Interstate Natural Gas Association of America

December 4, 2015

Via www.regulations.gov and email
U.S. Environmental Protection Agency
Attention Docket ID Number EPA–HQ–OAR–2010–0505
1200 Pennsylvania Avenue, N.W.
Washington, D.C. 20460

Re: Docket ID No. EPA-HQ-OAR-2010-0505 – "Oil and Natural Gas Sector: Emission Standards for New and Modified Sources," dated September 18, 2015 (80 FR 56593)

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" (Proposed Rule). The Proposed Rule would amend 40 C.F.R., Part 60, Subpart OOOO, the New Source Performance Standard (NSPS) for oil and gas operations, and proposes a new rule, Subpart OOOOa, for affected units that are modified, constructed, or reconstructed after the September 18, 2015 proposal date.

INGAA appreciates your consideration of these comments. Please contact me at 202-216-5955 or tpugh@ingaa.org if you have any questions.

Thank you.

Sincerely,

Theresa Pugh

Theresa Pugh
Vice President, Environment, Health and Construction

cc: Bruce Moore, U.S. EPA (via email)
David Cozzie, U.S. EPA (via email)
Paul Gunning, U.S. EPA (via email)
Jim Laity, Office of Management and Budget (OMB)

COMMENTS OF THE INTERSTATE NATURAL GAS ASSOCIATION OF AMERICA
ON THE PROPOSED RULE,
"OIL AND NATURAL GAS SECTOR: EMISSION STANDARDS
FOR NEW AND MODIFIED SOURCES"
Code of Federal Regulations Title 40, Part 60, Subpart OOOOa

80 Federal Register 56593, September 18, 2015

December 4, 2015

INTRODUCTION

The Interstate Natural Gas Association of America (INGAA) respectfully submits these comments in response to the "Oil and Natural Gas Sector: Emission Standards for New and Modified Sources" proposal (Proposed Rule).[1] INGAA's members represent the vast majority of the interstate natural gas transmission pipeline companies in the United States, operating approximately 200,000 miles of pipelines, and serving as an indispensable link between natural gas producers and consumers. INGAA and its members have a long history of working collaboratively with a variety of stakeholders on greenhouse gas (GHG) issues, including on methane.

The U.S. interstate natural gas pipeline network relies on more than 1,400 natural gas compressor stations to maintain the continuous flow of natural gas between supply areas and consumers.[2] INGAA's members alone operate approximately 1,000 compressor stations in the U.S. Compressor stations typically are placed 40-70 miles apart along the pipeline system to maintain flow by re-pressurizing the gas. Depending on the time of year, location, and customer demand to utilize their transportation contracts, these stations may operate day and night, year-round, to push re-pressurized gas through the pipelines. Each interstate natural gas compressor station, on average, houses between two and ten compressor units. Larger compressor stations may have as many as 10-16 compressor units with an overall horsepower rating per station from 50,000 to 80,000 horsepower and a throughput capacity exceeding three billion cubic feet of natural gas per day.[3] Each compressor station has thousands of pieces of equipment and component parts.

These interstate compressor facilities, if "modified" or "reconstructed," would be subject to the "Oil and Natural Gas Sector: Emission Standards for New and Modified Sources" proposal. In addition certain "new" compressor facilities would be subject to the rule. Therefore, INGAA members have a direct interest in the Proposed Rule.

[1] "Oil and Natural Gas Sector: Emission Standards for New and Modified Sources," 80 Fed. Reg. 56593 (Sept. 18, 2015).
[2] http://www.eia.gov/pub/oil_gas/natural_gas/analysis_publications/ngpipeline/index.html
"Compressor stations are 'pumping' facilities that advance the flow of natural gas. They … are designed to operate on a nonstop basis. The average station is capable of moving about 700 million cubic feet (MMcf) of natural gas per day, while the largest can move as much as 4.6 billion cubic feet (Bcf) per day." Energy Information Administration, Office of Oil and Gas, "Natural Gas Compressor Stations on the Interstate Pipeline Network: Developments Since 1996," November 2007. This data is understated since it relies on EIA data through 2007/2008 with selected updates.
[3] EIA, "About U.S. Natural Gas Pipelines, Transporting Natural Gas."

I. EXECUTIVE SUMMARY

The Interstate Natural Gas Association of America (INGAA) is the national trade association representing the Transmission and Storage (T&S) sector. The T&S sector has more than 1,400 natural gas compressor stations across 200,000 miles of pipelines in the United States.

INGAA and its members have a long history of working with a variety of stakeholders on greenhouse gas (GHG) issues, including methane. Nonetheless, INGAA has serious concerns with the rule proposed by the Environmental Protection Agency (EPA). The Proposed Rule would offer little, if any, environmental benefit compared with the more reasonable alternatives offered by INGAA. If finalized as proposed, the rule would impose significant costs and create the real risk of both increased methane emissions due to unnecessary blowdowns and disruptions of service to natural gas consumers.

For the T&S sector, the Proposed Rule would set standards of performance that would apply to any new, modified or reconstructed compressor, pneumatic control or pneumatic pump used at a compressor station. For these types of equipment, the proposed standards would take the form of certain work practice and operational requirements.

In addition, the Proposed Rule would set standards of performance for fugitive methane emissions at new, modified and reconstructed compressor stations. For these purposes, the Proposed Rule defines "modification" as any addition of a compressor or compression capacity at a compressor station. As such, EPA appears to presume (incorrectly) that any such change would increase fugitive emissions at a station. (This is not always the case.) Furthermore, EPA appears to assume (incorrectly) that such a change would increase fugitive methane emissions at the *entire* compressor station because the Proposed Rule makes the entire station the "affected facility" to which the standard of performance for fugitive emissions applies.

The proposed standard of performance for controlling fugitive methane emissions at a new, modified or reconstructed compressor station is an extensive leak detection and repair (LDAR) regime. The LDAR regime involves an initial survey of "fugitive emissions components," which is an expansively defined category of equipment. After the initial survey, an operator must survey semi-annually. The LDAR regime, however, also has a self-ratcheting dynamic. If a survey detects fugitive emissions from just three percent or more of the fugitive emission components during two consecutive semi-annual surveys, the survey frequency increases to quarterly.

The Proposed Rule requires an operator of a compressor station that identifies a leak through such a monitoring survey to repair the leak in 15 days, with the possibility for an extension only under limited circumstances. The failure in the Proposed Rule to provide a reasonable delay of repair provision will lead to adverse consequences, including the possible impairment of transportation service to pipeline customers during high-demand periods and increased methane emissions due to otherwise unnecessary blowdowns conducted to enable leak repairs.

INGAA's principal concerns with the Proposed Rule, and its proposed alternatives to remedy these concerns, are as follows:

EPA's definition of "modification" must be narrowed and clarified. INGAA points out that some physical or operational changes do not increase fugitive emissions. EPA's proposed definition for the T&S sector is entirely too broad and will, if not corrected, apply to an entire compressor station without any environmental justification. This expansion of the scope of the rule will greatly increase the cost of compliance and the likelihood of adverse consequences.

The proposed rule is flawed because it does not focus on the larger methane leaks, which EPA often calls "gross emitters." INGAA, along with others, has pointed out that a small number of sources account for greater than 80 percent of the volume of methane leaks attributable to the T&S sector. This is substantiated by EPA's Greenhouse Reporting Program data and the 2014 Natural Gas STAR program analysis. EPA should allow pipelines to focus on the greatest sources of leaks.

The proposed survey frequency combined with the proposed requirement to fix leaks within 15 days (and only a nominal opportunity for delay of repair) is neither justified nor feasible. As noted above, the intense focus on addressing fugitive emissions from smaller sources will lead to a misallocation of resources that will discourage T&S operators from addressing larger methane emissions at existing sources that are outside the scope of the Proposed Rule.

The proposal that the frequency of required leak surveys be determined by an arbitrary survey of the number of component parts that leak, rather than any measure of the volume of methane emissions, is arbitrary and capricious and inconsistent with other EPA New Source Performance Standard (NSPS) programs. Many new and modified compressor stations will have thousands of component parts. The possible consequence of this arbitrary metric, along with the low threshold for what constitutes a leak, could be that many new and modified compressor stations will trigger the quarterly survey requirement and repair mandate.

One of the most significant flaws in the Proposed Rule is EPA's failure to provide reasonable delay of repair provisions consistent with other EPA programs (such as the program for the Synthetic Organic Chemicals Manufacturing Industry). These other programs quite reasonably take into account repair feasibility, availability of parts, qualified personnel and other factors.

EPA's delay of repair provisions also fails to permit delays when the immediate repair will result in more methane emissions than would occur if the repair were delayed until the next unit shutdown. For example, EPA did not recognize that requiring leak repair within 15 days would necessitate blowdowns that otherwise would not occur, and that this could result in far greater emissions of methane than if more reasonable rules governed delay of repair. In many instances, it is likely that the methane emitted from a blowdown will greatly exceed the volume of methane emissions avoided by fixing a leak within 15 days.

INGAA urges EPA to allow a work practice standard such as INGAA's Directed Inspection and Maintenance Program (DI&M) that is more reasonable than the LDAR regime specified in the proposed rule. INGAA's DI&M addresses leak identification and repairs based upon more feasible repair criteria that account for station operations, customer demands, and availability of equipment and trained personnel while focusing on the largest sources of emissions. INGAA's DI&M program also would include verifiable documentation of repairs.

Furthermore, EPA did not take into account the existing leak repair program pursuant to Pipeline and Hazardous Materials Safety Administration (PHMSA) regulation. EPA should consult with PHMSA before proceeding in issuing a final rule.

INGAA believes EPA's cost-benefit analysis did not properly consider direct and indirect costs to the T&S sector for leak identification, station downtimes and repairs. EPA's cost estimates fail to identify the costs of service disruptions to pipeline customers caused by removing compressors from service to make repairs, and they do not include accurate costs for trained personnel to conduct the many activities under LDAR. In addition, EPA's Benefits Analysis relies upon a flawed Colorado study that exaggerates the expected reduction of emissions attributable to the LDAR program compared with that which would be achieved by other regulatory alternatives (including INGAA's DI&M Program).

EPA failed to make a separate legal Endangerment Finding for the T&S sector as a source category requiring this regulation. EPA should conduct a separate and explicit Endangerment Finding for the T&S sector under section 111(b)(1)(A) of the Clean Air Act (CAA) before proceeding with a final rule.

EPA failed to offer any justification for the proposed requirement of third-party auditors, which it does not now impose on other sectors subject to EPA regulation. INGAA opposes this proposed requirement.

INGAA requests that the final rule not take effect for 180 days following publication in order to allow sufficient time to train the personnel that will be needed to implement the rule.

II. DETAILED COMMENTS

A. Key Elements of the Proposed Rule Affecting the Transmission and Storage Sector.

For the T&S sector, the Proposed Rule sets standards of performance that apply to any new, modified or reconstructed compressor, pneumatic control or pneumatic pump used at a compressor station.[4] For these types of equipment, the proposed standards take the form of certain work practice and operational requirements.[5]

In addition, the Proposed Rule sets standards of performance for fugitive methane emissions at new, modified, and reconstructed compressor stations.[6] For purposes of these fugitive emissions requirements, the Proposed Rule defines "modification" as any addition of a compressor or compression capacity at a compressor station.[7] As such, EPA appears to presume that any such change would increase fugitive emissions at a station. Furthermore, EPA appears to assume that such a change would increase fugitive methane emissions at the *entire* compressor station because the Proposed Rule makes the entire station the "affected facility" to which the standard of performance for fugitive emissions applies.

The proposed standard of performance for controlling fugitive methane emissions at a new, modified or reconstructed compressor station is an extensive leak detection and repair (LDAR) regime.[8] The LDAR regime involves an initial survey of the collection of "fugitive emissions components," which is an expansively defined category of equipment.[9] After the initial survey, surveys are required semi-annually. However, the LDAR regime also has a self-ratcheting dynamic. If a survey detects fugitive emissions from just three percent or more of the fugitive emission components during two consecutive semi-annual surveys, the survey frequency jumps to quarterly.[10] Such a regime would require an operator to engage in a continuous leak identification and repair cycle, focusing significant company time and resources to identify minor and hard to locate leaks that do not emit appreciable volumes of methane. The commitment of resources required to meet this obligation to identify and repair all leaks, regardless of size, will limit an operator's ability to undertake voluntary leak detection and mitigation programs, such as the Methane Challenge to reduce methane emissions from existing sources.

The Proposed Rule requires an operator of a compressor station that identifies a leak through such a monitoring survey to repair the leak in 15 days, with the possibility for an extension only under limited circumstances.[11] Failure to provide a reasonable delay of repair provision will lead to adverse consequences, including the possible impairment of transportation service to

[4] 80 Fed. Reg. at 56663 (proposed 40 C.F.R. § 60.5635a(b), (c), (d)).
[5] 80 Fed. Reg. at 56665 (proposed 40 C.F.R. §§ 60.5380a, 60.5385a, 60.5390a, and 60.5393a).
[6] 80 Fed. Reg. at 56664 (proposed 40 C.F.R. § 60.5635a(j)).
[7] *Id.*
[8] 80 Fed. Reg. at 56667-69 (proposed 40 C.F.R. § 60.5397a).
[9] 80 Fed. Reg. at 56695 (proposed 40 C.F.R. § 60.5430a(definition of "fugitive emissions component")).
[10] 80 Fed. Reg. at 56668 (proposed 40 C.F.R. § 60.5937a(g)).
[11] 80 Fed. Reg. at 56667 (proposed 40 C.F.R. § 60.5937a(i)).

pipeline customers during high demand periods and an increase of unnecessary blowdowns, which would result in methane emissions in order to conduct the repair.

B. EPA Should Amend the Definition of "Modification" to Exclude Changes that do not Result in Emissions and Should Amend the Definition of Fugitive Methane at "Affected Facility" to cover only those Parts of a Compressor Station Actually Affected by a Modification.

With respect to the control of fugitive methane emissions, EPA proposes to define "modification" such that any addition of a new compressor or compression capacity triggers the fugitive emission control requirements at the compressor station "affected facility." Furthermore, EPA proposes to define the "affected facility" in this context as the entire compressor station. Both of these approaches are overbroad and exceed EPA's statutory authority. EPA's expansive definition of what entails a "modification" at an existing compressor station could affect many thousands of parts and components at existing compressor stations. Therefore, the impact of the Proposed Rule is significantly more expansive for the T&S sector than EPA acknowledges.

i. EPA may not presume that all additions of compression are "modifications" because not all additions of compressors *increase* fugitive emissions at a compressor station.

EPA proposes, for purposes of the fugitive emissions methane standard for compressor stations, that a "modification" to a station occurs any time that: (1) a new compressor is constructed at an existing compressor station; or (2) a physical change is made to an existing compressor at a compressor station that increases the compression capacity of compressor station.[12] This definition incorporates the concept of a physical change to a part of the station but omits an explicit demonstration that these changes result in an *increase* in emissions.

However, CAA § 111 defines "modification" in terms of both a change *and* a resulting emissions increase. Specifically, it defines the "modification" of a source as a physical or operational change that "increases the amount of any air pollutant emitted by such source or which results in the emission of any air pollutant not previously emitted."[13] In addition, EPA's own general regulations interpreting section 111 define "modification" to occur only when there is a physical or operational change and an increase in the source's emissions rate. [14]

Therefore, EPA's definition of "modification" for purposes of the proposed fugitive emission standards is not consistent with the Agency's statutory authority as the Agency has not provided

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[12] 80 Fed. Reg. at 56663-64 (proposed 40 C.F.R. §60.5365a(j)).
[13] CAA § 111(b)(4).
[14] EPA's modification rule is codified in 40 C.F.R. Part 60, which applies to all categories of NSPS sources. It states that a "physical or operational change to an existing facility which results in an increase in the emission rate to the atmosphere of any pollutant to which a standard applies shall be considered a modification." See 40 C.F.R. § 60.14(a).

a reasoned basis for *presuming* that *any* addition of compression at a compressor station *necessarily* increases fugitive emissions at the station.[15]

In fact, there are many instances in which the addition of a compressor or compression capacity at a compressor station does not result in an increase in fugitive emissions (or the rate of such emissions) at the station. For example, the addition of a new compressor at an existing facility may replace other units, and a single, larger unit may replace multiple smaller units. In these instances, emissions may actually *decrease* from newer equipment or from fewer components that have the potential to leak. Similarly, horsepower replacement or upgrades do not necessarily cause increased fugitive emissions.

For these reasons, we urge EPA to more narrowly and precisely define "modification" in the context of fugitive emissions at a compressor station so it covers only those additions of compressors or compression capacity *that increase the rate* of fugitive emissions of the station.[16] To this end, INGAA supports the American Gas Association's recommendations for changes to the regulatory definition of "modification."

ii. EPA should affirm the NSPS exemptions for routine maintenance, repair and replacement.

We request that EPA affirm that the exemptions in the general NSPS regulations remain available for fugitive emission components at compressor stations, including the exemption for physical or operational changes that constitute routine maintenance, repair and replacement.[17] These exemptions are important to provide certainty to operators of compressor stations that undertake such activities as the like-kind replacement of an old compressor with a new compressor. Such activities should not trigger "modifications" under the OOOOa Rule.

iii. EPA's definition of the fugitive methane "affected facility" unreasonably presumes that any addition of compression increases fugitive emissions throughout the entirety of a compressor station.

To be sure, there are cases in which the addition of compression at a compressor station can increase fugitive methane emissions. However, as explained below, the Proposed Rule unreasonably presumes that in all such cases the potential for fugitive methane emissions increases throughout the entire compressor station. EPA has appropriately solicited comment on the validity of this presumption.

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[15]Section 60.14 of the general NSPS regulations provides that "special provisions" in a subpart applicable to a particular source category may supersede any conflicting provisions in EPA's general NSPS regulations. Nevertheless, even such a "special provision" may not conflict with EPA's *statutory* authority under section 111. In other words, EPA might have authority to promulgate an interpretation of "modification" for purposes of the Proposed Rule that conflicts with the definition of that term in the general NSPS regulations, but it lacks authority to promulgate an interpretation of "modification" that conflicts with the definition of that term in CAA § 111(b)(4).
[16] In some instances, it might be more expedient for an operator to assume that a change has increased the emission rate at a station, and therefore implement the requirements of the regulation. However, this assumption should be an option for the operator, not a regulatory presumption.
[17] 40 C.F.R. § 60.14(e)(1).

EPA has proposed to define, for purposes of the fugitive methane emissions standard, the "affected facility" as the "collection of fugitive emissions components" at a compressor station.[18] EPA further proposes to define "fugitive emission component" as "any component that has the potential to emit fugitive emissions of methane… at a compressor site."[19]

The implication of these proposed definitions is that any addition of compression to any part of a compressor station is not only presumed to increase fugitive methane emissions (as discussed above), but moreover is presumed to increase these emission *throughout the entire station* – thereby triggering the requirement to apply the work practice standard for fugitive emissions at every one of the thousands of "fugitive emission components" in the station.

In the preamble, EPA acknowledges that "for some modified compressor stations, the added compressor may only be connected to a subset of the fugitive emissions sources on the site" – and therefore solicits comment on whether the abatement requirements should only apply to the subset of components actually affected.[20]

There are cases in which the addition of a compressor at a compressor station will increase throughput at only part of the station rather than the whole station—which means that the potential for an increase in fugitive emissions is confined just to the affected part. For example, a new compressor could be installed adjacent to existing compressors where the new compressor piping is connected directly into the existing compressor piping manifolds. A fugitive emissions increase would result from addition of valves and other components associated with the new compressor, but it would not increase the fugitive emissions from the existing compression manifold piping. Another example could be the addition of a new compressor in a new building at an existing compressor station. A fugitive emissions increase would result from the installation of the piping and components for the new compressor building into the existing station piping or mainline pipeline. However, fugitive emissions from the existing compressors and associated piping and components would not be increased.

For these reasons, INGAA urges EPA to define "affected facility" as the portion of a compressor station at which fugitive methane emissions increase as the result of a "modification." This change is necessary to ensure that the operator of a compressor station need only apply the fugitive emission abatement requirements at the portion of a station actually affected by the addition of a compressor or compression capacity.[21]

[18] 80 Fed. Reg. at 56663-64 (proposed 40 C.F.R. § 60.5365a(j)).
[19] 80 Fed. Reg. at 56695 (proposed 40 C.F.R. § 60.5430a (definition of "fugitive emissions component")).
[20] 80 Fed. Reg. at 56643.
[21] To be sure, as EPA observes, some operators may find it "advantageous . . . from an operational perspective to monitor all the components at a compressor station since the monitoring equipment is already onsite." 80 Fed. Reg. at 56643. However, such station-wide monitoring should be an *option* for the operator of an affected facility, not a requirement.

C. EPA's Standards of Performance for Affected Facilities in the Segment Should Focus on Gross Emitters.

i. EPA erred by focusing on the percentage of leaking components and equipment pieces at compressor stations rather than the volume of leaks.

EPA requests comment on whether the fugitive emissions standard for compressor station "affected facilities" should focus on larger leaks, which EPA refers to as gross emitters.[22] There is scientific evidence to support focusing on gross emitters, and INGAA agrees that the standard should focus on large leaks from gross emitters.

There is scientific evidence that the vast majority of leaks, over 80 percent, in the T&S sector come from a small number of sources called "gross emitters." The Environmental Defense Fund (EDF), industry and Colorado State University (CSU) published a collaborative study documenting that a small number of leaks, termed in that study as "super emitters," account for a large percentage of emissions from leaks. These leaks are also called either "gross emitters" or "long tail emitters." The CSU study concludes that "the highest emitting 10 percent of sites (including two super emitters) contributed 50 percent of the aggregate methane emissions, while the lowest emitting 50 percent of sites contributed less than 10 percent of the aggregate emissions."[23] In addition, EPA's Natural Gas STAR program, among other analyses, has demonstrated that a relatively small percentage of leaks contribute to the vast majority of emissions for natural gas operations, e.g., 80 to 90 percent of methane emissions from equipment leaks are from 20 percent of the leaks at compressor stations. Moreover, as discussed below, EPA's Subpart W monitoring data also supports the conclusion that a small category of equipment account for a majority of the fugitive emissions from a compressor station.

INGAA supports EPA's goal of reducing methane emissions from the T&S sector. EPA can meet its goal by permitting natural gas pipeline operators to focus on "gross emitters." INGAA strongly supports a programmatic approach that focuses on reducing emissions from sources with higher risk of producing larger leaks. In the case of the T&S sector, these sources are reciprocating compressor rod packing, centrifugal compressor seals, compressor blowdown valves, compressor isolation valves and storage tank dump valves. This is substantiated by EPA's Subpart W data.

EPA cannot overlook the scientific studies and data that support focusing on the largest or "gross" emitters. A focus on those specific components or equipment with the greatest chance of leaking and the most significant leaks will provide benefits similar to a comprehensive leak detection program – with significantly reduced costs and burden on the operators and less risk of disruption of natural gas service to pipeline shippers and ultimately consumers.

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[22] 80 Fed. Reg. at 56642.

[23] Subramanian, R, et al., "Methane Emissions from Natural Gas Compressor Stations in the Transmission and Storage Sector: Measurements and Comparisons with the EPA Greenhouse Gas Reporting Program Protocol", Environ. Sci. Technol., 49,3252-3261, DOI:10.1021/es5060258 (2015): http://pubs.acs.org/doi/pdf/10.10121/es5060258

The Proposed Rule includes a performance-based survey schedule that inappropriately depends on the percentage of compressor station component parts or equipment pieces that are leaking, rather than the volume of methane emissions from such leaks. In addition to conducting the survey, this approach requires a component count and tracking over time to assess the percentage of leaking components.

EPA defines "fugitive emissions component" as including, but not limited to, valves, connectors, pressure relief devices, open-ended lines, access doors, flanges, closed-vent systems, thief hatches or other openings on a storage vessel, agitator seals, distance pieces, crankcase vents, blowdown vents, pump seals or diaphragms, compressors, separators, pressure vessels, dehydrators, heaters, instruments and meters.[24] This can be more than 1,000 components per new compressor station. This definition is not consistent with the traditional list of fugitive or modified components found in the proposed rule for processing plant "equipment" and will cause confusion within the oil and gas sector and LDAR contractors. The definition will also result in many more components than traditionally identified in LDAR programs, which will increase survey time and cost for transmission compressor stations.

Under EPA's Proposed Rule, an operator must survey the fugitive components at a compressor station and determine the percent of components that are leaking. An operator then must conduct quarterly surveys if more than three percent of the compressor station's component equipment fails to pass a leak inspection survey two consecutive times.[25] Regardless of survey frequency, the Proposed Rule would require an operator to repair any leaks within 15 days.

Under this proposal, an operator would spend significant time searching to identify the source of very small leaks that individually result in a minimal volume of released methane. For example, EPA's proposed use of Optical Gas Imaging (OGI) equipment in the proposed rule could require an operator to detect and repair a small volume (often described as a wisp) from a compressor station piece of equipment that is equivalent to a small, 60 grams per hour release. The 60 grams per hour is less than three standard cubic feet per hour (SCFH). This level of leak rate detection in the Proposed Rule is equivalent to a "no leak" threshold for measurement procedures included in EPA's Subpart W reporting program.[26] The approach would waste valuable resources addressing small leaks rather than allowing the focus to be identifying and eliminating the gross emitters.

Operators should be permitted to delay the repair of leaks emitting *de minimis* amounts of methane and those that are difficult to locate and costly to fix. This will allow operators to set priorities for repair of large or significant leaks, resulting in more meaningful emissions reductions.

EPA has not justified why the one percent of equipment threshold for triggering a NSPS work practice standard is reasoned decision-making. Nor has EPA demonstrated why a particular number of equipment leaks, i.e., one percent, without regard to the volume released by the

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[24] https://www.federalregister.gov/articles/2015/09/18/2015-21023/oil-and-natural-gas-sector-emission-standards-for-new-and-modified-sources#h-74

[25] 80 Fed. Reg. at 56668 (proposed 40 C.F.R. § 60.5397a(h)).

[26] 40 C.F.R. §§ 98.233(k)(1)(iv) and 98.234(a)(5).

leaking equipment, is justified or how the benefits of the rule outweigh its cost. These thresholds are all the more arbitrary in light of EPA's own data supporting the conclusion that the vast majority of emissions can be addressed by focusing on the limited number of gross emitters.

As EPA notes in the Regulatory Impact Analysis (RIA), methane is not a health pollutant. Consequently, EPA has discretion in setting reasonable repair response times. The number of compressor station leaks not repaired over a one-month to two-year time interval will not affect climate change because of the relative *de minimis* nature of those methane emissions in contrast to methane in the global atmosphere. Therefore, reasonable delay-of-repair provisions that would mitigate many of the adverse consequences that are likely to result from the rule are appropriate.[27]

ii. EPA should accept INGAA's Directed Inspection and Maintenance Program since it provides a robust alternative to the proposed leak monitoring and repair program.

The vast majority of leaks from the T&S sector can be addressed by INGAA's DI&M program.[28] As recognized by EPA's Natural Gas STAR Lessons Learned document,[29] DI&M is an effective programmatic approach that focuses on large leaks. Further, EPA's GHG reporting program will provide the verification that methane leaks are being identified and repaired under DI&M.

The INGAA DI&M program provides the structure, program elements and procedures for development of a company-specific DI&M program that focuses on key leak sources within a facility that pose a higher probability of being "gross emitters" or "super emitters." These sources require measurement under EPA's Subpart W reporting program. They include reciprocating compressor rod packing, centrifugal compressor wet seal degassing vents, compressor blowdown valves, compressor isolation valves and scrubber dump valves.[30] The INGAA DI&M program also includes centrifugal compressor dry seals for completeness.

INGAA's DI&M program also includes adaptive management to refine facilities based on data collected, tracking of leaks, and repair of leaks, among others. Each of these components addresses programmatic requirements for a leak mitigation program analogous to program criteria included by EPA in the Proposed Rule. Specifically, INGAA's DI&M program provides for an annual survey (consistent with Subpart W) into the DI&M program. The program would

[27] "While we expect that the avoided emissions will result in improvements in ambient air quality and reductions in health effects associated with exposure to hazardous air pollutants (HAP), ozone, and particulate matter, we have determined that quantification of those benefits cannot be accomplished for this rule." Regulatory Impact Analysis of the Proposed Emission Standards for New and Modified Sources in the Oil and Natural Gas Sector, EPA-452-/R-15-002, August, 2015.

[28] INGAA's DI&M paper was provided to EPA in early 2015 and referenced as footnote 17 on page 17 of EPA's Natural Gas STAR Methane Challenge program. It is provided in Appendix C.

[29] "Directed Inspection and Maintenance at Compressor Stations." U.S. EPA Natural Gas STAR, Lessons Learned (see http://epa.gov/gasstar/documents/ll_dimcompstat.pdf), EPA430-B-03-008 (October 2003).

[30] There are six source types that must report for transmission compressor stations. Four of the six are leak sources- reciprocating compressors, centrifugal compressors, tanks and "other" leaks. Compressors and tanks require annual vent measurements. Other leaks require an annual leak detection survey. The other two sources- pneumatic controllers and blowdown- are vented emissions associated with station operations.

involve condition-based maintenance for rod packings and wet seals and annual leak surveys for the key compressor station components that have the greatest potential for emissions.

INGAA's DI&M program is supported by emissions data from the transmission segment reports submitted to EPA under Subpart W of the GHG Reporting Program (GHGRP).[31] Figure 1 illustrates data from EPA's website for the first three years of Subpart W reporting.[32] The vast majority of compressor station emissions are from reciprocating compressors, centrifugal compressors and tanks (*i.e.* scrubber dump valves) rather than component leaks. Two Subpart W emission sources—pneumatic devices and blowdowns—are not fugitive emissions. Compressor and storage tank emissions are associated with a select and limited number of components, while the proposed separately tabulated "leaks" category is the cumulative emissions from screening thousands of additional components throughout a facility. This "leaks" source category comprises a relatively small percentage of total leak emissions.

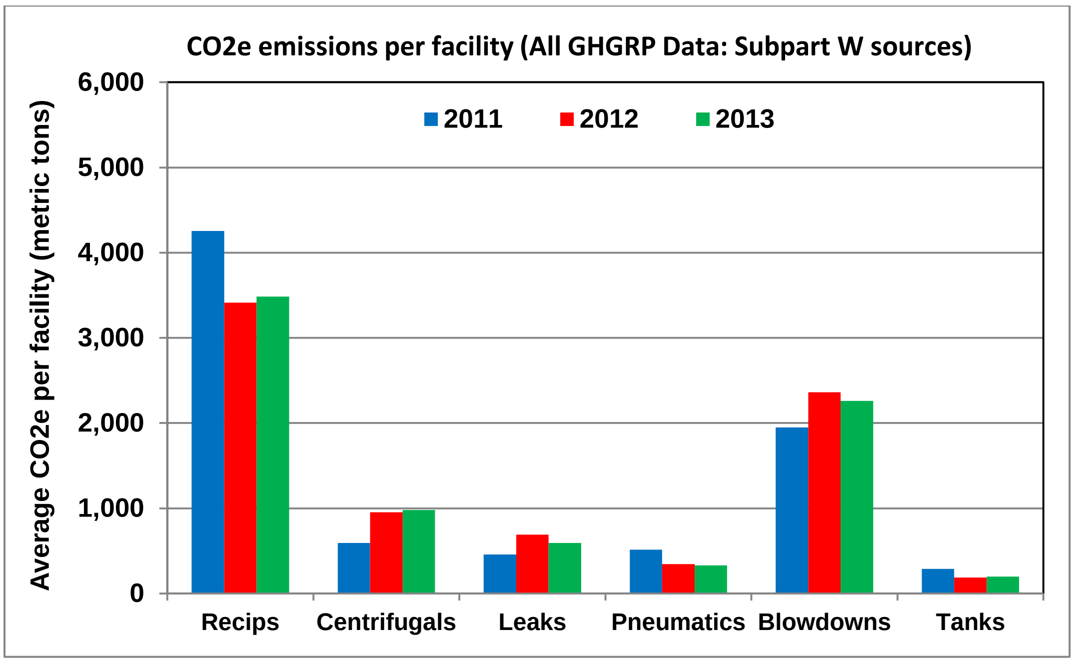

Figure 1. Transmission segment emissions by Subpart W source type (EPA data).

The INGAA DI&M program does not include this other equipment "leaks" category, since it requires surveying hundreds of additional components that account for only a relatively small portion of the total emissions from the four types of leak sources included in Subpart W.

INGAA's DI&M program is a preferred method since it is effective at reducing methane emissions by identifying and repairing leaks at compressor stations. It is a less burdensome, less

[31] 40 C.F.R. Part 98, Subpart W.
[32] Since the number of facilities increased from year to year, the emissions are presented on a per-facility basis. There are six source types that report for the transmission segment, and four of the six emission sources are associated with equipment leaks: reciprocating compressors, centrifugal compressors, (other) equipment leaks, and storage tanks (i.e., emissions are from leaking dump valves).

disruptive and less costly way of meeting EPA's objective of reducing methane emissions by identifying and repairing leaks at compressor stations, while considering the magnitude of leaks and practical matters that affect repair schedules. It can achieve similar reductions at lower costs by avoiding surveying thousands of pieces of components that it has been documented account for only a relatively small amount of the total emissions, and by avoiding repairs that are not cost effective to address (i.e., small leaks with high repair costs or practical operational matters affecting the repair schedule). INGAA's DI&M program would implement an annual inspection, maintenance and repair program, in which repairs were made consistent with safety and common sense timing. The affected facilities would identify and repair leaks based upon the severity of the leak in a manner that minimizes compressor station downtime.

INGAA recommends that EPA adopt INGAA's DI&M program, which focuses on identifying and repairing the largest leaks, rather than focusing on all leaks, including insignificant leaks.

iii. INGAA's DI&M program is more consistent with EPA's statutory requirements for establishing a work practice standard than LDAR.

In the case of fugitive methane emission components at compressor stations, EPA is acting under §111(h) of the Clean Air Act (CAA),[33] which provides authority to EPA to promulgate a particular work practice standard only if that standard reflects "the best technological system of continuous emission reduction which (taking into consideration the cost of achieving such emission reduction, and any non-air quality health and environmental impact and energy requirements) the Administrator determines has been adequately demonstrated)." section 111(h) also authorizes EPA to permit the use of an "alternative means of emission limitation" if EPA finds that it will achieve a reduction in emissions "at least equivalent to the reduction" achieved by the designated work practice.[34]

As explained in detail above, INGAA's DI&M program is a cost-effective and abundantly demonstrated technique that achieves substantial emission reductions in fugitive methane emissions at compressor stations. The LDAR program in the Proposed Rule, by contrast, imposes substantially higher costs and higher risks to "energy requirements" – with no meaningful gain in emissions mitigation. Therefore, if EPA appropriately fulfills its statutory obligation to "take into consideration" costs and impacts on energy requirements, it should eliminate LDAR in favor of DI&M. At a minimum, DI&M should be permitted as an "alternative means of emission limitation."

For these reasons, INGAA urges EPA either to: (1) determine that DI&M, not LDAR, is the work practice standard for fugitive methane emissions at compressor stations; or (2) permit the use of DI&M as an "alternative means of emission limitation" pursuant to CAA §111(h)(3).

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[33] CAA § 111(h) provides that, if in the judgment of the Administrator, it is not feasible to prescribe or enforce a standard of performance for a source category, he may instead promulgate a "design, equipment, work practice, or operational standard, or combination thereof" that meets the "best technological system of continuous emission reduction" test. For purposes of these comments, references to "work practice standard" also encompass design, equipment, or operational standards, or a combination thereof.

[34] CAA § 111(h)(3).

iv. EPA has not justified why a departure from annual leak detection surveys, consistent with Part 98, Subpart W reporting, is inadequate.

INGAA recommends that fugitive emissions program surveys be required annually, which is consistent with EPA's survey schedule for sources subject to Subpart W of the GHGRP. There is no indication that a more aggressive schedule provides any meaningful environmental benefit in regard to GHG impacts. Over time, EPA's GHGRP data will show whether associated emissions are reasonably stable or declining. In addition, the component count tracking adds an unnecessary burden that should be eliminated. If EPA retains the performance-based schedules in the final rule, INGAA recommends flexibility allowing operators to forgo component count tracking and implementation of the more rigorous reporting schedule.

D. EPA Should Not Require All Repairs within 15 Days or Should Provide for a Delay of Repair Given Potential Disruptions of Service Associated with Its Proposal.

EPA proposes to require that an operator repair or replace the source of leak emissions as soon as practicable, but no later than 15 calendar days after detection of the fugitive emissions.[35] The proposed rule requires that leaks, no matter how small, must be repaired within 15 days. The Proposed Rule provides a delay-of-repair provision, at proposed 40 C.F.R. § 60.5397a(j)(1), that is much more limited than the leak detection and repair programs prescribed by other EPA regulations. Specifically, EPA's proposed delay of repair provision states:

> Each identified source of fugitive emissions shall be repaired or replaced as soon as practicable, but no later than 15 calendar days after detection of the fugitive emissions. If the repair or replacement is technically infeasible or unsafe to repair during operation of the unit, the repair or replacement must be completed during the next scheduled shutdown or within 6 months, whichever is earlier.[36]

Therefore, EPA would require an operator to repair all leaks within 15 days unless the repair is "technically infeasible or unsafe to repair during operation of the unit." If one of these two conditions were met, EPA would require the operator to make all repairs within six months. EPA's proposal, however, does not provide operators with adequate relief for other justified delays of repair.

As described more fully below, EPA should provide for a more expansive delay-of-repair provision consistent with INGAA's DI&M program, which is modeled after other existing EPA regulations and state programs. EPA also should delete the proposed six-month limitation on the delay-of-repair provision in its Final Rule.

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[35] 80 Fed. Reg. at 56668 (proposed 40 C.F.R. § 60.5397a(j)(1)).
[36] *Id*.

i. EPA failed to explain why its leak repair requirements in its proposed rule do not provide for delay of repair consistent with its other programs.

In the Proposed Rule, EPA selected a 15-day repair period with insufficient delay-of-repair conditions for leak emissions. This is not consistent with the leak detection and repair programs prescribed by other EPA regulations such as Part 60, Subpart VV and Subpart VVa,[37] "Standards of Performance for Equipment Leaks of VOC in the Synthetic Organic Chemicals Manufacturing Industry for which Construction, Reconstruction, or Modification Commenced After January 5, 1981, and on or Before November 7, 2006." In addition, EPA's proposed delay-of-repair provision for leak emissions is inconsistent with the delay-of-repair provisions proposed by EPA in this rulemaking for closed-vent systems and storage vessels.[38]

Both Part 60, Subpart VV and VVa provide more reasonable criteria for delay of repair and more reasonable repair timelines. EPA has not explained why the delay-of-repair provision for identification and repair of methane emissions should be stricter than the provisions in other EPA regulations.

For example, Part 60, Subpart VVa at 40 C.F.R. § 60.482-9 provides that:

- "Delay of repair of equipment for which leaks have been detected will be allowed if repair within 15 days is technically infeasible without a process unit shutdown. Repair of this equipment shall occur before the end of the next process unit shutdown. Monitoring to verify repair must occur within 15 days after startup of the process unit." 40 C.F.R. § 60.482-9(a);
- Delay of repair for valves will be allowed if "The owner or operator demonstrates that emissions of purged material resulting from immediate repair are greater than the fugitive emissions likely to result from delay of repair." 40 C.F.R. § 60.482-9 (c)(1); and
- "Delay of repair beyond a process unit shutdown will be allowed for a valve, if valve assembly replacement is necessary during the process unit shutdown, valve assembly supplies have been depleted, and valve assembly supplies had been sufficiently stocked before the supplies were depleted. Delay of repair beyond the next process unit shutdown will not be allowed unless the next process unit shutdown occurs sooner than 6 months after the first process unit shutdown." 40 C.F.R. § 60.482-9 (e).

Part 60, Subpart VV provides identical delay of repair provisions.[39]

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[37] 40 C.F.R. Part 60, Subpart VV and VVa, "Standards of Performance for Equipment Leaks of VOC in the Synthetic Organic Chemicals Manufacturing Industry." *See e.g.,* 40 C.F.R. § 60.482-9a for delay of repair provisions.
[38] 80 Fed. Reg. at 56684-5 (proposed 40 C.F.R. § § 60.5416a(b)(10) and (c)(5).
[39] 40 C.F.R. § 60.482-9.

Therefore, unlike the delay-of-repair provision in this Proposed Rule, these other Part 60 provisions permit an operator to:

- Delay a repair beyond six months if the repair requires a shutdown and the next shutdown period will occur in more than six months (rather than a maximum delay of six months);
- Delay a repair if the operator demonstrates that purged (i.e., blowdown) emissions resulting from immediate repair exceed the fugitive emissions likely to result from the delay; and
- Delay a repair beyond the next shutdown if there are issues associated with the availability of valves or valve assemblies.

In addition, EPA does not explain why its delay-of-repair provision for fugitive emissions at a compressor station is more stringent than the proposed delay=of=repair provisions for the treatment of closed-vent systems. In proposed 40 C.F.R. § 60.5416a(b)(10),[40] EPA provides that:

> Delay of repair of a closed vent system or cover for which leaks or defects have been detected is allowed if the repair is technically infeasible without a shutdown, or if you determine that emissions resulting from immediate repair would be greater than the fugitive emissions likely to result from delay of repair. You must complete repair of such equipment by the end of the next shutdown.

Further, state regulatory programs also provide more reasonable criteria for delay of repair. For example, Colorado's LDAR rule for oil and gas operations includes delay-of -repair provisions. The Colorado rule provides that:

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

The Colorado regulation does not provide an explicitly defined or list of "good cause" criteria. Yet, "good cause" delay could include, based on practical experience, the need for a specialized technical skillset to complete the repair when scheduling requires more than 15 days, warranty issues that require more than 15 days to address parts replacement, and safety or accessibility issues that warrant waiting for a shutdown based on operator judgment.

The delay-of-repair provision in INGAA's DI&M program is modeled after delay-of-repair provisions in Part 60, Subpart VV and Subpart VVa and Colorado's regulatory program. Therefore, INGAA advocates that EPA revise proposed 40 C.F.R. § 60.539a(j)(1) to adopt the following delay-of-repair provisions from INGAA's DI&M program:

[40] 80 Fed. Reg. at 56684 (proposed 40 C.F.R. § 60.5416a(b)(10)).

EPA should permit an operator to delay repairs beyond the 15-day deadline, if an operator can satisfy and document one of the following conditions:

1. Repair Requires Unit /Station Shutdown – If the repair of any component is technically infeasible without a process unit shut down or if the source cannot be repaired during operation of the source.
2. Equipment Isolated From Process – If the repair is unnecessary because the equipment is isolated from the process (i.e., the component/equipment is taken out of gas service, and repair is completed before a return to service).
3. Valves Where Purged Gas Would Exceed Leaking Gas – If immediate repair of the equipment would result in vented emissions (from equipment purge) greater than the emissions resulting from delay.
4. Valves Where Leakage Would Be Controlled – If leaked gas is collected and destroyed, recovered in a control device, or used for some other beneficial purpose.
5. Repair Is Unsafe, Inaccessible, or Difficult to Monitor – If a repair cannot be made due to safety issues.
6. Equipment Must Be Ordered for Repair – If additional time is needed to procure equipment or components necessary to complete the repair, the repair timing will be based on equipment delivery dates that may depend upon manufacturer stock and shipment schedules.[41]
7. Specialized Skill Set Must Be Scheduled – If the repair requires a specialized technical skillset, the repair timing will be based on personnel scheduling.

EPA has not explained why this proposed rule requires a 15-day leak repair period with a limited six-month delay of repair condition only when the repair "technically infeasible or unsafe to repair during operation of the unit," when its other regulatory programs permit delay of repair in other, more numerous circumstances. INGAA believes that this provision is arbitrary and should be modified, as described above.

At a minimum, EPA should revise proposed 40 C.F.R. § 60.5397a (j)(1) to adopt the same delay-of-repair provisions in Part 60, Subpart VVa or, if not, explain its departure.

In all cases, the operator would address repairs as soon as practical. For example:

- If a repair requires a shutdown or if a repair is delayed due to emissions from purged gas exceeding the emissions that result from the leak, the operator would complete the repair the next time the unit or process is shut down and/or purged;
- For parts such as large valves with extended delivery times, the operator would complete the repair within 15 days of delivery or upon the next shutdown after delivery if a unit or process shutdown is required to complete the repair; and
- For repairs that require a specialized skill set, the operator would complete the repair planning within 15 days, and schedule and complete the repair as soon as feasible.

[41] Once an operator has the part, an operator will conduct the repair in 15 days if the repair does not require a shutdown. If the repair requires a shutdown, the operator will conduct the repair at next process unit shutdown.

ii. The 15-day repair requirement is unreasonable since most compressor station replacement parts are not available in 15 days.

EPA's proposal to require repairs within 15 days, without reasonable delay-of-repair provisions, is unworkable. T&S pipeline companies operate dozens of different models of reciprocating and centrifugal compressors with different vintages and manufactured by different vendors. Availability of replacement parts could be challenging especially for existing facilities that become subject to EPA's proposed modification provisions. Each compressor station, regardless of vintage, type or model, has thousands of components and equipment parts.[42] Operators do not warehouse all of the many replacement component parts – including a variety of valves, flanges and the many other components listed in the Proposed Rule. It is impractical to maintain such a large spare parts inventory. Due to the wide variety of compression equipment and compressor station piping, manufacturers do not stock all possible replacement equipment. Other than the most essential parts, ordering and obtaining those replacement parts from the manufacturer or other vendor becomes the critical path for completing repairs. This usually takes significantly longer than 15 days. Thus, delay of repair due to parts availability and delivery schedule is reasonable, and is a common delay of repair provisions in EPA and state LDAR programs.

Especially for existing compressor stations that trigger "modification," there often are waiting periods because replacement parts for older compressors cannot be acquired "off the shelf" and in many cases must be specifically manufactured on a special-order basis. For example, to replace a component, such as a crank shaft,[43] on a vintage reciprocating compressor would require the component to be removed from service and shipped to the manufacturer. The manufacturer then would make a mold of the component and re-cast a new piece. The process to remove, ship and re-cast a new component may take six months or longer. For additional examples, see Appendix D.

Moreover, EPA's six-month extension[44] – for repairs that require a pipeline operator to shut down a compressor station – does not apply to an operator that cannot receive replacement parts within 15 days. Even if EPA had proposed to include the unavailability of parts in its six-month extension, the six-month time period would be insufficient in all cases. The repair of an individual compressor unit or its associated piping components may limit the capacity of the compressor station even if the entire station does not shut down. Compressor stations normally have multiple compressor units. An individual compressor unit and its associated piping can be shut down to conduct a repair while the other compressor units at the station remain in operation. However, if the leak repair is within the overall compressor station piping, then a shutdown of the entire compressor station would be required. Both of these repair scenarios could potentially impact customer deliveries if EPA imposes a six-month time limit rather than relying on the next unit, process or station shutdown – whichever is necessary to complete a particular repair.

[42] See EPA's Background Technical Support Document for the Proposed New Source Performance Standards, 40 C.F.R. Part 60, Subpart OOOOa, August 2015, Table 5-11, page 61.
[43] A crank shaft is a mechanical part able to perform a conversion between reciprocating motion and rotational motion.
[44] 80 Fed. Reg. at 56668 (proposed 40 C.F.R. § 60.5397a(j)(1)).

Further, if all operators must adhere to the 15-day repair schedule, the interstate pipeline industry may not have a sufficient work force to comply with this timeline. Personnel capable of working on compressors and compressor station piping must meet the Pipeline and Hazardous Materials Safety Administration's (PHMSA) operator qualification requirements.[45] While companies currently have sufficient qualified personnel to conduct normal operations and repairs, the proposed Subpart OOOOa leak detection and repair requirements may significantly increase the number of qualified operators and maintenance personnel required to conduct leak surveys and repairs. Furthermore, the pipeline industry will be competing for qualified personnel to make necessary repairs at the same time it is implementing pipeline safety integrity management work pursuant to current and likely more rigorous upcoming regulations under the Pipeline Safety Act. The pipeline industry also is competing for personnel with the rest of the natural gas value chain – producers and local gas utilities – to comply with EPA's regulations and with the oil pipeline industry, which is performing its own pipeline safety work.

Therefore, EPA should modify its proposed rule to provide delay-of-repair provisions, as discussed above, consistent with INGAA's DI&M program.

iii. EPA failed to consider the adverse effects of the proposed rule.

EPA failed to consider the 15-day repair requirement's environmental and operational consequences, including the emissions that would occur to repair a leak and the service disruptions to customers while a piece of equipment is out of service for repair.

a. The proposed rule's 15-day repair requirement would result in unnecessary blowdowns and methane emissions releases.

EPA's proposal to require an operator to repair leaks within 15 days is unreasonable because, in many cases, it would necessitate releases of methane larger than what would have occurred without the rule. EPA's 15-day repair requirement will require operators, in many situations, to conduct a blowdown to vacate gas from the equipment or station piping before repairing or replacing leaking equipment or component(s) at a compressor station. One way to explain blowdowns is to use the water pipe inside a home as an example. A blowdown event at a pipeline connected to a compressor station would be similar to closing the main water valve to a home and then opening a faucet to allow all of the water to drain from the pipe before repairing a broken or cracked water pipe.

The amount of gas blowdown will vary, but, in many cases, it could be much greater than the methane emissions that would result from delaying the leak repair. If a significant blowdown event were required to complete a repair, it may be more environmentally beneficial to complete the repair at the next scheduled shutdown. EPA should allow operators flexibility to make reasonable judgments on whether to delay repair of a leak to minimize methane emissions.

For example, a leak can occur in a compressor unit's piping (valves, flanges, etc.) that would require the compressor unit to be shut down and the associated piping (from upstream isolation valve to downstream isolation valve) to be blown down resulting in greater emissions than what

[45] 49 C.F.R. Part 192, Subpart N.

would be emitted by the leaking components if the repair were delayed. Furthermore, if the leaking component(s) were part of the overall compressor station piping, then the entire contents of the compressor station piping would need to be blown down to conduct the repair. Once again, greater emissions would result from the blowdown than what was being leaked.

If an operator could delay the leak repair, it would have a greater opportunity to minimize, or possibly eliminate, the amount of additional methane gas it would need to blowdown. Typically, this would result in an operator completing the repair the next time the unit or process is blown down for other operational reasons. For example, an operator could make repairs during a month or season that the compressor is not operating due to lower flow volumes on the pipeline. Another option could be for a pipeline customer to draw down gas from the pipeline slowly to reduce the volume of gas in the pipe at or near the compressor or for the customer to move the gas into storage.[46] However, these options are case specific and each situation would need to be evaluated for feasibility. A 15-day repair deadline would not provide the operator with the flexibility to work with its customers (often referred to as shippers) to minimize releases. INGAA also notes that the re-routing of methane gas is not always possible to avoid blowdown because many older compressor stations and their pipelines are not designed to re-route natural gas.

In addition, not all leaks are significant, particularly if the leaks release *de minimis* amounts of methane to the atmosphere. In fact, EPA recognizes that some level of methane release is acceptable to accommodate necessary equipment operations. It is well reasoned for an operator to delay repairing a *de minimis* leak if the volume of methane emitted in the process of repairing the leak exceeds the methane emissions likely to result from the delay. EPA should allow operators the discretion to decide whether more methane emissions would result from conducting a blowdown in order to make a repair within 15 days (versus the volume of methane emitted should the leak not be repaired). In such cases, operators would continue to monitor a leak and the need to make repairs, and most commonly repair the leak when the unit or process is next blown down for other operational purposes.

Specifically, EPA should revise its proposal to permit an operator to delay a repair if it demonstrates that emissions resulting from the immediate repair (e.g., blowdown) exceed the fugitive emissions likely from the delay. The repair would be scheduled to be completed during the next unit, process or station shutdown, depending on what level of shutdown and blow down is needed to address the repair.

b. The proposed rule could result in service disruptions to pipeline customers.

There is no question that a pipeline operator may need to shut down an entire compressor station or a compressor unit to perform larger repairs. If, for example, a pipeline operator must replace a valve that is used to isolate the compressor station from the mainline, it typically would take the compressor station out of service for six days once the pipeline had obtained the replacement part(s) from the manufacturer/vendor. By contrast, if a pipeline operator must replace a smaller, eight-inch valve connected only to a compressor unit, the pipeline operator would need to take the compressor station out of service for three to four days. These estimates, however, assume that all compressor station equipment parts are readily available from the manufacturer and can be timely shipped to the location, which, as discussed above, may not be the case. The compressor station would be out of service for the full timeframe required to order and obtain the part(s) and to conduct the repair or replacement, or risk being out of compliance with Subpart OOOOa in order to continue operations to meet critical demand. In many cases, this total timeframe could significantly exceed 15 days.

During the time the compressor station is out of service, the pipeline will need to reduce maximum capacity on it system. Depending on its customers' demand for gas, a pipeline operator may need to restrict transportation service through affected segments of its system while the compressor station is out of service.

If a pipeline identifies a leak in January, during peak natural gas usage, and must make repairs within 15 days, then, under EPA's proposed rule, that pipeline operator would risk service disruptions and thereby impair reliability in order to repair even the most *de minimis* leaks. A similar case could occur during high cooling day demand periods when electric generators use natural gas as a fuel. The arbitrary 15-day repair requirement limits the ability of the pipeline operator to make important operational decisions to maintain the delivery of natural gas to its customers.

Moreover, a transportation reduction on one pipeline could affect other pipelines in the transportation delivery path. Natural gas is often transported across several pipelines, from a producing region to the ultimate customers. If one pipeline in the path is experiencing service disruptions due to the inability to plan and prioritize repairs, there could be service disruptions affecting larger areas and more gas customers along the entire gas delivery chain. It is possible that these larger service disruptions could affect industrial customers, including factories that have two or three manufacturing processes or continuous manufacturing over a 24-hour basis (such as chemical and refining industries). Additionally, some service disruptions might affect electric power generation, which will, under the Clean Power Plan (CPP) and separate state regulations, increasingly be using natural gas over coal-fired generation from 2016-2030. Hospitals, data management centers and other industrial manufacturing customers require reliable natural gas delivery through the interstate pipeline industry just as the electric power sector will require reliable natural gas delivery.

EPA's failure to acknowledge likely service disruptions caused by its 15-day repair requirement, without adequate delay-of-repair provisions as described above, is not reasoned decision making and fails to recognize the true costs of this rule.

In establishing the Best System of Emission Reductions (BSER) under the CAA, EPA can take into account non-air and energy issues and other factors. There are obvious and important implications on energy infrastructure and availability that EPA has not considered. INGAA believes that EPA should consider the feasibility, cost-effectiveness, non-air issues, and other issues when considering delay-of-repair provisions that should be included in the rule.

E. EPA's Cost-Benefit Analysis Is Flawed and Incomplete.

EPA's technical support document (TSD) includes EPA's estimates of control costs and cost effectiveness, including costs for proposed LDAR requirements to control fugitive methane and VOC emissions from T&S compressor stations. INGAA believes that EPA overestimated uncontrolled model plant emissions and fugitive emissions reductions, and underestimated the costs for LDAR implementation. INGAA recommends a complete review and revision of the analysis, and asks that EPA consider more current emission estimates, including information available from the GHGRP.

i. EPA overestimated uncontrolled model plant emissions.

EPA's estimate of model plant methane and volatile organic compound (VOC) fugitive emissions are based on component counts and emission factors from the 1996 EPA/GRI study. Therefore, these emission factors are based on data collected only at pre-1996 T&S facilities and do not represent a new T&S facility. Further, the leak rates most likely over-estimate emissions from current existing facilities that have adopted leak monitoring practices over the past 20 years.

It is likely that EPA could improve emission estimates for existing model plants using leak data recently collected for Subpart W of the GHGRP. Initial review of that data indicates current emission estimates from existing facilities are lower than EPA's model plant (based on 20 year-old data). Emissions would be even lower for a "new" model plant compared to existing facilities.

ii. EPA underestimated the number of annually impacted T&S compressor stations.

EPA's projected number of transmission and storage stations and associated compressor units that would become subject to the Proposed Rule is significantly underestimated, which greatly undermines EPA's costs analysis. EPA estimated that the average number of new transmission compressor stations and new storage stations through 2020 to be six and fifteen, respectively. EPA estimated that those numbers would increase to 36 transmission and 90 storage stations by 2025. EPA's estimates were based on estimated number of facilities in the GHG Inventory for the years 1990 to 2012 and determining the rate of change in the number of these facilities over this period. INGAA's member companies operate approximately 1,000 transmission compressor stations of which only less than 300 are storage stations. Based on national transmission and storage compressor station totals, it is unrealistic to expect that the number of new storage stations would more than double the number of new and modified transmission stations annually. Moreover, the most common method for expanding pipeline system operations is to install one or more new compressor unit at an existing compressor station rather than installing new compressor stations. The installation costs to expand an existing compressor station are significantly less expensive than installing new compressor stations. EPA failed to include an estimate for the number of and associated implementation costs for existing facilities that would become subject to the Proposed Rule due to modifications at existing compressor stations.

iii. EPA overestimated fugitive emissions reductions by citing a flawed Colorado study.

To estimate fugitive emission reductions as a function of LDAR monitoring frequency, EPA references a Colorado Air Quality Control Commission (CAQCC) Economic Impact Analysis. [47] There are two fundamental problems with EPA's reliance on the CAQCC analysis. First, sources relied upon by the CAQCC are undocumented. CAQCC references data having been obtained from EPA, but provides no documentation regarding the actual source of the data on which it relies. Second, while EPA references the CAQCC analysis as its support, it then without explanation a different and significantly more optimistic reduction factor for the increase in the emissions reduction achieved by increasing the frequency of the survey. Table 1 below compares the CAQCC analysis and the EPA reductions:

Table 1.

Colorado Air Quality Control Comission (CAQCC)		EPA Propoesed Rule	
Percent Reduction	Survey Frequency	Percent Reduction	Survey Frequency
40	annual	60	semi annual
60	quarterly	80	quarterly
80	monthly	-	-

INGAA strongly believes that survey frequency has a much smaller impact on performance than undocumented EPA source utilized by CAQCC. The credibility of EPA's estimate of how the frequency of surveys affects emissions reductions is seriously undermined by both the lack of well documented source data and the lack of explanation for the choice of even more optimistic estimates for how the frequency of surveys will affect emission reductions.

INGAA recommends that EPA should rely on a credible and well-documented study that assesses changes in LDAR effectiveness for different survey frequencies.

iv. EPA drastically underestimated LDAR implementation costs and INGAA finds them unrealistic.

EPA's approach to estimating LDAR costs included: (1) developing uncontrolled emissions estimates for a model transmission "plant" (i.e., compressor station) and a model storage plant; (2) developing nationwide uncontrolled emissions estimates based on the model plant emissions estimates and estimated numbers of new T&S compressor stations; (3) developing nationwide annual emissions control/reduction estimates for different LDAR monitoring frequencies (e.g., annual, semiannual, and quarterly); (4) developing annual control cost estimates for different LDAR monitoring frequencies; and (5) calculating estimated cost of control as dollars per ton of methane or VOC emissions reductions ($/ton).

[47] EPA's Technical Support Document at 70.

INGAA asserts that EPA's LDAR implementation/compliance cost estimates are consistently well below practical estimates of actual costs. Select examples of this unrealistic calculation include:

- Labor cost for each of the monitoring plan elements, such as reading the rule, were estimated to be $57.80 per hour[48]. This rate is well below an average burdened cost for an Environmental Engineer or Manager. Assuming a conservative average annual salary for an environmental engineer of $100,000 plus a benefits rate of 50 percent ($150,000 total annual costs), the total hourly rate would be $72.11, not $57.80.

- EPA asserts that the reading of the rule and instructions is estimated to require one person four hours to complete. This estimate is an order of magnitude below the level of effort required to read and fully understand a new rule. Further, it is likely that more than one person at a company needs to understand the rule requirements. For example, EPA includes 2.5 people to develop a monitoring plan.

- EPA asserts that development of a fugitive emission monitoring plan was estimated to require 2.5 people a total of 60 hours to complete at a cost of $3,468. This EPA estimate fails to consider that each facility must develop a method to track every fugitive emissions component at the facility. This could include component counts for the facility, and permanent tagging of all components or attaching a unique tag to each leaking component to comply with the § 60.5397a(k)(6) recordkeeping requirement. In order to develop a monitoring plan including the "walk through path" for each compressor station, it is likely that personnel would need to travel to each station to develop a monitoring plan meeting the OOOOa level of detail requirements. The actual level of effort would be significantly (perhaps, an order of magnitude) greater than EPA's estimate.

- EPA assumes that the cost to conduct leak surveys for thousands of components at each compressor station using OGI cameras would be $2,300. Based on INGAA member companies experience with conducting Subpart W surveys using OGI cameras, the contractor costs ranged from $5,000 to $10,000 per compressor station.

- Notification of compliance status was estimated to take one person one hour to complete for T&S facilities. Preparation of this compliance status report requires collection and verification of all leak detection and repair data to determine compliance. The level of effort could be days, not a single hour.

- EPA's estimated cost of a Method 21 monitoring device for repair verification is $10,800. EPA's analysis appears to be based solely on the use of Method 21 measurement devices. However, the proposed OOOOa leak survey requirement is through use of OGI cameras. OGI cameras cost (typically in the range of $85,000 to

[48] Technical Support Document, page 69.

$95,000) significantly more than Method 21 portable analyzers. EPA did not include the cost of OGI cameras in its cost estimates. EPA's analysis also appears to assume this single Method 21 device will be used company-wide by numerous T&S stations and does not consider the practical aspects (and cost) of shipping a single Method 21 portable analyzer to verify every repair within a 15-day period, let alone shipping costs for OGI cameras that could also be used to confirm leak repairs. Practical implementation of leak repair verification requirements would require a Method 21 portable analyzer for most, if not all, T&S stations. Associated costs, such as portable analyzer calibration gases, are not considered.

- EPA estimates the cost to re-survey the repaired components using a Method 21 portable analyzer that could not be fixed during the initial survey based on $2.00 per component. EPA's estimate is not explained or supported, and it illustrates a lack of understanding of resurvey implementation. Assuming a labor rate of $30 per hour for maintenance repair, EPA assumes that each repaired component survey can be completely conducted in four minutes. A Method 21 survey requires the tester to locate the Method 21 portable analyzer, conduct calibration and zero checks, locate each repaired component (and possibly travel to the facility), measure and record the hydrocarbon concentration, return travel, and document and submit results. Even if multiple repaired components are covered during a single survey, four minutes per component is a significant under-estimation, and does not consider components that fail the resurvey and must be repaired (and resurveyed) multiple times.

- Section 5.4.2 of the TSD, "Cost Impacts" for "Fugitive Emissions Detection and Correction with OGI," assumes 1.18 percent of compressor station components leak. However, section 5.4.3 of the TSD, "Cost Impacts" for "Fugitive Emissions Detection and Correction with EPA Method 21," assumes a compressor station leak percentage of 7.49 at a leak definition of 10,000 ppm. If the OGI has a detection limit of 10,000 ppm as indicated in the TSD:

> The OGI instrument that is used to conduct monitoring surveys must be capable of imaging gas that is half methane and half propane at a concentration of 10,000 ppm at a flow rate of ≥ 60 g/hr from a quarter inch diameter orifice. These criteria are based on the EPA's recent work with OGI systems indicating that fugitive emissions at a concentration of at least 10,000 ppm are generally detectible using OGI with proper monitoring and operating practices.[49]

- Then, the OGI and Method 21 leak percentages (at 10,000 ppm) would be expected to be similar. EPA does not explain why the two estimated leak percentages differ by a factor of six. Further, EPA estimates a leak percentage of 12.25 for a leak definition of 2,500 ppm and a leak percentage of 13.53 for a leak definition of 500 ppm. INGAA questions whether EPA believes that 13.5 percent of the components at a new T&S facility (one out of every seven) are actually leaking at a rate greater than the repaired component leak

[49] Technical Support Document, page 69.

concentration limit of 500 ppm. Clearly, EPA's cost-effectiveness analyses are confused and flawed, and should not be the basis for regulatory development.

- Table 2 presents data from the TSD that estimates annual methane emission reductions for different Method 21 portable analyzer monitoring frequencies and leak definitions for transmission stations. The data shows lower annual methane emission reductions for more frequent Method 21 portable analyzer monitoring, and are either flawed or should be fully explained. (See next page).

Table 2. Technical Support Document Model Plant Annual CH_4 Emissions Reductions based on Method 21 Monitoring at Transmission Stations

TSD Data Source	M21 Monitoring Frequency	Leak Definition (ppm)	Annual CH4 Reductions (tpy)
Table 5-22	Annual	10,000	51.1
Table 5-23	Semi-annual	10,000	44.9
Table 5-24	Quarterly	10,000	41.8
Table 5-22	Annual	2,500	58.6
Table 5-23	Semi-annual	2,500	57.4
Table 5-24	Quarterly	2,500	55.5
Table 5-22	Annual	500	61.1
Table 5-23	Semi-annual	500	60.5
Table 5-24	Quarterly	500	58.6

v. EPA failed to consider secondary impacts of the monitoring and repair of fugitive emissions leaks.

Section 5.4.2.4 of the TSD, "Secondary Impacts" states:

> No secondary gaseous pollutant emissions or wastewater are generated during the monitoring and repair of fugitive emissions components. There are some emissions that would be generated by the IR camera monitoring contractors with respect to driving to and from the site for the fugitive emissions survey however, these emissions cannot be quantified because there is no data related to the distance that would need to be traveled to the site. However, it is believed that the secondary impacts expected from the implementation of an OGI monitoring program would be minimal.

This statement fails to consider two very important issues. First, the repair of pressurized leaking components often requires depressurizing equipment and/or piping and the venting of gas. This is especially true for the Proposed Rule because EPA fails to include blowdown-related delay-of-repair discretion found in other LDAR regulations. The rule should consider the volume of gas that would be released to make a repair relative to the fugitive emissions when prescribing repair requirements. For example, the rule should allow delay of repair until the next shutdown if the volume of gas released to make the repair would exceed the estimated fugitive emissions. (See discussion at Section D.)

Second, transmission stations are generally located about every 50 to 80 miles along a pipeline. This distance could be used to estimate the distance traveled to and from a site by IR camera monitoring contractors and the associated emissions. Since the proposed LDAR program includes OGI technology and repair of all leaks visualized, there will be scenarios where the leak repair will result in an inconsequential emission reduction and "secondary" emissions from transportation will eliminate the benefit.

EPA should revisit LDAR implementation cost analyses using more current data and well-documented assumptions. This improved analysis should include PHMSA's existing leak regulations. Further, EPA's cost analysis should consider all of the additional costs addressed in INGAA's comments. Component repair costs at compressor stations can range from $200,000-$2.3 million when considering construction costs. There could be an additional $2.5 million in customer impact costs if the station was unable to provide natural gas to their customers.

vi. EPA has overstated the benefits of the proposed rule by ignoring the number of blowdowns that will need to occur to fix a leak.

EPA's calculation of the anticipated benefits of the Proposed Rule fails to factor in the mechanics of fixing a leak.[50] Operators will have to conduct blowdowns in order to fix numerous leaks at any given compressor station along the pipeline system. EPA states that it anticipates the Proposed Rule will result in a savings of 180,000 tons of methane in calendar year 2020.[51] However, in order to fix leaks, pipeline operators have to blow down the station piping to conduct the necessary repair work. Prior to producing a net benefit calculation, EPA needs to factor in the additional releases of methane that will be required in order to address leak repairs.

INGAA offers four schematics in Appendix D that will help EPA understand the variation of impacts at a compressor station resulting from out of service events. Each schematic offers a different compressor station segment outage and the respective equipment involved. Further, the schematics offer explanations on time, costs and permitting requirements.

vii. EPA failed to consider the cost of service disruptions and cost of pipeline reimbursements for outages.

EPA failed to consider fully the costs associated with a pipeline operator's obligation to refund customers' monthly firm reservation (demand charge) credits during periods a pipeline must reduce service to conduct compressor repairs. When there is an interruption of service on a pipeline and the shipper cannot use the capacity, it reserved through the reservation charge. Pipelines are required to provide shippers credits against their reservation charges.[52]

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[50] EPA-HQ-OAR-2010-0505-5258 at 4-4.
[51] *Id.*
[52] Natural gas shippers pay two fees for firm transportation service on an interstate natural gas pipeline. One is the "reservation charge," based on the amount of pipeline capacity reserved by the shipper, regardless of how much of that capacity that shipper actually uses. The second is a "usage charge," based on the actual volume of gas that the shipper transports on the pipeline. When there is an interruption of service on a pipeline, and the firm shipper cannot use the capacity it reserved through the reservation charge, the Commission requires pipelines to provide shippers credits against their reservation charges. *See Natural Gas Supply Association et al.*, Order on Petition, 135 FERC 61,055 (2011).

Since EPA's Proposed Rule would require a pipeline operator to complete leak repairs within 15 days and shut down every six months, regardless of the time of year or gas load, a pipeline operator may be forced to reduce firm transportation service, reducing pipeline reliability during high demand periods, in order to conduct the repair within the arbitrary repair timeline. This reduction in service carries significant costs to the pipeline operator. In one case, an INGAA member needed to reimburse customers $2.5 million in associated demand charge credits for a six-day outage/reduction in firm transportation service.

There also are added costs to pipeline customers and ultimately consumers associated with the cost of the gas that is removed (or vacated) from the pipe and the cost of new gas that must be purchased to replace the blown down gas.

viii. EPA should not include a social cost of methane in its cost-benefits analysis.

INGAA endorses the comments provided by NERA's economic consulting's analysis[53] as to how EPA has estimated Social Cost of Methane. EPA has counted the global benefits to climate change mitigation through methane reduction while counting only the U.S. T&S sector costs. Further, EPA's estimates of net benefits lack appropriate peer review that is necessary for use in supporting regulatory policy.[54] INGAA urges EPA to take these matters into consideration when setting the final NSPS rule regarding cost-effective reductions. As proposed, INGAA does not believe that EPA's NSPS is cost-effective, and it feels that the Proposed Rule exaggerates the benefits while significantly minimizing the costs to the T&S sector.

ix. EPA did not predict the costs if "modification" is triggered on existing compressor or compressor stations.

While INGAA cannot predict the precise number of existing compressor stations that could trigger "modification," it believes that the cost range could vary between $100,000 and $1 million dollars per affected existing compressor station. EPA did not include cost estimates for existing sources that might trigger modifications.

F. EPA Failed to Make a Separate Endangerment Finding Necessary to Include T&S Segment as a Source Category.

Section 111(b)(1)(A) of the CAA requires EPA to make a new endangerment finding for each new source category in order to establish standards of performance for the new source(s).[55] INGAA does not believe that EPA can appropriately add the downstream T&S sectors as a source category without the requisite endangerment finding. That endangerment

[53] "Technical Comments on the Social Cost of Methane as Used in the Regulatory Impact Analysis of the Proposed Emissions Standards for New and Modified Sources in the Oil and Natural Gas Sector;" Prepared for American Council for Capital Formation, Nov. 27, 2015. http://accf.org/wp-content/uploads/2015/12/NERA_TechnicalComments_ProposedMethaneRegs_FINAL.pdf
[54] EPA Regulatory Impact Analysis (RIA), Section IIV.
[55] *See* 42 U.S.C. § 7411(b)(1)(A).

finding would also mean explaining why addressing all of the compressor station equipment leaks (including component parts totaling perhaps 1,000 per compressor station) is warranted. INGAA does not believe that EPA can make that finding based upon relative contributions from those component parts, equipment and those much smaller leaks.

INGAA expresses concerns regarding EPA's addition of the downstream T&S sector as a part of EPA's 1979 source category of "crude oil and natural gas production," without a substantiated endangerment finding. INGAA respectfully disagrees with EPA, and believes that the T&S sectors are not included in the "crude oil and natural gas production" category. Accordingly, INGAA requests that EPA conduct an endangerment finding for the T&S sectors pursuant to section 111(b)(1)(A) of the CAA, prior to promulgating any NSPS regulations regarding the same.[56]

In the Proposed NSPS OOOOa Rule, EPA summarizes the statutory and regulatory history supporting its proposal. In relevant part, EPA published a list of source categories in 1979, which included "crude oil and natural gas production" ("Priority List").[57] In this 1979 Priority List, EPA determined that "crude oil and natural gas production" was a source category which may reasonably be anticipated to endanger public health or welfare. EPA was then able to promulgate standards of performance for "crude oil and natural gas production" pursuant to section 111(b) of the CAA.[58] Thus, in 1985 and 2012, EPA promulgated NSPS KKK, LLL, and OOOO, respectively, addressing VOC emissions from leaking components at onshore natural gas processing plants; sulfur dioxide emissions from natural gas processing plants; and VOC standards for equipment leaks at onshore natural gas processing plants, as well as at several oil and natural gas-related operations not covered by subpart KKK, including gas well completions, centrifugal and reciprocating compressors, natural gas-operated pneumatic controllers, and storage vessels.[59]

In this rulemaking, EPA broadly interprets the 1979 Priority List to cover the entire natural gas industry.[60] To support this position, EPA states:

> For example, the priority list analysis indicated that the EPA evaluated emissions beyond the natural gas production segment to include emissions from natural gas processing plants. The analysis also showed that the EPA evaluated equipment, such as stationary pipeline compressor engines, that are used in various segments of the natural gas industry.[61]

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[56] This issue was raised by another energy sector entity in 2010. API comments submitted to Docket ID Number EPA–HQ–OAR–2010–0505 on Nov. 11, 2011.
[57] *See* 44 Fed. Reg. 49222 (Aug. 21, 1979).
[58] *See* 44 Fed. Reg. at 49223.
[59] *See* 50 Fed. Reg. at 26,122 (June 24, 1985); 50 Fed. Reg. 40,158 (Oct. 1, 1985); 77 Fed. Reg. 49,490 (Aug. 16, 2015). Later, in 2013 and 2014, EPA amended NSPS OOOO. 78 Fed. Reg. 58,416 (Sept. 23, 2013); 79 Fed. Reg. 79,018 (Dec. 31, 2014).
[60] *See* 80 Fed. Reg. at 56600.
[61] *Id.*

EPA's stated rationale finds no support in the 1979 Priority List, the proposed rulemaking preceding the 1979 Priority List, the background document to the 1979 Priority List, or in any subsequent EPA rulemakings.

First, beyond listing "crude oil and natural gas production" as a source category, EPA did not discuss (in its mere five page publication) any segment "beyond the natural gas production segment," nor does the analysis show that "EPA evaluated equipment," such as stationary pipeline compressor engines.[62] In fact, neither the 1979 Priority List final rule, the 1979 Priority List proposed rule, nor the background document filed in support of the 1979 Priority List provide any explanation or support for EPA's interpretation.[63]

In addition, EPA's original listing intended to regulate two discrete categories of sources: first, large stationary sources (such as plants), and second, sources that typically emit at least 100 tons per year of a regulated pollutant.[64] The natural gas T&S sectors satisfy neither of these criteria, and could not reasonably have been considered a major-emitting plant at the time of the 1979 Priority Listing. Thus, it could not have been EPA's original intent in 1979 to include the T&S sectors in the category source "crude oil and natural gas production."

In fact, the background document filed in support of the 1979 Priority List buttresses this conclusion. In that document, EPA's only mention of the natural gas industry outside of the precise phrase "crude oil and natural gas production" occurs when it adds the word "plants" to the source listing, labeling the source category as "crude oil and natural gas production plants."[65] The inclusion of the word "plants" is a telling sign that EPA's original intent may have contemplated the regulation of natural gas processing plants—the closest thing to a major-emitting plant found in the natural gas sector.

Second, EPA's 1984 rulemaking does not support EPA's current position to include the T&S sector as a source listing. In fact, the 1984 rulemaking made clear that natural gas processing plants were the actual target of the "crude oil and natural gas production" source listing. The 1984 rule defined the source category, stating that "the crude oil and natural gas production industry encompasses the operations of exploring for crude oil and natural gas products, drilling for these products, removing them from beneath the earth's surface, and processing these products from oil and gas fields for distribution to petroleum refineries and gas pipelines."[66] EPA's definition focuses on extraction and production; it says nothing about T&S. Additionally, the T&S sectors contemplated in the current rule-making are well beyond the natural gas processing plant of the 1984 rulemaking. As EPA notes in the Proposed Rule emissions in the transmission and storage sectors have virtually no VOC and significantly less HAP content than those in the production and processing segments. Thus, EPA is erroneously treating the various, and very distinct, segments of the natural gas industry as one source category, directly contradicting its 1984 definition, which tailored the application of this source category.

[62] 44 Fed. Reg. 49222 (Aug. 21, 1979).
[63] *See* 43 Fed. Reg. 38,872 (Aug. 31, 1978); M.R. Monarch, Revised Prioritized List of Source Categories for NSPS Promulgation, EPA-450 / 3-79-023, at 9 (March 1979).
[64] *See* 44 Fed. Reg. at 49224.
[65] M.R. Monarch, Revised Prioritized List of Source Categories for NSPS Promulgation, EPA-450 / 3-79-023, at 9 (March 1979).
[66] 49 Fed. Reg. 2636, 2637 (Jan. 20, 1984).

Third, and because it is clear that the natural gas T&S sectors do not fall under the existing source category, EPA must provide an explicit endangerment finding to regulate this new source category. EPA's broad authority and discretion to list and establish NSPS for a source category is not so broad as to modify a source category without such a finding. EPA has the authority to regulate the natural gas T&S sectors only if it (1) defines the precise source categories of the transmission and storage sectors, and (2) determines that emissions from the T&S sectors may contribute to endangerment of health or the environment.[67] Absent these two express findings, EPA cannot arbitrarily expand a pre-existing source category to include new sources it never intended to include in the first place. EPA's attempt to provide "good reasons" to treat the various segments of the natural gas industry as one source category is insufficient. *See* 80 Fed. Reg. at 56,600. No matter how "good" the reason, such reasons must be cited in an endangerment finding.

Finally, EPA's alternative argument that it provides adequate support to satisfy an endangerment finding is insufficient under CAA section 111. Essentially, EPA is attempting to avoid its obligation to make an endangerment finding with respect to each individual segment of the natural gas industry, and to substantiate its proposed source performance standards. EPA's generalized argument in support of a new endangerment finding is insufficient under section 111(b).[68]

EPA's argument focuses broadly on potential environmental and health impacts caused by atmospheric concentrations of GHGs. Yet EPA fails to offer a detailed discussion of any potential specific impacts directly caused by the T&S sector. Second, EPA applies its endangerment finding broadly to the entire oil and gas industry as a whole, rather than specifically to the T&S sector (or other discrete industry sectors). While EPA provides some indication regarding the percent of contribution of methane to the total GHG atmospheric concentrations from the T&S sector, EPA's analysis does not sufficiently demonstrate that the T&S sector on its own warrants an endangerment finding under section 111(b) of the CAA– particularly given the low hazardous air pollutant emissions and almost no VOCs from the T&S sector. EPA cannot arbitrarily expand a pre-established source category in such a cursory manner.

INGAA believes that a T&S specific proposal is needed for EPA to expand its source category to include the natural gas T&S sectors. EPA's broad authority and discretion to list and establish NSPS for a source category is not so broad as to permit modification of a category list without an explicit endangerment finding. Because the natural gas T&S sector was not included in the original 1979 Priority Listing, and because background documentation and further analysis of that 1979 Priority Listing support the conclusion that EPA never intended to include the T&S sector, EPA is required to make a new endangerment finding before it can purport to regulate those sectors.

EPA attempts to argue that because EPA "evaluated equipment, such as stationary pipeline compressor engines that are used in various segments of the natural gas industry" it is reasonable

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[67] 42 U.S.C. § 7411(b).
[68] 80 Fed. Reg. at 56601.

to assume that EPA made an endangerment finding that encompassed all of those segments. There is no evidence that EPA made such an evaluation, much less a specific endangerment finding.

However, even if we accept for the sake of argument that such an "evaluation" occurred, there is no reason to believe that the mere evaluation of compressors equates to an endangerment finding for compressors in all segments of the natural gas value chain. In 2012, EPA "evaluated" VOC emissions from compressors in the T&S segment, and explicitly found that their emissions were not high enough to merit regulation – but EPA found that regulation of compressors in the *processing* segment was merited.[69] Accordingly, EPA's practice has been to evaluate different segments of the natural gas value chain independently – as different source categories – and to make findings for some segments but not others, even where different segments use the same types of equipment.

Therefore, EPA's own practice in this area makes clear that it is unreasonable to assume that the simple evaluation of sources in a particular segment of the natural gas value chain equates to an endangerment finding for that segment. Accordingly, EPA has not evaluated endangerment for the T&S sector pursuant to section 111(b)(1)(A) of the CAA.

G. EPA Has Not Acknowledged or Taken into Consideration Existing PHMSA Regulations for the Timing of Leak Repairs.

In the preamble, EPA frequently refers to the need to leverage existing programs. However, EPA does not indicate in the Proposed Rule that the agency has conducted any review, comparison, or reconciliation with other regulatory programs. In particular, EPA does not recognize the existing regulations that cover leak repairs. PHMSA has the authority to regulate leak detection and repair for natural gas pipelines and facilities and exercises that authority through its existing regulations.

Specifically, PHMSA requires operators to conduct leakage surveys, patrol rights-of-way, repair hazardous leaks promptly, and report unintentional estimated gas loss of three million cubic feet or more.[70] PHMSA requires that operators repair all "hazardous"[71] leaks promptly. Pipeline and facility operators must also report to PHMSA the number, location, and cause of all leaks eliminated or repaired annually.[72] PHMSA defines a leak in the annual reporting forms as "…unintentional escapes of gas from the pipeline that are not reportable as Incidents under § 191.3. A non-hazardous release that can be eliminated by lubrication, adjustment, or tightening is not a leak. Operators should report the number of leaks repaired based on the best data they have available."[73]

Rather than issuing its own leak repair regulations requiring operators to repair all leaks within 15 days, EPA should work with PHMSA to support the existing regulations. As illustrated

[69] 77 Fed. Reg. 49490, 49523 (Aug. 16, 2012).
[70] *See* 49 C.F.R. §§ 192.706, 192.703(c), 192.705, and 191.3.
[71] Hazardous under PHMSA regulation has no correlation to a Hazardous Air Pollutant under the Clean Air Act.
[72] *See* PHMSA F. 7100.2-1 at *http://phmsa.dot.gov/pipeline/library/forms*.
[73] Instructions for PHMSA F. 7100.2-1 at 13.

above, PHMSA recognizes that not all leaks are the same and operators need to acquire replacement parts and consider disruptions in service. EPA should consult with PHMSA and rely on the time frames for leak repairs set out in existing federal regulations**.** This type of collaborative effort meets the Administration's directive to agencies to coordinate on cross-cutting issues.[74]

H. EPA Fails to Justify Third-Party Verification Requirements for the T&S Sector, When EPA Does Not Require Such Verification for Other Sectors.

INGAA does not believe that EPA has provided any justification for mandating third-party verification for the T&S sector. Third-party verification is not a conventional part of the NSPS program where a third party must be hired to verify that the company met its regulatory obligations. INGAA points out that EPA has an ongoing enforcement and inspection program (in addition to the annual reporting under Subpart W) where any failure to have completed all requirements will be identified by EPA.

INGAA does not support third-party audit and verification programs. EPA, in the Proposed Rule, would require third-party audits for leak surveys and repairs (e.g., audit of OGI program), and third-party professional engineer verification of gas capture, closed vent and combustion device designs. The operator is responsible for compliance and third parties do not facilitate that process nor relieve the operator's obligations. In addition, it is unlikely that independent third parties are available that can adequately meet EPA's conflict of interest requirements and fulfill the roles desired by EPA, thus adding unnecessary burden for ineffective requirements.

Sector-specific training and experience would be lacking for "qualified professionals." For example, OGI is a relatively new technology for leak detection. Other than instrument vendors, operating company personnel and their hired third-party contractors (e.g., for Subpart W surveys) have the most experience with OGI technology for detecting leaks in natural gas operations. Since T&S facilities are the majority of facilities that require methane leak surveys under Subpart W, this expertise is unique. Third parties will not likely have the experience to conduct a meaningful audit. Third-party auditors are unlikely to have experience with gas transmission operations and are unlikely to have as much experience with OGI surveys as the operator's team. Thus, third parties cannot be expected to provide beneficial, insightful audit services or reasonable recommendations for an OGI program.

Similarly, transmission companies have in-house expertise and an established relationship with additional resources that address systems design. Third-party verification would likely be conducted by parties with far less experience regarding design considerations for natural gas operations.

In addition, the implications for third-party audits and verification are not clear. It is unclear if the operator would be obligated to implement "recommendations" from the audit that the operator did not support. Recommendations from auditors lacking gas transmission and OGI

[74] *See* FACT SHEET: Administration Takes Steps Forward on Climate Action Plan by Announcing Actions to Cut Methane Emissions (Jan. 14, 2015), available at https://www.whitehouse.gov/the-press-office/2015/01/14/fact-sheet-administration-takes-steps-forward-climate-action-plan-anno-1.

experience could present significant issues for operators and possible conflicts with other operational, safety or regulatory requirements.

It is unclear where the audit resources would come from, because OGI certification is primarily conducted by instrument vendors. These companies should not perform an independent audit service due to an obvious conflict of interest. Given the lack of trained auditors with appropriate sector-specific and technology experience, and lack of clarity regarding the breadth of audits and the requirements for implementing audit recommendations, it is difficult to assess potential costs at this time.

Lastly, EPA did not even attempt to quantify the cost of third-party audits. However, there is a strong chance that costs would be high, benefit would not be realized, and the early stages of an audit program would more likely consist of operators educating and training the third-party auditors on T&S operations and OGI performance. For these reasons, third-party programs should not be required in Subpart OOOOa.

III. MISCELLANEOUS COMMENTS

A. Leak Detection Methods Other than OGI Should Be Allowed.

The Proposed Rule requires Optical Gas Imaging (OGI) for leak detection, and EPA solicits comment on whether additional methods should be allowed. INGAA strongly supports including flexibility for leak detection, and EPA Method 21 should be in included as an option for leak surveys. In the preamble, EPA concludes that OGI is more cost effective than Method 21, but many factors can influence survey costs – including the availability of trained operators and OGI instruments, which are orders of magnitude more costly than Method 21 instrumentation. The operator should have the discretion to use other established methods for leak surveys, such as Method 21. The final rule should include Method 21 and the ability to implement other future EPA-approved technologies that are proven as equivalent to OGI or Method 21. If not, this program will be inconsistent with every other leak mitigation program in the U.S., as well as the Subpart W leak survey methodology.

EPA's Proposed Rule contains a leak survey method requiring the more restrictive OGI technology. However, EPA's Subpart W requirement allows either OGI or Method 21. EPA should strive for consistency with existing programs to avoid similar, duplicative efforts. Since a primary objective of the GHG Reporting Program was to inform policy decisions, EPA should better utilize data and information available from Subpart W reporting and reconsider environmental benefits and the need for regulation.

B. The Leak Threshold for Method 21 Surveys Should Be 10,000 ppm.

EPA solicits comment on the appropriate leak definition concentration if Method 21 is included in the final rule. As noted in the preamble, current NSPS include thresholds ranging from 500 to 10,000 ppm. It is important to understand that these thresholds were established for VOC regulations, where the measured stream may include constituents other than hydrocarbons. When nonhydrocarbon species are within the stream, the measured concentration is diluted to lower values. For the natural gas sector, typically ninety percent or more of the stream is methane and nearly the entire stream is hydrocarbon. Thus, relative to a diluted VOC stream, a smaller leak of natural gas will record a higher hydrocarbon concentration. In addition, for T&S the Proposed Rule is primarily interested in reducing methane emissions – rather than VOCs or Hazardous Air Pollutants (HAPs). Very small leaks that may be detected with a low concentration threshold (e.g., 500 ppm) are not likely to provide meaningful reductions when GHG impacts are the primary environmental concern.

Since existing NSPS with lower concentrations thresholds are associated with VOC regulations and different process streams, a higher threshold is appropriate for a regulation addressing methane leaks. INGAA recommends a leak definition concentration of 10,000 ppm. This is consistent with the range of thresholds in current regulations, also consistent with the OGI performance objectives in § 60.5397a(c)(7)(i)(B), and consistent with the Subpart W leak definition.

C. Survey Requirements Should Not Include Definition of a Walking Path.

The Proposed Rule requires a site-specific monitoring plan that includes a defined walking path. This is an ambiguous and unnecessary requirement, and more burdensome than leak monitoring programs required in other NSPS. The operator and survey team are responsible to ensure that all affected components are surveyed, as established by programs in existing regulations. The proposed requirement to identify and adhere to a defined walking path is unnecessary and should be removed from the rule.

D. The Initial Survey Schedule Should Be Revised to Allow 180 days from Startup, which Is Consistent with Performance Test Schedules in Other NSPS that Affect Compressor Stations.

The Proposed Rule requires an initial survey within 30 days of startup, and EPA requests comment on that requirement. Startup of a facility generally encompasses a busy period for operators, and includes schedules for other regulatory requirements associated with facility operations. More consistency with other NSPS and a more reasonable schedule is warranted. 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 NESHAP regulations, such as Part 60, Subpart JJJJ and Part 63, Subpart ZZZZ for reciprocating engines, and Part 60, Subpart KKKK for turbines. Those regulations allow a longer period to complete initial performance tests, and similar schedules are warranted for Subpart OOOOa. Similar schedules will also simplify managing compliance during the busy period following initial startup. Subpart JJJJ, Subpart KKKK, and Subpart ZZZZ allow 180 days or longer to complete the initial performance test. A similar schedule is warranted to complete the initial leak monitoring survey. INGAA recommends revising the schedule for the initial survey to within 180 days of startup.

E. Reporting on Company Websites Should Not Be Required.

EPA requests comment requiring operators "to report *quantitative environmental results* on their corporate maintained Web sites." *[emphasis added]* The preamble also ponders the type of information and data that could be included in such reports. INGAA objects to this proposition.

The details and nuances of regulatory compliance are not commonly understood. EPA notes that on-line reporting could improve transparency, but that claim is not supported by analysis or fact. EPA should not underestimate the complexities of interpreting "quantitative environmental results." Web site reporting is more likely to raise questions due to misinterpretation than to improve public transparency and insight.

Significant additional effort would be required to develop standardized information for reporting and clearly define the meaning for the reported information. The nuances of Subpart OOOOa would not be understood by the vast majority of third parties that may review the website reports. For example, pneumatic controller counts, justification for applying a high-bleed pneumatic controller and time frames for rod packing replacement are all examples of compliance information for Subpart OOOOa affected facilities. Compliance requirements include work practices, equipment standards and control requirements depending upon the affected source. The terminology and regulatory criteria are beyond the comprehension of most individuals that are not well acclimated to the rule and would befuddle many online readers rather than improve transparency. Interpretation of reported quantitative results would likely cause confusion (and possibly unneeded consternation) because the reader would not understand the context of a complex regulation. Reporting on company websites is an ill-conceived idea and should not be required.

F. For Reciprocating Compressors, Condition-Based Maintenance Should Be Included as an Alternative to Prescribed Maintenance Intervals.

INGAA's comments have addressed rod packing elsewhere, but INGAA wishes to make some technical suggestions to address maintenance schedules. For reciprocating compressor rod packing, the Proposed Rule includes a prescribed maintenance schedule or control of the leakage by routing it to a process (such as the engine combustion air). An additional option- should be included- the use of condition-based maintenance practices. Condition based maintenance may extend the operation of functional rod packing, precludes premature and wasteful rod packing maintenance/replacement, and encourages the development of innovative rod packing technologies.

EPA has acknowledged that condition-based maintenance is a practical approach in its Natural Gas STAR lessons learned document, "Reducing Methane Emissions from Compressor Rod Packing System."[75] A draft California Air Resources Board (CARB) regulation[76] for oil and gas operations includes condition-based maintenance for reciprocating compressor rod packing, with

[75] http://www.epa.gov/gasstar/documents/ll_rodpack.pdf

[76] CARB Proposed Regulation Order, Subchapter 10, Article 3, "Greenhouse Gas Emission Standards for Crude Oil and Natural Gas Facilities." http://www.arb.ca.gov/cc/oil-gas/meetings/Draft_Regulatory_Language_4-22-15.pdf (April 22, 2015).

a leak threshold of >2 SCFM requiring maintenance. The INGAA DI&M Guidelines include condition-based maintenance for reciprocating compressor rod packing. Since EPA's Natural Gas STAR program has demonstrated this work practice, it should be included as an alternative to the Proposed Rule requirements.

Companies understand the value of rod packing monitoring and maintenance/replacement programs and have instituted these programs as part of safety and standard maintenance practices. The final rule should include condition-based maintenance practices such as those in INGAA's DI&M program. These include:

- Rod packing condition-based maintenance, with performance assessed by measuring the rod packing leak rate in accordance with applicable industry standard practices (e.g., as defined in Subpart W procedures);
- A leak rate exceeding 2 SCFM would require rod packing maintenance/replacement at the next unit shutdown:
  - A nine-month window is necessary to allow a critical unit to continue operating during a high-use season. Maintenance will occur sooner if the unit is shutdown; and
- Monitoring would occur annually, which is consistent with the CARB proposal. A leak rate less than 2 SCFM demonstrates acceptable rod packing leakage.

Reliability engineering has advanced from following antiquated, periodic (i.e., preventative) maintenance to more use of predictive or condition-based maintenance, because it has been demonstrated that condition-based maintenance improves operational reliability and performance. Subpart OOOOa should not limit state-of-the art approaches or advancements in technology and maintenance procedures. Condition-based maintenance should be added as a compliance option for reciprocating compressor rod packing.

G. For Existing Centrifugal Compressors with Wet Seals, EPA Should Clearly Indicate that Routine Maintenance and Repair Does Not Trigger Applicability.

For existing units, interpretation of modification and reconstruction provisions is not always straightforward. The history of determination requests for other NSPS in EPA's Applicability Determination Index demonstrates this fact. For centrifugal compressors, only units with wet seals are affected units. For new installations, turbines with dry seals are installed and these units are not subject to the Proposed Rule. Dry seals have been common for over ten years, but a number of existing wet seal units remain in operation. Thus, the Proposed Rule would most likely affect existing centrifugal compressors that are modified or reconstructed. INGAA is concerned with regulatory interpretations that could unnecessarily change the status of existing units. EPA should provide additional background regarding exemptions when routine maintenance or repair is conducted. Additional evaluation is also needed regarding the potential high costs and minimal benefits associated with retrofit "control" of an existing centrifugal compressor with wet seals.

It is important to understand that some situations (e.g., associated with reconstruction or modification determinations for existing units with wet seals) could introduce unreasonable regulatory costs. EPA needs to properly consider reasonable scenarios and associated outcomes. INGAA discussed this with EPA during development of the original Subpart OOOO rule in 2011 and 2012. Existing units with wet seals that become subject to Subpart OOOO could be faced with extraordinary costs. The final rule should clearly indicate that routine repair and maintenance, including long-established component replacement programs, do not trigger Subpart OOOOa applicability.

Compliance costs (and cost benefit) could be an important issue in select cases where "applicability" triggered for existing units results in measures such as installation of control systems, or more extreme measures such as replacing wet seals with dry seals or unit replacement. Retrofit feasibility and peripheral costs could result in inordinate costs such that replacement is the only viable option. Since wet seal emission rates can vary – and are similar to dry seals in some cases – this requirement could be triggered with little or no environmental benefit.

The associated benefit is an important issue. As discussed earlier, EPA has failed to consider emissions information being compiled from Subpart W reporting for centrifugal compressors. Industry stakeholders are reviewing that information, and it indicates centrifugal compressor *wet seal emissions are far lower than EPA's current estimated*. Closer scrutiny is warranted to leverage important insights that can be gained from Subpart W measurements.

INGAA recommends that EPA more clearly indicate that routine maintenance and repair of a centrifugal compressor with wet seals does not trigger applicability. INGAA also recommends that EPA complete a thorough analysis of GHG Reporting Program data, which includes measurement of wet seal emissions for Subpart W T&S facilities. INGAA believes that such a review is likely to indicate that EPA should reassess the perceived environmental benefits from mitigation of wet seal degassing vent emissions, and reconsider whether this equipment category should be included in the regulation.

H. Subpart W Emissions Information Should Be Considered When Determining Environmental Benefits and the Need for Regulation.

Since 2011, operators have been reporting emissions information to EPA under the GHGRP. This includes thousands of new measurements at T&S compressor stations associated with Subpart W annual surveys. When the GHGRP was adopted, a primary EPA objective was to use that information to inform future policy. In 2015, as GHG programs migrate from emission reporting to emissions reductions, the GHGRP data has not been used for its stated purpose. There is little indication that EPA has considered four years of Subpart W reporting, including many measurements, to inform this rulemaking.

Industry stakeholders are engaged in a review process and initial results raise questions about the Proposed Rule. It appears that Subpart W data provides some compelling data, including these examples:

1. Emissions measurement data supports DI&M by reinforcing the understanding that a small minority of leaks are responsible for the majority of compressor station leak emissions;

2. Emissions measurement data indicates that emissions from centrifugal turbines with wet seal degassing vents are many times lower that EPA's current estimates; and

3. Pneumatic controller counts and emissions estimates indicate that pneumatic device emissions are lower for T&S than current EPA estimates, and a relatively minor contributor to T&S methane emissions.

The first item provides support for focusing on gross emitters by allowing DI&M. The other two items raise questions about environmental benefit estimates and whether regulation of those sources is warranted.

INGAA recommends that EPA engage in a more thorough and thoughtful process that considers Subpart W data, including T&S measurement data. INGAA welcomes additional discussion on this topic and related stakeholder projects that are reviewing and analyzing Subpart W data.

I. GHGRP Data Indicates T&S Emissions from Continuous Bleed Pneumatic Controllers Are Relatively Low. Thus, Pneumatic Controllers in T&S Should Not Be an Affected Source.

The GHGRP requires reporting of T&S emissions from pneumatic controllers based on an inventory of devices (by type) and associated emission factors. Review of GHGRP reported data and comparison to estimates (e.g., per facility) from EPA's annual inventory indicate that GHGRP pneumatic device emission estimates are several times lower than EPA's national inventory estimate for the T&S sector.

EPA should more closely review and consider the more current information from the GHGRP. GHGRP reporting indicates that pneumatic controller emissions are far lower than EPA's historical estimate. Thus, these emissions comprise a small percentage of total methane emissions from T&S sources. EPA should consider excluding pneumatic device regulations from the regulation for T&S compressor stations.

J. EPA Should Clarify that for T&S, Pneumatic Controllers Are Only an Affected Source at Compressor Stations.

As stated above, INGAA does not believe pneumatic controllers should be covered in the final rule. However, if EPA decides to include T&S pneumatic controllers as an affected source, the final rule should more clearly indicate that Subpart OOOOa only applies to devices located at compressor stations and not at locations along the pipeline (e.g., metering stations).

From preamble discussion and support documents, it appears that EPA only intends to regulate pneumatic devices at compressor stations. However, the Proposed Rule does not clearly state this, and clarification is warranted. The Proposed Rule applicability section and definition could lead to the conclusion that pneumatic controller affected sources in T&S are not limited to pneumatics located at compressor stations.

In § 60.5365a(d)(1), the affected source is listed for pneumatics not located at gas processing plants, which includes T&S operations:

> (d)(1) Each pneumatic controller affected facility not located at a natural gas processing plant, which is a single continuous bleed natural gas-driven pneumatic controller operating at a natural gas bleed rate greater than 6 scfh.

And, "pneumatic controller" is defined in § 60.5430a:

> *Pneumatic controller* means an automated instrument used for maintaining a process condition such as liquid level, pressure, delta-pressure and temperature.

Neither of these citations limits applicability to the compressor station for T&S operations. Either or both of these subsections should be revised to indicate that for T&S, pneumatic controllers are only subject if located at a compressor station. If EPA intends broader applicability, then its support analysis is lacking, and additional analysis is required to accurately assess the costs and benefits from regulating pneumatics at other locations along a pipeline (e.g., at metering stations).

K. INGAA Recommends Removing Pneumatic Pumps as an Affected Source for T&S Facilities.

The Proposed Rule includes T&S pneumatic pumps as an affected source if there is a control device located on site. Control for this situation would require a vapor recovery system and some means to combust, catalytically oxidize, or re-use the stream. EPA requests comment and additional information on gas assist glycol dehydrator pumps and the associated emissions. Although INGAA does not have detailed information readily available, these pumps are not prevalent in T&S and when at a site (e.g., a storage facility with dehydration), vapor recovery or other control devices are usually not located at the site.

INGAA's interpretation is that this requirement would only apply if a pump is present, as well as the associated control (i.e., existing vapor recovery and control system is a prerequisite to applicability). For the T&S sector, cumulative emissions from glycol dehydrator pumps are very low, and compressor stations typically do not have an available control system. For some upstream operations, it is more likely that a control device will be co-located at the site due to other requirements associated with storage tank or other emissions. For transmission compressor stations, dehydrators are very uncommon and the need for a control device is unlikely (i.e., not required by other regulations). Storage facilities may include a dehydrator, but NSPS affected sources may not include a gas assist dehydrator pump. In addition, control devices are relatively uncommon because other regulations, such as the oil and gas NESHAP[77] (Part 63, Subpart HHH) only require control in certain circumstances (e.g., for a large dehydrator and dependent upon the dehydrator throughput and natural gas BTEX[78] content). For these reasons, INGAA recommends removing pneumatic pumps as an affected source for T&S facilities.

L. Recordkeeping.

Recordkeeping requirements should not be transformed into new reporting requirements, and leak survey requirements should not be expanded to include additional digital records.

EPA requests feedback on recordkeeping issues. For example, EPA proposes utilizing technology to facilitate sharing records directly with regulatory agencies. EPA also requests comment on expanding the use of technology such as digital pictures for leak surveys. INGAA does not support expanding reporting and recordkeeping. The Proposed Rule's reporting and recordkeeping requirements require the use of digital surveys showing latitude and longitude. OGI cameras typically do not have the functional capability to record latitude and longitude. This is not consistent with other LDAR programs and should be removed. If EPA considers adding requirements, stakeholders should be provided the opportunity to comment on the specific requirements.

The Proposed Rule includes separate requirements for recordkeeping and reporting, which is the standard format for NSPS and NESHAP regulations. INGAA does not support new methods for sharing records directly with agencies, as this blurs the line between recordkeeping and reporting obligations. Each has its place and context in regulations, and information that is directly shared with agencies should be clearly proposed and justified as a reporting requirement, so that stakeholders have an opportunity to comment.

EPA also requests comments on the viability and benefits of reporting and recordkeeping approaches that utilize technology such as digital pictures, and areas where such use might be expanded. The Proposed Rule includes defined recordkeeping and reporting requirements. It is likely that EPA will receive recommendations from other parties requesting such documentation and reporting (including to cover digital pictures associated with leak surveys). If EPA intends to amend recordkeeping and reporting requirements that differ from the Proposed Rule, EPA should provide another opportunity for comment on those new requirements.

M. EPA Requests Comment on Whether Ozone Health Impacts from Methane Should Be Considered. INGAA Does Not Support Including this Analysis since Methane Is Not Defined as a VOC.

EPA requests comments on whether ozone health impacts should be considered. Several documents are listed in the docket (e.g., related studies), but those documents are not readily available due to copyright or other issues. The implication is that methane is a reactive hydrocarbon that significantly contributes to ozone atmospheric chemistry – i.e., methane is a volatile organic compound. Federal regulations include a clear definition of the hydrocarbon

[77] National Emissions Standards for Hazardous Air Pollutants
[78] Benzene, Toluene, Ethylbenzene and Xylenes

species that are considered VOCs[79]. Methane is not considered a VOC. Thus, EPA should not embark on environmental analysis that contradicts long-established EPA definitions. Ozone impacts should not be included in the cost-benefit analysis. (See INGAA's Social Cost of Methane).

N. EPA Should Incorporate by Reference INGAA's Prior Comments on EPA's Methane White Papers.

INGAA submitted comments in response to EPA's White Papers in 2014 and asks that those comments and the cost analyses be incorporated by reference.

IV. CONCLUSION

INGAA's comments suggest revisions to EPA's Proposed Rule that, if accepted, will provide the basis for a workable, cost-effective program to achieve meaningful reductions in methane emissions from new and modified T&S sector sources. INGAA would be pleased to meet with EPA or the Office of Management and Budget during the review period to answer any operational questions. Please contact Theresa Pugh, vice president of environment and construction policy, at tpugh@ingaa.org or 202-216-5955.

[79] 40 CFR § 51.100(s)

APPENDICES

Appendix A
INGAA White Paper, "Directed Inspection and Maintenance for Reducing Leak Emissions from Natural Gas Transmission and Storage Compressor Stations: Greenhouse Gas Reporting Program Data Supporting a Focused Leak Mitigation Program," prepared by Innovative Environmental Solution, Inc. (Sept. 2015).

Appendix B
Relevant Pipeline and Hazardous Materials Safety Administration Regulations

Appendix C
INGAA DI&M Guidelines, "Directed Inspection and Maintenance Voluntary Program Elements and Procedures for Natural Gas Transmission and Storage Compressor Stations."

Appendix D
Diagrams/illustrations of Compressor Station Repair Processes and Timing Needed for Making Repairs Once Existing Sources Are Affected By Modification Language

APPENDIX A

Directed Inspection and Maintenance for Reducing Leak Emissions from Natural Gas Transmission and Storage Compressor Stations:
Greenhouse Gas Reporting Program Data
Supporting a Focused Leak Mitigation Program

Prepared for:

Interstate Natural Gas Association of America (INGAA)
20 F Street, N.W., Suite 450
Washington, D.C. 20001

Prepared by:
Innovative Environmental Solution, Inc.
Cary, IL

September 2015

INTRODUCTION AND BACKGROUND

It has been shown that a relatively small percentage of leaks contribute the vast majority of leak emissions for natural gas operations. For example, 95% of methane emissions from equipment leaks are from 20% of the leaks at natural gas transmission compressor stations.[80] Directed Inspection and Maintenance (DI&M) is a leak mitigation practice that leverages this characteristic of compressor station leaks through procedures that focus repairs on larger leaks while limiting resources expended on inconsequential leaks. This White Paper provides background and technical support for implementing DI&M, as described in the INGAA DI&M Guidelines, to mitigate natural gas transmission compressor station equipment leaks.

The INGAA DI&M Guidelines provide the structure, program elements, and procedures for a company-specific DI&M program. The Guidelines focus on key leak sources within a facility that have a higher probability of being large leaks – referred to as "gross emitters" in recent EPA documents. The focused list of sources is based on previous studies, company experience, and available information, including data from the EPA Greenhouse Gas Reporting Program (GHGRP). The key leak sources are discussed further below, and GHGRP data collected for an industry research project are analyzed to demonstrate that the INGAA DI&M Guidelines focus on the appropriate leak sources.

INGAA members operate compressor stations that are required to report GHG emissions under the GHGRP. An ongoing project is being conducted by the Pipeline Research Council International (PRCI) to collect data submitted to EPA through its electronic greenhouse gas reporting tool (e-GGRT). The PRCI project is also collecting supplemental data that provides additional information on associated facility and equipment operations, and on vent measurements. Data from the PRCI project was analyzed to document that the sources included in the INGAA DI&M Guidelines represent the vast majority of equipment leak emissions from natural gas transmission compressor stations. Data and associated analysis is presented in this document.

INGAA GHG GUIDELINES – EQUIPMENT LEAK SOURCES AND RELATIONSHIP TO SUBPART W LEAK SOURCES

Leak sources included in the INGAA DI&M Guidelines are similar to emissions sources that require measurement in Subpart W of the GHGRP. The primary interest is compressor related leak sources, and the INGAA DI&M Guidelines go beyond the requirements of Subpart W by including leak sources and operating modes that are not included in GHGRP reporting. The sources included in the INGAA DI&M Guidelines are shown in Table 1.

[80] "Directed Inspection and Maintenance at Compressor Stations." U.S. EPA Natural Gas STAR, Lessons Learned (see http://epa.gov/gasstar/documents/ll_dimcompstat.pdf), EPA430-B-03-008 (October 2003).

Table 1. Affected Equipment / Component List for DI&M Program.

<table>
<tr>
<td>• Reciprocating compressor blowdown valve leakage through blowdown vent in any mode as found:
1. Leakage during “Operating” mode
2. Leakage during “Standby Pressurized” mode</td>
<td rowspan="2">• Reciprocating rod packing leakage[A] in any mode as found:
1. Reciprocating rod packing emissions during “Operating” mode
2. Reciprocating rod packing emissions during “Standby Pressurized” mode</td>
</tr>
<tr>
<td>• Reciprocating compressor unit isolation valves (suction and discharge) leakage through the associated vent during “Not Operating, Depressurized” mode</td>
</tr>
<tr>
<td rowspan="2">• Centrifugal compressor blowdown valve leakage through the blowdown vent in any mode as found:
1. Leakage during “Operating” mode
2. Leakage during “Standby Pressurized” mode</td>
<td>• Centrifugal compressor unit isolation valves (suction and discharge) leakage through the associated vent during “Not Operating, Depressurized” mode.</td>
</tr>
<tr>
<td>• Centrifugal compressor wet or dry seal leakage through associated vent(s) in any mode as found (see modes listed above for rod packing).</td>
</tr>
<tr>
<td colspan="2">• Storage tank vents to atmosphere from scrubber dump valve leakage.</td>
</tr>
</table>

[A] Reciprocating compressor rod packing is designed to leak, even when new.[81] Repair decisions and timing that considers condition-based maintenance for rod packing will be defined in the DI&M Plan.

The primary focus is on compressor emissions from large valves and other known leak sources, such as reciprocating compressor rod packing and centrifugal compressor wet seal degassing vents. The list of sources includes combinations of the emission source and the compressor mode that are not included in GHGRP reporting, including: reciprocating compressor rod packing leakage in standby-pressurized mode; centrifugal compressor dry seals; and centrifugal compressor sources in standby-pressurized mode. As discussed below, GHGRP data indicates storage tank emissions from scrubber dump valve leakage is not a significant source, but because this is a source of interest included in Subpart W, storage tanks are included in the INGAA DI&M Guidelines.

The equipment leak sources *excluded* from the INGAA Guidelines are components such as connectors, valves, and open ended lines associated with yard piping or compressor house gas lines. As discussed in the next section, evaluation of detailed data from the PRCI project demonstrates that these emissions are generally a small portion of overall leak emissions.

[81] EPA Natural Gas STAR Lessons Learned document, “Reducing Methane Emissions From Compressor Rod Packing Systems.” October 2006. http://www.epa.gov/gasstar/documents/ll_rodpack.pdf

PRCI GHG DATA COMPILATION PROJECT

Compressors stations that exceed the GHGRP annual emissions reporting threshold of 25,000 CO_2 equivalent (CO_2e) metric tons are subject to reporting under Subpart C (combustion emissions) and Subpart W (leaks, venting, blowdowns). Subpart W requires annual leak measurements for compressor-related sources and storage tanks. In addition, a leak survey that counts leaks by component types is required for other facility equipment. Since significant new data is being collected, PRCI is conducting an ongoing project to gather data from its members, and compile and analyze the data. This includes Subpart W data submitted to EPA and supplemental data on equipment, operations, and measurement methods. The project is analyzing the data to assess development of improved emission factors for compressors. The data can also be analyzed to provide technical support for ongoing dialogue related to GHG emission estimates and emission reduction opportunities.

The first year of Subpart W reporting was 2011, and data elements reported to EPA were broadened in January 2015. Since reporting was more limited in the initial three reporting years, the PRCI project supplemented the e-GGRT data with additional information. In addition to e-GGRT data, companies provided supplemental data on facility equipment, operations, and methods used for vent measurement. This supplemental data is needed to better understand the reported emissions and to support analysis such as emission factor development.

The PRCI data was collected from members and the dataset does not include all companies or facilities that report to EPA. However, the majority of facilities are included in the PRCI dataset: 70% of all EPA facilities are included for 2011 and over 60% are included for 2012. As discussed in the following section, the emission trends for each Subpart W source type are similar for the PRCI dataset and the entire EPA dataset.

The PRCI GHG dataset is being analyzed to assess whether updated emission factors can be developed for reciprocating compressors and centrifugal compressors. In addition, the data is available to support technical analysis on GHG issues such as source-specific emissions, emission trends, the distribution (by size) of measured leaks, the prevalence of “large” leaks, and measurement methods performance. At this time, the PRCI dataset includes 2011 and 2012 data. Final review is being completed for 2013 data, which will be added to the PRCI dataset. Data collection and compilation for the 2014 reporting year will occur in late 2015.

DATA ANALYSIS AND DISCUSSION

The figures presented in this document are based on PRCI 2011 and 2012 data, with one exception. Figure 2 includes the entire EPA dataset downloaded from EPA’s website. Figure 1 presents PRCI data for 2011 and 2012 by Subpart W emissions source. Figure 2 shows all data from EPA for 2011, 2012, and 2013. Facility counts differ from year to year. Thus, to facilitate comparison, the emissions are presented as a facility average (i.e., total emissions for each source type divided by the total number of facilities for the respective datasets). Storage facility data is more limited (i.e., fewer facilities report and fewer emission sources are included in GHGRP reporting), so the data analysis focused on the transmission segment.

Data has been collected for 2011 – 2013 reporting years; PRCI data in this document is from 2011 and 2012. These data were reported based on a methane global warming potential (GWP) of 21, and this document does not correct the GWP to its current value (GWP = 25). The EPA website "all facility" data for 2011 – 2013 presented in Figure 2 is also based on a GWP of 21.

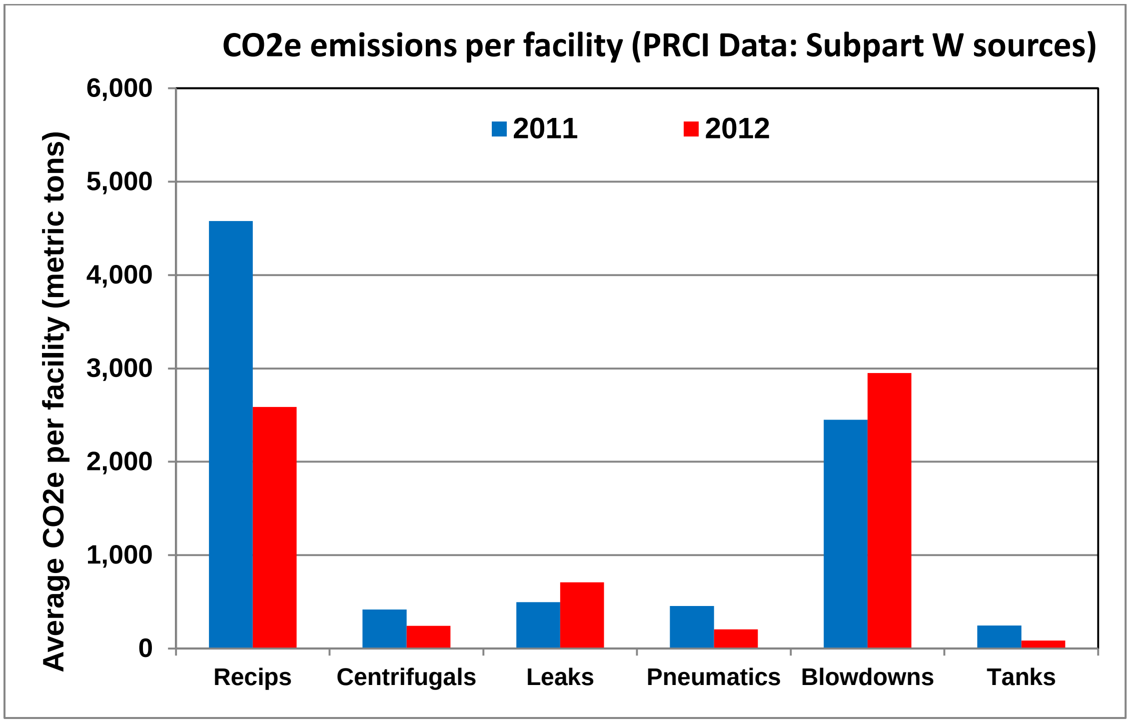


Figure 1. Emissions by Subpart W source type (PRCI data)

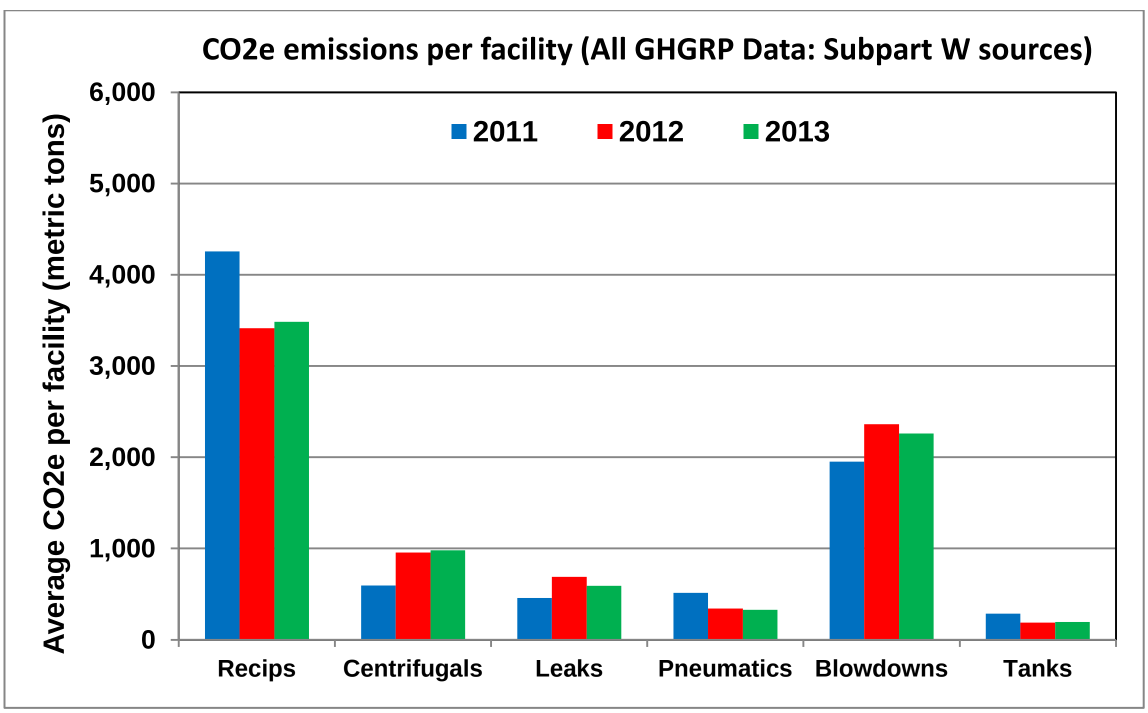


Figure 2. Emissions by Subpart W source type (All EPA data)

The two figures show similar reported emission levels and similar trends. Several observations follow:

- Reciprocating compressor emissions and blowdown emissions are more than 70% of the total emissions.

- Reciprocating compressor emissions decreased in the second year of the program. A larger decrease occurred for facilities included in the PRCI dataset compared to the entire GHGRP dataset. There are several factors that likely contribute to the decrease after the first year: 2011 allowed the use of "best available monitoring methods" (BAMM) when the program was launched; some large leaks were likely repaired following discovery in 2011; and, measurement method used may have changed.

- The 2013 data from EPA shows that emissions were similar in the second and third reporting years and generally differ from reported emissions for the first year.

- Vented emissions from pneumatic devices decreased in the second year of the program. That emission estimate is based on device count by type (high bleed, low bleed, intermittent) and emission factors. It is likely that categorization by device type improved in 2012 – e.g., in the first year of the program conservative estimates based on best available information classified devices as high bleed that were subsequently confirmed as low bleed devices.

- There is a difference between the PRCI data and "all EPA" data for centrifugal compressor emissions. The PRCI project will likely examine this data more closely to determine whether the reason for the difference can be discerned. However, the difference does not impact the discussion and conclusions that follow in the document regarding sources included in the INGAA DI&M Guidelines.

For the six Subpart W sources, four are leak-related sources where the reduction option is a leak mitigation program (e.g., LDAR, DI&M). Blowdowns are a separate category of emissions and emission reduction opportunities are generally based on the feasibility of alternative operating practices for select types of events. Pneumatic device venting is reduced by using low bleed devices or compressed air systems.

The other four source types are the candidate compressor station emission sources for leak mitigation:

- Reciprocating compressor emissions from rod packing, isolation valves, and blowdown valves.

- Centrifugal compressor emissions from isolation valves, blowdown valves, wet seal degassing vents, and dry seals. (The latter is not included in Subpart W reporting.)

- Emissions through storage tank vents from leaking condensate tank dump valves.

- Equipment leaks from equipment and components other than those listed above (i.e., "other" leak emissions).

Blowdowns are a separate category of emissions and a significant contributor to overall facility emissions. Because blowdowns are a different category than leaks and EPA has not included facility blowdown reductions in proposed mitigation programs, and compressor station methane leak mitigation is the focus of a DI&M program, blowdown emissions in Figure 1 are not included in analysis or discussion below. Pneumatic device vented emissions are also a different category than leaks, but EPA proposed programs include reducing pneumatic device emissions, so limited additional discussion on pneumatic emissions is provided below.

Pneumatic device emissions are relatively small for the transmission and storage segments. Pneumatic device emissions are included in Figure 3 to compare emissions for methane emission sources recommended as reduction opportunities in proposed EPA programs: the EPA voluntary Methane Challenge program for existing sources, and the proposed NSPS rule that regulates methane emissions from new facilities (Subpart OOOOa).

Figure 3 shows the same PRCI data as Figure 1, using a different bar chart format and excluding blowdowns. The "other" leak emissions (Subpart W leaks not from compressors or tanks) are presented in two categories consistent with Subpart W methodology, where leaks survey results track whether or not the leaking component is in compressor service (i.e., thermal cycling and vibration from compressors may affect leak size and frequency).

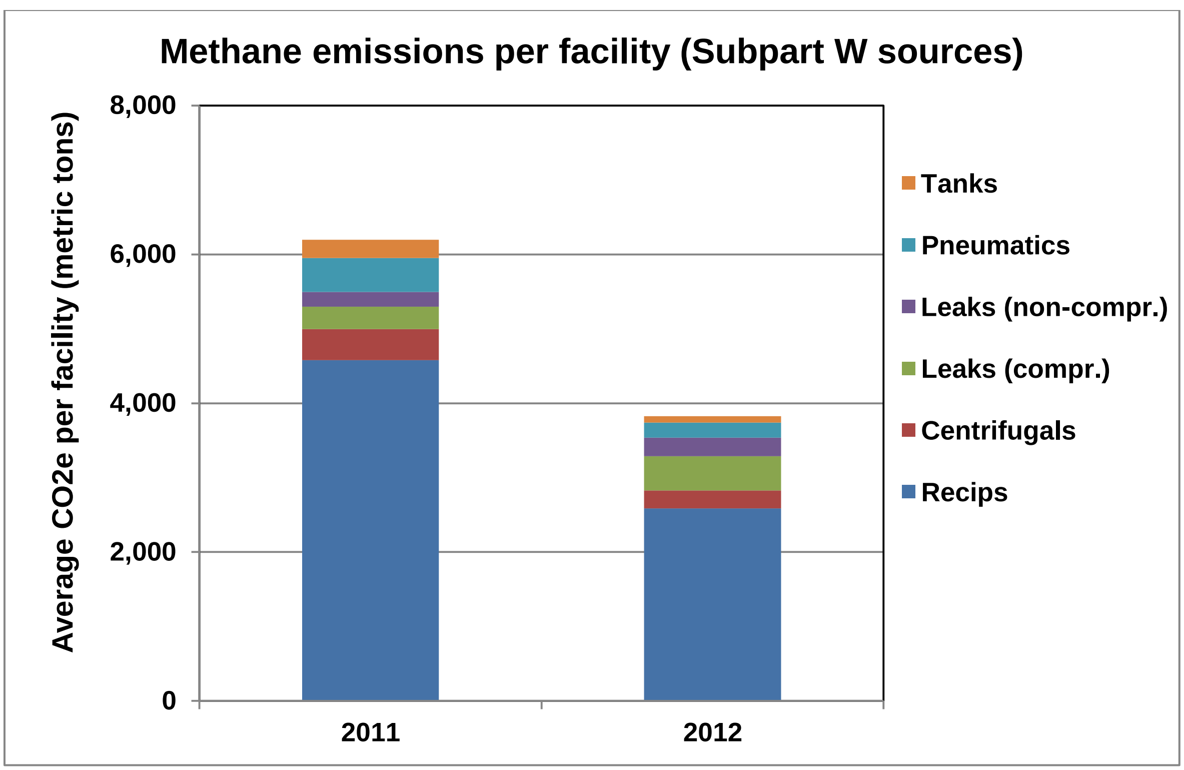


Figure 3. Subpart W emissions by source type for leaks and pneumatic venting.

Pneumatic device venting is 7% of these emissions in 2011 and 5% in 2012. For the remaining leak sources, reciprocating compressors, centrifugal compressors and tanks are included in the INGAA DI&M Guidelines. These sources comprise over 90% of the total leak emissions in 2011 and over 80% of the total in 2012. Addressing compressors and tanks requires surveying a limited number of vents, while the remaining 10 to 20% of leak emissions are associated with hundreds of components spread over the entire facility. Additional detail on leak emissions is provided in figures below.

In addition, the emission estimates from "other" leak sources excluded from the INGAA DI&M guidelines are based on a count of leaks detected in the annual survey and emission factors. The component-specific emission factors in Subpart W are based on 10 to 20 year old data, and it is likely that emissions have decreased as leak mitigation programs have become more common. Thus, if "other" leak emission estimates based on older data over-estimate emissions, then measured Subpart W leak data from compressors and tanks would comprise a larger percentage of the leak emissions than indicated by the Subpart W data.

The PRCI leak data from the figures is also presented in Figure 4 and Figure 5, which show additional details for the 2011 and 2012 Subpart W data for leak emission sources. Additional details associated with the leak sources that comprise total compressor leak emissions is available based on the emission source-operating mode combinations measured for Subpart W. The five categories include reciprocating compressors, centrifugal compressors, storage tank (dump valve leakage), and "other leaks" for components either in compressor service or non-compressor service. EPA usually groups the "other leaks" into a single category, but the Subpart W emission estimate uses different emission factors for each component type depending on whether or not the component is in compression service. For the categories other than tanks, the total emissions are comprised of emissions from multiple sources and different compressor modes, including:

1. Reciprocating compressors (typically released to atmosphere through elevated vents):
   a) Rod packing emissions when the unit is operating;
   b) Isolation valve emissions when the unit is shutdown and de-pressurized;
   c) Blowdown valve emissions when the unit is operating or in standby-pressurized mode.
2. Centrifugal compressors (typically released to atmosphere through elevated vents):
   a) Wet seal degassing vent emissions when the unit is operating (this is more a vent source than a leak source, but is grouped with centrifugal compressor leak emissions for tracking purposes);
   b) Isolation valve emissions when the unit is shutdown and de-pressurized; and
   c) Blowdown valve emissions when the unit is operating.
3. "Other leaks" in either compressor or non-compressor service, with the total emissions estimate based on emissions from each of five component types:

a) Connectors;

b) Valves;

c) Open ended lines (OELs);

d) Pressure relief valves (PRVs); and

e) Meters.

The figures show each of the categories (i.e., the primary bullet in this list), as well as the emissions from the specific leak sources associated with each category (i.e., the sub-bullets in this list). The percentage of total leak emissions for each source or category is shown in the figures. For "other leaks," where total emissions for the five component types are a small overall contributor to leak emissions, the percentage shown is for the total rather than for each of the five component types.

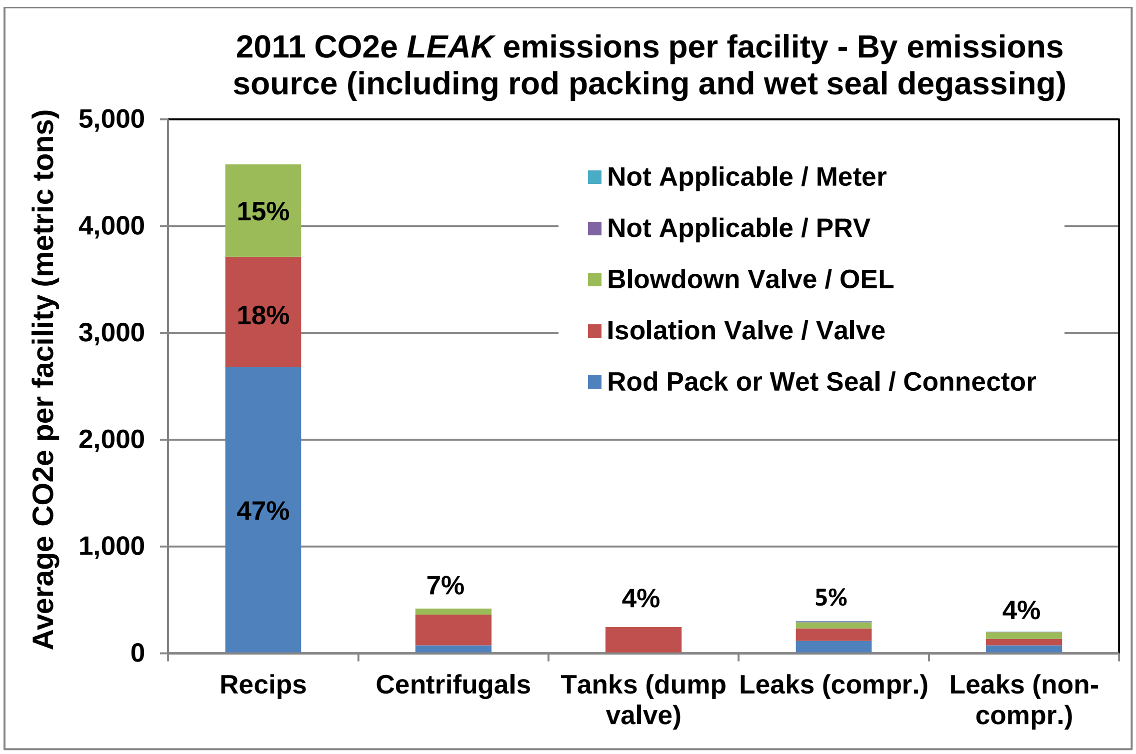


Figure 4. 2011 leak emissions by category and emissions source for Subpart W reported emissions compiled for the PRCI project.

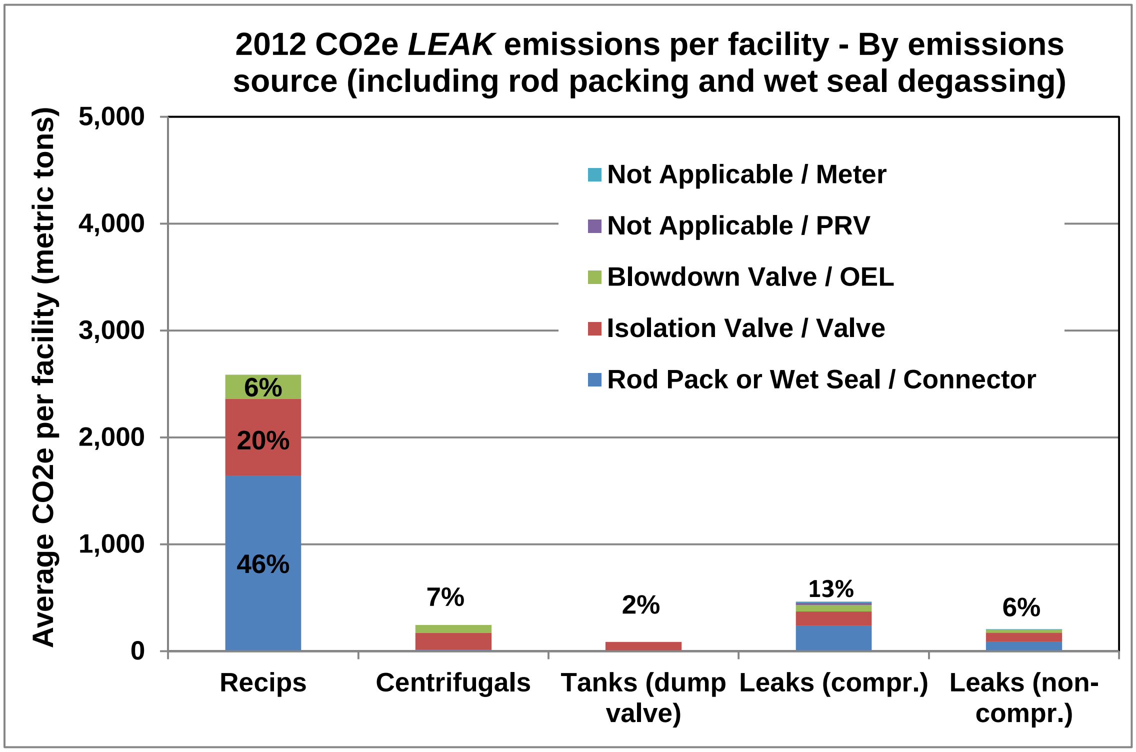


Figure 5. 2012 leak emissions by category and emissions source for Subpart W reported emissions compiled for PRCI project.

The first three leak categories – reciprocating compressors, centrifugal compressors, and storage tank dump valves – are included in the INGAA DI&M Guidelines and the latter two are not directly included in the program. Existing programs, such as walk-throughs that conduct audio-visual-olfactory (AVO) review for safety purposes will address "other leaks" within the facility, but those activities are not detailed in the INGAA DI&M Guidelines.

The number of potential leaks surveyed varies significantly for the first three categories compared to "other leaks." To reiterate, the three categories included in the INGAA DI&M Guidelines are based on sources that are measured for Subpart W and require surveying a minimal number of sources. The other leaks category requires surveying hundreds of additional components.

For example, potential leak sources for a reciprocating compressor (see items 1(a), 1(b) and 1(c) in the list above) will include rod packing leakage, two isolation valves (suction and discharge side of the compressor) and a blowdown valve. Thus, a limited number of vent lines need to be surveyed to identify leakage for the three leak categories in the INGAA DI&M Guidelines. In contrast, the other potential leak sources (see five component types in items 3(a) through 3(e) in the list above) are comprised of *hundreds* of components throughout the compressor station that would require surveying. About 80% or more of leak emissions are covered through the focused program in the INGAA DI&M Guidelines.

These two figures show the relative contribution of leak emissions by category and associated leak source for the first two years of Subpart W reporting. For 2011 (Figure 4):

- The three categories included in the INGAA DI&M Guidelines **comprise 91% of the total** leak emissions.
  - 5,240 metric tons CO_2 equivalent emissions on average for all facilities in the PRCI dataset.
- The two leak categories not included in the INGAA DI&M Guidelines – other equipment leaks in compressor service or non-compressor service – comprise 9% of the total emissions and less than 500 metric tons.

For 2012, total leak emissions are lower, which is likely due to repair of some of the larger leaks discovered in 2011 (e.g., reciprocating compressor leak emissions). From Figure 5:

- The three categories included in the INGAA DI&M Guidelines **comprise 81% of the total** leak emissions.
  - 2,915 metric tons CO_2 equivalent emissions on average for all facilities in the PRCI dataset.
- The two leak categories not included in the INGAA DI&M Guidelines – other equipment leaks in compressor service or non-compressor service – comprise 19% of the total emissions and approximately 665 metric tons.

Additional detail on individual measurements and the contribution of large leaks to the overall total is available for the three leak categories included in the INGAA DI&M Guidelines. Data presented in the figures below show that a DI&M program following the INGAA Guidelines may ultimately demonstrate that an even more focused program is warranted (e.g., the relative emissions from blowdown valve leakage compared to isolation valve leakage may have implications for requirements such as survey frequency).

Figures 6 and 7 present PRCI measured emissions by source type and compressor mode – e.g., rod packing emissions in operating mode, isolation valve emissions in shutdown de-pressurized mode. Figure 6 presents a cumulative distribution of reciprocating compressor emissions for the four unique source-operating mode combinations in Subpart W. In Figures 4 and 5 above, the blowdown valve emissions for two different compressor modes are combined for the portion of the bar chart that shows "blowdown valve" emissions. The blowdown valve emissions are separated by Subpart W mode in Figure 5. Figure 7 presents the same information for the three source-compressor mode combinations for centrifugal compressors.

For the cumulative distribution plots, all of the measurement data are ranked from largest to smallest and cumulatively added. Only the "non-zero" measurements are included in these figures (i.e., the tail would be longer if additional measurements showing no leakage were included). These data show that leaking blowdown valves and centrifugal compressor degassing vents are smaller contributors to facility emissions than isolation valves and reciprocating compressor rod packing.

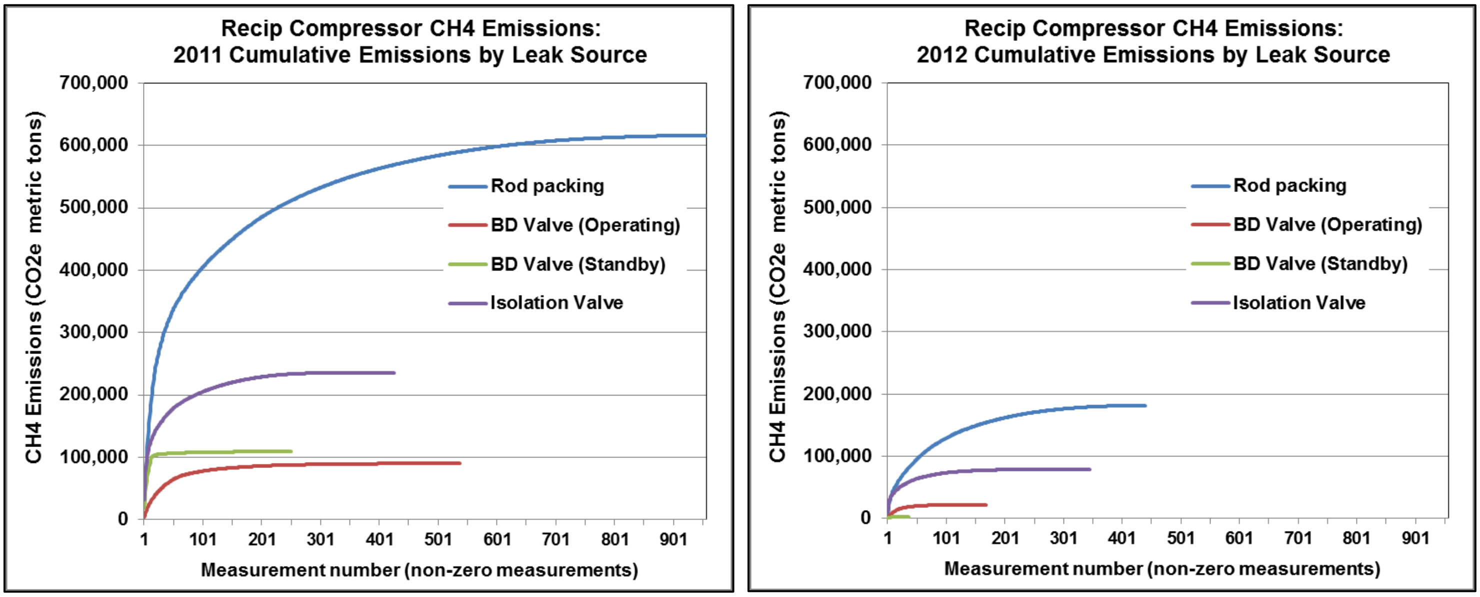


Figure 6. Reciprocating compress emissions by source – mode combination: Rod packing (operating mode), blowdown valve (operating mode or standby-pressurized mode) and isolation valve (shutdown-depressurized mode).

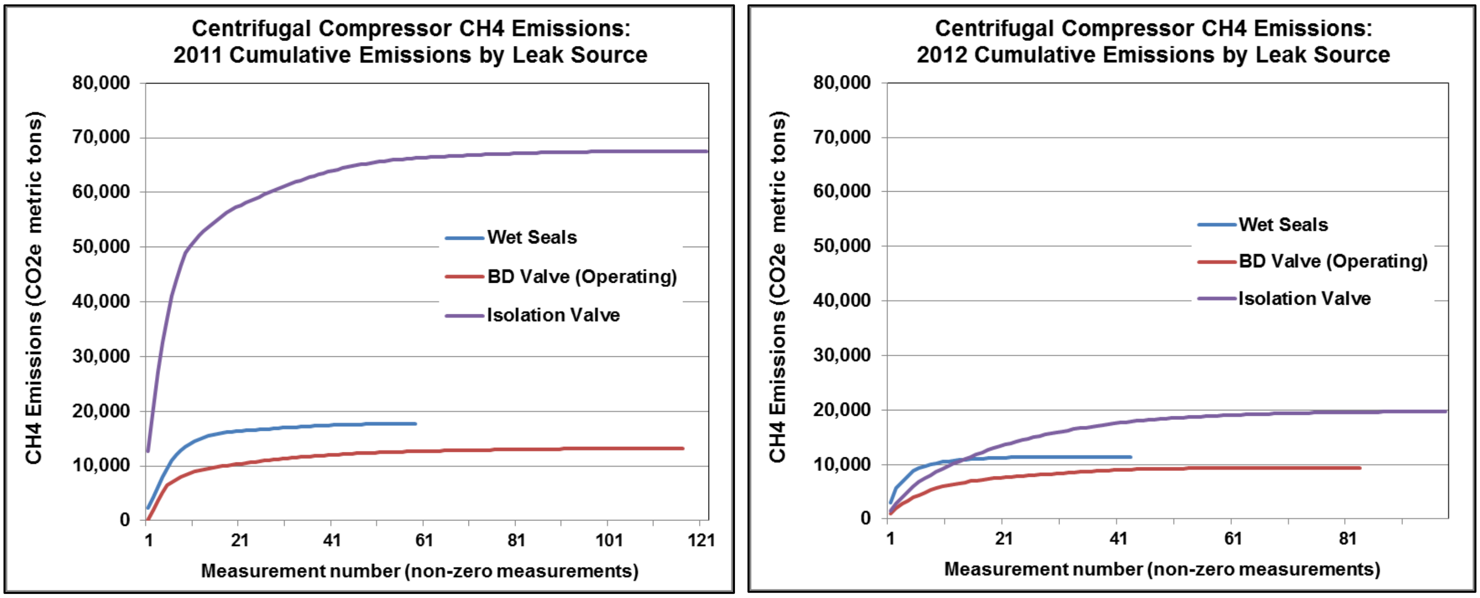


Figure 7. Centrifugal compress emissions by source – mode combination: Wet seal degassing (operating mode), blowdown valve (operating mode) and isolation valve (shutdown-depressurized mode).

For reciprocating compressors, rod packing leakage is a large contributor to total emissions. For both reciprocating and centrifugal compressors, isolation valves are an important source. In a DI&M

program, repair decisions consider the leak size and the repair cost (or degree of difficulty). This approach is based on historical data that shows that a relatively small number of leaks comprise the majority of emissions. The same phenomenon is demonstrated in Figures 6 and 7. For example, in 2011 there were about 440 measurements of reciprocating compressor isolation valve emissions. The top 20% (about 90 measurements) comprise over 85% of the emissions from isolation valves. This trend is even more pronounced for the reciprocating compressor blowdown valves measured in standby mode in 2011. Several measurements (about 2% of the total) account for nearly all of the emissions from this source.

These figures, along with the storage tank figure below, show that the INGAA DI&M Guidelines include leak sources that PRCI Subpart W data shows as relatively small contributors. However, the INGAA Guidelines chose to include sources associated with Subpart W measurements, and additional sources not covered by Subpart W (e.g., rod packing in standby-pressurized mode) to provide the opportunity to develop a larger dataset and more clearly demonstrate larger leak sources. While total emissions for other leak sources are a larger percentage than some categories included in the INGAA Guidelines (e.g., Figure 5 shows that 13% of total leak emissions in 2012 are from other leaks for components in compressor service), those total emissions are from many components, while sources with smaller relative emissions included in the INGAA Guidelines (e.g., tanks are 2% in 2012) are associated with discrete sources that have a higher risk of large leaks.

A focus on the "gross emitters" is the most effective approach to reduce methane emissions. The data collected from a DI&M program, in conjunction with other ongoing data being reported for Subpart W (e.g., leak surveys for "other" leaks), will provide insight into program performance. As the program is implemented, performance will be defined, and the need to consider program adjustments (e.g., to focus on *more or fewer* potential leak sources) will be identified.

Storage Tanks Emissions

Although a relatively small source compared to compressor leaks, EPA has expressed concern regarding leaking dump valves, and Subpart W requires measurement of the associated tank vents. Thus, storage tanks are included in the INGAA DI&M Guidelines. Figure 6 shows PRCI data results from *non-zero* measurements in 2011 (111 non-zero measurements) and 2012 (51 non-zero measurements). *Cumulative* emissions for all tank measurements are shown in the left graph. The graph on the right shows each individual measurement. These data show that total tank emissions are relatively small and decreased from 2011 to 2012. Additional observations include: a relatively small number of facilities / measurement contribute most of the emissions; there were fewer leaks in 2012 than in 2011; and, there were fewer large leaks in 2012 than in 2011.

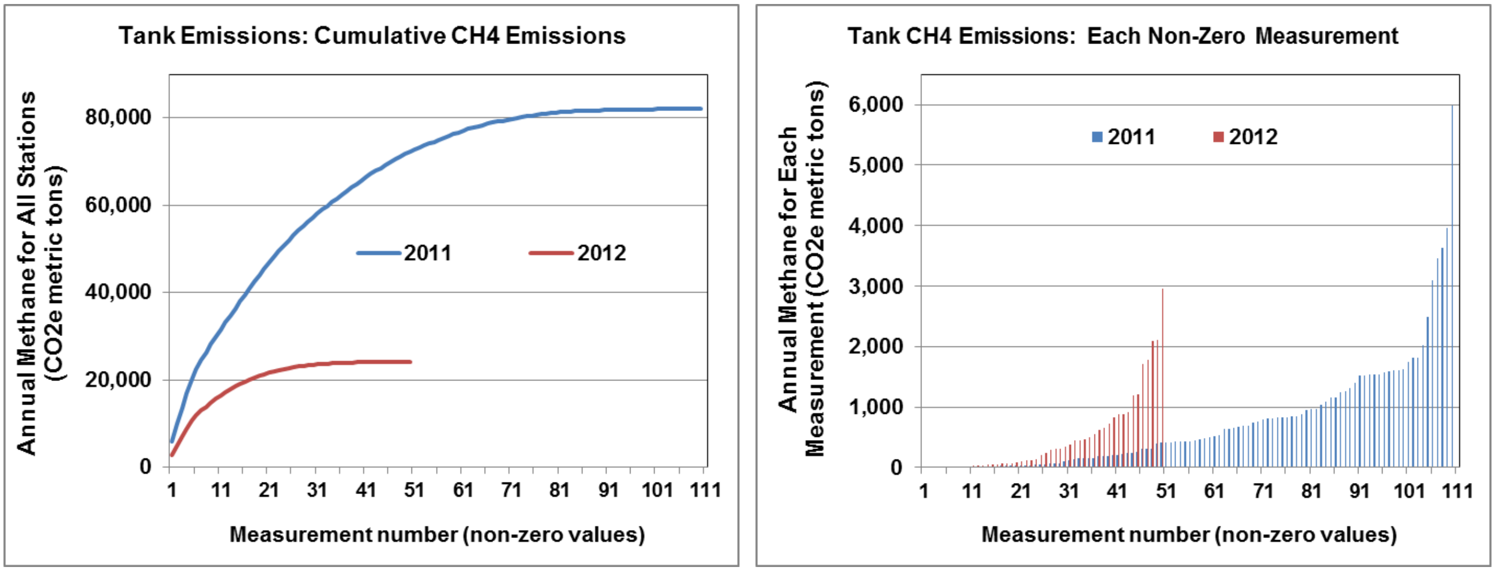


Figure 6. Storage tank emissions from leaking dump valves in 2011 and 2012. Cumulative distribution of all non-zero measurements (left graph) and leak rate for each non-zero measurement (right graph).

CONCLUSIONS

DI&M is a proven approach for reducing methane emissions from leaks at natural gas transmission and storage compressor stations. The INGAA DI&M Guidelines focus on compressor station leak sources that pose a higher risk of being a large leaker, include compressor and storage tank sources that require leak rate measurement under Subpart W, and include additional leak sources excluded from Subpart W (e.g., reciprocating compressor rod packing in standby-pressurized mode, centrifugal compressor dry seals).

Subpart W data and supplemental data from a PRCI project shows that the leak sources included in the INGAA DI&M Guidelines address more than 80% of emissions from compressor station leaks. Thus, a focused DI&M program provides an effective leak mitigation approach. Data gathered as a DI&M program is implemented also provides the ability to assess performance, ensure that the appropriate sources are included, and consider program adjustments to address insights gained from facility leaks and reduction opportunities.

APPENDIX B

RELEVANT PIPELINE AND HAZARDOUS MATERIALS SAFETY ADMINISTRATION REGULATIONS

49 C.F.R. Part 192

§ 192.703 General.

(a) No person may operate a segment of pipeline, unless it is maintained in accordance with this subpart.

(b) Each segment of pipeline that becomes unsafe must be replaced, repaired, or removed from service.

(c) Hazardous leaks must be repaired promptly.

§ 192.705 Transmission lines: Patrolling.

(a) Each operator shall have a patrol program to observe surface conditions on and adjacent to the transmission line right-of-way for indications of leaks, construction activity, and other factors affecting safety and operation.

(b) The frequency of patrols is determined by the size of the line, the operating pressures, the class location, terrain, weather, and other relevant factors, but intervals between patrols may not be longer than prescribed in the following table:

	Maximum interval between patrols	
Class location of line	**At highway and railroad crossings**	**At all other places**
1, 2	71/2 months; but at least twice each calendar year	15 months; but at least once each calendar year.
3	41/2 months; but at least four times each calendar year	71/2 months; but at least twice each calendar year.
4	41/2 months; but at least four times each calendar year	41/2 months; but at least four times each calendar year.

(c) Methods of patrolling include walking, driving, flying or other appropriate means of traversing the right-of-way.

§ 192.706 Transmission lines: Leakage surveys.

Leakage surveys of a transmission line must be conducted at intervals not exceeding 15 months, but at least once each calendar year. However, in the case of a transmission line which transports gas in conformity with §192.625 without an odor or odorant, leakage surveys using leak detector equipment must be conducted—

(a) In Class 3 locations, at intervals not exceeding $7\frac{1}{2}$ months, but at least twice each calendar year; and

(b) In Class 4 locations, at intervals not exceeding $4\frac{1}{2}$ months, but at least four times each calendar year.

49 C.F.R. Part 191

§ 191.3 Definitions.

As used in this part and the PHMSA Forms referenced in this part—

…..

Incident means any of the following events:

(1) An event that involves a release of gas from a pipeline, or of liquefied natural gas, liquefied petroleum gas, refrigerant gas, or gas from an LNG facility, and that results in one or more of the following consequences:

(i) A death, or personal injury necessitating in-patient hospitalization;

(ii) Estimated property damage of $50,000 or more, including loss to the operator and others, or both, but excluding cost of gas lost;

(iii) Unintentional estimated gas loss of three million cubic feet or more;

(2) An event that results in an emergency shutdown of an LNG facility. Activation of an emergency shutdown system for reasons other than an actual emergency does not constitute an incident.

(3) An event that is significant in the judgment of the operator, even though it did not meet the criteria of paragraphs (1) or (2) of this definition.

§191.5 Immediate notice of certain incidents.

(a) At the earliest practicable moment following discovery, each operator shall give notice in accordance with paragraph (b) of this section of each incident as defined in §191.3.

(b) Each notice required by paragraph (a) of this section must be made to the National Response Center either by telephone to 800-424-8802 (in Washington, DC, 202 267-2675) or electronically at *http://www.nrc.uscg.mil* and must include the following information:

(1) Names of operator and person making report and their telephone numbers.

(2) The location of the incident.

(3) The time of the incident.

(4) The number of fatalities and personal injuries, if any.

(5) All other significant facts that are known by the operator that are relevant to the cause of the incident or extent of the damages.

APPENDIX C

Directed Inspection and Maintenance
Voluntary Program Elements and Procedures for
Natural Gas Transmission and Storage Compressor Stations

1.0 PURPOSE

The purpose of a Directed Inspection and Maintenance (DI&M) program is to identify leak sources and mitigate methane emissions based on a prioritization process that assesses emissions potential. It has been shown that a relatively small percentage of leaks contribute the vast majority of emissions for natural gas operations – e.g., 95% of methane emissions from equipment leak are from 20% of the leaks at compressor stations.[82] DI&M leverages this characteristic of compressor station leaks through procedures that focus repairs on larger leaks and avoid unnecessary repairs to inconsequential leaks. DI&M is an effective and practical approach for reducing methane emissions from equipment/component leaks. A DI&M program involves periodic component and vent leak screening at a facility, leak characterization, and prioritized repair of leaking components. Implementing DI&M is a proven, cost-effective way to reduce methane emissions from leaks. This guideline document provides the structure, program elements, and procedures for a voluntary company-specific DI&M program. The program elements in this document discuss options for program implementation, such as facilities that will be included and the implementation schedule. The facilities included, as well as the specific components and metrics of a company's program, will be defined in their company-specific DI&M Plan (hereinafter referred to as "the DI&M Plan"). The DI&M Plan will be reviewed and updated as necessary to reflect program maturation as data is collected.

2.0 APPLICABILITY

2.1 Affected Facilities and Phase-in Period

The company will define a basis for phasing in surveys at compressor stations (hereinafter referred to as facilities) in the DI&M Plan. All facilities will be surveyed over a five-year phase-in period.

2.2 Affected Equipment / Emissions Sources

The company DI&M Plan shall include surveys focused on key leak sources within a facility with a higher probability of significant leakage, based on key sources of leakage identified in previous studies and available company (and other) information. The list will include the equipment and components identified in Table 1, and the DI&M Plan will include additional information on the emission sources, such as compressor counts, compressor type, etc. Table 1 includes equipment/component leak sources associated with reciprocating compressors, centrifugal compressors, and storage tanks. This focuses resources

[82] "Directed Inspection and Maintenance at Compressor Stations." U.S. EPA Natural Gas STAR, Lessons Learned (see http://epa.gov/gasstar/documents/ll_dimcompstat.pdf), EPA430-B-03-008 (October 2003).

and efforts on leak sources that have been historically proven as the main contributors to total leak emissions.

In addition, the company DI&M program will track leaks repaired during standard operational activities associates with safety and maintenance practices. Company practices (e.g., daily or routine facility walk-through) will be outlined in the DI&M Plan.

As data is obtained through the voluntary DI&M program, methane emissions from facility surveys may be used to refine the basis for focused surveys and survey intervals, as detailed in the DI&M Plan. At their discretion, companies may include other equipment / components in the DI&M Plan.

Table 1. Affected Equipment / Component List for DI&M Program.

<table>
<tr><td>• Reciprocating compressor blowdown valve leakage through blowdown vent in any mode as found:
3. Leakage during “Operating” mode
4. Leakage during “Standby Pressurized” mode</td><td rowspan="2">• Reciprocating rod packing leakage[A] in any mode as found:
3. Reciprocating rod packing emissions during “Operating” mode
4. Reciprocating rod packing emissions during “Standby Pressurized” mode</td></tr>
<tr><td>• Reciprocating compressor unit isolation valves (suction and discharge) leakage through the associated vent during “Not Operating, Depressurized” mode</td></tr>
<tr><td rowspan="2">• Centrifugal compressor blowdown valve leakage through the blowdown vent in any mode as found:
3. Leakage during “Operating” mode
4. Leakage during “Standby Pressurized” mode</td><td>• Centrifugal compressor unit isolation valves (suction and discharge) leakage through the associated vent during “Not Operating, Depressurized” mode.</td></tr>
<tr><td>• Centrifugal compressor wet or dry seal leakage through associated vent(s) in any mode as found (see modes listed above for rod packing).</td></tr>
<tr><td colspan="2">• Storage tank vents to atmosphere from scrubber dump valve leakage.</td></tr>
</table>

[A] Reciprocating compressor rod packing is designed to leak, even when new.[83] Repair decisions and timing that considers condition-based maintenance for rod packing will be defined in the DI&M Plan.

2.3 Exclusions

Facilities or units subject to leak detection and repair (LDAR) requirements under an existing air quality regulation or permit condition(s) will be identified in the

[83] EPA Natural Gas STAR Lessons Learned document, “Reducing Methane Emissions From Compressor Rod Packing Systems.” October 2006. http://www.epa.gov/gasstar/documents/ll_rodpack.pdf

DI&M Plan. The operator may elect to achieve leak reductions at these facilities through that existing program rather than through DI&M (see Section 4.2). Elements of an LDAR program are not discussed further in this document, although select criteria herein are based on LDAR[84] approaches (e.g., delay of repair) and citations are provided.

In addition, a company may elect to monitor a potential leak source such as a compressor vent by using a continuous flow indicator (e.g., flow meter). The approach used for flow monitoring will be identified in the DI&M Plan, however leak screening and characterization procedures discussed in this document would not apply to these vent lines.

3.0 STANDARDS FOR IDENTIFYING LEAKS AND INITIAL REPAIR

Facilities will implement a defined and documented process for identifying and characterizing leaks. This section identifies provisions for leak screening, leak tracking, immediate repair, and leak rate characterization.

3.1 Survey Schedule

Per Section 2.1, an initial leak survey will be completed at all facilities over a five-year phase-in period. Subsequent to the initial phase-in period, all facilities will continue to be surveyed as defined in the DI&M Plan. Leak surveys will address the equipment / components discussed in Section 2.2.

3.2 Standard Maintenance Repairs and Immediate Repairs During the Survey

In addition to scheduled leak surveys according to Section 3.1, and repairs according to Section 4, leaks may be identified and repaired during normal site operations and maintenance activities. In addition, a leak discovered during the facility survey may be immediately repaired. The operator can repair these leaks without determining the leak concentration or completing the characterization described in Section 3.5. Records of successful repairs shall be retained according to Section 5.

3.3 Identification and Screening of Equipment / Component Leaks

3.3.1 Leak *Identification* Procedures

Facilities will follow industry standard test methods and procedures for identifying and screening leaks. Standard instrumentation will be used, including but not limited to an optical imaging (e.g., infrared) camera (hereinafter referred to as "IR camera"). Methods and instrumentation will be identified in the DI&M Plan, and may include advanced or innovative monitoring technologies if the instrument or method is appropriately demonstrated. In addition, rather than leak screening, a company may elect to measure the leak rate for a particular

[84] For example, see 40 CFR, Part 60, Subpart VVa, "Standards of Performance for Equipment Leaks of VOC in the Synthetic Organic Chemicals Manufacturing Industry for Which Construction, Reconstruction, or Modification Commenced After November 7, 2006." §60.480a through §60.489a.

component or potential leak source (as discussed in Section 3.5) and not conduct leak screening based on exceeding the concentration threshold.

The accuracy of leak measurement methods varies and can be affected by operational and meteorological conditions. The DI&M Plan will identify industry standard practices, methods, and instrumentation available for leak characterization, and the associated quality assurance / quality control (QA/QC) measures.

If leakage is detected, the leaking component shall be assessed using one of the following procedures to determine if the leak threshold (see Section 7 and the DI&M Plan) is exceeded:

- Leak Concentration: Natural gas detectors or gas sensors are required if determining whether the measured concentration exceeds the leak threshold defined in the DI&M Plan.
  - If the measured concentration does not exceed the leak threshold, the component is not considered a "leak" for the purposes of the DI&M program.
- Leak Rate: As an alternative to assessing the leak concentration, owners can characterize the leak *rate* (see methodology in Section 3.5) for any leaking component identified using an IR camera (or comparable screening method).
  - If the measured rate does not exceed the leak threshold, the component is not considered a "leak" for the purposes of the DI&M program.
- Leak Categorization using IR camera:[85] A trained IR camera operator can categorize a detected leak as below the leak threshold, in which case the component is not considered a leak for the purposes of the DI&M program.
- The operator may choose to conduct an immediate repair according to Section 3.2 rather than measuring the leak concentration or characterizing the leak rate.

For equipment/components that are not accessible from the ground, the IR camera should be used to screen for leaks (e.g., for elevated vents without sample ports).

3.3.2 Equipment/Component Leak Sources and Screening

The sources in Table 1 and discussed in the company DI&M Plan shall be screened for leaks. The survey team should be experienced to identify and screen these sources, and discern the difference between leaks from these sources and other releases, such as maintenance related blowdowns, vent line differentiation, and emissions from combustion stacks (e.g., engines, turbines, heaters, or boilers).

[85] The company DI&M Plan may include a methodology for an experienced IR camera operator to assess the leak image and categorize the leak. For example, visualization of a "wisp" would be classified as a small leak that is commensurate with a leak concentration or leak rate less than the leak threshold, and not considered a leak for the purposes of the DI&M program.

For reciprocating and centrifugal compressors, leak screening (and leak characterization conducted according to Section 3.5) should be completed in the as-found mode of operation and the operating mode identified in Table 1 should be logged. As discussed in Section 2.3, vents equipped with a meter or instrument to identify leakage are excluded from the DI&M survey and those sources are monitored as defined in the DI&M Plan.

3.4 Tracking Leaks

Any equipment or components with a leak screening value greater than the leak threshold value defined in Section 7 or the DI&M Plan is considered a "leak" for subsequent program considerations (i.e., the procedures that follow). These components will be entered into a company management system for tracking leaks, as defined in the DI&M Plan.

3.5 Leak Rate Determination

The objective of measuring or characterizing a leak is to obtain a relative understanding of the magnitude of emissions and associated potential for reductions. Unless immediately repaired, leaks screening above the leak threshold (as defined in Section 7 or the DI&M Plan) will be tracked in a company-defined management system, and characterized.

(a) *Exceptions*

The company DI&M Plan will identify exceptions[86], such as the following:

1. Unsafe, Inaccessible, or Difficult to Monitor:
    a. If the leak is unsafe, inaccessible, or difficult to monitor, the component will be placed on the delay of repair list (see Section 4.3) and, if feasible, repaired during the next planned unit or station shut down.

    b. For (a) and per item (3) below, the DI&M Plan may specify a procedure for an experienced IR camera operator to assess the visual image and identify insignificant leaks that do not warrant follow-up action (i.e., repair, inclusion on delay of repair list, or addition of sample ports).

2. Manifolded or merged vent lines may not isolate the source of the leak and often cannot segregate individual leak source contribution. For example, if compressor cylinder rod packing vent lines may be manifolded together, individual lines may not be accessible, and it may not be possible to isolate the individual cylinder(s) leaking rod packing.

    The company owner or operator shall complete a review and document options for installing sample ports upstream in the vent lines prior to the manifold following the initial leak discovery. If sample ports cannot be

[86] Exceptions are based on existing leak mitigation programs. For example, LDAR programs include Delay of Repair provisions, such as 40 CFR, Part 60, Subpart VVa, §60.482-9a.

installed, document the finding, and complete a review to document potential alternatives to mitigate or eliminate the leak.

3. For exceptions from leak characterization, the company may include a methodology in its DI&M Plan for a trained IR camera operator to assess the leak image and conclude that further characterization is not necessary.

(b) Leak rate characterization or estimation

Measurements will be completed using industry standard methods, practices, and instrumentation, including but not limited to a high volume sampler, calibrated vent bag, or other standard combination of flow rate and concentration characterization such as a totalizing vane anemometer or intrinsically safe hot wire anemometer, and natural gas detectors or gas sensors. Acceptable methods may also include monitoring techniques, such as the IR camera, that indicate the relative leak rate compared to other sources at the facility, as defined in the DI&M Plan.

For exceptions in (a) where leak rate measurement is not conducted, the leak rate shall be estimate using a company-specific or company-defined emission factor, as defined in the DI&M Plan.

3.6 Survey Frequency Review

The company DI&M Plan may include provisions to revise the survey frequency defined in Section 3.1 as information is gathered over multiple surveys. The decision should be based on performance metrics related to the prevalence of leaks, the leak rate characterization, and/or the need for repairs. The DI&M Plan will be reviewed and updated as necessary to reflect program maturation as data is collected, as discussed in Section 4.4.

4.0 PRIORITIZATION OF LEAKS FOR REPAIR

The characterized leak rates will be recorded according to Section 5. Leaks repaired immediately will be recorded but are excluded from the following process. The remaining leak rate volumes from a survey will be prioritized and repaired based on a performance metric, or combination of metrics, defined in the company DI&M Plan. Leak reduction metrics should be based on a multi-year programmatic approach where the metric is achieved over a multi-year period defined in the DI&M Plan. Implementation of the DI&M program is expected to achieve substantial methane emission reductions from compressor station components.

Progress toward meeting the metric will be tracked based on data acquired. Data currently available to establish a performance metric is limited.[87] Thus, annual and cumulative performance will be assessed and the metric will be refined as needed per the objectives of the DI&M Plan. The metric will be based on:

- Reducing leakage by a defined percentage or mass (tons) over an estimated baseline emission level, and/or
- Reducing leakage to a performance level (e.g., emissions per facility, emissions as a percentage of throughput) commensurate with leak mitigation best practices.

Program data will be assessed annually to demonstrate progress towards meeting the metric(s). Company data will be analyzed to assess annual and cumulative emissions performance since program inception to demonstrate methane emission reduction progress. The program data may be compared to historical company data, EPA National GHG Inventory emissions, or other appropriate historical data.

4.1 Repairs and Repair Confirmation

As described in Section 3.2, the company may elect to repair a leak following the leak screening step. Those actions will be recorded, but that repair decision is separate from Section 4 repairs. For a leak selected for repair based on the Section 4 prioritization, the following steps will be taken:

1. Leaks selected for repair (i.e., high priority leaks) will be repaired as soon as practical, as defined in the DI&M Plan. In some cases (e.g., extended facility outage where the system is not pressurized), repair confirmation may be delayed, in which case repair status will be checked when practical.
2. Priority leaks that cannot be repaired according to the schedule defined in the DI&M Plan will be identified as outlined in Section 4.3 (Delay of Repair).
3. Repairs will be confirmed by demonstrating that leaks are eliminated per the leak threshold definition.

[87] As the program is implemented and data become available, larger leaks will be addressed. In future surveys, fewer leaks that warrant repair would be expected. As the program matures, the data is predicted to identify a stable performance level (e.g., emissions per facility, emissions as a percentage of throughput) commensurate with a rigorous leak mitigation best practices program.

A repair attempt by the company is not required for a component or equipment that is under warranty. The company will vigorously seek repairs to be completed by the warrantor per the terms and conditions of the warranty.

4.2 Alternative Program Approaches

As discussed in Section 2.3, the company may elect to reduce leak emissions by satisfying conventional LDAR requirements for VOCs, such as those in 40 CFR Part 60 Subpart KKK– Standards of Performance for Equipment Leaks of VOC From Onshore Natural Gas Processing Plants.

4.3 Delay of Repair (DOR)

Repairs can be delayed if *one* of the following conditions is satisfied. The justification for each leak repair delay will be documented.

1. Repair Requires Unit / Station Shutdown – If the repair of any component is technically infeasible without a process unit shut down or if the source cannot be repaired during operation of the source.
2. Equipment Isolated From Process – If the repair is unnecessary because the equipment is isolated from the process (i.e., the component/equipment is taken out of gas service, and repair is completed before a return to service).
3. Valves Where Purged Gas Would Exceed Leaking Gas – If immediate repair of the equipment would result in vented emissions (from equipment purge) greater than the emissions resulting from delay.
4. Valves Where Leakage Would Be Controlled – If leaked gas is collected and destroyed, recovered in a control device, or used for some other beneficial purpose.
5. Valve Assembly Supplies Unavailable – If valve assembly replacement is necessary during the process unit shutdown, and valve assembly supplies have been depleted.
6. Repair Is Unsafe, Inaccessible, or Difficult to Monitor – If a repair cannot be made due to safety issues.
7. Repair Cannot Be Accommodated in Current Budget Cycle – If repair costs exceed a reasonable annual budget, repair will be addressed in a subsequent budget cycle.
8. Equipment Must Be Ordered for Repair – If additional time is needed to procure equipment or components necessary to complete the repair, the repair timing will be based on equipment delivery dates that may depend upon manufacturer stock and shipment schedules.
9. Specialized Skill Set Must Be Scheduled – If the repair requires a specialized technical skillset, the repair timing will be based on personnel scheduling.

10. Equipment/Component Is Under Warranty – If a repair is delayed due to warranty issues.

In some cases, a delayed repair can be cancelled before the repair is performed. When delay of repair applies for a leaking component or equipment that remains in service, the component or equipment may be considered to be repaired and removed from the DOR list if subsequent monitoring indicates readings below the leak threshold. In this case, the basis for removing the leak from the repair list will be documented.

The DI&M Plan may include alternative monitoring schedules for leaks on the DOR list.

4.4 Review of Program Results and the Company-Specific DI&M Plan

The DI&M Plan will be assessed and may be updated to reflect implementation insights from program results. At a minimum, the DI&M Plan will be reviewed, and revised as appropriate, after the initial 5-year phase-in period is completed.

5.0 RECORDKEEPING

The company will maintain records in hard copy or electronic format for at least five years following the date of the survey, including the following records:

1. Survey dates, log including personnel performing the leak survey/characterizations, and Quality Assurance and Quality Control (QA/QC) for survey methods;
2. Record of each repaired leak by source type, including leak screening or leak rate record, date of repair, and verification of repair;
3. Delay of Repair (DOR) list and justification;
4. For leaks not repaired or on the DOR list, the count of leaks and the total leak rate.

6.0 DATA QUALITY ASSURANCE AND CONTROL

Leak screening, concentration measurements, leak characterization, instrument calibrations and performance checks shall follow industry standard methods, procedures, and guidance.

7.0 DEFINITIONS AND COMMON TERMS

Accessible from the ground means within 2 meters (6.5 feet) of the grate or surface. Does not require a ladder or step to access.

***Calibrated bag (also known as a vent bag*)** means a flexible, non-elastic, antistatic bag of a calibrated volume that can be affixed to an emitting source such that the emissions inflate the bag to its calibrated volume.

Compressor service refers to equipment and components associated with a compressor.

DI&M Plan means the company-specific plan that defines detailed criteria for the company's directed inspection and maintenance program, such as: the included facilities and sources within the facility, implementation schedule, survey schedule, performance metric, and leak screening and characterization methods and QA/QC.

Equipment leak detection means the process of identifying leakage from equipment, components, and other point sources.

Facility means an affected compressor station.

Flowmeter means a device that measures the mass or volumetric rate of flow of a gas, liquid, or solid moving through an open or closed conduit (e.g., flowmeters include, but are not limited to, rotameters, turbine meters, coriolis meters, orifice meters, ultra-sonic flowmeters, and vortex flowmeters).

Inaccessible component means a component meeting any of the following criteria:

1. Buried,
2. Insulated in a manner that prevents access to the component by a monitor probe,
3. Obstructed by equipment or piping that prevents access to the component by a monitoring probe,
4. Obstructed or covered by floor grating that would require removal and replacement of flooring using a crane or other mechanical lifting method,
5. A component where access would require entry into a confined space as defined by OSHA,
6. Inaccessible because it would require elevating the monitoring personnel more than 2 meters above a permanent support surface or would require the erection of scaffold or use of a manlift, or
7. Not able to be accessed at any time in a safe manner to perform monitoring. Unsafe access includes, but is not limited to access that would require near proximity to hazards such as electrical lines, excessive noise, vented gas releases or would risk damage to equipment.

Leak means any unintended methane vapor release from a component into the ambient air or into a building. This may include leakage above an acceptable threshold defined by the manufacturer.

Leak characterization means flow rate measurement or otherwise categorizing (e.g., by a trained IR camera operator) the size of a leak. A company may elect to omit leak screening and proceed immediately to the leak characterization step.

Leak screening means the initial procedure to assess whether leakage is occurring based on methods such as IR camera screening. If the initial screening does not measure concentration (e.g., an IR camera is used for leak screening) and a concentration measurement is conducted for comparison against the leak threshold concentration, the concentration measurement is also part of the leak screening procedure.

Leak survey or Survey means the complete on-site procedures associated with screening for leaks and characterizing the leak rate from identified leaks.

Leak threshold means the local concentration as measured by natural gas detectors / gas sensors at the surface of a leak source that indicates that a methane emission (leak) is present, or a measured leak rate. The leak threshold is an instrument meter reading based on methane as the reference compound or a measured methane leak rate as follows:

Option 1: If an instrument reading of 25,000 ppm or greater of methane is measured, a leak is detected.

> 25,000 ppm or 2.5%

OR

Option 2: If a leak rate exceeds 6.0 SCFH or an alternative identified in the DI&M Plan based on company experience from their leak mitigation program or manufacturer's data.

Leaks observed by the IR Camera in the absence of an associated concentration measurement or leak rate measurement are considered a leak, unless documented otherwise based on a procedure for a trained IR Camera operator to classify leaks defined in the DI&M Plan. For rod packing, a separate threshold or condition-based maintenance approach may be defined in the DI&M Plan (see Table 1, footnote A).

Natural gas means a naturally occurring mixture or process derivative of hydrocarbon and non-hydrocarbon gases found in geologic formations beneath the earth's surface, of which its constituents include, but are not limited to, methane, heavier hydrocarbons and carbon dioxide.

Repair means that equipment is adjusted, repaired, replaced or otherwise altered, in order to eliminate or reduce a leak below the applicable leak threshold. A successful repair is confirmed using any qualitative or quantitative screening instrument or method.

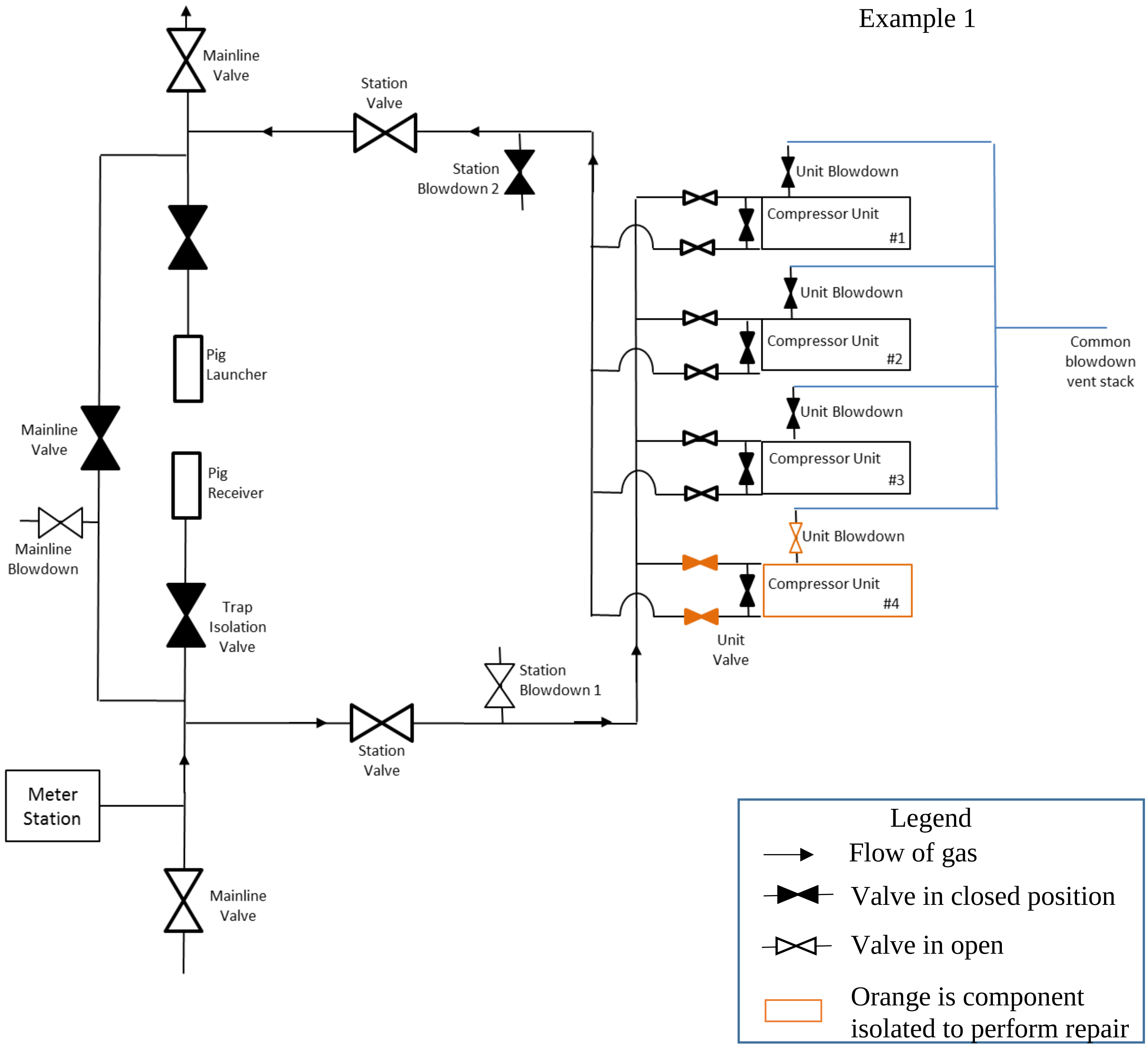
Valve means any device for halting or regulating the flow of a liquid or gas through a passage, pipeline, inlet, outlet, or orifice; including, but not limited to, gate, globe, plug, ball, butterfly and needle valves.

Vent means an open-ended line or pipe from which emissions are released to atmosphere.

APPENDIX D

Diagrams/illustrations of Compressor Station Repair Processes and Timing Needed for Making Repairs Once Existing Sources Are Affected by Modification Language

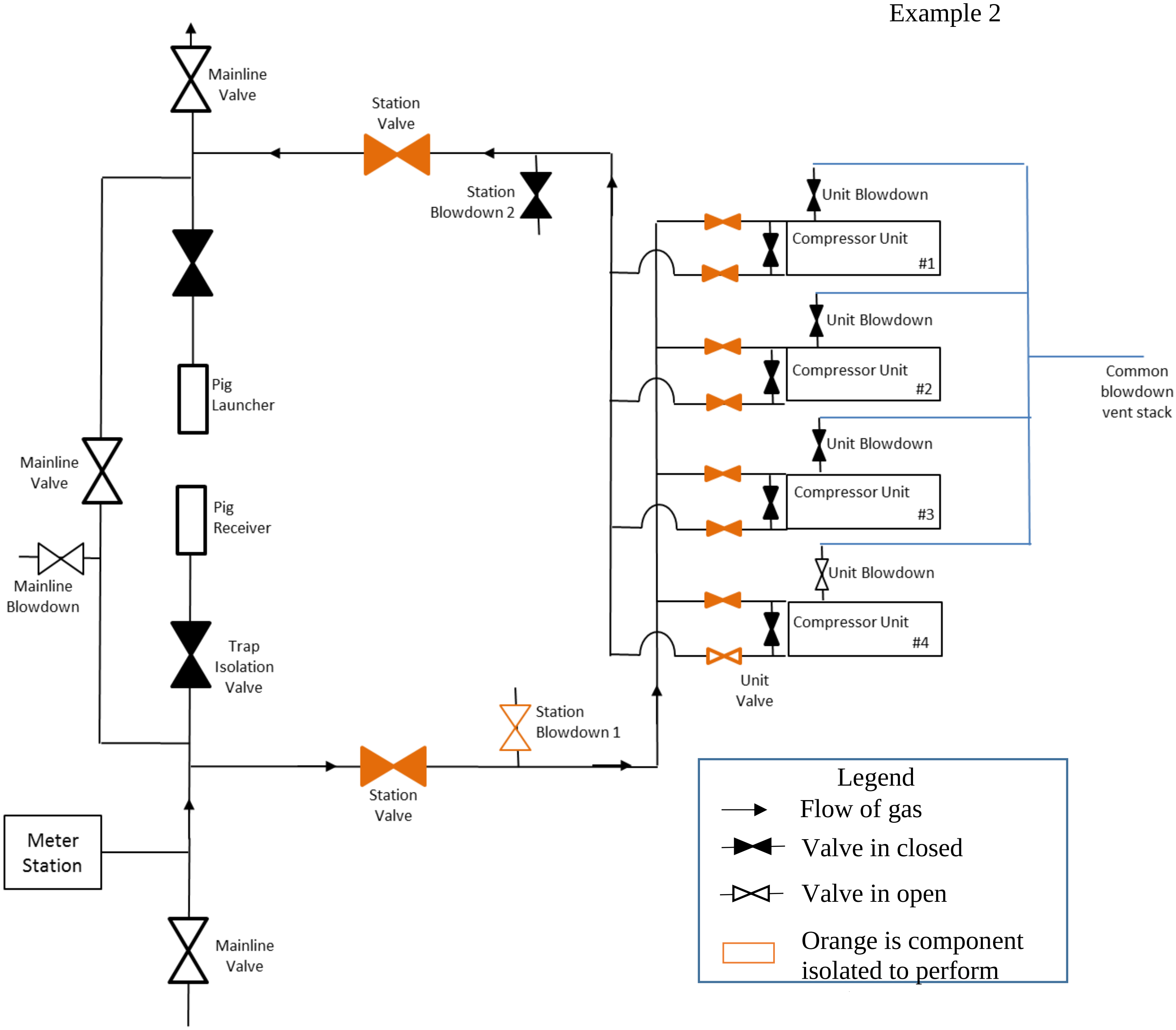
The examples below show four scenarios with the many components and pieces of equipment at a typical compressor station that could trigger a leak repair and what a repair would entail. INGAA emphasizes that no two repairs are alike and the repair schedule varies depending on how long it takes the pipeline to order and receive the piece of equipment from the compressor manufacturer, and how long the repair takes. These four examples assist in explaining what a compressor station repair may involve.



<u>Example 1: Small repair on single compressor unit</u>

A leak on a single compressor unit can be isolated without blowing down the compressor station. In this example prior to making any repairs on compressor unit number 4, the operator must take the single unit offline reducing the volume of gas in the unit and then close the unit valves to the compressor unit from the station piping. The compressor station crew needs to vacate the remaining gas from compressor unit number 4 by conducting a unit blowdown through the highlighted unit blowdown valve. A repair in this section of the station likely involves small diameter piping and valves which can be replaced in a short period of time (e.g. three to four days) once parts are available. However, some vintage components are no longer produced by the manufacture and a custom piece would need to be manufactured to replace the component. This vintage piece may take up to six months to design and manufacture.

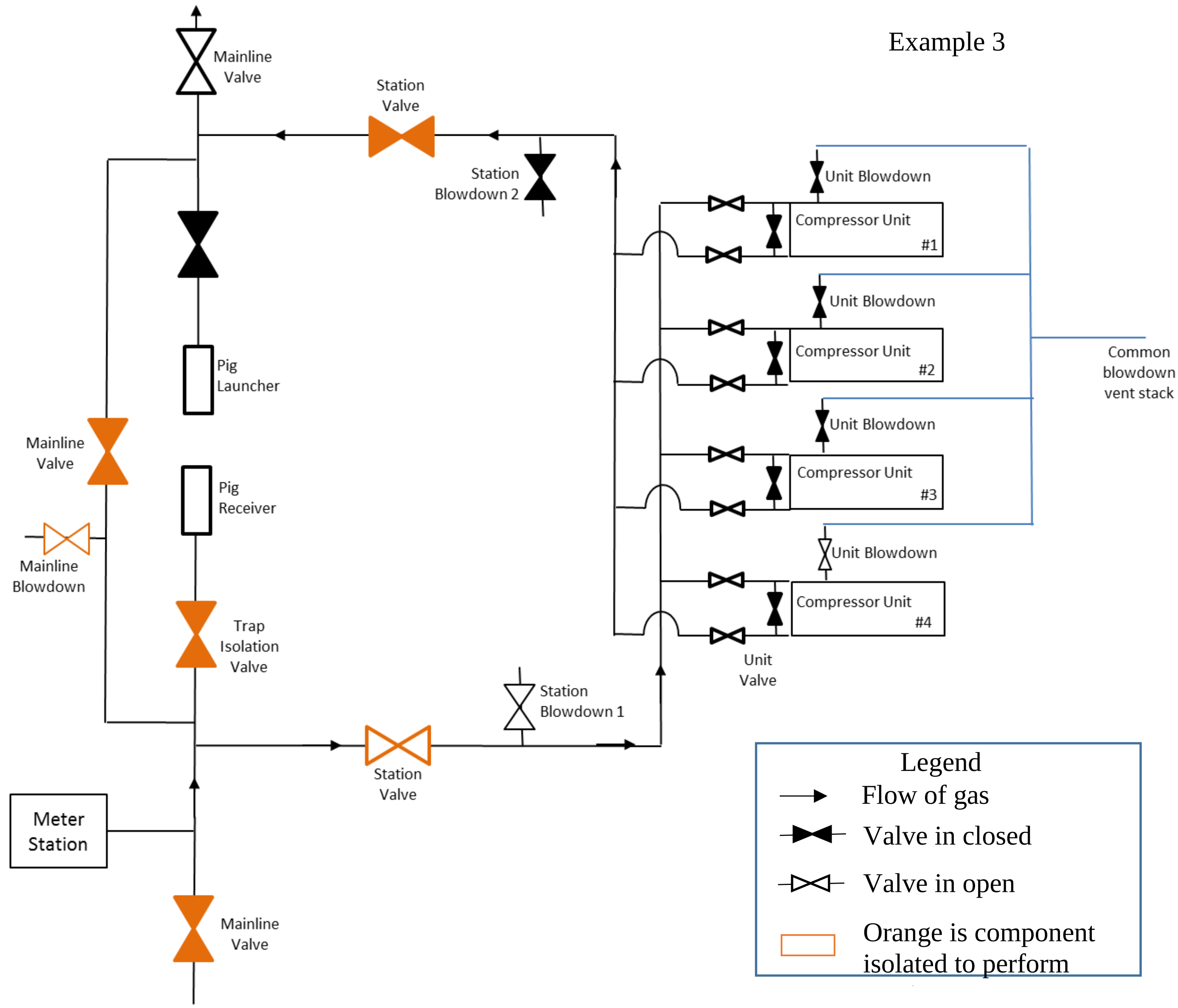
Example 2



<u>Example 2: Medium size repair within a compressor station</u>

There are multiple pieces of equipment between the mainline pipe and the compressor units, this equipment includes scrubbers, valves, tanks and various equipment. If a repair must be made to this equipment the compressor station must be taken offline. Once the station is taken offline the compressor station crew will perform a station blowdown from the station blowdown valve highlighted. A repair in this section is likely to involve large diameter pipe and large diameter valves which will require a longer time period to complete the repair. This repair is likely to trigger various permits and will need to have soil erosion and sediment control for the excavation area. Once the station is taken offline the operator will lose the horsepower associated with the station and there will likely be customer impact on deliveries.

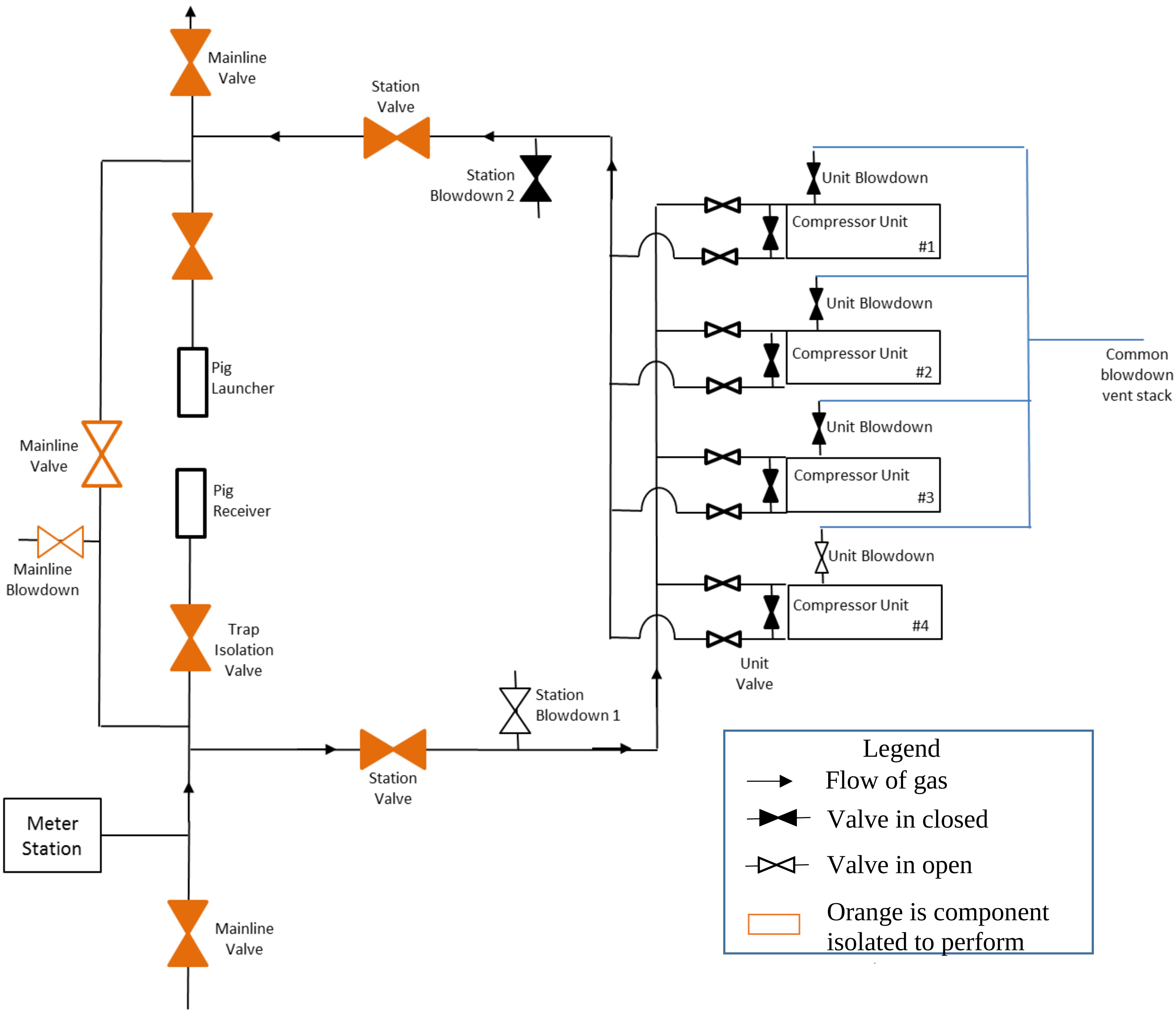
Example 3



Example 3: Large repair that involves mainline pipe

A leak at the station valve would require the compressor station and the upstream segment of the mainline pipeline to be taken out of service. The amount of gas in the mainline pipe will vary significantly depending on pipe diameter and the distance to next mainline valve. In a PHMSA Class 1 location, that can be as much as 20 miles. A repair in this section of pipe will require a blowdown either through the station blowdown or through the mainline blowdown. Pipe in this section tends to be large diameter along with large diameter valves, if the repair requires excavation the amount of time to complete this repair could be several days to a week. This repair will likely trigger various permits and will need to have soil erosion and sediment controls for the excavation area. Once the station and segment of pipe is taken offline the operator will lose the horsepower associated with the station and pipeline capacity which will likely cause customer impact.

Example 4



Example 4: Large repair that involves the mainline valve

A leak on the mainline valve would require the compressor station along with the upstream and downstream pipeline segments to be taken out of service. In a PHMSA Class 1 location the valves could be as much as 20 miles, in each direction, from the compressor station. This repair could result in gas being blowdown for 40 miles of pipe. Pipe in this section tends to large diameter along with large diameter valves. This repair could be one week to several weeks. This repair will likely trigger various permits and will need to have soil erosion and sediment controls for the excavation area. Once the station and segment of pipe is taken offline the operator will lose the horsepower associated with the station and pipeline capacity which will likely cause customer impact.