Interstate Natural Gas Association of America

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U.S. EPA Docket Center
Mailcode 28221T
1200 Pennsylvania Ave, NW
Washington, D.C. 20460

RE: Revisions and Confidentiality Determinations for Data Elements Under the Greenhouse Gas Reporting Rule, Docket ID No. EPA-HQ-OAR-2019-0424

The Interstate Natural Gas Association of America (INGAA), the trade association that represents the interstate natural gas pipeline industry, respectfully submits these comments in response to the United States Environmental Protection Agency's (EPA or Agency) proposed "Revisions and Confidentiality Determinations for Data Elements Under the Greenhouse Gas Reporting Rule" (hereinafter, Proposed Rule), which was published in the Federal Register on June 21, 2022[1].

INGAA members own and operate the vast majority of the interstate natural gas transmission and storage segment in the U.S. and Canada. INGAA member companies transport more than 95 percent of the nation's natural gas through approximately 200,000 miles of interstate natural gas pipelines. In 46 of the 48 contiguous United States, INGAA member companies operate over 5,400 natural gas compressors at over 1,300 compressor stations and storage facilities along the pipelines to transport natural gas to local gas distribution companies, industrials, gas marketers, and gas-fired electric generators.

Accordingly, this rulemaking is of tremendous importance to INGAA and its members. Indeed, INGAA has participated in all EPA rulemakings involving regulation of methane from the oil and natural gas source category, including recently proposed preamble language entitled "Standards of Performance for New, Reconstructed, and Modified Sources and Emissions Guidelines for Existing Sources: Oil and Natural Gas Sector Climate Review."[2]

INGAA members currently invest significant resources to report Greenhouse Gas (GHG) emissions in accordance with 40 CFR 98 Subpart W (Subpart W) and the proposed revisions as reflected in the Proposed Rule will have a significant impact on INGAA's members. In fact, by EPA's cost estimates, sources subject to Subpart W will bear approximately 82% of incremental burden associated with the Proposed Rule[3] even though based on 2020 Greenhouse Gas Reporting Program data[4] are responsible for about 12% of GHG emissions.

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[1] 87 Fed. Reg, 118 (June 21, 2022)
[2] EPA Docket ID No. EPA-HQ-OAR-2021-0317 (INGAA's comments on Proposed Preamble Language) (Attachment 1 to these comments) (hereinafter INGAA's Preamble Comments)
[3] 87 Fed. Reg, 118 (June 21, 2022), Table 7, page 37032
[4] https://www.epa.gov/ghgreporting/ghgrp-reported-data

THE INFLATION REDUCTION ACT & THE PROPOSED RULE

On August 16, 2022, President Biden signed into law the Inflation Reduction Act (IRA).[5] The IRA mandates the EPA impose and collect a charge on methane emissions from the petroleum and natural gas sector where methane emissions from an applicable facility exceed a pre-determined waste emissions threshold.[6] The fee starts at $900 per metric ton of methane in calendar year 2024, increasing to $1,200 in 2025, and then tapering off at $1,500 in 2026 and later years. Congress determined that relevant aspects of the program, including *which* facilities are subject to the charge and *how* to calculate the amount of methane subject to the charge, will be based on EPA's Greenhouse Gas Reporting Program (GHGRP) Subpart W.

To implement the methane charge program, Congress mandated EPA to revise Subpart W within two years (by August 16, 2024) to ensure that reporting and calculation of the methane charge are based on empirical data, accurately reflect the total methane emissions and waste emissions from the applicable facilities, and to allow owners/operators to submit empirical emissions data to demonstrate the extent to which a charge is owed.

With this clear direction from Congress, INGAA recommends EPA forgo finalization of the portion of the Proposed Rule related to Subpart W. In a final rule, EPA can justify forgoing the Subpart W revisions due to the congressional mandate in the IRA and state that it will propose comprehensive Subpart W revisions to fulfill the mandate in the IRA. After finalization, EPA can analyze the IRA and develop a new rulemaking that responds to the congressional mandate. This rulemaking can include new requirements that respond directly to the IRA, as well as portions of the Proposed Rule related to Subpart W that EPA deems to be of continued relevance and importance to the program. A single rulemaking will reduce the burden on both industry and the Agency.

As you will see below, INGAA advocates for improved data quality and further quantification, which aligns with Congress's goal of utilizing empirical data. Working through these (often highly complicated) issues in the context of a new rulemaking will provide EPA, regulated stakeholders, and the public at-large the needed time and proper regulatory vehicle to make a single, comprehensive update to GHGRP Subpart W.

INGAA is committed to being at the table for those discussions and to work together to help EPA achieve the goals of the IRA.

EXECUTIVE SUMMARY

INGAA recognizes that EPA's GHGRP data are used by a variety of stakeholders for information purposes, for benchmarking purposes, and to report US GHG emissions. GHG emission data must be accurate, representative, and timely to fulfill the various uses of the data. Accordingly, INGAA appreciates the opportunity to submit comments on the Proposed Rule and offers them in the spirit of efficiently and effectively improving the accuracy and quality of GHG data reported by the natural gas transmission and storage (T&S) sector.

[5] https://www.govinfo.gov/content/pkg/BILLS-117hr5376rh/pdf/BILLS-117hr5376rh.pdf.
[6] See Sec. 60113. Methane Emissions Reduction Program.

INGAA is particularly pleased with EPA's efforts to reduce burdensome and in some cases, duplicative, reporting requirements as reflected by more than 35 data elements that are proposed to be removed because they do not add value. For example, INGAA believes the proposed removal of the requirement to conduct reciprocating and centrifugal compressor measurements in not-operating-depressurized mode at least once every three years will eliminate extra work that did not provide any meaningful GHG data.

It is important to note that INGAA members are continuously looking for new and innovative ways to reduce GHG emissions from T&S sources. In many cases, technological advances that reduce GHG emissions or improve GHG emissions measurement outpace the regulatory process. Accordingly, INGAA strongly encourages EPA to include flexibility for affected facilities to implement new GHG reduction and measurement technologies when those technologies are supported with defensible data. The ability to rapidly deploy new technology to reduce and measure GHG emissions will become even more important with the anticipated revisions to the GHGRP mandated by the IRA.

INGAA is providing comments on several items that can be grouped into the following three areas:

1. Accommodate Technology Advances that Improve the Quality of Reported GHG Data

1.1. To achieve reductions in emissions from technological advancements, the rule should provide flexibility that allows operators the option to use either the factors provided in Table W-9 or improved emission factors (EF) based on company or vendor test data.

1.2. INGAA recommends the rule allow flexibility to integrate advanced technologies that become available, such as the option of using optical gas imaging (OGI) emissions quantification system as an accepted technology for methane emissions quantification. Technology advancements may confirm the performance of OGI emissions quantification systems that are under development, but the current regulations do not provide a mechanism to incorporate such technological advances into Subpart W.

2. Apply Appropriate Emission Factors for the T&S Sector

2.1. The current T&S emission factors for OGI should be retained. The current emission factors are based on studies and leak rate measurement from the T&S sector. The proposed emission factors for optical gas imaging OGI are based on studies from upstream emission sources and those studies are not representative of methane emissions from T&S sources.

2.2. EPA should allow operators the option to use emission factors based on past Subpart W measurements for the calculation of emissions from T&S sources instead of requiring ongoing annual testing. Affected sources in the T&S sector have completed Subpart W measurements for over a decade and this data allows for the generation of defensible emission factors.

2.3. The final rule should provide clear explanations that year-over-year increases do not necessarily reflect changes in actual emissions, but rather changes in accounting methods. In particular, an explanation is needed for updates to natural gas-fired reciprocating engine methane exhaust emission factors and for facility leak emissions should EPA adopt a higher emission factor for OGI leak surveys.

2.4. Instead of mandating new measurements for centrifugal compressor dry seals, INGAA recommends that EPA allow operators the option to use emission factors established by equipment vendors or on-board measurements available from the unit's system. Further, INGAA and Pipeline Research Council International (PRCI) have provided EPA defensible emission factor data for rod packing emissions, and company-specific factors are available based on measurements conducted since 2011. Accordingly, INGAA recommends that EPA allow operators the option to use emission factors for rod packing emissions instead of ongoing annual measurements and a new requirement to measure rod packing in standby pressurized mode.

3. Address a Diverse Range of General Issues

3.1. In lieu of a resurvey of the entire facility, INGAA recommends that EPA allow operators to use leak detection and repair records to determine the number of hours a component leaked instead of using the default value of 8,760 hours.

3.2. EPA should reconsider limiting the use of automatic Best Available Monitoring Methods (BAMM) to the first year of reporting and allow requests for the use of BAMM beyond the first year. INGAA members, as do others affected by the proposed regulations, use a variety of systems to collect, compile, reduce, and report GHG data. INGAA recommends that EPA extend the compliance date to January 1 of the year following rule promulgation thereby establishing a compliance date that allows operators at least six months to modify and verify data collection and management systems. Further, EPA established precedents when GHGRP (specifically Subpart W) was first promulgated allowing operators' use of BAMM for up to two years through a combination of automatic BAMM and subsequent requests. While INGAA members appreciate the opportunity for the use of BAMM, a limited extension of those provisions beyond the first reporting year is necessary to allow operators the necessary time to establish compliance programs given the broad revisions to the GHGRP.

3.3. It is difficult for INGAA to fully assess the requirements and impacts of the Proposed Rule, because the underlying compliance requirements of OOOOb and OOOOc are not yet known. At the time INGAA submitted these comments, the proposed regulatory text was still under review at the White House's Office of Information and Regulatory Affairs and not publicly available.

3.4. INGAA recommends that EPA increase the threshold for reportable large leaks to 5.5% of the 40 CFR Part 98 threshold of 25,000 metric tons CO_2e per year, bringing the quantity in line with the Pipeline Hazardous Materials and Safety Administration (PHMSA) threshold of 3,000,000 standard cubic feet (49 CFR 191.3(1)(ii)).

3.5. INGAA recommends that EPA remove tank monitoring requirements when tanks are routed to a flare because as noted in the preamble to the proposed rule, there have been no leaks reported over the past 6 years.

3.6. INGAA is requesting that EPA provide clarity on dry seal monitoring to indicate that only gas side monitoring is required.

3.7. The Proposed Rule establishes new flare activity reporting requirements that are irrelevant to the calculation of GHG emissions and should be removed. Specifically, the proposed new requirements in 98.236(n)(2)(ii) do not validate or improve GHG emissions reporting and should be removed.

3.8. Based on the complexity of liquefied natural gas (LNG) systems, INGAA recommends that EPA allow site-specific engineering estimates based on best available data for acid gas removal (AGR) vents.

3.9. INGAA recommends that acoustic leak detection be allowed for manifolded compressors in some situations.

DETAILED COMMENTS

INGAA's detailed comments are provided below.

1.1. INGAA supports the emission factor updates for combustion exhaust methane emissions from reciprocating engines but recommends flexibility that allows operators to use emission factors, when appropriate, that reflect technological innovation that decreases emissions.

INGAA Supports Exhaust Methane Emission Factors Updates

The Proposed Rule updates combustion exhaust methane emission factors (EF) for natural gas-fired reciprocating engines that drive compressors. INGAA has consistently supported more accurate methane EFs for natural gas-fired reciprocating engines since the original 2009 Subpart C proposal.[7] As discussed in previous INGAA comments, the longstanding Subpart C EF is adequate for some combustion equipment (e.g., turbines, boilers) but under-estimates combustion exhaust methane emissions from reciprocating engines. The proposed emission factor updates, presented in Table W-9, represent reasonable average values and INGAA supports this revision.

Flexibility is Needed to Ensure Reported Emissions Reflect Technological Advancements

However, additional flexibility is warranted so that operators can reflect technological advancements in the exhaust methane emissions estimate for reciprocating engines. While oxidation catalysts do not effectively reduce methane from lean burn engines, advanced combustion-based technologies can reduce exhaust methane. For example, improved in-cylinder bulk mixing through approaches such as high-pressure fuel injection can reduce emissions of both NOx and methane / products of incomplete combustion. EPA should allow the use of operator- or vendor-defined EFs, based on measurement data, so that technological advancements that reduce methane are reflected in the annual inventory. If not, the GHGRP will not incorporate mitigation program results. This is especially important because these emissions could result in imposition of a "methane fee" under the recently passed Inflation Reduction Act. For example, EPA's recent Good Neighbor proposal[8] would require nitrogen oxides (NO_x) reductions on thousands of T&S reciprocating engine compressor drivers.[9] Two-stroke lean-burn (2SLB) engines requiring NO_x control may install low emissions combustion (LEC) technology that includes high-pressure fuel injection and ignition timing control. In some cases, LEC control may reduce methane emissions. The 2SLB EF in Table W-9 does not accurately reflect methane emissions for such LEC-equipped engines, and those units should be allowed to use an appropriate EF based on company or LEC vendor data. Since these facilities may also be subject to methane fees, this erroneous EF could result in financial penalties for the operator. Thus, it is imperative that EPA provide flexibility to use defensible operator data or vendor data or specifications as an alternative to Table W-9 EFs.

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[7] For example, see EPA-HQ-OAR-2008-0508-0480, INGAA Comments on Proposed GHG Reporting Rule, June 9, 2009; and INGAA presentation for meeting with EPA staff on November 19, 2019

[8] "Proposed Federal Implementation Plan Addressing Regional Ozone Transport for the 2015 Ozone National Ambient Air Quality Standard," 87 FR 20036, April 6, 2022

[9] INGAA comments on "Proposed Federal Implementation Plan Addressing Regional Ozone Transport for the 2015 Ozone National Ambient Air Quality Standard," June 21, 2022.

Subpart C Common Pipe and Aggregation Methodologies Should Be Retained

Subpart C allows emission calculations for natural gas-fired combustion units to be completed using Tier 1 or Tier 2 common pipe or aggregation methods. Implementation of updated emission factors dependent on unit type should not compromise access to those calculation methods for natural gas-fired units, and Subpart C should clearly indicate that operators can use available data to identify the fraction of fuel assigned to different unit types (with different combustion exhaust methane EFs). Compressor stations often include different types and sizes of compressor drivers, such as one or more two-stroke lean-burn engines, four-stroke lean-burn engines, and turbines at the same facility. Operators should be allowed to use available records (e.g., unit size, heat rate, annual run time) to estimate annual fuel usage and assign the appropriate exhaust methane EF from Table W-9 (for engines) or Table C-2 (for turbines, boilers, etc.) for aggregated or common pipe estimates.

1.2 The Proposed Rule should support and encourage advanced technologies, such as OGI emissions quantification technologies, and create a pathway where proven systems can be an accepted measurement technology for methane emissions.

The OGI camera is used across numerous industries to visualize emissions from leaks and vents. Currently, Subpart W allows the use of the OGI cameras for the identification of leaks and may be used to screen for emissions from certain vented sources, such as transmission storage tanks. Once emissions are identified with an OGI camera, additional measurement technologies or emissions calculation methodologies are employed to quantify the emissions.

Recent technology advancements have resulted in the development of OGI emissions quantification systems and offer a significant improvement opportunity in emissions quantification if/when technology performance is validated. For example, the QL320 developed by Providence Photonics and marketed by FLIR systems uses the output from a FLIR GF320 camera and translates the collected data into gas-specific emission measurements using a combination of an algorithm and gas-specific response factors. Once performance is proven, the QL320 and other advances in OGI quantification technology could be used to directly quantify methane emissions from equipment leaks, vents, and/or certain pneumatic devices as an alternative to using emission factors, currently approved monitoring technologies, and related assumptions.

The use of OGI or other leak quantification technology would be particularly beneficial for centrifugal and reciprocating compressor vent emissions. The onshore natural gas transmission compression industry segment is required to report emissions from transmission storage tanks that are attributable to leakage through the scrubber dump valve. Where required, emissions from these vents are estimated based on measurements performed using calibrated bagging, high volume samplers, flow meters, or acoustic leak detection devices.

A calibrated vent bag is a plastic bag of known volume that is placed over a vent and inflated via the vent emissions. The time required for the bag to fully inflate is recorded by the technician. This process is repeated three times and the average of the inflation times is used along with the known volume of the bag to compute the flow rate. This measurement method has obvious potential inaccuracies that are largely attributable to human error (e.g., judgement of when the bag is “full”, precision of inflation start and stop time, changes to flow rate due to backpressure caused by the bag). A flow meter may also be used to measure vent flow rate.

Alternatively, an acoustic leak detector could be used to measure flow across a normally closed valve upstream of the vent. Calibrated vent bags, flow meters, and acoustic leak detectors all have the potential to contribute to inaccurate emissions quantification. These techniques measure total exhaust flow, not pollutant emission rate.

The only vent measurement technology currently approved for use under Subpart W that directly measures methane emission rate is a high-volume sampler (HVS). However, the primary manufacturer of the HVS stopped production several years ago and HVS systems are being introduced into the market now but are not well established. An OGI emissions quantification system would provide a comparable alternative to the high-volume sampler for directly measuring methane emissions from vents. This example is indicative of the general concern – Subpart W should be updated to support a reasonable pathway for integrating methane emissions monitoring and measurement technological advances.

An OGI emissions quantification system or other systems under development that provide the ability to quantify leaks without directly measuring at the equipment interface would also provide benefits in the areas of efficiency and safety. When using currently approved vent measurement methods, personnel are often required to access the vent via an elevated support surface (e.g., ladder), which takes additional time and poses safety risks. A proven OGI emissions quantification system would provide accurate measurements that can be performed safely and efficiently at ground level.

2.1 For OGI-based leak surveys, the analysis for the T&S sector using data from upstream sectors is not representative of T&S operations and T&S leaker emission factors (EFs) should not be revised.

The Proposed Rule would add new emission factors for estimating equipment leak (leaker) emissions when using an alternative method to Method 21, including the OGI camera. The OGI Alternative method leaker EFs are approximately 4 times higher and based on an EPA technical support memorandum[10] ("Subpart W TSD Memo") that analyzes emission factors for operations in upstream segments – i.e., onshore production and gathering and boosting. For leak surveys using the OGI camera (and other methods in section 98.234(a) other than Method 21), EPA developed an "OGI enhancement factor." The OGI enhancement factor, a 4.1 multiplier, is based on EPA analysis of upstream data. EPA then applies that factor to T&S (and other sector) leak emission factors based on Method 21 leak detection. However, EPA failed to acknowledge that current leaker EFs for the "downstream" segments are already significantly higher than the analogous EF for upstream segments. The current T&S EFs are higher because the T&S EFs are based on more robust datasets from studies[11,12,13] that included direct measurement of leaks, while the current upstream segment EFs are based on studies that applied "correlation equations" to

[10] EPA-HQ-OAR-2019-0424-0120

[11] Clearstone (Clearstone Engineering Ltd.). 2002. *Identification and Evaluation of Opportunities to Reduce Methane Losses at Four Gas Processing Plants*. Prepared for Gas Technology Institute under USEPA Grant No. 827754-01-0. June 20, 2002.

[12] NGML (National Gas Machinery Laboratory, An Institute of Kansas State University), Clearstone Engineering Ltd and Innovative Environmental Solutions, Inc. 2006. *Cost-Effective Directed Inspection and Maintenance Control Opportunities at Five Gas Processing Plants and Upstream Gathering Compressor Stations and Well Sites.*

[13] Clearstone (Clearstone Engineering Ltd.). 2007. *Fugitive Emissions Pilot Project: Measurement of Natural Gas Emissions from the Canadian Natural Gas Transmission and Distribution Industry*. Prepared for Canadian Energy Partnership for Environmental Innovation (CEPEI). April 16, 2007.

estimate leak rates.

INGAA strongly opposes EPA's proposed approach to adjust transmission, storage, and LNG leak EFs for OGI due to several factors:

- EPA has not provided a sound technical basis for its conclusion that an OGI enhancement factor based on studies of different segments using different study design and different methodological approaches should apply to T&S leaker emission factors.
- The differences for the upstream sector are likely due, at least in part, to the equipment / components surveyed (e.g., production well pad versus gathering compression) and not solely due to the different detection methods. EPA has already accounted for compression versus non-compression service components for transmission compressor stations.
- The leak rates implied by the proposed factors for transmission OGI leak EFs are very large and inconsistent with OGI detection thresholds. The T&S leak EFs are based on different studies and more detailed methods (e.g., direct leak rate measurement) than the historical EFs for upstream sources.
- Significant disparities (i.e., significant under-estimation) in leak emission estimates for T&S sources is not supported by recent studies of this segment.

EPA has not provided adequate justification or support to apply the OGI enhancement factor to T&S and LNG leaker emission factors. The current leaker EFs should be retained since it is inappropriate to apply an "enhancement" based on analysis of data from a different segment that includes significant disparities in both study design (e.g., direct measurement versus correlation equation-based emission estimates) and operational equipment. In fact, the <u>Subpart W TSD Memo does not provide any T&S data to support its conclusion or the proposed revision.</u>

The Subpart W TSD Memo states:

> "…our analysis of measurement study data from onshore production and gathering and boosting facilities demonstrates the need for separate OGI leaker emission factors to more accurately account for emissions. We ***expect*** [***emphasis added***] that the leaker factors for other industry segments that are based on measurements of Method 21-identified leaks ***may*** [***emphasis added***] similarly underestimate the emissions from leaking equipment when OGI (or other alternative methods besides Method 21) are used to detect the leaks.

An unsupported "expectation" that upstream segment emissions measurement data "may" similarly impact T&S is not sound justification for applying the 4.1 multiplier to T&S emission factors. Discussion of additional technical issues that raise questions about data applicability to T&S follows.

<u>A high-level review of data from upstream studies does not support a 4.1 multiplier</u>

EPA has concluded that the "multiplier" for upstream emission factors is due to the leak detection method (i.e., Method 21 versus OGI leak screening), but there are other significant factors that must be considered. For example, the more recent OGI data reviewed by EPA has a prevalence of different components when compared to the historical leaker EFs for upstream segments.

EPA calculated the 4.1 multiplier by dividing emission factors developed from two recent leak emissions quantification studies (Zimmerle[14] and Pasci[15]) and the current Table W-1E leaker emission factors based on the Method 21 10,000 ppm leak definition. EPA then proposes to apply the 4.1 multiplier to current Subpart W Method 21 10,000 ppm leaker emission factors for natural gas transmission and storage, and LNG facilities to develop emission factors that would apply to leaking components found during leak surveys conducted using OGI. One of many EPA conclusions is that the differences for the upstream segments are due solely to the detection method. However, that may not be the case, because it appears different equipment categories are represented. Over 80% of the gas-service components surveyed and measured for the Zimmerle and Pasci studies were at gathering and boosting facilities or otherwise in compressor-service (i.e., all 180 facilities in the Zimmerle study were gathering and boosting and about 40% of the components surveyed at 67 facilities for the Pasci study were at gathering and boosting facilities or otherwise in compressor-service).

The Subpart W TSD Memo does not demonstrate that this prevalence of compressor components surveyed for the Zimmerle and Pasci studies is representative of the components for the onshore natural gas production and gathering and boosting industry segments, where there are many components associated with the wellhead and non-compressor components in proximity. It is likely that the newly proposed (OGI) Table W-1E emission factors are significantly higher than the current Table W-1E emission factors because the new emission factors are based on measurements that over-represent compressor components.

For the transmission segment, EPA has already addressed this issue by publishing different emissions factors for compressor and non-compressor service. Compressors are subject to vibration and thermal cycling and thus EFs are greater than non-compressor components in Table W-3A; for example, the average "compressor component emission factor / non-compressor component emission factor" ratio for T&S in Subpart W is about 5.4. The fact that EPA has accounted for this characteristic for transmission compressor station leak EFs is cause enough to conclude that the 4.1 multiplier proposed by EPA is not appropriate.

<u>Large leaks of the magnitude of the proposed T&S emission factors would be readily detected</u>

The proposed leaking component emission factors for T&S are very large (e.g., 163 scfh for PRVs, 79 scfh for meters, 71 scfh for OEL, and 61 scfh for valves). This equates to over one kg/hr in all cases, which is several orders of magnitude higher than OGI methane leak detection thresholds[16]. Since EFs are averages of all measurements (i.e., total emissions divided by number of measurements), these emission factors infer that only very large leaks, with emissions rates orders of magnitude higher than established (or work practice required) detection limits, are all that is detected by OGI at T&S facilities. INGAA is not aware of any

[14] Zimmerle, D., K. Bennett, T. Vaughn, B. Luck, T. Lauderdale, K. Keen, M. Harrison, A. Marchese, L. Williams, and D. Allen. 2019. *Characterization of Methane Emissions from Gathering Compressor Stations: Final Report*. Prepared for the U.S. Department of Energy under Contract No. DE-FE0029068. October 2019 Revision.

[15] Pacsi, A. P., T. Ferrara, K. Schwan, P. Tupper, M. Lev-On, R. Smith, and K. Ritter. 2019. "Equipment leak detection and quantification at 67 oil and gas sites in the Western United States." *Elementa: Science of the Anthropocene*, 7: 29.

[16] EPA alternative work practice criteria, proposed Appendix K requirements, and OGI vendor publications document detection thresholds significantly less than 100 g/hr.

study or EPA analysis that supports this conclusion.

Similarly, the EPA 4.1 multiplier presumes the "frequency" of leaks detected by Method 21 that are missed by EPA. Leak EFs are based on study data that divides total emissions (measured or estimated emissions, by component type) by the number of leaking components ("N"). Example calculations can be performed that define the number, N, of OGI missed leaks that are required to result in a 4.1 multiplier, and N is dependent on the total emissions not found (e.g., assume 10 to 30% of the total emissions are due to the leaks missed with OGI). This exercise indicates that OGI would need to miss the vast majority of leaks (e.g., on the order of 70% or more leaks would be missed with OGI, or OGI would detect only 1 in 3 to 1 in 4 leaks compared to leaks detected with Method 21 at 10,000 ppm screening threshold) which is not supported based on current understanding of leak detection methods (e.g., for gathering and boosting, Pasci found approximately 30% more (small) leaks with Method 21).

<u>T&S leak EFs are based on direct measurement and T&S estimates do not indicate leak emissions are under-estimated</u>

It is important to understand that the technical basis for the leaker EFs that apply in the existing regulation is very different, depending upon the segment. As noted in the EPA support memo, upstream EFs used estimation methods (e.g., correlation equations) following the EPA "Leak Protocol" document. In contrast, T&S EFs are based on robust data sets from studies that conducted direct measurement of leaks (e.g., with High Volume Sampling System). Because a more thorough and complete T&S dataset is available, the historical EFs for T&S are significantly higher than EFs for upstream segments. Recent studies for T&S[17] that include OGI leak surveys indicate that current methodologies provide a reasonably accurate estimate of facility emissions. The cited study was funded cooperatively by T&S companies and the Environmental Defense Fund and concluded that T&S emissions are *not* under-estimated (see Figure 4 of the study), and that transmission fugitive (i.e., leak) emissions are *not* under-estimated. The EPA proposed change would increase those emissions by a factor of 4, which contradicts data from the T&S sector.

In conclusion, EPA should not update leak EFs in the Proposed Rule using data from studies that use different methodologies to correlate leaker EFs for segments that are not represented in the studies. EPA should also consider other factors (e.g., differences in component types surveyed, measured versus inferred emission estimates) rather than concluding detection methods are the sole reason for differences between studies. EPA's approach leads to flawed conclusions, and it is not appropriate to apply the "correction factor" from upstream studies to EFs in downstream sectors. The current Subpart W EFs for transmission, storage, and LNG facilities are supported by existing studies, including data specific to those segments, and should be retained and not updated.

2.2. Over fourteen thousand measurements conducted at transmission and storage facilities to meet Subpart W requirements were documented in PRCI reports that analyzed 2011 – 2016 data. With eleven years of data now available for analysis, EPA should allow operators the option to use available measurements data to develop emission factors rather than

[17] Methane Emissions from the Natural Gas Transmission and Storage System in the United States," Zimmerle, et.al., Environmental Science and Technology, July 2015 (e.g., see Figure 4 and Figure 5).

requiring ongoing annual measurements.

In the 2010 Subpart W rulemaking, EPA required compressor vent measurements in sections 98.233(o) and (p) due to the lack of emissions data.[18] With tens of thousands of measurements completed since the initial 2011 reporting year, EPA should allow operators the option to use emission factors rather than continuing to mandate annual compressor vent measurements. The emission factors could be based on analysis of 2011 through 2016 measurement data in PRCI reports[19,20,21] provided to EPA and/or company specific EFs based on measurement data used to develop emission factors for "modes not measured" in any particular annual survey. For the former case, PRCI EFs could be used following the same methodology currently available to upstream sectors that apply an EF (e.g., emission estimates based on unit counts and EFs). For the latter case, the Subpart W calculations used to development mode-specific emission factors based on company measurements since 2011 could be used as the basis for ongoing calculations. Subpart W uses a three-year average for company-specific EFs, and companies could use either the most recent 3-year average or compile and average measurement data since 2011 as the basis for their EFs. With EFs available as an option, new measurements would no longer be mandatory.

For example, the August 2018 PRCI report compiled and analyzed over 14,000 measurements of emissions / leaks from compressor isolation valves, compressor blowdown valves, rod packing, and wet seal degassing vents. The September 2018 companion PRCI white paper presented compressor emission factors based on that Subpart measurement data compiled it the PRCI report. The PRCI emissions factors could be used in conjunction with unit counts, similar to the Subpart W methods that have been used for upstream segments since 2011.

In addition, Subpart W already includes calculation methods for developing company-specific estimates based on the company's measurements. Annual measurements are completed "as found", so every source and operating mode (i.e., operating, standby pressurized, and not operating depressurized) is not measured every year. Sections 98.233(o) and (p) require operators to calculate compressor emission factors for modes where measurements are not completed based on previous company measurements. If ongoing measurement is eliminated or optional, ongoing estimates could be completed using those same methods based on the available data.

The measurement dataset available industry-wide or at a company-level has resolved the data deficiency EPA identified over a decade ago. In addition, the GHGRP rarely requires direct measurements for other industries, and this disparity for T&S sources under Subpart W should not continue. EPA should no longer require this additional measurement burden and, instead, should allow the T&S sources the option to calculate emissions using emission factors rather than mandated annual measurements. INGAA offers its assistance to work with EPA to develop Subpart W regulatory text to achieve this objective.

Similarly, annual transmission tank measurements (to detect a leaking scrubber dump valve) and

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[18] 76 FR 18620. Proposed rule (April 12, 2010) preamble discussion – e.g., direct measurement required because, "no credible engineering estimation methods or emissions factors exist."
[19] PRCI Report Catalog No. PR-312-16202-R02, "GHG Emission Factor Development for Natural Gas Compressors," April 2018.
[20] PRCI White Paper, Catalog No. PR-312-18209-E01, "Methane Emission Factors for Compressors in Natural Gas Transmission and Underground Storage based on Subpart W Measurement Data," September 2019.
[21] PRCI Report Catalog No. PR-312-16202-R03, "Methane Emissions from Transmission and Storage Subpart W Sources," August 2019.

annual leak surveys should be optional rather than a mandatory requirement. Leak survey results and transmission tank measurements over the last decade provide insight into the associated emissions and prevalence of anomalies such as scrubber dump valve leaks. For example, the August 2019 PRCI report documented leak prevalence based on 2011 – 2016 GHGRP data in a report[22] provided to EPA. Operators should have the option to calculate emissions based on industry-wide or company-level emission factors based on available measurement data. Additional context on reporting for leaky scrubber dump valves is provided in Comment 3.4, as substantive emissions from an operational anomaly would be addressed under the "other large release event" category that is being added to Subpart W.

Extensive data collected over more than a decade allows for the development of emission factors that characterize T&S operations. Accordingly, EPA should allow operators to use available emission factors – based on industry-wide or company-specific measurement data – rather than continuing to require ongoing annual leak measurements and leak surveys at T&S facilities.

2.3. The Proposed Rule incorporates new emission factors and establishes new monitoring requirements leading to increased GHG emissions reporting which are the result of expanding the rule and changing the accounting procedures, not necessarily in increases in actual GHG emission from reporting facilities.

INGAA members have worked diligently over the years to accurately report and reduce GHG emissions. The proposed emission factors, if adopted in a final rule, along with new emission sources will result in significant increases in year-over-year GHG emissions for the first year even if facilities operate exactly as they had in the prior year. This apparent increase in emissions on paper might be misunderstood. It is therefore important that EPA carefully craft messaging that can help the public, environmental advocacy groups, shareholders, and the international community understand that increased emissions numbers due to the Proposed Rule are associated with changes to calculating methodologies and are not necessarily reflective of actual increases in GHG emissions from reporting facilities.

2.4. The Proposed Rule would add new measurements for T&S centrifugal compressors with dry seals and for reciprocating compressor rod packing in standby pressurized mode. Mandatory new measurement requirements are not warranted, and EPA should allow operators the option of using other data sources for estimating emissions.

EPA has acknowledged that the GHGRP is not intended to include 100% of facility emissions but rather focus on key sources. Thus, EPA chose not to include centrifugal compressor dry seal emissions (in operating or standby pressurized mode) or reciprocating compressor emissions in standby pressurized mode in Subpart W reporting. The Proposed Rule would add measurement for those emission sources. In Comment 2.2, INGAA recommends allowing operators to use emissions factors for compressors based on a wealth of measurement data for operating modes included in Subpart W since 2011. INGAA does not support new measurement requirements for compressors based on perceived data gaps that EPA did not deem relevant when Subpart W was originally adopted. If EPA's position has changed, operators should be provided the option to conduct additional measurements or estimate dry seal emissions and standby pressurized rod

[22] *See citation 21.*

packing emissions based on other emissions rate data available and the annual hours in the respective modes.

For centrifugal compressors with dry seals, emissions could be estimated based on vendor data (e.g., data from Solar, which is the prevalent manufacturer of T&S turbines) or measurement data available from on-board instrumentation for some units. For the former, a Solar Product Information Letter (PIL)[23] presents typical dry seal leak rates as a function of operating pressure. For the latter, some units measure this rate with the onboard operational control system to track seal health. The rule should allow and provide clarity for clear operating and maintenance requirements for such devices (e.g., follow manufacturer specifications) so that the continuous measurement data can be used. These data sources are also preferred because the systems are not designed to accommodate access for a periodic measurement. Positive line pressure would result in leakage into the compressor house, and potentially trigger gas sensors, which could result in unit shutdown and venting to atmosphere.

For reciprocating compressor rod packing, measurements are currently required in operating mode and a wealth of measurement data is available. For standby pressurized mode, the emission rate could be based on previous studies (e.g., see discussion in PRCI compressor emission factor paper), measurement data from operating mode, or other data available in the literature. The larger contributing factor to these "missing" emissions is the amount of time not accounted for in the current rule (i.e., 2011 – 2016 data analyzed by PRCI indicated reciprocating compressors, on average, are in standby pressurized mode 30% of the time) rather than deviation in the hourly leak rate for the two modes where rod packing leakage occurs.

EPA previously determined that rod packing emissions in standby pressurized mode was not warranted but the Proposed Rule changes that perspective. This conclusion is questionable because the collective emissions from rod packing is very likely lower than when Subpart W was initially adopted and will continue to decrease (and not significantly contribute to total facility emissions) because rod packing is regulated for new sources and is or will be regulated for existing sources by the EPA (Subparts OOOO, OOOOa, and proposed OOOOb and OOOOc) and/or by state regulations.

At a minimum, if EPA believes that this previously excluded source should be added to Subpart W reporting, available data from rod packing measurements in operating mode and from the literature should be closely scrutinized to assess whether the emissions implications justify this change in EPA's position, and justify the need for new measurements rather than relying on other available emission rate data.

For both sources, information or related data are available to provide an emission rate for estimating annual emissions. Thus, new measurement requirements for dry seals and for rod packing in standby pressurized mode are not warranted. At most, EPA should require

[23] Solar Turbines, Product Information Letter (PIL) 251, "Emissions from Centrifugal Compressor Gas Seal Systems," January 2019.

measurement for two or three years then eliminate the new measurement requirement once data is available for this source and allow operators to use company-specific emission factors based on their past measurement data.

3.1. The Proposed Rule must allow operators to use leak detection and repair records to determine the number of hours a component leaked instead of using the default value of 8,760 hours.

In the Proposed Rule, the total annual total volumetric emissions of GHG are calculated by multiplying the leaker emissions factor by the total time the surveyed component was assumed to be leaking (63.233(q)(2) Calculation Method 1: Leaker emission factor calculation methodology Equation W-30)[24]. The procedure assumes a component continuously leaks since the prior annual survey. In cases where a Subpart W survey is only done once per year (the rule requirement), this assumption results in using 8,760 hours as the total time a component was leaking.

Whereas official Subpart W leak surveys of the entire facility are only required once per year, many facilities have mandated Leak Detection and Repair (LDAR) programs that survey components on a more frequent schedule and require first attempt at repair within as little as 15 days. The recordkeeping and reporting provisions of these programs are required to document and verify the repair of the leak. In these cases, it can be proven that the component was not leaking for the entire year. A date of when the leak stopped is specifically documented.

The calculation procedures in the proposed rule do not allow a facility to account for the emissions eliminated by repairing the leak off cycle from the leak survey schedule. Ignoring the cessation of emissions from fixing a leak between Subpart W surveys overestimates the GHG emissions. Allowing for documented leak repair records to be used will result in more accurate emission estimation and is consistent with the goals of the proposed rules is to improve the accuracy of the emission estimations.

Therefore, INGAA is asking EPA to develop a method where operators can use documented leak repairs to calculate the total time a component is assumed to be leaking.

3.2. The Proposed Rule establishes a compliance date of January 1, 2023, which does not allow industry sufficient time to prepare.

INGAA members appreciate EPA's recognition that affected facilities might not have all of the equipment, systems, and QA/QC procedures in place to support the monitoring requirements in the Proposed Rule beginning on the proposed effective date of January 1, 2023. For that reason, the Proposed Rule is allowing the use of best available monitoring methods from January 1, 2023, to December 31, 2023. However, EPA is requiring that the calculation methodologies and equations set forth in the Proposed Rule be used if best available monitoring methods are used. Further, the Proposed Rule references 40 CFR subparts OOOOb and OOOOc and 40CFR part 60 Appendix K, which are yet to be promulgated.

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[24] 87 Fed. Reg, 118 (June 21, 2022), page 37081

INGAA members, as do others affected by the proposed regulations, use a variety of systems to collect, compile, reduce, and report GHGRP data. Modifying the configurations of environmental reporting systems requires the effort of specialized personnel working with the technical end users. The process requires programming development, user testing, user acceptance testing, then validation before it is successfully used. The industry will need, at a minimum, several months to modify and update these data collection and reporting systems and verify that updates yield accurate data. To update these systems effectively and efficiently, INGAA members need to understand the requirements of 40 CFR subparts OOOOb and OOOOc and 40 CFR part 60 Appendix K. The effort required to modify and verify the accuracy of GHGRP reporting systems is dependent upon finalization of these rules. Given the uncertainty surrounding the release of final versions of these proposed rules, INGAA recommends that EPA establish an effective date of January 1 of the year following promulgation of all related regulations, provided that facilities have at least six months to develop, implement, and verify the accuracy of new data collection, reduction, and reporting systems.

Given the breadth of factors affecting GHG reporting, INGAA also recommends that EPA allow affected facilities two years for automatic BAMM with the option to request BAMM for specific items for a third year. This will enable affected facilities to properly implement and verify the monitoring methods that are affected by proposed revisions to the GHGRP, 40 CFR subparts OOOOb, OOOOc, and 40 CFR part 60 Appendix K.

3.3. It is difficult for INGAA to fully assess the requirements and impacts of the Proposed Rule, because the underlying compliance requirements of OOOOb and OOOOc are not known.

On November 15, 2021, EPA proposed preamble language entitled "Standards of Performance for New, Reconstructed, and Modified Sources and Emissions Guidelines for Existing Sources: Oil and Natural Gas Sector Climate Review" (hereinafter, Proposed OOOOb, c)[25]. As INGAA noted in INGAA's comments to Proposed OOOOb, c (hereinafter, INGAA OOOO Comments, provided as Attachment 1), "the absence of proposed regulatory text makes it difficult to provide meaningful comments on proposed OOOOb and OOOOc." Proposed OOOOb, c indicated that EPA would be issuing a supplemental proposal with proposed regulatory text; however, as of the date of publication of the Proposed Rule, EPA has not issued the supplemental proposal with proposed text. Until INGAA understands the requirements of subparts OOOOb and OOOOc, INGAA cannot fully assess the requirements and impacts of the Proposed Rule with respect to GHG emission data accuracy, quality, and representativeness.

INGAA recommends that EPA withhold references to 40 CFR part 60 subparts OOOOb and OOOOc requirements until the regulatory text has been promulgated. At that time, EPA should

[25] 86 Fed, Reg, 217 (November 15, 2021)

once again seek stakeholder comment and then amend the rule to include appropriate references to 40 CFR part 60 subparts OOOOb and OOOOc.

3.4. The emission threshold for "other large release events" should be increased, and INGAA recommends the "incident" reporting threshold in PHMSA regulations.

INGAA understands EPA's desire to include otherwise unreported "large release events" that may occur in a particular year, and the Proposed Rule preamble discusses examples from recent years. However, the emissions from the two examples are orders of magnitude higher than the proposed threshold. For example, the Aliso Canyon event was 100 times larger than the applicability threshold for natural gas facilities and 10,000 times larger than the proposed threshold of 250 metric tons CO_2e emissions or approximately 500,000 standard cubic feet (SCF) of natural gas. The proposed Subpart W threshold, which is 1% of the applicability threshold, should be increased slightly to a threshold of 3,000,000 SCF of natural gas, or approximately 5.5% of the GHGRP applicability threshold for natural gas facilities, which is consistent with the "incident" reporting threshold in Department of Transportation (DOT) Pipeline Hazardous Materials and Safety Administration (PHMSA) regulations.[26]

INGAA believes that defining a large release event at 1% of the applicability threshold is inappropriately low. As an example, and to provide context, while INGAA strongly disagrees with the proposed increase in T&S leaker emission factors for OGI-based surveys (see Comment 1), a single leak that occurs for a year for four of the six component types would exceed the "large release event" threshold proposed by EPA using those increased EFs. This context speaks to both the inappropriateness of the increase in T&S OGI-based leaker EFs, and the inappropriately low threshold for "other large release events". Surely emissions from a single leak from a common component like a valve or meter, estimated using emission factors that are intended to be indicative of average leak emissions, should not be equated to a "large release event."

Using the PHMSA threshold provides consistency with other federal reporting, a precedent from PHMSA regulations, and a much more reasonable threshold. And, for comparison to the preamble example, the Aliso Canyon event was still approximately 1,800 times larger than a reporting threshold of 3 million SCF (or approximately 1,400 mt CO_2e emissions).

<u>Additional Implications for Anomalous Events</u>
Adding reporting for other large release events addresses anomalies that may occur that are not covered by Subpart W methodologies. For transmission compressor stations, Subpart W includes an annual measurement to assess anomalous operation – i.e., transmission tank vent screening and measurement. The associated source for that measurement is not the tank, but rather a leaky or stuck condensate tank dump valve. In effect, that measurement was required so that EPA could assess the frequency and magnitude of dump valve leakage or anomalous performance. As discussed in comments above, INGAA recommends allowing emission factor-

[26] 49 CFR 191.3(1)(ii)

based estimates rather than ongoing annual transmission tank measurements. In addition, by adding reporting for “other larger release events”, anomalous dump valve performance would be addressed regardless of the transmission tank reporting requirement.

PRCI compiled data[27] shows that the related emissions “on average” were relatively minor based on 2015 and 2016 Subpart W data, with a facility-level emission factor of approximately 300 mt CO2e per year, but only about 10% of facilities finding a leaky dump valve. Interestingly, the PRCI data[28] indicates just over 50 instances for both 2015 and 2016 where scrubber dump valve leakage occurred, and for those leaks, the average leak rate was just approximately 310 SCF per hour. That equates to 2.7 million SCF if the leak occurs for an entire year, or similar in magnitude to the PHMSA based threshold discussed in this comment and recommended for Subpart W other large release events. Event frequency and magnitude for scrubber dump valves have likely decreased since that data was collected as mandatory or voluntary LDAR programs have become more common for compressor stations. Analysis of data available to EPA from eleven years of Subpart W measurements would document that trend. Thus, INGAA recommends that EPA eliminate the transmission storage tank requirements in Subpart W since the new “other large release event” requirement in §98.233(y) would address those emissions when a leaking dump results in emissions exceeding the threshold.

3.5. Historical GHG reporting data indicate that it is not necessary to monitor tank vents annually when tank emissions are routed to a flare.

EPA is proposing that transmission tanks emissions routed to a flare should not be a specific source but be classified as miscellaneous flared source. EPA has proposed this because, as is documented in the preamble to the Proposed Rule, over the past 6 years for transmission tank vent stacks routed to a flare there have been no leaks reported and the reported flared emissions have been 0 metric tons of GHGs. INGAA agrees with this reclassification.

However, the EPA is proposing to retain the current requirements in 40 CFR 98.233(k)(1) and (2) to monitor the tank vent stack annually for leaks and to quantify the leak rate if a leak is detected. As was stated in the preamble, there have been no leaks reported over the past 6 years. Therefore, we believe that the requirements to continue to monitor for leaks should be eliminated. Eliminating the monitoring requirements for the transmission storage tanks when there have been no emissions reported over the past 6 years is consistent with the stated intent to streamline monitoring and calculation methodologies where "continuing to collect data on the same frequency would unlikely provide significantly different values.”

As an additional point, it is INGAAs understanding from the preamble that the transmission tank monitoring is required because "it would not be possible to tell if there were any scrubber

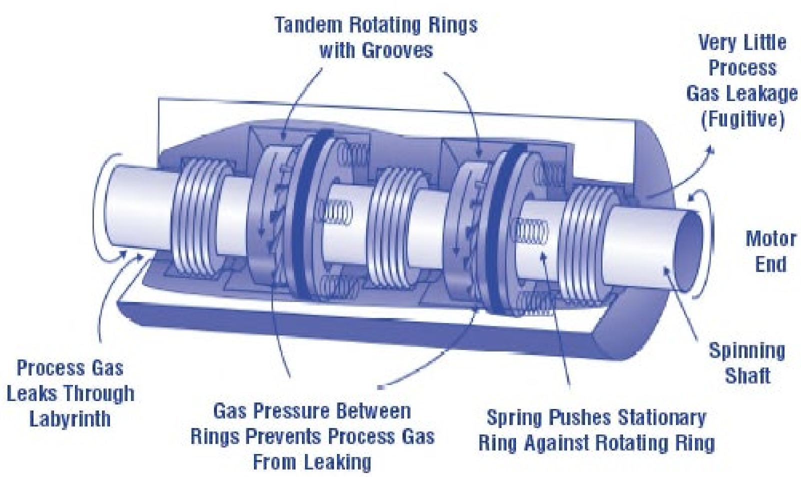
[27] PRCI Report Catalog No. PR-312-16202-R03, “Methane Emissions from Transmission and Storage Subpart W Sources,” August 2019.
[28] PRCI August 2019 Report, Figure 8 and Section 5

dump valve leaks if only a combined emission stream is measured.[29]" INGAA does not believe the tracking of dump valves emissions is reason enough to justify the monitoring of every transmission tank given the low-GHG emissions from this category of sources. This does not advance Objective II.A.2 "Improvements to Existing Emission Estimation Methodologies" and we believe it goes against Objective II.B.2 "Revisions to Streamline Monitoring and Calculation Methodologies." The rules requiring the knowledge of the total flare volume and composition are adequate to accurately account for emissions from the transmission tanks.

For these reasons INGAA recommends that EPA remove the requirement to monitor transmission storage tanks when they are routed to a flare.

3.6. Clarity is needed on dry seal monitoring.

63.233(o)(2)(iii) requires volumetric measurements for centrifugal compressor dry seal vents. As a point of clarification, a dry seal compressor has two dry seals (see figure below[30]): a dry seal on the gas side compressor (inboard) and a dry seal on the air side motor and shaft bearing (outboard). There are "very little" gas emissions from the dry seal on the outboard side according to EPA's documentation on reducing emissions from compressor seals, and therefore there is no reason to require volumetric emissions from the outboard dry seal.



INGAA requests that EPA clarify that 233(o)(2)(iii) include only measuring volumetric emissions from the compressor side dry seal.

[29] Page 285 of 820 in the "revisions-and-confidentiality-determinations-for-data-elements-under-the-greenhouse-gas-reporting-rule."
[30] From https://www.epa.gov/sites/default/files/2017-09/documents/reducingemissionsfromcompressorseals.pdf p.16

Additionally, permitted measurement techniques proposed in 40 CFR 98.233(o)(2)(ii)(A) through (D) consist of manual methods such as temporary anemometers and flow meters (e.g., rotameters) and other rudimentary methods. Orifice, venturi, and nozzle devices are covered in 98.3(i)(3).

Other devices for measuring vented emissions may include thermal dispersion meters and Coriolis meters. The rule should allow for such meters or other measurement devices to be used either thru BAMM application or as outlined in the monitoring plan. OEMs and third party vendors may already provide monitoring systems for dry seal vents; however, they would be excluded for use under the Proposed Rule because they don't fall under the specific measurement techniques or standards as noted in 98.238(o)(2)(ii)(A) through (D). EPA should add language allowing operators to use other measurement techniques (including BAMM) for all years starting in 2023 and beyond.

For orifice, venturi, and nozzle devices, 98.3(i)(3) states 'initial quality assurance consists of in-situ calibration of the differential pressure (delta-P), total pressure, and temperature transmitters.' It should be noted that in order to calibrate pressure or temperature transmitters in situ, cutting and alterations of the vent piping will be required which will require the gas compressor to be shut down and taken out of service. The in-situ calibration clause should be removed from the above citation so that these transmitters could be removed from service and replaced with factory or site-calibrated transmitters, allowing minimal disruption to pipeline operations.

For these reasons volumetric emissions should not be required on the motor and shaft bearing side.

3.7. The proposed flare activity reporting requirements found at 98.236(n)(2)(ii) do not support GHG emissions reporting or validate reported GHG emissions.

Proposed section 98.236(n)(2)(ii) includes requirements to report information such as the flare name or other identification information, the types of emission sources routed to the flare, total volume of gas routed to the flare, the type of flare, estimated fraction of the total volume routed to the flare when it is not lit, flare assist type, whether the flare has a continuous pilot or autoigniter, whether a continuous pilot is continuously monitored, and if the continuous pilot is not monitored, how periods when the pilot is not lit are identified. None of this information is used to calculate or validate GHG emissions. If EPA requires this information for something other than GHG reporting, it should obtain it through a formal information request that includes rationale for why this information is needed instead of including the information in this rulemaking. INGAA therefore recommends that EPA remove the proposed requirements found at 98.236(n)(2)(ii).

3.8. Based on the complexity of liquefied natural gas (LNG) systems, INGAA recommends that EPA allow site-specific engineering estimates based on best available data for AGR vents.

EPA requested comments on whether all four calculation methods currently provided in 40 CFR 98.233(d) are appropriate for facilities in the LNG Import/Export industry segment and if not, how specific calculation methods could be adjusted to be more applicable to this industry segment. 98.233(d)(1) through (4) documents four calculation methodologies for CO_2 vented directly to the atmosphere: Calculation Method 1 (if there is a Continuous Emission Monitor System (CEMS)), Calculation Method 2 (vent meter is installed), Calculation Method 3 (estimation method using inlet or outlet gas flow rates), and Calculation Method 4 (estimation method using simulations from software packages). EPA further states that the estimations under Calculation Methods 3 and 4 (i.e., 98.233(d)(3) or (4)) may provide incorrect and impossible calculated volumetric emissions. Therefore, EPA correctly proposed new provisions for specific situations for AGR vents comingled with other sources and routed to a flare or thermal oxidizer. Some of these methods still utilize Calculation Methods 3 and 4. With the possible errors in these methods and the further complexity of liquefied natural gas (LNG) systems, INGAA suggests the estimation methods under 98.233(d)(3) and (4) should not be utilized for acid gas removal vents at LNG facilities under any circumstance. LNG facilities are very complex with a variety of technologies and processed integrated. Streams at an LNG facility are often comingled with emissions from other source types. Further, the volume and composition of the streams (directly or comingled) are not necessarily monitored continuously. In these stream situations at an LNG facility the four calculation methodologies do not fit with typical plant procedures. Under certain circumstances, data may be available to utilize Calculation Methods 1 and 2 appropriately. LNG facilities have found that site-specific engineering estimates based on best available data is the most accurate, and sometimes the only way, to calculate emissions.

INGAA recommends that the Proposed Rule be modified to make it clear that site-specific engineering estimates based on best available data will be allowed for calculation emissions from all AGR vents at LNG facilities whenever Calculation Methods 1 and 2 are inappropriate.

3.9. The Proposed Rule removes acoustic leak detection from screening methods allowed for manifold groups of compressor seals. INGAA believes acoustic leak detection should be allowed for manifolded compressors in some situations.

As noted in 40 CFR 98.234(a)(5), acoustic leak detection is applicable only for through-valve leakage. The acoustic method can be applied to individual compressor sources, but it cannot be applied to a vent that contains a group of manifolded compressor sources downstream from the individual valves or other streams that may be manifolded together. The inclusion of this method for manifolded compressor sources was in error and we are proposing to remove it from 40 CFR 98.233(o)(4)(ii)(D) and (E) and 40 CFR 98.233(p)(4)(ii)(D) and (E) to improve accuracy of the measurements, consistent with section II.A.2 of this preamble.

INGAA believes eliminating the use of acoustic leak detection from manifold groups of compressors is ignoring the fact that there is acoustic leak detection is a valuable tool in attributing source contribution to manifolded compressors. The acoustic device is a good tool for identifying leaks. For example, we have seen a case where a company has 4 reciprocating engines venting to a single stack (i.e., manifolded compressors). A high flow meter was used to take a measurement at the common vent. There was a leak identified but and a VPAC acoustic device was used to try to isolate which unit was leaking. Three units were in standby pressurized mode, and one was in standby depressurized. In this case the acoustic detection was done upstream of where the streams were comingled.

INGAA requests EPA to continue to allow the use of acoustic leak detection in manifold compressor situations to identify which valve is leaking.

INGAA appreciates EPA's continued efforts to improve the GHGRP and hope that the comments we have provided will be helpful and constructive. INGAA appreciates the opportunity to comment and welcomes the opportunity to elaborate or respond to any questions.

Regards,

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Attachments: Attachment 1, INGAA OOOO Comments

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