Interstate Natural Gas Association of America

December 17, 2018

Via www.regulations.gov and email

U.S. Environmental Protection Agency
Attention Docket ID Number EPA–HQ–OAR–2017–0483
1200 Pennsylvania Avenue, N.W.
Washington, D.C. 20460

Re: Docket ID No. EPA-HQ-OAR-2017-0483 – "Oil and Natural Gas Sector: Emission Standards for New, Reconstructed, and Modified Sources Reconsideration," 83 Fed. Reg. 52,056 (Oct. 15, 2018)

Dear Docket Clerk:

The Interstate Natural Gas Association of America (INGAA), a trade association of the interstate natural gas pipeline industry, respectfully submits these comments in response to the Environmental Protection Agency's (EPA) proposed rule, "Oil and Natural Gas Sector: Emission Standards for New and Modified Sources Reconsideration" (Proposed Rule). The Proposed Rule would amend 40 C.F.R., Part 60, Subpart OOOOa, the New Source Performance Standard (NSPS) for oil and natural gas operations that are modified, constructed, or reconstructed after September 18, 2015.

INGAA member companies transport more than 85 percent of the nation's natural gas, through approximately 200,000 miles of interstate natural gas pipelines. Across the United States, INGAA member companies operate over 6,000 reciprocating compressors and over 1,000 centrifugal compressors installed at compressor stations along the pipelines to transport natural gas to local gas distribution companies, industrials, gas marketers, and gas-fired electric generators. Over the past two decades, INGAA and its members have worked extensively with EPA as emission regulations and methane emission programs that affect natural gas operations were developed and implemented. The natural gas transmission industry has developed technical documents on emissions and technology performance, conducted cooperative research projects, and developed emissions mitigation technologies and practices to address emissions. Industry experience provides a thorough understanding of methane emissions and emissions mitigation.

These comments summarize INGAA's concerns with the Proposed Rule. INGAA appreciates your consideration of these comments and welcomes additional dialogue. Please contact me at 202-216-5955 or ssnyder@ingaa.org if you have any questions. Thank you.

Sincerely,

Sandra Y. Snyder

Sandra Y. Snyder
Regulatory Attorney for Environment & Personnel Safety
Interstate Natural Gas Association of America

cc: David Cozzie, U.S. EPA (via email)
Karen Marsh, U.S. EPA (via email)
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COMMENTS OF THE INTERSTATE NATURAL GAS ASSOCIATION OF AMERICA ON THE PROPOSED RULE, "OIL AND NATURAL GAS SECTOR: EMISSION STANDARDS FOR NEW, RECONSTRUCTED, AND MODIFIED SOURCES RECOSIDERATION"

Code of Federal Regulations Title 40, Part 60, Subpart OOOOa

83 Fed. Reg. 52,055 (Oct. 15, 2018)

Submitted: December 17, 2018

The Interstate Natural Gas Association of America (INGAA) respectfully submits these comments in response to the Environmental Protection Agency's (EPA) proposed amendments to Subpart OOOOa, the New Source Performance Standard (NSPS) for crude oil and natural gas facilities for which construction, modification, or reconstruction commenced after September 18, 2015 (Proposed Rule).

EXECUTIVE SUMMARY

INGAA members operate reciprocating and centrifugal compressors at natural gas transmission and storage facilities, which are regulated under Subpart OOOOa. The Proposed Rule would primarily affect implementation of leak detection and repair (LDAR) programs at affected INGAA member facilities. As noted in the Proposed Rule preamble and under Executive Order 13563, the U.S. regulatory system "…must be based on the best available science."[1] The comments that follow provide information to EPA regarding current operations and the best science currently available. INGAA's primary concerns are as follows:

(1) LDAR surveys should be conducted with compressor operations as they are found. Natural gas transmission compressor stations typically include multiple compressors. These compressors are often in different modes (e.g., some units are operating pressurized, some are in stand-by (i.e., not operating) pressurized mode, and some are in not operating and depressurized mode (i.e., shut down and blown down)) depending on pipeline demand. Therefore, requiring surveys to be conducted with the compressors in a particular mode will complicate compliance, increase costs, and will likely result in additional vented emissions that exceed the emissions from any potential leaks associated with a particular mode. To avoid these unintended consequences, INGAA recommends that compressor leak surveys be conducted in the mode in which the compressors are found when the survey is conducted.

(2) Based on the best available science, INGAA supports conducting LDAR monitoring on an annual basis for transmission and storage facilities (with compressor operations as they are found).

(3) EPA should revise the delay of repair provisions to eliminate the requirement to complete a repair if a planned vent blowdown occurs.

(4) EPA should revise its Technical Support Document (TSD) to reflect emissions data and cost estimates that are more accurate and up-to-date. INGAA provides additional details in an attached appendix to clarify documents that INGAA submitted to EPA and the Office of Management and Budget and to which EPA responded in a memo.

(5) INGAA supports the proposed amendments to the Alternative Means of Emission Limitations (AMEL) provisions that support state program LDAR equivalency and allow AMELs for groups of facilities.

INGAA appreciates the opportunity to comment on the Proposed Rule and offers its assistance to reconcile the issues herein.

[1] 83 Fed. Reg. at 52,088 (Oct. 15, 2018).

DETAILED COMMENTS

1. INGAA recommends conducting LDAR surveys with facility operations as they are found when the survey is conducted.

EPA has proposed adding a requirement in 40 C.F.R. § 60.5397a(g)(2) where "[e]ach compressor must be monitored while in operation (*i.e.,* not in stand-by mode) at least annually." EPA has requested feedback on the effect compressor mode has on fugitive emissions and on a requirement to conduct monitoring only during times that are representative of operating conditions for the compressor station. Appendix A and information that INGAA previously provided to EPA[2] provide information about the impact that compressor mode has on fugitive emissions.

For the reasons below, INGAA believes monitoring should be conducted with operations as found, because that is indicative of representative operating conditions.

A typical natural gas transmission compressor station is designed so that there are enough compressors (i.e., units) installed at the station to meet peak natural gas demand. Peak demand may occur, for example, during cold winter months if there is high heating demand. On most days, a typical station will not be operating at full (peak) capacity and some units may be in standby-pressurized mode and/or not operating and depressurized. Compressor stations typically include multiple compressors, and a given facility will have variable operating conditions (e.g., all compressors operating, some compressors operating, some units in standby-pressurized mode, and some compressors not operating and depressurized).[3] In other words, representative operating condition is anytime the facility is in operation, regardless of how many (or how few) compressors are operating at a given time for a given compressor station. Unit operation will always be contingent upon demand. When the station is operating, the facility will be pressurized regardless of the mode of a particular compressor, and every unit will have potential leak emissions regardless of its mode.

INGAA is very concerned about the potential unintended consequences associated with this aspect of the proposed rule, which may negatively impact emissions, operations, and compliance costs. The proposed requirement to conduct surveys of each compressor while operating should not be adopted. Conducting surveys while each compressor is operating will add significant complexity to scheduling LDAR surveys, will increase LDAR compliance costs (beyond the costs accounted for in EPA's analysis), and, as discussed below, will increase methane emissions in some cases. Leak surveys are typically scheduled weeks in advance, yet compressor demand can change throughout the day. Therefore, there is not a guarantee that a compressor will be operating when the survey crew arrives at the station. Regardless of the status of a particular compressor, emissions can potentially leak from the compressor – e.g., from pressurized compressor components when a reciprocating compressor is operating or in standby-pressurized mode; isolation valve leakage can occur when the unit is not operating and depressurized.

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[2] EPA-HQ-OAR-2017-0483-0038, Attachment 1, "Methane Emissions from Natural Gas Transmission and Storage Facilities: Review of Available Data on Leak Emission Estimates and Mitigation Using Leak Detection and Repair."
[3] More information about operating modes is provided in Appendix A at 12 - 17.

Conventional LDAR programs are conducted with the facility "as found" and have never specified unit-level operations,[4] and imposing such a requirement in Subpart OOOOa will have potential negative consequences. For example, the cost and environmental impacts associated with conducting an LDAR survey while all compressors are operating were not considered by EPA in its TSD. At most facilities, it is rare to have all of the compressors operating at one time because compressor stations are designed for peak (i.e., maximum) demand. Thus, the proposed requirement would impact operations and system demand management.[5] In order to comply with the proposed requirement to survey a compressor while it is operating, operators would need to start up compressors that are not operating and depressurized just to conduct the leak survey, then shut down those units again and blowdown the equipment (i.e., vent gas to the atmosphere) in order to return the unit to not operating, depressurized mode. By unnecessarily starting up a unit, the emissions associated with startup, shutdown and the blowdown will likely significantly exceed the potential emissions from any leaks discovered during the survey. Because peak demand may be rare for some compressor stations, some compressors rarely operate (e.g., may not operate for an entire year); therefore, a survey that is conducted with that rarely used compressor operating will not be representative of typical operating conditions. For clarity, INGAA has provided an example below to demonstrate the potential emission implications:

- Assume Compressor A is offline due to low natural gas demand and has been blown down (i.e., not operating-depressurized). Compressor A would need to be purged (causing methane emissions), then started up in order to conduct the leak survey in operating mode (causing combustion emissions), but would not need to continue operating after the survey has concluded. Thus, a blowdown would be required after performing the survey (causing more methane emissions). If the compressor was driven by a natural gas-fired turbine or engine, there would be additional combustion-related emissions released during startup and shutdown.
- The following assumptions are based on data reported to EPA under Subpart W of the GHG Reporting Program:
  - A compilation of data from Subpart W leak surveys indicate that on average less than 20 leaks are discovered in an annual leak survey.[6] According to these Subpart W data, connectors are the most prevalent component type to found leaking during an annual survey. The discovery of one leaking connector on Compressor A during the leak survey is the most likely scenario. INGAA has evaluated below the potential emissions from two component types (valves and connectors) based on two different emission estimate approaches (Subpart W data and the California Air Resource Board report (CARB report)[7]).
    - Based on Subpart W component emission factors[8] for a Method 21 survey and assuming the leak continues for one month (i.e., 30 days), the emissions from the leaking component would be:
      - **0.14 tons of methane** from a leaking valve; or

[4] Existing federal LDAR programs such as NSPS VV, VVa, KKK, & OOOO and state LDAR programs do not specify equipment operating scenarios.
[5] To be clear, it is unlikely that compressors would be shutdown unnecessarily to conduct a survey because pipeline operators fulfill their customers' contractual needs for natural gas.
[6] Subpart W of the Greenhouse Gas Reporting rule does not mandate leak repair; thus, Subpart W data represent somewhat controlled emissions because some repairs may be made, but they are not mandatory.
[7] Air Resources Board RFP No. 13-414: Enhanced Inspection & Maintenance for GHG & VOCs at Upstream Facilities – Final (Revised), Sage Environmental Consulting LLC (December 2016).
[8] 40 C.F.R. Part 98, Subpart W, Table W-3A.

    - **0.05 tons of methane** from a leaking connector.
  - Based on component-specific correlation equations in a recent report from CARB and assuming a Method 21 screening value of 10,000 ppm, the emissions are:
    - **< 0.0001 tons of methane** from a leaking valve (~ 0.016 lbs); or
    - **< 0.0001 tons of methane** from a leaking connector (~ 0.012 lbs).
  - From Subpart W compressor blowdown reporting for an example transmission pipeline company (2016 reporting year, over 30 subject facilities), the average emissions associated with compressor blowdowns were **4.6 tons of methane** per event (not including emissions from testing run time or purging).
- Regardless of the assumption for component leak emissions, the blowdown emissions alone would be many times higher than the monthly emissions from a leaking component.

Requiring that all surveys be conducted in operating mode will also increase the cost of complying with the LDAR requirements beyond the costs calculated by EPA. For example, if a specific compressor cannot operate because of low natural gas demand, the LDAR team may need to make multiple trips to the compressor station to survey each of the compressors at that station during operating mode.[9] Conducting multiple surveys would increase the cost of compliance. Alternatively, if an operator were to comply with the proposed requirement by starting up compressors that are not needed to meet demand, multiple units will need to be cycled on and off during the survey in order to avoid disruptions to end users or manage natural gas supply. Cycling units on and off takes time and would extend the duration of the survey, thereby increasing the cost of each survey. Some further examples of issues related to imposing the proposed operating mode requirement are provided below.

- If there is low natural gas demand, proper operation of an unneeded compressor may not be possible because compressors are designed to compress natural gas, which is not always feasible due to customer demand and pipeline conditions.
- As noted above, LDAR surveys often need to be scheduled weeks in advance. For example, when a survey crew arrives at a compressor station with five compressors, two of the five compressors may be operating in order to meet the current demand (i.e., compressors 1 and 2 are operating while compressors 3-5 are in a not operating-depressurized mode). EPA's proposed regulatory change would require surveying leaks from compressors 1 and 2, before shutting them down (which may involve conducting blowdowns to ensure safety). To continue to meet demand, compressors 3 and 4 would need to be brought online to survey for leaks. One of the compressors would need to be shutdown (and possibly blown down) so that compressor 5 could be surveyed for leaks while in operating mode. If the station prefers to keep compressors 1 and 2 operating, it may shutdown (and possibly blowdown) the compressors that are operating (e.g., compressors 3 and 5) and compressors 1 and 2 would then need to be restarted and returned to service. These operational changes extend the length of time the LDAR survey crew spends on site, increasing the cost of the survey. The cost of the survey is also higher due to the increased manpower to perform all of the engine startups and shutdowns and coordinate system operations. Starting and stopping the compressors in this manner

[9] Additional trips to survey a given compressor station will also result in increased emissions from the vehicle used by the survey crew to travel to and from the compressor station. These additional emissions should also be considered in EPA's analysis.

would also increase GHG emissions due to the necessary blowdowns and purges (as explained above).

- Determining the operating needs to continue to meet demand while swapping out the compressors can be further complicated if the compressors have different horsepower capacities or if the compressors can only move natural gas on certain lines (which are common issues).
- Yet another issue that makes it more difficult to conduct all the surveys at once is that compressors are periodically out of service for major overhauls or repairs. If a major overhaul or repair is underway, it would not be possible to survey the compressor in operating mode that day and that unit would need to be surveyed at another time.

In light of these concerns, INGAA recommends completing the survey with compressors operating "as found." If not, EPA should undertake additional analysis to better understand the potential operational and cost implications of this proposed requirement, including analyzing how the proposed requirement could affect management of integrated natural gas pipeline systems. INGAA could not complete such a complex analysis within the 60-day comment period.

Finally, the nomenclature regarding compressor mode should be clearly explained in the final rule – i.e., operating, standby pressurized, and not operating-depressurized modes are consistent Subpart W nomenclature. For example, proposed 40 C.F.R. § 60.5397a(g)(2) would require conducting a survey of each compressor, "…while in operation (*i.e.,* not in stand-by mode) . . . . " As noted above, standby mode typically refers to a situation where the compressor remains pressurized and leaks could occur from pressurized components. EPA should clarify in the final rule the three typical compressor modes (e.g., see Subpart W of the GHG Reporting Program): operating mode, standby-pressurized mode, and not operating (or shutdown)-depressurized mode.

2. INGAA supports an annual LDAR survey frequency for transmission and storage facilities based on the best science available.

EPA has proposed modifying the frequency of conducting LDAR surveys on compressor stations from quarterly to semi-annually. EPA has also requested comment on whether annual surveys would be appropriate for compressor stations.

As explained further below, INGAA supports conducting LDAR monitoring at transmission and storage compressor stations less frequently than the current quarterly requirement for several reasons. INGAA provided data to EPA earlier this year to show that annual leak surveys achieve the fugitive emissions control efficiency EPA estimated for quarterly monitoring.[10,11] INGAA also submitted comments to EPA during prior comment periods on Subpart OOOOa[12] and is now supplementing that information and data with Appendix A to directly respond to EPA's memo assessing the documents INGAA submitted to EPA earlier this year.[13] For convenience, INGAA has provided a summary of this

[10] EPA-HQ-OAR-2017-0483-0038, Attachment 1 "Methane Emissions from Natural Gas Transmission and Storage Facilities: Review of Available Data on Leak Emission Estimates and Mitigation Using Leak Detection and Repair."

[11] EPA-HQ-OAR-2017-0483-0038, Attachment 3 "Supplement to INGAA White Paper on Subpart OOOOa TSD Estimates of Leak Emissions and LDAR Performance - rev 1."

[12] EPA-HQ-OAR-2010-0505-6872.

[13] EPA-HQ-OAR-2017-0483-0038, "EPA Analysis of Fugitive Emissions Data Provided by INGAA."

information below. Additional details are available in the original submissions referenced throughout this document.

A. Recent and representative leak measurement data from implementation of a multi-year oil and natural gas system leak mitigation program that uses a direct inspection and maintenance (DI&M) approach indicates that about 75 – 80% reduction in emissions can be achieved using *annual* monitoring.

A Canadian Association of Petroleum Producers (CAPP) 2014 report entitled "Update of Fugitive Equipment Leak Emission Factors"[14] estimates that oil and natural gas equipment leak emissions decreased about 75% since DI&M best management practices (BMP)[15] were implemented (in 2007 and later). Although the leak survey frequency is not specified in detail in the CAPP report, the leak mitigation program used for the study indicates that components subject to Subpart OOOOa LDAR provisions (e.g., valves, connectors, pressure relief valves, open-ended lines, etc.) would be surveyed annually or less frequently. INGAA submitted a white paper to EPA and OMB providing additional information about the CAPP report.[16]

EPA's memo, "EPA Analysis of Fugitive Emissions Data Provided by INGAA,"[17] evaluated the CAPP data, identified several unknowns about the CAPP DI&M program, and expressed concerns about certain program aspects not corresponding exactly to a regulation-based annual LDAR program. However, as Table 1 below shows, the CAPP data are more representative of current LDAR programs for natural gas systems, and the CAPP report provides a much more reliable estimate of LDAR control efficiencies than the example calculations for the EPA Leak Protocol LDAR control efficiency (CE) model cited by EPA. Table 1 compares the CAPP data to the data that are the basis for the EPA Leak Protocol LDAR CE model example calculations because this is the only LDAR control efficiency estimate provided by EPA (of the three EPA examples discussed below) that is fairly transparent and supported by real data and transparent calculations.

[14] EPA-HQ-OAR-2010-0505-4826. "Update of Fugitive Equipment Leak Emission Factors," Canadian Association of Petroleum Producers (CAPP), February 2014.

[15] "Management of Fugitive Emissions at Upstream Oil and Gas Facilities," Canadian Association of Petroleum Producers (CAPP), January 2007.

[16] EPA-HQ-OAR-2017-0483-0038, Attachment 1, "Methane Emissions from Natural Gas Transmission and Storage Facilities: Review of Available Data on Leak Emission Estimates and Mitigation Using Leak Detection and Repair" at 6-7.

[17] EPA-HQ-OAR-2017-0483-0038.

Table 1. Comparison of Data Used to Estimate LDAR Control Efficiencies for the CAPP Study and for the EPA Leak Protocol LDAR CE Model Example Calculations

Parameter	CAPP Study	EPA Leak Protocol LDAR CE Model Example Calculations
Annual LDAR control efficiency	75 – 80%	42 – 68% (40% assumed for optical gas imaging, OGI)
LDAR control efficiency basis	Emissions directly measured and calculated from M21 surveys & M21 screening value-based emission factors (EFs)	Example calculations based on a theoretical model
Components controlled	Valves, emergency vents, pressure relief valves, open-ended lines, flanges, connectors, compressor seals, blowdown systems.	Valves only
Years data collected	2007 +	Data reports published 1980 – 1982
Industry / Process streams	Oil and natural gas	Synthetic organic chemical manufacturing industry (SOCMI), which includes corrosive streams atypical of oil and natural gas systems
Data set size	120 facilities over multiple years; ~250,000 components	Leak occurrence rate based on 71 gas service valves

While EPA's memo responding to INGAA's analyses was critical of the CAPP data, Table 1 shows that the data used to develop the CAPP Study LDAR control efficiency is much more robust, current, and representative of natural gas operations than the data used for the example calculations for the EPA Leak Protocol LDAR CE model. The CAPP Study data are more representative of current natural gas compressor station operations for several reasons. First, the CAPP Study data is from the oil and natural gas sector – not a chemical plant. More leaks may occur at chemical plants due to corrosive process streams that can corrode component gaskets and seals. These corrosive streams are not representative of operations in the oil and natural gas sector. Second, the CAPP study data are much more current and thus more representative of equipment and maintenance advancements and improvements since the late 1970s and early 1980s when the data that are the basis for the EPA Leak Protocol example calculations were collected. Third, the CAPP Study represents the wide array of potentially leaking components – not just valves, as in the EPA example calculation data. Fourth, the CAPP Study reflects a much larger data set – several orders of magnitude larger than the EPA example calculation data. Lastly, the EPA LDAR control efficiency estimates are from example calculations presented in the EPA Leak Protocol to illustrate how to use the LDAR CE model. These LDAR control efficiencies were not measured for oil and natural gas systems. Appendix A and Appendix 1 of INGAA's White Paper[18] provide additional details and discussion of these data sets.

Admittedly, the CAPP Study LDAR control efficiency measurements are not perfect, but the CAPP Study data are clearly the best available science for estimating LDAR control efficiencies for current natural gas systems. EPA has presented its rationale for disregarding the CAPP study results in a memo provided in the docket; however, as discussed in Appendix A, INGAA disagrees with EPA's conclusion and does not support relying on example calculations based on decades' old data from an entirely different type of facility – synthetic organic chemical plants – rather than using measured gas leak control efficiencies from an extensive oil and natural gas DI&M program.

B. The LDAR control efficiencies that EPA used are based on unsupported and flawed data and analysis.

EPA's underlying administrative record does not show that conducting fugitive emissions monitoring more frequently than annually would provide any meaningful environmental benefit. INGAA carefully reviewed EPA's TSD for the Proposed Subpart OOOOa Reconsideration.[19] The TSD stated that if annual monitoring is conducted, the estimated fugitive emissions control efficiency is 40%, 60% for semi-annual monitoring, and 80% for quarterly monitoring. EPA cited the following three sources for these control efficiencies: (a) a Colorado Air Quality Control Commission (CAQCC) cost-benefit analysis for LDAR,[20] (b) example calculations for a LDAR CE model from the EPA Leak Protocol document,[21] and (c) an ICF study.[22] INGAA provides a brief overview of the deficiencies in each of these data sources below and refers EPA to INGAA's prior comments and submissions for more detail.

a. The CAQCC LDAR Cost-Benefit Analysis

This analysis simply states: "Based on EPA reported information, the Division calculated a 40% reduction for annual inspections, a 60% reduction for quarterly inspections, and an 80% reduction for monthly inspections." This sentence is the entirety of the discussion (and "support") in the CAQCC analysis regarding LDAR fugitive emissions control efficiency as a function of survey frequency. CAQCC did not provide a reference or citation for the "EPA reported information" that served as the basis for these calculations.

EPA cited a CAQCC report prepared in support of its recently revised Regulation Number 7 to estimate fugitive emissions reductions as a function of LDAR monitoring frequency. The CAQCC Economic Impact Analysis ("EIA") estimated the following reductions for LDAR

[18] EPA-HQ-OAR-2017-0483-0038, Attachment 1, "Methane Emissions from Natural Gas Transmission and Storage Facilities: Review of Available Data on Leak Emission Estimates and Mitigation Using Leak Detection and Repair."

[19] EPA-HQ-OAR-2017-0483-0040 at 24-26.

[20] EPA-HQ-OAR-2010-0505-7573. Colorado Air Quality Control Commission, *Cost-Benefit Analysis for Proposed Revisions to Regulation Number 3 and 7 (5 CCR 1001-5 and 5 CCR 1001-9).* February 7, 2014.

[21] EPA-453/R-95-017. *Protocol for Equipment Leak Emission Estimates, November 1995*, *available at* Docket ID No. EPA-HQ-OAR-2017-0483.

[22] EPA-HQ-OAR-2010-0505-7633. ICF International, Leak Detection and Repair Cost-Effectiveness Analysis, Prepared for Environmental Defense Fund, Dec. 4, 2015, Revised May 2, 2016, *available at* https://www.edf.org/sites/default/files/content/edf_ldar_analysis_120415_v7.pdf.

frequencies: 40% reduction for annual monitoring of well production tank batteries; 60% reduction for quarterly monitoring; and 80% reduction for monthly monitoring. In reaching this conclusion, the CAQCC relied on EPA documents or positions; however, the EPA example (from the Leak Protocol illustrative calculation) does not actually support the 40/60/80 percent reduction assumptions.

Rather, the control efficiencies originally assumed general values from chemical plants and petroleum refineries (not oil and natural gas facilities—or any sector of the oil and natural gas industry). They also relied on outdated information and data (in some cases dating back to 1980), and provided simple averages that do not reflect actual distribution of components (e.g., the average is not properly weighted). Thus, the EPA documents do not provide any actual data demonstrating that monitoring more frequently than annually is necessary, effective, or environmentally beneficial.

Given the flaws in the underlying EPA documents, CAQCC's conclusions lack credible support. By relying in turn on the CAQCC report, this proposed rule similarly lacks adequate support.

EPA's reliance on this uncredible data is further evidenced by EPA's own conclusion from its set of five technical white papers in April 2014, stating that available studies (which included the EPA Best Practices Guide and EPA Leak Protocol) "did not provide information on the potential emission reductions from the implementation of an annual, semiannual, quarterly or monthly OGI monitoring and repair program." Thus, as a threshold matter, the CAQCC's assumptions are questionable.

Even if the CAQCC's assumptions could be supported by appropriate data (that would need to be introduced into EPA's record), EPA altered the CAQCC's results without support or explanation. For example, the CAQCC EIA estimated 60% reduction for quarterly monitoring frequency, whereas EPA assumed 60% reduction for a semi-annual monitoring frequency. The CAQCC Study estimated 80% reduction for monthly monitoring frequency, whereas EPA assumed 80% reduction for a quarterly monitoring frequency. Without adequate data or supporting rationale, these conclusions are not legally defensible. EPA's record needs to reflect data and assumptions that can withstand potential judicial review.

b. EPA's Leak Protocol document

The EPA Leak Protocol LDAR CE Model leak emissions reduction estimates are based on example calculations for a LDAR CE model with high uncertainty and biased by flawed and unrepresentative data and assumptions associated with sparse and outdated data from valves in chemical plant service. These reduction estimates were not supported by actual measurements of gas leak emission reductions. Table 1 above and the associated discussion demonstrate the flaws in these LDAR control efficiency estimates and the underlying data. *See also* INGAA White Paper at 3 – 7.[23]

[23] EPA-HQ-OAR-2017-0483-0038, Attachment 1, "Methane Emissions from Natural Gas Transmission and Storage Facilities: Review of Available Data on Leak Emission Estimates and Mitigation Using Leak Detection and Repair."

c. The ICF Study

The ICF study is another model-based estimate driven by inputs and assumptions. It does not present *measured* leak emission reductions. EPA posted PowerPoint slides in the docket summarizing the ICF study results. These slides include two disclaimers regarding the limitations of the analysis: "limited time series data is available on the impact of different LDAR frequencies on reduction in leak frequencies in each subsequent survey" and "Assumption in this study is based on best available data from Colorado." The Colorado data appears to be *monthly* survey results from Colorado. Thus, control efficiencies for less frequent surveys (i.e., quarterly, semi-annual, and annual) appear to be estimated values based solely on model assumptions. The only numerical estimate of LDAR control efficiencies that is presented is for quarterly leak surveys, and the tabulated model results supporting this quarterly LDAR control efficiency estimate could not be correlated to accompanying graphical results. The PowerPoint slides do not present detailed results and the assumptions used for the modeling alternative survey frequencies are not discussed or defined.

Regulatory requirements should be based on substantive and detailed reports rather than high level PowerPoint slides. The public and regulated community needs to be provided with the opportunity to review the detailed report in order to evaluate the underlying model data, assumptions, and calculations. *See* pages 8 and 9 of the INGAA White Paper supplement for additional discussion and details.[24]

Given these flaws with the three sources EPA cited, the record does not support the fugitive emissions control efficiencies that EPA used, and quarterly monitoring was not appropriate for compressor stations. The CAPP Study shows about an 80% control efficiency is achievable with annual monitoring, commensurate with EPA's target for quarterly monitoring; thus, annual monitoring is appropriate for compressor stations.

In the preamble to the proposed rule, EPA expressed concern that "if the EPA were to move to an annual monitoring frequency, owners and operators might conduct fugitive emissions monitoring during scheduled maintenance periods such as times when there is less demand on the station. This might present the appearance of lower fugitive emissions than if the monitoring occurred during peak seasons, thus decreasing the effectiveness of the program for controlling fugitive emissions, unless the monitoring procedure can assure that does not occur."[25] INGAA believes this concern is unfounded because it highly unlikely that companies would intentionally coordinate monitoring with planned station maintenance to influence monitoring events. As discussed above, companies schedule leak surveys weeks in advance and are required to fulfill their customers' contractual needs for natural gas; the pipeline demand and associated station compressor modes during the survey are unknown when those leak surveys are scheduled.

Finally, INGAA supports providing flexibility for conducting annual surveys by allowing at least 9 months and no more than 13 months between surveys. If, however, EPA were to adopt a requirement

[24] EPA-HQ-OAR-2017-0483-0038, Attachment 3, "Supplement to INGAA White Paper on Subpart OOOOa TSD Estimates of Leak Emissions and LDAR Performance - rev 1."
[25] 83 Fed. Reg. at 52,070.

for semi-annual LDAR surveys, EPA would need to provide similar flexibility to avoid causing scheduling constraints.

3. INGAA supports the proposed amendments to the LDAR program schedule for a first attempt at repair and component repair.

INGAA supports the proposed amendments to the LDAR program schedule in § 60.5397a(h) that would require a "first attempt at repair" within 30 days of detection of fugitive emissions, followed by a requirement that identified fugitive emissions be "repaired" within 60 days of detection (or placed on the delay of repair list). INGAA also supports the definition of "repaired" and "first attempt at repair" for purposes of fugitive emissions monitoring in § 60.5430a.

4. INGAA recommends revisions to the LDAR provisions in § 60.5397a(h)(3) regarding operational activities or events that would trigger repair of a component on the delay of repair list.

When a leak is discovered during an LDAR survey, Subpart OOOOa allows compressor station operators to delay certain repairs under specific circumstances. Even before this obligation existed, operators historically identified and repaired leaks as they deemed appropriate and per any applicable state permit requirements or conditions. Most leaks that are discovered can be repaired immediately. However, under certain circumstances some repairs may take more time. Decisions regarding repairs are always informed by operational, supply, manpower, and other considerations. Companies will continue to make these determinations and repair leaks as they deem appropriate.

INGAA has previously raised its concerns about the delay of repair provision in 40 C.F.R. § 60.5397a(h)(2). In a letter to EPA dated December 8, 2017,[26] INGAA responded to EPA's November 2017 request[27] for input on staying certain Subpart OOOOa requirements. EPA subsequently adopted revisions to subsection (h)(2)[28] regarding "unplanned" events (e.g., an emergency or unplanned blowdown) that previously would have triggered repair, but INGAA still has concerns with this portion of the rule. Unduly restrictive delay of repair provisions can threaten to disrupt natural gas supply and potentially create compliance or contractual risks for operators.

INGAA's concerns are related to language in § 60.5397a(h)(2) that require repair to be completed, "…during *<u>the next scheduled compressor station shutdown</u>*, . . . *<u>after a planned vent blowdown</u>* or within 2 years, whichever is earlier" (emphasis added). These specific concerns are as follows:

- *"Planned" blowdowns.* A transmission pipeline is a dynamic system where equipment is constantly reacting to meet the current demands placed on the system. Equipment at compressor stations routinely cycles on and offline based on system-wide pipeline demand and flow conditions. When equipment is taken offline, it may be depressurized (i.e., blown down). However, a planned blowdown should not trigger the requirement to repair leaks on the delay of repair list. Blowdowns occur as part of standard compressor station operations for regular maintenance activities, to prevent safety concerns, avoid damage to equipment, and manage equipment as demand for natural gas changes.

[26] EPA-HQ-OAR-2017-0346-0414.
[27] 82 Fed. Reg. 51,788 (Nov. 8, 2017).
[28] 83 Fed. Reg. 10,628 (Mar. 12, 2018).

Even if equipment has been blown down, it may need to be quickly (and remotely) returned to service in response to increased natural gas demand. Compressor station equipment routinely cycles on and offline. However, as written, the delay of repair provision in Subpart OOOOa prevents an operator from blowing down equipment (if this event is "planned") and then bringing the compressor back online unless any previously identified leaks on the delay of repair list were repaired. Thus, if an operator needed to repair a meter along a pipeline going into a compressor station and a blowdown is required, the operator could not make that meter repair and restart the compressor unless all the leaks at that compressor station on the delay of repair list are repaired before startup. Alternatively, the rule might prevent an operator from trying to repair some leaks at the earliest opportunity. For example, an operator might have identified two leaks and both are on the delay of repair list. One leak can be repaired quickly after conducting a blowdown (e.g., a leaky valve), but another leak will require a new part that has not yet been fabricated or delivered. The rule should not discourage operators from completing one repair just because both leaks cannot be repaired at the same time.

- *Lack of parts is a valid reason to delay repairs*. The parts necessary to repair a leak at a compressor station are often not readily available or in stock. Not only do parts come in various sizes, but parts are not necessarily interchangeable between different manufacturers or vintages. Some compressors that have been modified, and that are subject to this rule, may be more than 50 years old, and compressor parts and configurations have changed over time. In many cases, for older vintage units, the original compressor manufacturer has sold the service of providing replacement parts to a separate company. Very few compressors of a certain vintage or model may still be operating and there is not enough demand to keep replacement parts for these units readily available. In these situations, if a part breaks on an older compressor, the comparable part used on a new compressor model might not be the right size or configuration to make the repair. In many cases, parts may need to be custom ordered and/or custom manufactured and machined. It may take several months to fabricate those parts to fit older models. Additionally, some parts are manufactured overseas, which can significantly prolong delivery time.

  It would be too costly and impractical for an individual operator to stockpile every potential type and size valve or part that might be needed to repair a leak.[29] Similarly, it is also unreasonable to expect *compressor manufacturers or aftermarket parts manufacturers* to maintain a stockpile of custom parts that they may never sell due to low demand.

  If a scheduled shutdown or planned blowdown occurs after the operator has ordered a replacement part necessary to repair a leak on the delay of repair list, the compressor should not need to stay shutdown until the leak has been repaired because it could be an extended period of time before the new part arrives and is ready to be installed. Keeping the compressor shut down could potentially disrupt the supply of natural gas to end-use consumers and might cause the operator to violate its contractual agreement with its customers.

- *New parts cannot always be immediately installed*. The rule must provide operators with the flexibility to delay repairs when warranted. The rule does not take into account situations where a new leak is discovered shortly before a planned shutdown and there is not enough time to fabricate, deliver, test, and install the new part or to make other logistical arrangements for the recently identified leak to be repaired during the upcoming planned downtime. Operators need adequate time

[29] *See* EPA-HQ-OAR-2010-0505-6872 at 18.

to develop a safe repair plan for the types of leaks that need to be delayed – such as those that require replacement parts, logistical prearrangements (e.g., special tooling or heavy equipment for major repairs), skilled labor, etc.

Thus, INGAA recommends that *repairs of leaks on the delay of repair list should be deferred to the next scheduled shutdown for maintenance, following EPA's precedent when regulating natural gas processing plants.* In order to ensure that repairs are conducted safely and effectively, it is critical that operators be allowed to defer repairing leaks on the delay of repair list until the next scheduled shutdown for maintenance. When EPA adopted regulations at natural gas processing plants, EPA acknowledged the importance of making repairs during planned shutdowns and when parts are available. *See* 48 Fed. Reg. 279 (Jan. 4, 1983) (explaining the basis for allowing delay of repair in Subpart VVa); 40 C.F.R. § 60.481a. Subpart VVa also provides additional clarification that shutdowns, or partial unit shutdowns, that are less than 24 hours in length are *not* considered a process unit shutdown for natural gas processing plants and thus, do not trigger repair obligations for natural gas processing plants under Subpart OOOO. *See* 40 C.F.R. § 60.5400(a). INGAA believes these were rational and safe requirements for natural gas processing plants and EPA should adopt a similar philosophy for natural gas compressor stations.

EPA has not provided a rational basis to treat natural gas compressor stations (which are typically unmanned and smaller sources than natural gas processing plants and do not have on-site warehouses with spare parts) more stringently. In other words, EPA should not require that natural gas compressor stations make repairs immediately upon the occurrence of a planned vent blowdown, regardless of its length, if natural gas processing plants are allowed to defer making such repairs until the next scheduled shutdown or when parts are available.

Recommendations to address problems with the delay of repair provision. While INGAA's members are concerned about the compliance risks associated with delay of repair, the extent of this potential problem should be kept in context – compressor station repairs will be infrequently delayed because most leaks will be repaired expeditiously and during the 30-day (first attempt at repair) or 60-day period after discovery. For example, instrument leaks or leaks from fittings or valve packing can typically be repaired immediately. The need to delay repairs will be the exception – not the rule. Furthermore, these repairs will not be indefinitely delayed because compressor stations have periodic scheduled shutdowns required to comply with U.S. Department of Transportation's Pipeline & Hazardous Materials Safety Administration (PHMSA) pipeline safety regulations. Moreover, the rule could be modified to impose recordkeeping requirements to document that the delay was justified. EPA could amend § 60.5420a(c) to accommodate any such additional recordkeeping obligations.

EPA should revise its delay of repair provisions to require that all equipment and component leak repairs be completed at the next scheduled maintenance shutdown at the compressor station, not to exceed two years from leak discovery. INGAA suggests EPA make the following amendments:

> *If the repair or replacement is technically infeasible, would require a vent blowdown, a compressor station shutdown, 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 compressor station shutdown* ***for maintenance****, well shutdown, well shut-in, ~~after a planned vent blowdown~~ or within 2 years, whichever is earlier.*

> ***Delay of repair will be allowed beyond the next scheduled compressor station shutdown for maintenance but within the 2 year period if (a) replacement parts cannot be acquired before the next scheduled shutdown for maintenance or (b) the delay is attributable to other good cause. The operator must document: the location and nature of the leak, the date the leak was added to the delay of repair list, the basis for delaying the repair, the date replacement parts were ordered, the vendor providing the parts, and the anticipated delivery date. Replacement parts must be promptly ordered after determining it is necessary to delay the repair and replacement parts are required to make the repair. The repair must be completed within 30 business days of receipt of the replacement parts, during the next scheduled maintenance shutdown after the parts are received (if the repair requires a shutdown), or within 30 business days after the cause of delay ceases to exist. The Administrator may approve further extensions on a case-by-case basis.***

Need for "other good cause" exception. EPA should expand the delay of repair provision to allow an operator to delay a repair for "other good cause." Unforeseen circumstances can occur and the regulatory language should not be so narrow as to prevent delaying repairs where they are unavoidable or make sense to avoid service disruptions. See INGAA's December 2017 comments for additional discussion of this issue.

Precedent for these changes. The foregoing edits are modeled after regulations adopted by the State of Colorado (which allows a repair to be delayed if parts are unavailable or for other good cause).

5. The TSD should be updated to reflect the best available data and information in the cost-effectiveness analysis.

The TSD [30] should be updated to include the best available data and information in the LDAR cost-effectiveness analysis for compressor stations. INGAA previously provided EPA with gas leak emissions data, LDAR control efficiency data, and LDAR cost estimates data that are more reliable and accurate than the data in the TSD.

Leak Emissions. The TSD LDAR cost effectiveness analysis for transmission and storage natural gas compressor stations is based on non-compressor component leak emissions from Model Plant compressor stations. These Model Plants are based on 25-year old data from the 1996 GRI/EPA Study.[31] Thus, the TSD Model Plants do not represent emissions from compressor stations in 2018, and they likely over-estimate emissions relative to modern operations because compressor stations have implemented improved seal and valve technology and maintenance practices over the past 20 years, and many facilities have participated in the voluntary EPA Natural Gas STAR program.

INGAA submitted a white paper[32] to EPA in June 2018 that provides estimates of leak emissions from transmission and storage compressor stations that are more representative of emissions from compressor stations in 2018 than data from the TSD Model Plant (see also discussion in Appendix A). INGAA's

[30] EPA-HQ-OAR-2017-0483-0040.

[31] Gas Research Institute (GRI)/U.S. EPA. Research and Development, *Methane Emissions from the Natural Gas Industry, Volume 8: Equipment Leaks*. June 1996 (EPA-600/R-96-080h).

[32] EPA-HQ-OAR-2017-0483-0038, Attachment 1 "Methane Emissions from Natural Gas Transmission and Storage Facilities: Review of Available Data on Leak Emission Estimates and Mitigation Using Leak Detection and Repair."

leak emissions estimates are more representative because its estimates are based on hundreds of Subpart W leak surveys conducted at transmission and storage compressor stations between 2011 to 2016.

The Subpart W data show lower compressor station non-compressor component leak emissions than the GRI/EPA Study estimates by about a factor of four, meaning that the Model Plant over-estimates emissions from current compressor stations. The INGAA white paper and Attachment A provide additional detail on these Subpart W leak survey data, which are more appropriate estimates of leak emissions from present day transmission and storage compressor stations.

LDAR Control Efficiency. As explained in Comment 2 (and INGAA's previous submissions to EPA), the best available science estimates that annual surveys result in LDAR control efficiencies of about 80%. More frequent surveys (e.g., semi-annual) would produce marginally better control efficiencies (e.g., about 90%).

LDAR Cost Estimates. The LDAR implementation costs presented in the September 2018 Subpart OOOOa TSD[33] are essentially unchanged from the May 2016[34] and August 2015[35] TSDs, and EPA has not provided additional data and analysis to justify why the costs are unchanged.

Given that EPA's cost analysis has not changed since 2015, INGAA's comments on the Subpart OOOOa proposed rule[36] remain valid. These comments noted that "EPA drastically underestimated LDAR implementation costs and INGAA finds them unrealistic." INGAA refers EPA to pages 23 – 26 of those comments which address INGAA's concerns with the TSD LDAR cost assumptions. In sum, considering the high bias in the TSD Model Plant compressor station uncontrolled leak emissions (about a factor of four) and the low bias in the TSD LDAR implementation cost estimates, the TSD cost-effectiveness estimates for LDAR (i.e., $/ton methane emission reductions) could be about an order of magnitude low. The TSD [37] should be updated to include the best available data and information in the LDAR cost-effectiveness analysis for compressor stations.

In addition, INGAA reviewed the September 2018 TSD and identified three key issues:

(1) From page 28:

> "In 2016, we assumed that each company defined area would require the purchase of an instrument to perform Method 21 monitoring for the resurvey. However, it is our understanding that if repairs are not made during the monitoring event, OGI or the alternative method in section 8.3.3 of Method 21 (soap solution) are used instead. Therefore, the cost estimates were updated to remove the capital cost of purchasing a Method 21 instrument."

In order to use OGI for a resurvey of a repair not made during the monitoring event, a compressor station either needs to purchase an OGI instrument and train personnel in its use, or hire OGI survey contractors to survey the facility after the repairs are completed. The TSD cost analysis does not include these potentially costly items. OGI will be needed to verify the repair of component leaks that cannot be

[33] EPA-HQ-OAR-2017-0483-0040.
[34] EPA-HQ-OAR-2010-0505-7631.
[35] EPA-HQ-OAR-2010-0505-5120.
[36] EPA-HQ-OAR-2010-0505-6872.
[37] EPA-HQ-OAR-2017-0483-0040.

detected using soap solution (e.g., leakage through a closed valve that is emitted to atmosphere through an elevated vent).

(2) From page 63:

> "It is important to note that since we utilize the average emissions factors, as discussed in section 2.3.5, the emissions are not affected by any changes in the percent leaking values used. Therefore, the only effect the percent leaking has on the cost of control is due to a change in the cost of repairs."

INGAA disagrees with this statement because gas leak emission estimates based on average emission factors (i.e., population emission factors with activity data that is the total population of components, leakers + non-leakers) are directly correlated with the percent leaking components (e.g., components with a Method 21 screening value greater than a threshold value) in the underlying leak measurement data used to develop the emission factors. The percent leaking components should be used to estimate the leak repair costs associated with emission estimates based on average emission factors. Percent leaking components and associated repair costs should not be evaluated independent of population EF-based emission estimates (i.e., emission estimates and percent leaking components should be from the same set of data). Rather than using population emission factors to estimate uncontrolled gas leak emissions, leaking component counts and leaking component emission factors from Subpart W reporting could be used to estimate uncontrolled gas leak emissions; that is, using Subpart W data, the number of leaking components requiring repair is known and directly correlated to the emissions.

Because leak control programs have fixed cost elements (e.g., prepare monitoring plan, management and scheduling, leak survey, reporting) and variable cost elements (primarily leak repair costs), LDAR will be less cost-effective (i.e., higher $/ ton methane reduced) for lower emissions operations (i.e., the fixed costs are a greater fraction of the total costs). An LDAR cost control analysis should base the repair costs on the percent leakers that is the basis for the leak emission estimate.

(3) The same percent leakers (1.18%) is used for estimating repair costs for quarterly, semi-annual and annual LDAR surveys, and the repair costs for quarterly LDAR surveys are four times greater than for annual surveys. Assuming that, over time, leak formation rate is fairly steady, total leakers found and repaired each year should be about the same for four quarterly LDAR surveys and one annual LDAR survey. Thus, in this simplified view, leaks found and repaired during each quarterly survey should be about one-fourth of the leaks found and repaired during each annual survey.

6. INGAA supports the proposed amendments to extend the deadline for the initial LDAR monitoring survey to longer than 60 days and recommends a deadline of 180 days.

INGAA supports proposed amendments to § 60.5397a(f)(2) that would extend the deadline for the initial LDAR monitoring and recommends a deadline of 180 days. The startup of a new compressor station is a complex process requiring the commissioning of diverse process equipment, monitoring systems, and control systems. Startup is generally a very busy period for operators. If there are any issues during startup, then trouble-shooting will be necessary and remedies must be identified. Off-site support personnel or third-party technical specialists may be needed to resolve these problems and the process may be time consuming. Further, inclement weather could cause additional complications. Thus, the weeks following new facility start up (the break-in period) can be very busy, and requiring an initial leak survey within 60 days of startup is a burden for operators who may still be trying to deal with operational issues.

INGAA recommends that the deadline be extended to 180 days to align with other facility regulatory compliance activities. Starting up a facility requires compliance with other regulatory requirements. The requirements in Subpart OOOOa should be more consistent with other NSPS requirements that apply to other operations at the facility. For example, most new compressor stations include natural gas-fired compressor drivers – i.e., reciprocating engines or combustion turbines. These units are also subject to NSPS and National Emission Standards for Hazardous Air Pollutants (NESHAP) regulations, such as Part 60, Subpart JJJJ for stationary spark ignition internal combustion engines; Part 63, Subpart ZZZZ for reciprocating engines; and Part 60, Subpart KKKK for turbines. Those regulations allow more than 60 days to complete initial performance tests. Subpart JJJJ, Subpart KKKK, and Subpart ZZZZ allow 180 days or longer to complete the initial performance test. Adopting similar deadlines in Subpart OOOOa will also simplify managing compliance during the busy period following initial startup. A similar 180-day schedule is warranted to complete the initial leak monitoring survey required under Subpart OOOOa.

In sum, INGAA recommends that the initial survey schedule be revised to allow completion within 180 days of facility startup. This schedule is consistent with performance test schedules in other NSPS requirements that affect compressor stations and allows ample time for new facilities to complete startup activities and assume normal operations prior to the initial leak survey.

7. As to whether a modification has occurred at a compressor station, INGAA supports the determination should be based on whether there is an increase in *compressor* horsepower. INGAA also recommends clarifying the modification provisions in § 60.5365a(j).

In the preamble,[38] EPA solicits feedback on whether *engine* horsepower is the appropriate measure to use when assessing whether a compressor station has been modified. INGAA recommends basing this determination on *compressor* horsepower. The text in the preamble is clearer than the actual language in § 60.5365a(j). Therefore, INGAA recommends revising § 60.5365a(j) as follows:

(j) The collection of fugitive emissions components at a compressor station, as defined in § 60.5430a, is an affected facility. For purposes of § 60.5397a, a "modification" to a compressor station occurs when:

(1) An additional compressor is installed at **<u>an existing</u>** compressor station; or

(2) **<u>The replacement of one or more compressors at an existing compressor station results in a net increase in the total compressor(s) horsepower replaced</u>**~~One or more compressors at a compressor station is replaced by one or more compressors of greater total horsepower than the compressor(s) being replaced~~. When one or more compressors is replaced by one or more compressors of an equal or smaller total horsepower than the compressor(s) being replaced, installation of the replacement compressor(s) does not trigger a modification of the compressor station for purposes of § 60.5397a.

[38] 83 Fed. Reg. at 52,074.

8. Reciprocating Compressors Rod Packing Vent Control: Closed vent/vapor collection systems should not be required to operate under negative pressure because of safety concerns from oxygen potentially introduced into the system.

Closed vent system/vapor collection systems to control recuperating compressor rod packing vent emissions should not be required to operate under negative pressure because operating under negative pressure may inadvertently introduce oxygen into the collection system, which can create a combustible/explosive mixture. Such vent lines typically operate at low pressures. Thus, any leaks would be very small and would not warrant operation of the vent control system at negative pressure because of the associated safety hazard. Further, such leaks, which are expected to be very few, would be identified and repaired by the periodic inspections required by § 60.5416a.

9. Alternative Means of Emission Limitation (AMEL): INGAA supports AMEL provisions that accept approved state LDAR programs as LDAR alternatives and allow multiple facilities to be grouped under a single AMEL.

INGAA supports the proposed AMEL provisions that accept alternative compressor station LDAR standards for state LDAR programs for California, Colorado, Ohio, and Pennsylvania. INGAA recommends an ongoing streamlined process to review to approve additional state programs as LDAR requirements continue to be adopted.

Further, INGAA supports allowing groups of facilities (e.g., compressor stations operated by a single company or on a pipeline) to be grouped under a single AMEL. INGAA member companies operate hundreds of compressor stations across several states which include the same types of affected equipment. Such grouped facilities have common equipment and operating practices, and requiring redundant site-specific AMELs is not necessary or efficient. Once an AMEL is adopted, EPA should also consider an expedited and streamlined process to support broader use of that AMEL at other similar facilities.

In response to additional EPA questions on this topic, INGAA generally accepts the criteria in 40 C.F.R. § 60.5398a(c)-(d) regarding an AMEL application. However, field data obligations should not be so burdensome that companies are disincentivized from pursuing cutting edge technology. Extensive improvements have been made on methane sensor technology and additional research is ongoing to develop new sensor devices. Once proven to be accurate and reliable, EPA should incentivize companies to deploy these new technologies in order to reduce the burden associated with current methods of conducting leak surveys and potentially conduct real-time monitoring. In addition, section (d)(2) should generally refer to “affected facilities” rather than a “production site” because an AMEL may be requested at compressor stations and not just well / production facilities.