecessarily burdensome, as periodic verification of smokeless operation during normal site visits is sufficient to ensure smokeless operation of the combustors.

For these reasons, ANGA and AXPC request that the Agency reconsider the suite of compliance requirements set forth in the Final Rule that are discussed above, including specifically Section 60.5415(e)(2)(vii)(C), and we refer EPA to our August 3, 2012, comments for a more detailed discussion of these issues as well as some potential options for continuous monitoring methods.

Recordkeeping and Reporting

1. The Agency changed the reporting deadline in Section 60.5420(b) of the Final Rule to "30 days after the end of the initial compliance period." In the proposed rule EPA had proposed a reporting deadline of one year after the initial startup date for the affected facility or one year after the date of publication of the final rule in the Federal Register, whichever is later. The reporting deadline as changed in the Final Rule is not feasible, given the amount and detail of data required to complete the report. Manual and automated data collection and reporting systems can have significant lead times, making a 30 day turnaround of accurate data very difficult (if not impossible) in many cases. Turnaround time was not an issue with respect to the deadline in the proposed rule, as the report would simply have included the data and information that had been collected and assembled in time for submission of the report, and the period covered by the report would have simply been the time period that was covered by the data. Because ANGA and AXPC did not have an opportunity to identify these logistical problems with respect to the new provisions set forth in the Final Rule, we request that EPA reconsider the reporting deadlines set forth in Section 60.5420(b) in light of these concerns. We also suggest that a reporting deadline of 60 days after the end of the reporting period would be feasible.

Pneumatics

1. The exemption from notification requirements for certain affected facilities set forth in Section 60.5420(a)(1) does not include exemption from the reconstruction notification requirements of Section 60.15. ANGA and AXPC believe that there is no reason not to have this same equipment be exempted from the reconstruction notification requirements, and requests that the Agency reconsider the scope of the exemption at Section 60.5420(a)(1) and include language extending the exemption to include the reconstruction notifications.

2. The standards for controllers located both at non-processing and processing facilities also constitute an exemption from the definition of affected facility. The standard of Section 60.5390(c)(1) requires use of low bleed devices for pneumatic controllers installed after October 15, 2013, but low bleed devices are not affected facilities subject to the rule. The only devices that would be subject to the NSPS are those that must be high bleed for functional purposes. In addition, Section 60.5410(d)(3) states that to achieve initial compliance with the standards for pneumatic

controller affected facilities, you must maintain records that indicate your affected facility has a bleed rate less than or equal to 6 cubic feet per hour. If a device has that bleed rate, it is not an affected facility. The same logic and circular applicability confusion apply to the requirements for the processing facility pneumatics. ANGA/AXPC seeks confirmation that there are no compliance requirements for such non-affected facilities.

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ANGA and AXPC thank you in advance for your consideration of this request for administrative reconsideration of the provisions of the final Subpart OOOO regulations. Please call Amy Farrell at 202-715-1742 if you have any questions regarding this request or the issues discussed herein.

Amy Farrell
Vice President of Regulatory Affairs
America's Natural Gas Alliance

V. Bruce Thompson
President
American Exploration and Production Council

Attachment (8/3/2012 ANGA and AXPC Comment Letter)

Cc: Gina McCarthy
Peter Tsirigotis
Steve Page
Bruce Moore
David Cozzie

August 3, 2012

Bruce Moore
Senior Technical Advisor, Oil and Natural Gas Sector
Office of Air Quality Planning and Standards
U.S. Environmental Protection Agency
Research Triangle Park, NC 27711

Attention Docket ID Number EPA-HQ-OAR-2010-0505

RE: Comments of America's Natural Gas Alliance-Oil and Natural Gas Sector: New Source Performance Standards and National Emission Standards for Hazardous Air Pollutants Reviews. Docket ID No. EPA-HQ-OAR-2010-0505

Dear Bruce:

America's Natural Gas Alliance (ANGA) and the American Exploration and Petroleum Council (AXPC) appreciate this opportunity to provide written feedback on the U.S. Environmental Protection Agency's (EPA) Final Rule entitled— Oil and Natural Gas Sector: New Source Performance Standards and National Emission Standards for Hazardous Air Pollutants Reviews, signed April 17, 2012.

We have included a number of suggestions that we believe will improve the regulation as we move into the implementation phase. We are also seeking clarification of the Agency's intent regarding a number of provisions in the regulatory text. To that end, we have included a number of questions throughout the document, and would appreciate a written response from the Agency so that we are better able to plan and ensure compliance once the regulatory requirements are in effect. In a number of areas we also suggest revisions to the text that will ensure clear, unambiguous interpretation of the rule language.

Thank you for your time and assistance,

Amy Farrell
Vice President of Regulatory Affairs
America's Natural Gas Alliance

V. Bruce Thompson
President
American Exploration and Production Council

Gas Well Completions

- §60.5420(a)(2)(i) requires notification "no later than 2 days prior to the commencement of each well completion operation". The 2 day notification requirement is unclear as to whether it refers to 2 calendar days, 2 business days, or 48 hours. Due to the difficulty in tracking the hours of submittal and completions operations initiation, as well as the continuous nature of drilling and completions operations, ANGA and AXPC recommend that §60.5420(a)(2)(i) be modified to specify a due date of no later than 2 business days.

- ANGA and AXPC appreciate EPA's efforts to encourage early action by exempting recompleted wells that comply with the REC requirement from becoming an affected facility. However, the rule requires exempt recompleted wells to comply with all of the notification, recordkeeping, and reporting requirements of §60.5375 that are associated with recompleted wells that are not exempt. As a result, the burden associated with an exempt recompletion is essentially the same as the burden for a regulated recompletion. If EPA wants to encourage early action, it should modify §60.5365(h)(1) to state that the REC must only meet the operational or work practice standard requirements of §60.5375(a). Such a change to the regulation would provide a real incentive to operators to conduct more reduced emission completions and generate real environmental benefit from reduced flaring and increased gas capture rates.

- There are periods during normal completions operations when fluids are not able to be sent to the separator in order to be flared or captured (as described in Attachment A) without the use of a flaring pit. We understand that it was not EPA's intent to encourage the use of pits or to require frequent deviation reporting from §60.5375(a)(1) and (a)(3) during these periods. Can you please confirm that, during periods when capture or flaring is not feasible, EPA does not intend to require fluids to be routed to a separator and subsequently captured or flared as long as emissions are minimized and resource recovery is maximized to the greatest extent possible? Consistent with our current assumptions about EPA's intent, we suggest that §60.5375 be modified as follows:

    1. Revise the definition of flowback in §60.5430 to "flowback means the process of allowing fluids to flow from a natural gas well following treatment and cleanout of the wellbore, either in preparation for a subsequent phase of treatment or in preparation for turning or returning the well to production. The flowback period begins after hydraulic fracturing or refracturing and plug drillout when material introduced into the well during treatment returns to the surface with detectable natural gas. The flowback period ends with either well shut in or when the well is producing continuously to the flow line or to a storage vessel for collection, whichever occurs first." Natural gas is detectable when the lower explosive limit (LEL) is greater than or equal to 1% or methane is greater than or equal to 10,000 ppm as measured within 25 feet of the fluid release point. Measurement devices shall be calibrated in accordance with manufacturer recommendations."

    2. Revise §60.5375(a)(3) to add at the end of the last sentence "… except in accordance with §60.5375(a)(5) or (a)(6), in conditions that may result in a fire hazard or explosion, or where high heat emissions from a completion combustion device may negatively impact tundra, permafrost or waterways."

    3. Add section §60.5375(a)(5) to state that routine maintenance activities such as choke and orifice changes, equipment setup and teardown, excess pressure relief, and equipment cleaning, you must only comply with the requirements of §60.5375(a)(2) and (a)(4).

    4. Add section §60.5375(a)(6) to state that for pitless operations, in the event of temporary equipment malfunctions, flowback plugging, or well control incidents, you must take corrective action as expeditiously as possible and comply with the requirements of §60.5375(a)(2) and (a)(4).

- Can you please clarify if it is EPA's intent to require operators to keep records of digital photographs of each green completion? The preamble suggests that EPA intended to provide an alternative recordkeeping and reporting option that included digital photographs, but the regulatory language (§60.5420(c)(1)(v)) requires that records of the photograph be maintained regardless of which method is used to report. We recommend that §60.5420(c)(1)(v) be modified to read “For each gas well affected facility required to comply with both §60.5375(a)(1) and (a)(3) and reporting using the alternative digital photograph and list of affected facilities method.”

- The rule does not include any provisions in §60.5375(a)(3) or §60.5375(f)(2) for areas where flaring is restricted by local ordinance (i.e., DFW). Requiring flaring where restricted could lead to conflicting regulatory requirements and default non-compliance for operators. As such, we recommend that EPA include an additional exemption in §60.5375(a)(3) and §60.5375(f)(2) for other regulatory restrictions. Can you please clarify whether EPA intends to provide any exemptions to the provisions in §60.5375(a)(3) or §60.5375(f)(2) for areas where flaring is restricted by local ordinance? If such exemptions will not be provided, can you describe what other actions the Agency is planning to ensure that operators are not at risk of forced non-compliance because of the conflicting requirements?

Storage Vessels

- §60.5395(a) requires producers to “determine the VOC emission rate for each storage vessel affected facility using any generally accepted model or calculation methodology.” Can EPA you please clarify whether the initial VOC emission determination required by §60.5395(a) is to be based on actual average emissions, similar to the requirements of §63.772(b)(2) for glycol dehydration units? In other words, is the 6 ton per year threshold based on controlled emissions? We recommend that EPA adopt this interpretation and allow emissions to be estimated based on enforceable controls in place (e.g. a federally enforceable state rule or a federally enforceable permit).

- ANGA and AXPC recommend that EPA revise the rule to include provisions for reevaluating actual annual emissions and emissions control requirements on an annual basis. This is appropriate given the natural decline of liquid production from a well as well as the uncertainty in emission projections. If actual annual emissions from an affected facility are found to be below 6 tons per year for the reporting period and are projected to remain below 6 tons per year, ANGA and AXPC recommend allowing the removal of controls. This would ensure that additional combustion emissions are not produced from the use of supplemental fuel in order to control a small amount of VOC emissions. This be could be accomplished by adding a provision to the definition of storage vessels as follows:

  The following are not considered storage vessels:
  *****
  Vessels with actual annual emissions less than 6 tpy.

- §60.5395(a)(1) requires that sources located at facilities without any other wells in production calculate emissions within 30 days and install any required controls within 60 days of start-up. However, the sample results and wellpad production data generally required to calculate emissions are often not available within 30 days of startup. Without this information, it is not possible to make accurate emissions estimates, which makes the design, installation, and operation of a control device very difficult. If emissions or liquid production are underestimated in the design phase, there may be liquid carryover and/or excess waste gas, leading to safety concerns (including fire and explosion hazards) and control efficiency reduction if backpressure causes vessel pressure relief devices to release vapors to atmosphere. On the other hand, if emissions and production are overestimated it will lead to excess fuel consumption and additional emissions. Without proper control device design, operators may not be able to comply with the requirement of the rule and may need to replace or redesign the controls, the cost of which was not included in EPA’s costs analysis. As such, ANGA and AXPC suggest that §60.5395(a) be revised to require the emission evaluation within 60 days and control device installation within 120 days.

- §60.5395(a)(2) requires that sources located at facilities with other wells in production calculate emissions and install any required controls upon start-up. However, this is infeasible in many cases. While it is true that there would be production data available for the existing well or wells, the age of the well, formation type, location within the formation, and characteristics of the well including lateral length, proppant used, and direction of fractures can lead to great variability and unpredictability in any compositional or production estimates. Not only does the lack of this consistency preclude operators from estimating emissions before start-up, but as discussed above, also makes the design, installation, and operation of a control device upon startup very difficult. As such, AXPC and ANGA recommend that EPA provide the same allowance for emission determination and control installation for all wells (60 days and 120 days respectively), regardless of whether or not there are other collocated wells in production.

- ANGA and AXPC appreciate and support EPA's exemption of portable storage vessels in §60.5430. However, the definition still has potential to include frac tanks, which ANGA and AXPC believe EPA intended to exclude. Please clarify whether it was EPA's intent to exclude frac tanks? Not only are emissions estimates extremely difficult to calculate due to the highly variable composition and volume of the fluids contained, but these vessels are not pressure rated and cannot be safely controlled. Additionally, the inclusion of frac tanks in this affected source category could inappropriately encourage the use of pits over tanks or the reduced use of multiwell drilling programs. In order to reduce the overall environmental footprint of exploration and production operations companies have increasingly been drilling multiple wells on a single location. In order to complete all of the wells, however, frac tanks sometimes need to remain on-site for more than 180 days. In consideration of the inability to control these tanks and the adverse unintended environmental impacts that could result from the current definition of storage vessel, ANGA and AXPC recommend that EPA include an exemption for frac tanks. Suggested language for such an exemption follows:

  The following are not considered storage vessels:
  *****
  (4) Vessels that are designed and operated to contain flowback fluids for the duration of the completions operation. Completions operations begin when hydraulic fracturing commences and ends when all wells on the location are either shut in or are flowing continuously to the sales line.

- The current definition of storage vessels in §60.5430 could potentially apply to storage vessels with few to no emissions such as lube oil and chemical storage tanks. ANGA and AXPC do not believe that it is EPA's intent to include such vessels and recommends the Agency make clear such tanks are not covered by the rule.

- §60.5420(b)(6)(ii) requires that "documentation that the VOC emission rate is less than 6 tpy for meeting the requirements in §60.5395(a)" be included in the annual report. However, ANGA and AXPC believe that reporting this information is burdensome and unnecessary. Similar to other non-applicability determinations, ANGA and AXPC believe that maintaining records of this documentation is sufficient to demonstrate compliance and recommend that §60.5420(b)(6)(ii) be removed from the rule.

Control Device Requirements

- The control devices included in the rule are not representative of the devices that are typically used to control emissions from storage vessels in the production sector. While the terms vapor recovery unit, flare, and enclosed combustion device are used commonly within the industry, there is significant discord with EPA's definitions and treatment of such sources within the rule. Additionally, many of the compliance requirements for enclosed combustion devices are infeasible for the typical, often remote, field combustor. (Note that similar concerns were brought up with regards to NESHAP Subpart ZZZZ requirements for area sources and subsequently revised in a proposed rule). More detail on the control device definitions and requirements is included below.

Combustion Control Devices

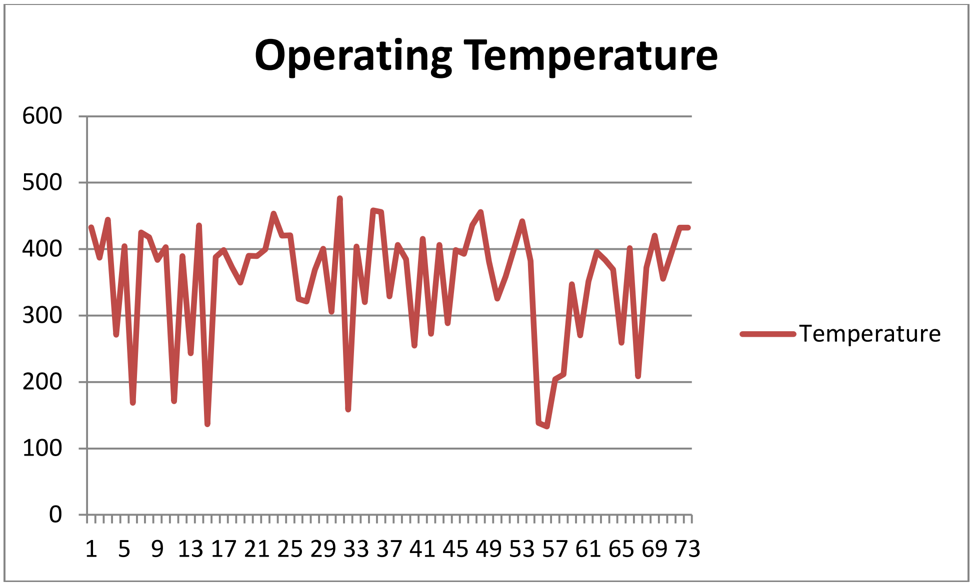
- §60.5412(a) defines two categories of combustion control devices that may be used to control storage vessels – enclosed combustion devices and flares. However, the enclosed combustors or ground flares commonly used in industry to control emissions from storage vessels do not fall within either of the two categories as defined by the rule. These control devices, such as the VOCinerator™ unit manufactured by MESSCO and the Emission Control Device unit manufactured by Cimarron, utilize a burner (or a series of burners) and pilot flame that are open to atmosphere in order to oxidize hydrocarbons and other combustibles emitted from the storage vessels. For safety reasons, these control devices are often wrapped in steel shrouds, but remain open to atmosphere. These devices meet the control efficiency requirements of the rule and are categorized by AP-42 as ground flares with combustion taking place at ground level (lower than 10 meters). As such, AXPC/ANGA requests that the definition of flare in §60.5430 be revised to remove the "(without enclosure)" and as such treat these combustors as flares under the rule. We believe that these devices will comply with the compliance demonstration requirement of §60.18. Alternatively, we recommend that a new control device category be created for ground flares with appropriate testing and monitoring requirements, as described in the following sections.

- The compliance requirements for enclosed combustion devices were derived from the NESHAP Subpart HH control requirements for major sources of HAP emissions and area sources that are located near an urban area. However, the wellpad facilities where the majority of the storage vessel affected facilities will reside are unmanned and are often very remote, do not have power, and are minor sources of VOC and HAP emissions. As such, if combustors were to be treated as enclosed combustion devices in the current rule there are several requirements that cannot be logistically or economically achieved.

- Following is an operational summary of how combustors work, a discussion on the definition of these devices versus enclosed combustion devices in the rule, and a discussion on the aspects of the enclosed combustion device requirements that are technically infeasible for field combustor control devices to comply with.

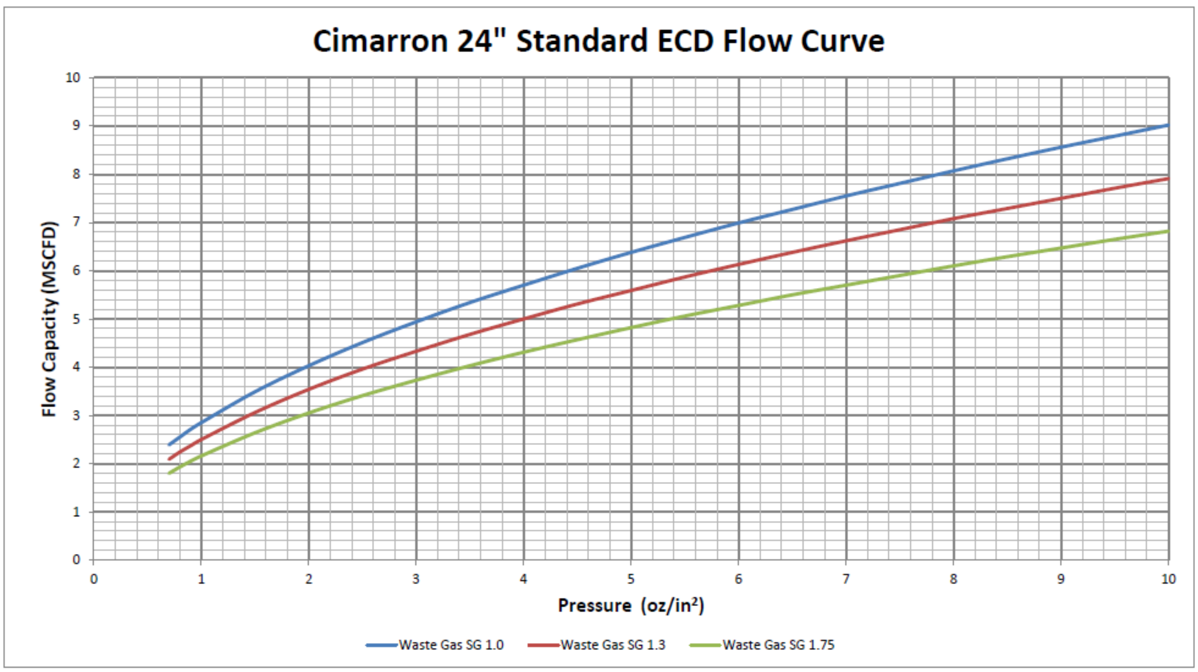
<u>Combustor Operation</u>

It is important to understand the functionality of the combustion control devices that are used to control storage tanks at remote sites. These devices are usually enclosed flares that utilize natural draft to induce air into the combustion area and operate under dynamic load conditions. Flash gas routing to the combustion devices is not a steady stream but rather a dynamic stream with waste gas primarily generated as the well unloads fluids. The variable flow directly correlates to the combustion zone temperature and is shown in the following graph. As the well unloads, flash gas is routed to the flare and the combustion temperature rises. As fluid production to the tank stops, associated flash gas also ceases to flow, allowing the combustion temperature to fall to the temperature associated with the pilot flame.



It would be difficult to set an appropriate minimum temperature that would be indicative of complete VOC/HAP destruction. Periodic monitoring of flame presence is sufficient to verify emission reduction. Continuous parameter data logging is not feasible on well pads without electricity.

For these devices, there is a direct relationship between inlet pressure (oz. per square inch) and flow capacity (MSCFD), as shown in the figure below and attached example documentation.



<u>Additionally, in an effort to reduce emissions and save fuel, combustor manufacturers such as ABUTEC have increasingly been utilizing devices that to not require supplemental fuel to maintain the pilot light and rather hold back pressure on the device and utilize an electronic ignition system upon release of the vapors to the device. These devices are reliable, meet the control efficiency requirements of the rule, and have undergone testing to demonstrate their performance.</u>

<u>Definition of Enclosed Combustion Device</u>

- §60.5412(a)(1) provides the following as examples of enclosed combustion devices, each with a completely enclosed combustion zone: "thermal vapor incinerator[s], catalytic vapor incinerator[s], boiler[s], and process heater[s]." The aforementioned ground flares are neither boilers nor process heaters, nor do they utilize a catalyst bed and are not catalytic vapor incinerators. The efficiency of a thermal vapor incinerator is dependent on proper vapor mixing and a specific residence time in the combustion chamber, and because of this "are not well suited to vapor streams that fluctuate," such as those from a storage vessel vapor system. Furthermore, a thermal vapor incinerator utilizes uniform temperature distribution to achieve its destruction rate efficiency. This is the primary difference between the ground flares commonly used to control tank emissions and a thermal vapor incinerator. In order to create the uniform heat distribution and well-defined residence times required to meet the design destruction rate efficiency, these incinerators require a completely enclosed combustion chamber, which the aforementioned devices do not have. ANGA and AXPC understands that EPA intends to provide a non-exhaustive example list of enclosed combustion control devices under §60.5412(a)(3). However, the field combustors in use are not operationally equivalent to this combustion source category and should not be treated as such. Both types of control devices should be allowable under Subpart OOOO, each with appropriate parametric monitoring provisions.

<u>Infeasible Compliance Requirements for Enclosed Combustion Devices</u>

- As the rule has recognized in other sections, exploration and development in some remote locations introduces several challenges to effective capture of continuous monitoring parameter data. Some remote locations do not have electricity to power logging systems, remote data acquisition systems, or the phone lines or bandwidth available to transmit data every hour.

- Due to the inherent variability of flow to the control device, hourly monitoring may not be indicative of the periodic flow events and an alarm system may be more appropriate in order to ensure compliance with an operating limit.

- The flow monitors that are capable of measuring the widely variable flow rates are very expensive, particularly those that comply with the accuracy requirements of +/- 2%. ANGA and AXPC believe that this level of accuracy would require an ultrasonic meter, which have an estimated cost of $45,000. Given the difficulty and cost of accurate flow measurement, as well as the direct relationship between inlet pressure and flow capacity, ANGA and AXPC believe that measurement of inlet pressure should serve as a surrogate monitoring parameter for the flow rate.

- Control devices such as the ABUTEC medium temperature flare (control philosophy attached) are increasingly being used that eliminate the need for a continuous pilot light. These devices hold minimal back pressure on the system and then utilize an electronic ignition system to ignite vapors once the set point is reached (typically around 4 oz) and the solenoid valve opens to release the vapors. Testing has proven that these devices are compliant with all of the requirements of the rule except that they do not require a continuous pilot light and thus require special monitoring provisions.

- Paragraph C requires the operator to perform a 2 hour visible emissions test using Method 22 on a monthly basis. These tests would require significant additional resources and are unnecessarily burdensome. ANGA and AXPC believe the intent of this requirement is to ensure that the combustion devices are designed and operated on an ongoing basis with no visible emissions, as required for flares in §60.18(c)(1). However, ANGA and AXPC believe periodic verification of smokeless operation during normal site visits will ensure the smokeless operation of the combustors. Furthermore, ANGA and AXPC believe that the prescription of corrective actions is unnecessary and will lead to costly and unwarranted repairs. Rather, corrective actions should be determined and documented on a case-by-case basis.

Continuous Monitoring Requirements

Given these operational challenges and the wide variety of monitoring capabilities found throughout the nation, ANGA and AXPC recommend that EPA include several monitoring options that satisfy the intent of the rule while providing the operational flexibility to make implementation feasible for all operators. With the understanding that EPAs intent is to ensure the proper and smokeless operation of field combustors, the following options are recommended:

Option 1

The control device and associated equipment will be physically inspected and documented on a monthly basis or as often as condensate is loaded out, whichever is less frequent. The inspection shall include verification of the following: (see Colorado Regulation 7 Section XII requirements for the Denver non-attainment area)

- Absence of smoke
- Pilot is lit or electronic ignition system is functioning properly
- All vapors are routed to the control device with all valves on the vapor line open
- All thief hatches are closed and latched

If deviations are detected during an inspection, an explanation will be documented and corrective action taken and documented as expeditiously as practicable. Subsequent corrective action shall be taken and documented as needed in order to ensure continuous compliance with the specified criteria.

Option 2

The presence of the pilot light or proper operation of the electronic ignition system will be verified and the storage tank/combustor inlet pressure will be monitored every four hours. Pressure measurements will be compared to the manufactures specifications or the operating range established during initial performance testing in order to demonstrate compliance. Pressure measurement devices will have an accuracy of +/- 5% of the calibration range. Additionally, the smokeless operation of the flare will be verified during normal site visits. Deviations will be documented and reported and corrective action taken as expeditiously as practicable.

Emission Testing Requirements

For those make/model control devices that are not manufacturer certified, the on-site emission testing is very costly (estimated $10,000 per test) and should not be required for each device. Alternatively, ANGA and AX PC recommend that a given make and model should be exempt from testing requirements once an operator has demonstrated compliance and established a representative operating parameter limit on three units.

No Detectable Emissions Demonstration Requirement

Like emission testing, the requirement to conduct Method 22 monitoring to demonstrate no detectable emissions from the closed vent system is onerous and expensive (estimated $500 per monitoring event). As an alternative, we would recommend that the initial compliance demonstration replicate the subsequent annual visual inspection requirements.

Recordkeeping and Reporting

- For affected facilities that are constructed, modified, or reconstructed between August 23, 2011, and the final rule publication date, in accordance with §60.5370 there are no compliance requirements until 60 days after publication of the final rule. AXPC and ANGA believe that it is reasonable to maintain records of the list of all affected facilities during this period in order to demonstrate applicability to the rule. No notifications will be retroactively submitted, the detailed recordkeeping requirements of §60.5420(c) will not be maintained, and initial annual reports will not address this period. Can you please confirm whether this will be sufficient to demonstrate compliance during this period?

- For affected facilities that are constructed, modified, or reconstructed between the initial reporting period's start of final rule publication and the compliance date of 60 days after publication, AXPC and ANGA believe that it is reasonable to maintain records of and report the list of all affected facilities during this period in order to demonstrate applicability to the rule and comply with the requirements of §60.5420(b)(1). However, no notifications will be retroactively submitted, the detailed recordkeeping requirements of §60.5420(c) will not be maintained, and initial annual reports will not include the additional information required by §60.5420(2)-(7). Can you please confirm this will be sufficient to demonstrate compliance during this period?

- For affected facilities that are constructed, modified, or reconstructed between the initial compliance date of 60 days after publication, but do not have operational compliance requirements until 1 year after publication or some other later date, AXPC and ANGA believe that it is reasonable to comply with the requirements of §60.5420 except for the reporting and recordkeeping requirements associated with non-applicable operational compliance requirements such as control device monitoring for the duration of the period until the operational compliance requirements become effective. Can you please confirm this will be sufficient to demonstrate compliance during this period?

- The reporting deadline included in the rule is not feasible given the amount and detail of data required to complete the report. Manual and automated data collection and reporting systems can have significant lead times, making a 30 day turnaround of accurate data very difficult if not impossible in many cases. As such, ANGA and AXPC suggest that EPA extend the reporting deadline in §60.5420(b) to 60 days after the end of the reporting period.

Pneumatics

- The notification exemption in §60.5420(a)(1) does not include the reconstruction notification requirements of §60.15. ANGA and AXPC believe that it is EPA's intent to have also excluded this section and recommend the addition of this section in the exemption.

- The standards for controllers located both at non-processing and processing facilities also constitute an exemption from the definition of affected facility. ANGA/AXPC seeks confirmation that there are no compliance requirements for such non-affected facilities.

- There is an inconsistency in the rule with regards to the requirement for affected facility controllers at processing plants. The definition of affected facility excludes non-continuous bleed gas-actuated controllers including intermittent or no bleed devices. Additionally, the standard as specified in §60.5390(b)(1) requires that affected facilities have a bleed rate of zero. This requirement is consistent with language throughout the rule except that §60.5410(d)(2) states that in order to demonstrate initial compliance you must demonstrate that your device is "driven other than by the use of natural gas," precluding the use of non-continuous bleed gas-actuated controllers. We believe that it was EPA's intent to require the use of a device with no continuous bleed rate and request that §60.5410(d)(2) be revised to state "your pneumatic controller has a natural gas bleed rate of zero." If this revision is not made the requirement to comply within 60 days of rule publication is infeasible given the infrastructure and equipment lead time required to install instrument air or another non-natural gas motive gas system. In this case we request that the compliance date be extended to one year after rule publication date.

- The reporting requirements in §60.5420(b)(5) references (b)(5)(i-v), yet the section only includes (b)(5)(i-iii). We believe that it was EPAs intent to reference (b)(5)(i-iii) and recommend that the rule be corrected as such.

- While the rule takes into consideration the need for exemptions to the standard to allow for high bleed devices due to functional needs including response time, safety, and positive actuation in §60.5390(a), it does not take into account the functional need for low bleed pneumatic controllers at processing facilities. As such, we request that provisions also be included to exempt affected facilities at processing facilities from the standard if such functional needs can be demonstrated and documented.

Equipment Leaks at Processing Facilities

- While the rule has maintained the monitoring exemption from NSPS KKK for pumps in light liquid service, valves in gas/vapor and light liquid service, and pressure relief devices in gas/vapor service at processing facilities with a design capacity of less than 10 mmscfd 60.5401(d), it fails to exempt the connectors that are newly required to be monitored. We believe that it was EPA's intent to also exempt such facilities from the connector monitoring requirements of §60.482-11a and requests that the rule be modified to include such exemption. Each valve will have associated connectors so there is no way to monitor these connectors without also monitoring the associated valve. As such, if the exemption is not extended to connectors the exemption for valves is virtually meaningless.

Appendix A. Completion Operations that Preclude Capture or Combustion

The provisions of §60.5375(a)(1) and (3) require that for the duration of flowback all liquids and gas are recovered "with no direct release to the atmosphere" and when infeasible, flowback emissions must be routed to a completions combustion device. However, there are periods during flowback when fluids contain no or minimal amounts of gas and are not able to be recovered or flared. These periods may include initial flowback with and without energized fracturing with inert gases and certain operational and maintenance activities, as described below.

Additionally, there are events which may occur several times during a completions operation, particularly for high geo-pressure wells (defines as having 7,500 to 11,000 psi geopressure), during which fluids cannot be safely or logistically flared or captured. In these instances, whatever gas is entrained in the fluids must be vented.

Initial flowback

Without energized fracturing

After fracturing or refracturing, the plugs are drilled out with a coil tubing or snubbing unit or a workover rig. During this period of drillout, there is a large volume of liquid and sand debris in the flowback stream and generally minimal to no gas (higher likelihood of entrained gas for high geopressure wells). In order to capture or flare the entire flowback stream, additional oversized separators would be required that are of very limited availability. Without such equipment, as is the industry practice now (including during reduced emission completions), flowback for the duration of the drillout period needs to be routed to open-top tanks. Immediately following plug drillout, flowback can be routed to the test separator and captured or combusted as required by the rule.

In terms of the availability of the oversized separators necessary to capture the entire flowback stream during plug drillout, after meeting with several vendors we estimate that in the areas of Texas and Louisiana there are only approximately 12-15 of the super separators required for high geopressure wells. Not only is this quantity insufficient for completions operations in the area, but the separators are often also used in drilling operations, creating further shortage. This shortage of oversized vessels is also present in lower geopressure development areas.

While EPA recognizes in the preamble of the rule that an estimated 1,300 additional units will be required to meet the requirements of §60.5375(a), they did not account for the need for these additional oversized separators in their evaluation. Accordingly, if initial flowback during drillout is required to be separated and captured or flared, additional time would be needed past the 2015 compliance date in order for manufacturers to build the additional equipment required for each completion or recompletion, whether emissions are captured or combusted.

In addition to the unavailability of equipment, there is another logistical challenge in that the test separators needed require some gas in the stream in order to function properly and avoid liquid carry over into the gas line. This is due to the fact that the dump valves on the separators are gas actuated and if there is insufficient gas in the flowback stream, which there generally is not, the separators will not dump fluids to the tank and instead liquids will get sent to the flare or sales line, creating problems and additional emissions either way.

With energized fracturing

Operations that use inert gases such as nitrogen or carbon dioxide to fracture the wellbore will have no or de minimis amounts of natural gas or other combustible components in the initial flowback stream. While this initial flowback can technically be separated and the gaseous stream sent to a combustion device as suggested by USEPA in the preamble of the rule, it is unlikely that the pilot light would remain lit in such a high flow and low-hydrocarbon environment. Additionally, even if a pilot were to be able to be maintained, it is estimated that it would require upwards of 500 mcfd of supplemental fuel in order to meet minimal btu requirements of the combustion device (as specified in §60.18). Fuel requirements will vary depending on the volume and composition of the flowback stream and it is not uncommon to require 1 mmscfd. For the minimal 500 mcfd scenario, this equates to additional emissions of 13 tpy total hydrocarbon, 34 tpy CO, and 6 tpy NOx (based on AP-42 factors) in order to combust de minimis amounts of VOCs.

Operational and Maintenance Activities

The following situations can occur during normal operations and preclude the use of a separator and thus recovery or flaring of de minimis amounts of gas.

- Bleeding Pressure - when changing chokes or orifice plates and while rigging up or down the coil tubing unit, snubbing unit or workover rig, pressure often needs to be bled off from the well or equipment.

- Dumping sand separators and parts catcher to tanks – in order to ensure proper operation, the sand separator and parts catcher need to be periodically cleaned out. In order to perform the cleaning operation, the separator or catcher needs to be bypassed. Upon completion of the cleaning operation, flowback can be immediately rerouted through the test separator and captured or flared.

- Excess casing pressure – on occasion excess intermediate or surface casing pressure builds up during flowback and is required to be vented to relieve the pressure, releasing a de minimus amount of gas.

- Excess pressure on vessels – on occasion, the separator plugs up (blocks entrance or exit of fluids/gas) and pressure rises in the vessel itself, causing a relief valve to vent all pressure to atmosphere.

- Excess back pressure - if there is too much back pressure due to the use of the separator and proper returns begin to fall off, flowback needs to be sent to the tanks in order to maintain circulation

Upset Conditions

The following upset situations preclude the use of the test separator

- Screenouts - on occasion, sand packs in the well-bore after coming out of suspension and the well must be flowed back immediately at maximum velocity (i.e. sent to a tank or pit).

- Separator equipment malfunction – in order to fix the equipment, flow needs to be re-directed and pressure bled off (vented).

- Repairing equipment - When repairing flowback or other lease equipment, pressure needs to be bled off of the needle valves, releasing de minimus amounts of gas.

- Plugging off other equipment – on occasion, flowback can plug off, causing sufficient and proper returns to drop and requiring the rerouting of all returns to an open top tank to keep circulation. Equipment that become plugged include:
    - Sand separator
    - Parts catcher
    - Hydraulic and choke manifolds
    - Test separator

    - Flow arm and flow lines
    - Wellhead
    - Bottom hole assembly (down hole)

- Stuck coil tubing – while rare, if coil gets stuck down hole, the well cannot be surged to the test separator without overpressuring the vessel, requiring the well to be surged to a tank.
- Well control operations—well control incidents and corrective actions may require system or wellbore fluids to be bled off or vented under emergency situations.