July 18, 2016

Electronic submittal: http://www.arb.ca.gov/lispub/comm/bclist.php

Clerk of the Board
California Air Resources Board
1001 I Street
Sacramento, CA 95812

Re: INGAA's Comments on the CARB Proposed Regulation for Greenhouse Gas Emission Standards for Oil and Natural Gas Facilities

Clerk of the Board:

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 California Air Resources Board (ARB) proposed regulation, "Greenhouse Gas Emission Standards for Crude Oil and Natural Gas Facilities" (Proposed Rule). The Proposed Rule and support documents were released on May 31, 2016, and INGAA welcomes the opportunity to provide comments. These comments are submitted on several specific issues in the Proposed Rule that introduce new approaches for methane standards or compliance approaches for natural gas transmission and underground storage facilities.

Natural gas provides 25 percent of the basic energy needs in the United States. INGAA's members represent the vast majority of the interstate natural gas transmission pipeline companies in the United States, including two in California. INGAA's members operate approximately 200,000 miles of pipelines and many compressor stations and underground natural gas storage facilities, and serving as an indispensable link between natural gas producers and consumers. The North American natural gas pipeline system is an energy highway that is the envy of the world. INGAA and its members have a long history of working collaboratively with a variety of stakeholders on air quality and greenhouse gas (GHG) issues, including the U.S. EPA and State agencies. INGAA appreciates your consideration of these comments. Please contact me at 202-216-5930 or tboss@ingaa.org if you have any questions.

Sincerely,

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INGAA COMMENTS ON CARB PROPOSED RULE, "GREENHOUSE GAS EMISSION STANDARDS FOR CRUDE OIL AND NATURAL GAS FACILITIES"

California Code of Regulations, Title 17, Division 3, Chapter 1, Subchapter 10 Climate Change, Article 4

PROPOSED REGULATION ORDER

Subarticle 13: Greenhouse Gas Emission Standards for Crude Oil and Natural Gas Facilities 6

July 18, 2016

The Interstate Natural Gas Association of America (INGAA) appreciates the opportunity to submit these comments in response to the California Air Resources Board (ARB) proposed rule, "Greenhouse Gas Emission Standards for Crude Oil and Natural Gas Facilities" (Proposed Rule). An overview of INGAA comments and recommendations includes:

1. It is premature for the ARB to propose monitoring standards for natural gas storage facilities until recommendations from the Aliso Canyon natural gas task force and Federal minimum standards are issued, per the PIPES Act of 2016. In the interim, INGAA recommends the use of established consensus standards for pipeline safety to minimize methane emissions from leaks.
2. Technologies for continuous ambient and wellhead monitoring of natural gas storage facilities are currently not technically proven. The performance of these technologies is still being evaluated, and they have not been commercially demonstrated at this scale. Continuous ambient and wellhead monitoring should not be required. INGAA recommend the use of established consensus standards for pipeline safety to minimize methane emissions from leaks.
3. The Proposed Rule includes leak detection and repair (LDAR) requirements that differ from established regulatory approaches and recent federal regulatory requirements (e.g., NSPS Subpart OOOOa). For natural gas transmission and storage (T&S) facilities, INGAA recommends: eliminating performance criteria that limit the *number* of leaks based on component population counts, revising requirements related to survey frequency and operator training, and, revising delay of repair provisions.
4. The Proposed Rule includes requirements for upstream storage tanks, separators, and production wells, which do not appear to apply to natural gas transmission and storage (T&S). For T&S segments, applicability of tank and separator requirements should be clearly indicated. Production wells and underground natural gas storage wells should be clearly differentiated.

Detailed comments follow.

<u>Detailed Comments</u>

1. It premature for the ARB to propose monitoring standards for natural gas storage facilities until recommendations from the Aliso Canyon natural gas task force and Federal minimum standards are issued, per the PIPES Act of 2016. In the interim, INGAA recommends relying on recently developed consensus standards (API RP 1170 and API RP 1171) and eliminating the requirements in §95668(i).

<u>Potential Federal Regulations and Consensus Standards Can Address Storage Field Concerns</u>

On June 22, 2016 President Obama signed federal legislation, the PIPES Act of 2016.[1] Section 12 of the PIPES Act requires the U.S. Department of Transportation Pipeline and Hazardous Materials Safety Administration (PHMSA) to issue safety standards for underground storage facilities within 2 years. The Act states that "The Secretary *may* authorize a State authority

[1] Protecting our Infrastructure of Pipelines and Enhancing Safety (PIPES) Act of 2016, Pub. L. No. 114-183 (June 22, 2016) (codified as U.S.C. § 60141).

(including a municipality) to participate in the oversight of underground natural gas storage facilities … A State authority may adopt additional or more stringent standards for intrastate underground natural gas storage facilities ***if** such standards are compatible with the minimum standards prescribed under this section."*[2] The Act also requires PHMSA to take into consideration the recommendations of the Aliso Canyon natural gas leak task force in developing minimum safety standards for underground natural gas storage facilities. Specifically, the task force must: (i) analyze and develop conclusions regarding the cause and contributing factors of the recent Aliso Canyon natural gas leak, (ii) analyze the measures taken to stop the leak and alternatives that could have been used instead, (iii) develop an assessment of the impacts of the leak on health, safety and the environment, and (iv) analyze how local, State and Federal agencies responded to the incident. Congress provided the task force with up to 180 days – or December 19, 2016 – to prepare a report summarizing its findings on these issues. The deadline to form this task force was mere days ago (July 7, 2016). Given that PHMSA has yet to issue Federal minimum standards for natural gas storage wells and the Aliso Canyon task force has yet to issue a final report summarizing its findings and recommendations, it is premature for the ARB to propose monitoring standards for natural gas storage wells at this time.

Also, the U.S. EPA has initiated a process to develop performance standards for oil and gas facilities, including natural gas storage, through a Notice requesting comment on an existing oil and gas industry Information Collection Request (ICR). The ICR will require companies to submit detailed information on equipment, operations, emissions, controls, and costs. EPA plans to complete the ICR process in early 2017 and use that information to develop an existing source regulation.

Prior to the recent storage field incident in the Los Angeles area, INGAA and others undertook an effort to develop best practices that provide guidance to operators on how to design, operate, and ensure the integrity of underground natural gas storage. Along with INGAA, trade associations that address all segments of the natural gas industry, including the American Petroleum Institute (API) and American Gas Association (AGA), participated in an effort to develop consensus practices and standards. This culminated in the release of two recommended practices (RP) in September 2015 accredited by the American National Standards Institute (ANSI). API RP 1171[3] addresses storage in depleted hydrocarbon reservoirs and aquifer reservoirs, which comprise the vast majority of storage fields. API RP 1170[4] addresses storage in salt caverns. Trade association members have committed to these practices through board resolutions, and the practices are being implemented by individual companies.

The new consensus standards and recent, planned, and potential new federal regulations provide platforms to address storage field integrity, safety, and environmental concerns. INGAA recommends relying on those initiatives and eliminating the proposed storage monitoring requirements in §95668(i).

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[2] *Id.*

[3] Summary – API Recommended Practice 1171©, http://www.api.org/~/media/files/publications/whats%20new/1171_e1%20pa.pdf .

[4] Summary – API Recommended Practice 1170©, http://www.api.org/~/media/files/publications/whats%20new/1170_e1%20pa.pdf .

The California Department of Conservation, Division of Oil, Gas & Geothermal Resources (DOGGR) has also released draft *Requirements for Underground Gas Storage Projects.*[5] These draft regulations also include monitoring/screening requirements. If ARB elects to retain the proposed monitoring requirements, INGAA urges ARB to work with DOGGR to develop consistent requirements before any new regulations from ARB or DOGGR come into effect.

2. **The Proposed Rule includes natural gas storage facility monitoring requirements in §95668(i) that are not feasible based on currently proven technologies. The economic analysis should be revised and benefits should be estimated to support the proposed monitoring requirements. INGAA recommends relying on recently developed consensus standards (API RP 1170 and API RP 1171) and eliminating the requirements in §95668(i).**

Proposed Continuous Monitoring Technology is Not Proven

The continuous monitoring technology for storage facility monitoring required by §95668(i)(1)(A) and (C) is not proven, because these provisions primarily rely upon the use of optical gas imaging (OGI), which is a periodic screening device used to *qualitatively* identify leaking components. OGI does not quantify leak volumes or leak rates. §95668(i)(1)(A) – (C) provides a list of three monitoring requirements. The requirements include: (A) Continuous monitoring of the ambient air. (B) Daily screening of each storage wellhead assembly and surrounding area within 200 feet of the wellhead; or (C) Continuous monitoring of each storage wellhead assembly and surrounding area within 200 feet of the wellhead. ARB background documents (e.g., Economic Analysis cost estimates) imply that ARB intends for condition (A) to apply, plus either (B) or (C). There are technological issues associated with the continuous monitoring proposed in subsections (A) and (C). A comment below also reviews the economic analysis for these three options, including the daily "manual inspection" option in subsection (B). Cost considerations are superseded by the technological issues.

The Economic Analysis and other support documents provide minimal detail on the automated monitoring technologies considered by ARB, and the cost estimates are based on either (1) applying optical gas imaging (OGI) with costs apparently based on presumed costs for infrared (IR) camera, such as the FLIR camera or (2) a combination of unspecified ultrasonic monitors and IR detectors. Thus, it appears ARB anticipates OGI would be used in a continuous operating mode. While INGAA members have used OGI for periodic leak surveys, INGAA does not believe that commercial technologies are available for continuous monitoring. This perspective is supported by the U.S. Department of Energy (DOE), which launched a program to address this technology gap, as discussed below.

Although vendors are attempting to adapt OGI for continuous operation, its market entry and use to date for methane detection is as a hand held camera for short term field tests rather than continuous operation. OGI functionality provides leak *detection*, but does not quantify leak rates or provide quantitative assessments such as changes from a baseline level, which is a performance metric in the Proposed Rule. ARB background documents also indicate ultrasonic meters could be used for monitoring. There is no detail on such technology, commercial

[5] Requirements for California Underground Gas Storage Projects, Discussion Draft, §1726 (Jul. 8, 2016)

products, or its application. INGAA does not agree with ARB conclusions that such technology is available to meet rule requirements.

ARB improperly assumes the availability of a commercial system for fixed mounted leak detection that requires little or no user intervention. For methane detection, OGI is currently used as a hand held instrument requiring human interface for leak determination. This technology has not been commercially implemented at compressor stations or storage fields for the purpose of autonomous ambient monitoring or for leak detection. FLIR, the leading OGI technology provider, has investigated gimbal mounted systems for use in fixed mount applications, but software, system integration, communication, audible and visual alarm or warning system development and integration still need to be tested and validated. Then, performance would need to be proven for the application and distances associated with storage wellheads and associated equipment. For such use, additional concerns would need to be addressed such as intrinsic safety requirements, labor from human intervention to investigate false positives, QA/QC criteria (e.g., calibrations, periodic audits) for continuous operation, and an alternative optics (e.g., telephoto lens) to allow storage wellhead surveying at greater distances.

In addition, ARB envisions monitoring that includes a performance metric requiring action when levels vary by more than 10% from a baseline. This monitoring paradigm is not established and is highly uncertain. It is unclear how such monitoring would be implemented for the two technologies noted by ARB – i.e., OGI or ultrasonic meters. For example, because methane is ubiquitous in the atmosphere from natural and anthropogenic sources, monitoring ambient methane levels would raise site-specific technical challenges that would differ for every storage field, such as: proximity to and prevalence of other methane sources (e.g., agricultural operations, wetlands); natural variability on an hourly, daily, and seasonable basis; wind direction and wind speeds; site topography; other meteorological effects; and surrounding area topography, buildings, and other physical features. In addition, maintenance and other operational activities could result in short term "deviations from a baseline" that actually result from standard and accepted practices. Thus, both operational and natural influences (e.g., natural diurnal affect depending on meteorology) imply that a "static" baseline is not appropriate, further complicating the ability to assess "performance." Developing the basis for establishing a "baseline," and inherent variability from "normal" scenarios, would likely become a complex research program, and months or years of monitoring could be required to understand the associated uncertainty and variability.

In addition to establishing a baseline, establishing an action level at a 10% deviation includes analogous complexities. OGI technology is not suited for assessing a quantitative change and has not been proven in that capacity. OGI *detects* methane but does not otherwise determine or quantify an associated measurable value. There are obvious and huge technical challenges in relying on OGI for the monitoring required by §95668(i)(1)(A) or (C). It is also unclear how ultrasonic technology noted by ARB would be used in this capacity.

Technology gaps for methane monitoring have been acknowledged by the DOE, and DOE has launched an Advanced Research Projects Agency-Energy (ARPA-E) program: the ARPA-E Methane Observation Networks with Innovative Technology to Obtain Reductions (MONITOR) program. This program includes multiple research projects targeting development of monitoring envisioned by §95668(i). DOE notes that MONITOR projects are

> …developing innovative technologies to cost-effectively and accurately locate and measure methane emissions associated with natural gas production. Such low-cost sensing systems are needed to reduce methane leaks anywhere from the wellpad to local distribution networks….[6]

This innovation is needed because:

> Existing methane monitoring devices have limited ability to cost-effectively, consistently, and precisely locate and quantify the rate of the leak.[7]

The ARPA-E MONITOR program includes six projects that would provide methane monitoring systems with continuous or near-continuous capabilities for sensing leaks and characterizing leak rates. Another five projects are investigating technologies that are even earlier in development where it is premature to research an integrated, functional system. The program was launched in 2015, and projects will include a demonstration phase if earlier phases meet performance objectives. The demonstration testing would occur in the third year. This national R&D program will not conduct the demonstration phase for about two more years. In addition, there are no assurances of success. Some of the projects employ OGI approaches, but it does not appear that ultrasonic monitoring implied by the ARB analysis is being assessed.

The DOE program is indicative of the current state of the science, and shows that technology is not available to address the monitoring envisioned by §95668(i). Due to technological limitations, INGAA recommends eliminating §95668(i).

<u>The Economic Analysis Should be Revised and Benefits Should Be Estimated</u>

The ARB Economic Analysis (EA) should be revised to address errors, omissions and questionable assumptions. The analysis does not estimate environmental benefits, and that estimation should be completed to justify the requirements. As discussed further below, recently developed consensus standards provide an avenue to managing storage field operations.

Storage well monitoring costs are included in Appendix B to the Staff Report, Initial Statement of Reasons. Appendix B is the ARB Economic Analysis (EA), and Section L, "Monitoring Plan," provides ARB estimates for the storage monitoring requirements. While ARB estimates benefits for other proposed standards, it does not estimate benefits from §95668(i). This oversight is significant because monitoring costs are substantial and have been under-estimated in the EA.

INGAA understands ARB's interest in storage field well leaks and the underlying intent of the proposed monitoring, but INGAA does not believe that §95668(i) would result in significant benefits. Qualitative leak monitoring programs, including OGI and audio-visual-olfactory inspections, are sufficient to detect leaks in a timely manner without the excessively burdensome, uncertain, and costly criteria proposed in this rule. At most, the proposed storage

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[6] DOE ARPA-E website for MONITOR program, http://arpa-e.energy.gov/?q=arpa-e-programs/monitor.
[7] *Id.*

field Monitoring Plan may result in a brief reduction in the duration of a major incident leak and is unlikely to preclude such an incident.

The storage well monitoring costs in the EA include numerous errors, deficiencies, unsupported data, and inconsistencies. These flaws raise questions about the reliability of the cost-effectiveness analysis used to support the proposed storage facility monitoring requirements.

A detailed cost review of ARB's Economic Analysis (EA) is not provided here. But, INGAA is aware of a detailed review of ARB's estimated storage field monitoring costs prepared by Southern California Gas Company (SoCalGas) as a part of its comments to ARB. INGAA supports the methodology and general conclusions of the SoCalGas review.

The EA review completed by SoCalGas concludes that costs are under-estimated by a factor of 3 to 4.

The reasons that these costs have been under-estimated include:

- ARB reliance upon cost information from businesses that would profit from providing automated leak detection systems. No data or evidence is provided to document that systems have been successfully implemented for storage facility applications, and references for monitoring system costs were not provided.
- The EA includes *NO costs* for:
  - Operation and maintenance of automated wellhead monitoring systems;
  - Method 21 leak screening and subsequent leak repairs required by §95668(i)(4) and (5);
  - Contingencies for unproven technologies applications;
  - Data collection and alarm systems for notification of company and agency personnel;
  - Monitoring Plan preparation, and recordkeeping and reporting; and
  - Site and corporate support for survey teams (e.g., scheduling, leak repair).
- Based on experience with implementing OGI for more established handheld leak surveys, costs are under-estimated for:
  - Capital cost of ambient monitoring equipment (e.g., including the number of monitors because multiple monitors would be required);
  - O&M costs associated with the ambient monitoring equipment;
  - OGI unit costs and the number of cameras required for wellhead monitoring to ensure camera availability and continuous compliance with the rule; and
  - Scenarios that erroneously conclude well groupings that allow the monitoring of multiple wells with a single instrument.
- The cost estimate assumes the monitoring systems have a ten year lifetime, which is highly optimistic for sensitive instrumentation that has not been proven for continuous monitoring applications.

In addition, CARB has not considered the environmental, landowner, and permitting impacts and associated costs of installing the ancillary infrastructure required to operate the proposed new monitoring technology. Storage wells traditionally have minimal power and communications infrastructure. Installation of overhead power/communications infrastructure to each facility and/or well to comply with §95668(i) represents a large amount of construction, including in previously undisturbed areas. The EA does not seem to recognize this; it appears wireless technology and/or underground burial is assumed. Additionally, "for purposes of the impact analysis, ARB assumes that compliance with the daily monitoring requirements will be achieved through installation of the grid detection system or through installation of wellhead sensors." As discussed, commercial systems are not currently available to support this assumption.

The EA severely underestimates the initial cost of ancillary infrastructure (e.g., power, control, communications, security) associated with adding monitoring equipment to often-remote locations. Storage wells traditionally have minimal power and communications infrastructure. Installation of overhead power/communications infrastructure to each facility and/or well to comply with §95668(i) represents a large amount of construction. The cost of this ancillary infrastructure will greatly surpass the $84,630 estimated in Appendix B.

The review showed that the EA includes other deficiencies and flaws, such as arithmetic calculation errors (e.g., three on page B-53 alone) and conflicting cost assumptions (e.g., capital cost of monitoring equipment per well is listed as $54,000 in the text and $90,000 in the equation on page B-52).

In sum, the EA generally assumed that the monitoring equipment is purchased with no other transaction costs (i.e., installation, personnel training, troubleshooting, ongoing O&M). Collectively, these issues contribute to a significant under-estimate of costs. The SoCalGas review concluded that these costs are low and are off by a factor of 3 to 4. In addition to costs considered in the SoCalGas review, additional EA under-estimates are evident for power and communications infrastructure.

<u>If §95668(i) is Retained, Revisions are Warranted</u>

If ARB elects to retain the proposed monitoring requirements, revisions are needed to address technical issues and implementation. As discussed above, there are technical challenges and cost implications associated with implementing the proposed rule monitoring provisions for underground storage facilities. If requirements are retained in the final rule, §95668(i) should be revised to attempt to mitigate technical issues and develop a functional monitoring program with feasible criteria.

a. <u>Applicability of the three options in §95668(i)(1)(A) – (C)</u>

The applicability of the three "options" in §95668(i)(1)(A) – (C) should be clearly defined. Based on punctuation, (A) is a stand-alone sentence, and (B) and (C) are a list of two options. In addition, support documents imply that ARB anticipates item (A), plus (B) or (C) would be implemented. INGAA recommends requiring only one of the three options, as all of the options require extraordinary effort and, if functional, provide similar assurance. If technical challenges associated with continuous monitoring can be addressed, any of the three items would provide real time or daily data on site integrity and multiple requirements are not warranted.

By requiring compliance with one of three options, operators would be able to consider a near-term "manual" program based on item (B), while technology for continuous monitoring systems matures and becomes commercially available. Operators could later opt to migrate from a manual process to more automated approach as warranted by technological advances.

b. Schedule, baseline determination, and phased implementation

Although INGAA recommends the removal of continuous monitoring requirements for reasons stated earlier in this document, we discuss some additional considerations if continuous monitoring is required (i.e., §95668(a)(1)(A) plus (B) or (C) is required). Additional time and effort will be needed to identify and validate technologies that meet the Proposed Rule criteria, while fulfilling operator expectations for performance and reliability. As discussed above, an extended implementation period will likely be necessary to develop a monitoring "baseline" that considers site-specific variability and uncertainty. Additional time may also be needed to allow continuous monitoring technologies to mature.

ARB should consider a staged implementation approach that includes a design and testing phase prior to requiring compliance with performance objectives. This is necessary because developing a "baseline" and measuring deviations from that baseline will be fraught with uncertainty. This would result in compliance uncertainty, which is untenable for operators. As discussed above, there are many unknowns in understanding a baseline and perceived deviations, so an extended schedule is warranted to gather information and "test" this process. After implementation, operators would report on lessons learned and requirements could be revisited. Based on insights gained as monitoring data is collected, a plan could be developed for full implementation of monitoring requirements with defined performance metrics (e.g., comparison versus baselines values).

Without such an approach, continuous monitoring would surely face significant near-term technical challenges, and determining compliance could be complex. While INGAA supports transparency, prematurely implementing a monitoring approach would likely yield false positives and mis-inform the nearby community and public.

3. For natural gas transmission and storage (T&S), the leak detection and repair standards should be revised to minimize or avoid burdensome requirements, and eliminate punitive compliance criteria.

The Proposed Rule includes leak detection and repair (LDAR) requirements in §95669. The standards follow typical LDAR approaches in some cases, but also include requirements that introduce new compliance approaches and criteria, or include frequent inspections. INGAA offers comments on several issues:

- Compliance criteria that require a component population count should be eliminated. (This requirement was removed from the final NSPS Subpart OOOOa rule based on comments received from stakeholders.)
- Performance metrics based on the number or percentage of leaking components should be eliminated.
- Quarterly survey frequency is not warranted for natural gas T&S facilities.

- For OGI surveys, "Level II Thermographer" training should not be required.
- The process of identifying "critical components" that can delay repair is overly complicated and should be eliminated.
- Additional time should be allowed for delaying repair of critical components, as long as the delay is justified.

Component population counts should not be required.

The Proposed Rule introduces LDAR concepts that require "population counts" of components. Table 1 and Table 3 of the Proposed Rule establish leak definition concentration thresholds and an allowable number of leaks above those thresholds as a percentage of components inspected (or a defined number of leaks if less than 200 total components are surveyed). Thus, the regulatory criteria require completing component counts at affected facilities. Historically, the population of components (i.e., component counts) have been used with correlation equations or emission factors as a means to estimate emissions from equipment leaks. More recently, "leaker emission factors" have been developed to provide the ability to estimate equipment leak emissions based on the count of leaking components, rather than the total component count. This approach is used for natural gas T&S facilities that report under Subpart W of the GHGRP.

Component counts have not been integral to LDAR *performance* criteria and this concept is not substantiated. For its recent Subpart OOOOa rulemaking, EPA initially proposed to base survey frequency on the percentage of leaking components, which would have required component counts. Based on stakeholder comments, that approach was not retained in the final rule and component counts are not required. INGAA is not aware of any data that correlates meaningful emissions reductions based on the percentage of leaks found that exceed a particular Method 21 concentration screening measurement. The Method 21 measured concentration is a poor surrogate for actual leak *rates* (as documented in the literature[8]), but, lacking an economical alternative, has been used in LDAR programs. The proposed approach to assess a percentage of leaks above a particular screening concentration results in compounding technical inadequacies – i.e., component population is not necessarily indicative of leak emissions, nor is Method 21 concentration indicative of leak rate. For these reasons, INGAA recommends deleting criteria related to component population counts for natural gas T&S facilities.

LDAR performance criteria based on a percentage of leaking components should be eliminated.

In addition, the aforementioned tables specify the *maximum* number of leaks allowed. As discussed above, population count criteria should not serve as the foundation of LDAR compliance. The objective of LDAR programs is to detect and repair leaks based on defined leak criteria (i.e., OGI screening, Method 21 screening). Adding punitive performance criteria that would result in non-compliance for actually finding and repairing leaks is not supportable.

ARB has not provided any information that correlates LDAR activities or operator behavior with the prevalence of leaks, how leaks occur and grow over defined time periods, and how operator

[8] There are a number of examples in the literature, including: (1) Lott, R.A., T. Howard, and M. Web. 1996. *Estimating Fugitive Emissions: Problems and Solutions.* Presented at the Fugitive Emissions Symposium, Las Vegas, NV, August 15-16, 1996; (2) EPA Protocol for Leak Emission Estimates, EPA-453/R-95-017, November, 1995.

practices affect leak prevalence and size (with ARB assessing size based on a very imperfect Method 21 concentration threshold). Thus, the performance criteria in Tables 1 and 3 that limit the number of leaks above defined leak concentration thresholds is not warranted and unsubstantiated. INGAA strongly recommends eliminating the "allowable number of leaks" performance criteria in Tables 1 and 3 for natural gas T&S facilities.

A quarterly survey frequency is not justified.

For natural gas T&S facilities, EPA documents, Subpart W data from compressor leak measurements, and other available material show that a small number of leaks contribute the vast majority of emissions. INGAA comments[9] on the Subpart OOOOa proposed rule provide additional background, including details regarding unsupported EPA assumptions about the influence of survey frequency on LDAR performance. With a few leaks contributing to produce most emissions, the objective should be to identify and repair those leaks. That can be achieved with surveys and regular audio-visual (A-V) inspections that are conducted less frequently than quarterly.

The Proposed Rule includes regulatory A-V inspections to detect leaks (e.g., daily at manned facilities), and as large leaks (that contribute the vast majority of emissions) develop, the leaks would very likely be discovered via A-V inspections. With no data to substantiate the incremental performance resulting from more frequent surveys, INGAA recommends an annual survey for T&S facilities, buttressed by the A-V inspection requirement.

Level II Thermographer training should not be required for OGI surveys.

The use of OGI was not included in earlier draft versions of the rule. The Proposed Rule includes OGI as an option, and §95669(g)(2) requires, "…a technician with minimum Level II Thermographer or equivalent training." ARB did not provide a reason for this training or certification so this requirement should be eliminated.

The natural gas transmission and storage (T&S) industry has been a leader in implementing OGI for leak surveys, and supported early development of the FLIR technology (and others) through research funded by the Gas Research Institute (GRI) over 15 years ago. Thus, T&S operators are familiar with the technology and its application. In addition, operators have been using OGI for federal GHG Reporting Program surveys (i.e., Subpart W surveys) since 2011. This includes leak surveys conducted in-house, and hiring third party contractors to conduct OGI surveys.

Standard operating practices are established for OGI instrumentation and EPA has included quality assurance requirement in the recent NSPS Subpart OOOOa. "Level II Thermographer" training is not an established qualification for leading practitioners of OGI leak surveys, and the proposed requirement adds an unnecessary expense and burden without a demonstrated value. In addition, CARB has not identified the criteria that would be used for thermographer qualification, or assessed the availability of qualified certification professionals or the associated certification costs. The requirement should be eliminated from §95669(g)(2).

[9] EPA docket document number EPA-HQ-OAR-2010-0505-6872. INGAA Comments on EPA Proposed Subpart OOOOa Rule (Dec. 4, 2015).

The process to define "critical components" should be eliminated or streamlined.

It is imperative that LDAR implementation include the ability to delay repairs of natural gas T&S facilities if warranted. Existing federal and state regulations provide examples of Delay of Repair (DoR) provisions. The Proposed Rule includes a requirement to identify a list of "critical components" that are candidates for DoR if warranted, and requires Administrator approval of the critical components. Additional criteria, such as tagging critical components, are included in the rule. INGAA recommends deleting the critical component approach to DoR because it is cumbersome and adds unnecessary burden and bureaucracy. For example, a compressor and all associated piping that is imperative to gas delivery for a particular region would surely qualify as critical equipment. A literal reading of the rule would require approval for all of the related sub-components (connectors, valves, etc.) and tagging of these components. This would result in hundreds or thousands of tags at a typical compressor station, which could raise safety questions – e.g., the tags could hinder operator access for maintenance or other tasks.

INGAA recommends an alternative approach to DoR based on other established LDAR regulations in Subpart VVa and NSPS Subpart OOOOa that require the operator to retain records documenting the DoR, but not seek approval as defined in the ARB rule. ARB or local air districts would have the ability to inspect records to ensure compliance. The rule should be revised to eliminate the "critical component" approach to DoR. Instead, the DoR approach should consider provisions such as delaying repairs that would require equipment or process blowdowns that would result in more emissions than the leak emissions until the next planned / scheduled shutdown. As discussed in the next comment regarding schedule, DoR should also include provisions modeled after the Colorado LDAR rule and include the following:

- If parts are unavailable, order parts promptly and complete repair within 15 working days of parts receipt (or the next planned / scheduled shutdown after the part is received if repair requires shutdown).
- If delay is attributable to another good cause, complete repair within 15 working days after the cause of delay ceases to exist. The operator must document the cause.

These two items are important provisions that are relevant when unique circumstances arise that preclude the ability to complete repair within the maximum time allowed in the Proposed Rule.

CARB should correct the "Repair Time Period" in Table 2 and Table 4 to 12 months.

For LDAR, §95669(h)(3) and (i)(4) specify the maximum time allowed for repair of critical components, and up to 12 months is allowed. This is a revision from earlier versions of the Proposed Rule that indicated 180 days, and the longer timeframe is warranted. However, ARB omitted revisions to these criteria in Table 2 and Table 4. For the "Repair Time Period" indicated in Tables 2 and 4, the line item for critical components should be revised to: "Next shutdown or within ~~180 calendar days~~**12 months.**"

When delay of repair is allowed, the 12-month maximum delay is too restrictive for select scenarios.

Delay of repair provisions generally include the requirement to complete repairs as soon practical, with operator obligation to document the situation. The Proposed Rule establishes a 12-month maximum, and there are occasional unique circumstances when that may not be possible for natural gas T&S facilities. For example, compressor stations typically include multiple compressors, and the compressors include "isolation valves" to segregate a unit from the process when not operating, or the valves required to isolate the station piping from the transmission pipeline. Those large valves are not "off the shelf" items and may include subcomponents / parts that require special machining or construction that are built when needed. The timing to order and obtain such parts, and then find an appropriate time to complete the repair (e.g., during a planned shutdown) without disrupting customer service may exceed 12 months. EPA acknowledged this in the recent Subpart OOOOa final rule by allowing up to two years to make repairs. Repairs should not be required within 12 months for these select scenarios. If this schedule limit is not revised in ARB's final rule, there could be unintended consequences, such as:

- Requiring shutdown and blowdown of the equipment to complete the repair; blowdown emissions could exceed the emissions associated with the leak.
- Requiring shutdown of critical energy infrastructure if the equipment / part is not available within 12 months, or a planned shutdown does not occur within 12 months once the "delayed" part is received. This could affect natural gas system reliability – e.g., service disruptions during times of critical energy demand. Shutdown timing should preclude conflicts with a regulatory requirement to operate (e.g., Federal Energy Regulatory Commission).
- Necessitating that companies undertake extraordinary measures with inordinate costs to attempt to meet this requirement because 12 months is not sufficient time.

These circumstances will be rare, and the operator can document the basis for delays beyond 12 months. ARB should not include this limit in the rule because of potential detrimental outcomes.

4. For natural gas T&S facilities, applicability of separator and tank requirements should be clearly indicated and *Production wells and* Underground Storage wells should be Differentiated in the rule.

The Proposed Rule includes standards for separators and tanks in §95668(a) and standards for well-related operations in §95668(b), (g), and (h). These requirements appear to apply to upstream *production* operations and not to natural gas T&S operations, but that is not always evident. Therefore, ARB should clarify the applicability of requirements for the natural gas T&S segments. For §95668(a), it is fairly clear that natural gas T&S facilities are not subject, and the standard applies to production separators and tanks. For the three well-related standards, it is not immediately clear if the standard is referring solely to *production* wells, or if it also affects *underground storage* wells.

ARB should improve clarity by revising the rule to refer to the well type. For example, the definition of "Well" in §95667(a)(67) broadly includes production wells and underground storage wells, so additional review is needed to determine applicability or exclusions for storage wells. As explained below, §95668(b) and (g) standards do **not** apply to storage wells. But it appears that well casing vent measurement requirements in §95668(h) would apply to storage wells. The rule should be revised to more clearly indicate applicability and avoid confusion when the rule is implemented.

Separators and Tanks

The Proposed Rule includes standards for separator and tank systems in §95668(a). Natural gas T&S operations include tanks and separators, but emissions from this source type (i.e., from liquids flashing) are not an issue because natural gas is processed upstream of the T&S segments. Based on Proposed Rule definitions, §95668(a) does not apply to the natural gas T&S segment because of the following definition in §95667(a)(54):

> (54) "Separator and tank system" means the first separator in a crude oil or natural gas production system and any tank or sump connected directly to the first separator.

The definition refers to *production* and the first separator, or a tank or sump directly connected to that separator, so §95668(a) is not applicable to natural gas T&S facilities. As discussed below, applicability of other requirements related to production wells are not as clear as this situation, and INGAA recommends re-titling the sections to add clarity. In this case, §95668(a) would provide additional clarity if titled, "**Production** Separator and Tank Systems."

§95668(b) – Circulation Tanks for Well Stimulation Treatments

For natural gas storage wells the applicability of §95668(b) is not immediately evident. INGAA concludes that this standard does not apply to storage wells based on the inter-related definitions and citations:

- "Well stimulation treatment" traditionally refers to processes to improve gas flow from *production* wells, and a definition is included in the rule at §95667(a)(65).

> "Well stimulation treatment" means the treatment of a well designed to enhance crude oil and natural gas production or recovery by increasing the permeability of the formation and as further defined by the Division of Oil, Gas, and Geothermal Resources SB 4 Well Stimulation Treatment Regulations, Chapter 4, Subchapter 2, Article 2, section 1761(a) (December 30, 2014).

The description clearly refers to natural gas *production* and not to storage wells. However, excluding natural gas storage wells based solely on the definition is not obvious. For example, the proposed definition does not clearly exclude storage well clean out and maintenance.

For clarity, this should be indicated in the rule by titling the section, "Circulation Tanks for **Production** Well Stimulation Treatments." Alternatively, the definition at §95667(a)(65) could be revised to clearly indicate that natural gas storage wells are excluded.

§95668(g) – Liquids Unloading of Natural Gas Wells

Applicability of §95668(g) should also be clarified for natural gas storage wells. The rule text and definitions do not clearly indicate applicability, but ARB support documents indicate that §95668(g) applies to *production* wells. For example, the Draft Environmental Analysis describes the affected process as production wells:

> Over time, natural gas wells accumulate liquids that can impede and sometimes halt gas production. When the accumulation of liquid results in the slowing or cessation of gas production, removal of fluids (e.g., liquids unloading) is required in order to maintain production.

The description refers to gas *production* three times and storage wells are not mentioned. In addition, the ARB Initial Statement of Reasons document includes "plain English" background on oil and gas operations and processes in Section II.B. The background on Liquids Unloading in subsection (1)(b) describes a process for production wells; natural gas storage wells are not discussed.

ARB should clearly indicate that §95668(g) is not applicable to storage wells. The rule could be revised to indicate §95668(g) applies to, "Liquids Unloading of Natural Gas **Production** Wells." Alternatively, the definition of "liquids unloading" at §95667(a)(28) could be revised to clearly indicate that natural gas storage wells are excluded.

§95668(h) – Well Casing Vents

The applicability of the Rule to storage well casing vents is less clear than the other standards discussed above. The Proposed Rule requires operators of wells with a well casing vent open to the atmosphere to measure the natural gas flow rate from the well casing vent annually, retain records, and submit an annual report to ARB. There is not information available within the rule or background documents that clarify whether natural gas storage wells are excluded. Thus, it appears that §95668(h) applies to natural storage wells.

Similar to the clarifications requested above, ARB should clarify the applicability of §95668(h). If §95668(h) does not apply to natural gas storage wells, this could be clarified by titling the section, "**Production** Well Casing Vents." If this section applies to storage well casing vents, the rule should be revised to clearly indicate that this vent line is not included in the LDAR program for natural gas storage wells.