Interstate Natural Gas Association of America

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The Interstate Natural Gas Association of America (INGAA), a trade association that represents 26 members of the interstate natural gas pipeline industry, respectfully submits these comments in response to the United States Environmental Protection Agency's (EPA or Agency) 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 Rule), which was published in the Federal Register on November 15, 2021.[1] INGAA notes that the Proposed Rule does not contain any proposed regulatory text. INGAA will be commenting on the proposed regulatory text once EPA releases it.

INGAA members own and operate a large percentage of the transmission and storage segment of the oil and natural gas source category. Accordingly, this rulemaking is of tremendous importance to INGAA and its members. Indeed, INGAA has participated in all of the EPA rulemakings involving regulation of methane from the oil and natural gas source category.[2] Most recently, EPA issued a Request for Information on "Reducing Emissions of Methane and Other Air Pollutants

[1] 86 Fed. Reg. 63,110 (Nov. 15, 2021).

[2] *See, e.g.*, Docket ID No. EPA-HQ-OAR-2010-0505-4104 (Nov. 22, 2011) (INGAA's comments on proposed Subpart OOOO) (Attachment 1 to these comments) (hereinafter, INGAA OOOO Comments); Docket ID No. EPA-HQ-OAR-2010-0505-0682 (Dec. 4, 2015) (INGAA's comments on proposed Subpart OOOOa) (Attachment 2 to these comments) (hereinafter, INGAA OOOOa Comments); Docket ID No. EPA-HQ-OAR-2017-0483-1002 (Dec. 17, 2018) (INGAA's comments on reconsideration of portions of Subpart OOOOa) (Attachment 3 to these comments). Each of these sets of comments are incorporated herein by reference.

from the Oil and Natural Gas Sector" during the pre-rulemaking phase for the Proposed Rule, and INGAA provided EPA with comments (hereinafter, INGAA Pre-Rulemaking Comments) in response to that request.[3]

INGAA's members support clear and reasonable federal regulation of methane emissions and have been taking steps to reduce their methane emissions.[4] The industry has been working to identify work practice standards that reduce methane emissions and has been implementing those standards. For example, the American Gas Association prepared a white paper analyzing blowdown emissions from transmission and storage and distribution that provided guidance and methods on how to reduce emissions from a blowdown.[5]

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. This includes over 3,500 stationary natural gas-fired reciprocating engines, 1,500 combustion turbines, and 300 electric motors that drive the compressors. Most of these units are considered "existing" under the Clean Air Act and will thus be subject to any emission guideline EPA promulgates.

The Proposed Rule contains three separate proposed subparts: (1) proposed revisions to New Source Performance Standard (NSPS) OOOOa, which governs new, modified, and reconstructed sources that commence construction after September 18, 2015; (2) proposed NSPS OOOOb, which will govern new, modified, and reconstructed sources that commence construction after November 15, 2021; and (3) proposed emissions guidelines (EG) OOOOc, which will govern existing sources that commenced construction on or before November 15, 2021.[6]

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[3] Docket ID No. EPA-HQ-OAR-2021-0295-0033 (June 30, 2021) (Attachment 4 to these comments). These comments are incorporated herein by reference.

[4] *See* INGAA, *2021 Vision Forward: Addressing Climate Change Together*, (Jan. 2021), available at https://www.ingaa.org/File.aspx?id=38523&v=6553c6c8 (INGAA's 2021 Climate Statement, which includes a commitment to work together as an industry towards achieving net-zero GHG emissions by 2050); INGAA, *Methane Emissions Commitments*, https://www.ingaa.org/File.aspx?id=38582 (INGAA's 2018 voluntary methane commitments).

[5] American Gas Association, *Blowdown Emission Reduction White Paper* (Aug. 5, 2020). This white paper is attached to these comments as Attachment 5.

[6] As discussed in Section IX of these comments, the proposed applicability date of November 15, 2021, for OOOOb and OOOOc is incorrect.

EXECUTIVE SUMMARY

INGAA members own and operate a large percentage of the transmission and storage segments of the oil and natural gas source category that are subject to OOOOa and would be subject to proposed OOOOb and OOOOc. INGAA members support clear and reasonable federal regulation of methane emissions and have been taking steps to reduce their methane emissions. INGAA provides the following comments on the Proposed Rule:

- The absence of proposed regulatory text makes it difficult to provide meaningful comments on proposed OOOOb and proposed OOOOc. EPA's failure to provide the proposed regulatory text is unusual and is inconsistent with the intent of the Administrative Procedure Act. INGAA urges EPA to follow through on its plan to issue a supplemental proposal with the proposed regulatory text. INGAA will submit comments on the supplemental proposal and the proposed regulatory text and asks EPA to allow sufficient time (i.e., at least 90 days) for preparation of comments on that proposal. In the absence of the regulatory text, commenting on certain aspects of the Proposed Rule is difficult—if not impossible. For example, it is unclear in several places what type of wells EPA intends to regulate in certain situations. INGAA cannot evaluate the Proposed Rule when it is unclear what is being proposed to be regulated.

- As a general matter, INGAA supports EPA's proposed revisions to OOOOa, including extending all of the provisions of the Technical Amendments Rule to apply to methane emissions from all segments of the source category, including transmission and storage. These amendments made sense when they were done as part of the Technical Amendments Rule, and INGAA supports extending these provisions to the transmission and storage segment.

- EPA should provide for delay of repair due to lack of availability of parts in OOOOc. This is necessary to avoid reliability impacts to customers and system disruptions. Allowing a delay of repair for this reason has been done by other states, including Colorado and Maryland, and EPA should also follow this approach. Delay of repair for parts availability is particularly needed with regard to existing units because the parts for these units may not be readily available or in stock. Parts are not interchangeable between different manufacturers, models, or even vintages of the same equipment. Therefore, parts sometimes need to be custom ordered and/or manufactured, which takes time.

- EPA should continue to provide a functionality exemption for pneumatic controllers for safety and reliability reasons. The Agency properly recognized when it promulgated OOOO and OOOOa that there are circumstances where gas-driven pneumatic controllers are needed. Nothing has changed to warrant removing the functionality exemption. Situations exist were the use of gas-driven pneumatic controllers is necessary for safety reasons. If electric supply gets disrupted, important safety equipment such as emergency shutdown valves still need to work. Gas-driven pneumatic controllers provide the best and most reliable method for ensuring this safety equipment works when needed. Importantly, the emissions from gas-driven pneumatic controllers in the transmission and storage segment are small, and retaining the exemption for that segment of the source category will not result in significant methane emissions.

- EPA's proposed standard for wet seal compressors requires substantial reevaluation and revision. EPA's best system of emissions reduction (BSER) analysis relies on an outdated, inflated emission factor for wet seal units that the Agency used in the OOOO and OOOOa rulemakings. In its annual GHG inventory, however, EPA has since properly replaced the emission factor for wet seal units with a much lower factor that is more representative of these units, and any proposed standard should reflect that lower factor. In addition, many existing wet seal compressors should not require additional emission controls because the units are designed to emit very low, or even zero, degassing emissions. EPA should make clear in the proposed regulatory language and final rule that wet seal compressors that predominantly recirculate degassing emissions satisfy the proposed control requirements for wet seals or are excluded from the rule. Similarly, compressors that utilize mechanical seals in which the oil does not come into contact with the natural gas have zero degassing emissions and should be excluded from the rule. A de minimis exemption for wet seal compressors that have very low utilization (e.g., less than 500 hours annually) should also be adopted because it is not cost effective to require the proposed controls in these circumstances. Finally, even for wet seal compressors of conventional design, EPA needs to reevaluate its BSER determination to use current, more accurate emissions estimates, as well as a realistic assessment of the feasibility and cost of potential controls.

- INGAA supports EPA's proposal to adopt a condition-based standard for the replacement of rod packing for reciprocating compressors. INGAA believes, however, that this condition-based standard should not replace the current fixed schedule standard previously adopted under OOOOa. Rather, INGAA proposes that EPA should adopt both approaches as alternative standards. Adopting a different standard in this rulemaking than the OOOOa fixed schedule standard would be disruptive to the many companies that have voluntarily adopted the fixed schedule approach for their existing fleets of reciprocating compressors (and to facilities in states that have promulgated standards modeled after OOOOa). This disruption is not justified, because the BSER analyses show that the cost effectiveness of the two approaches is very similar, and it is far from clear that either approach would result in larger emission reductions.

- Proposed Appendix K unfortunately contains requirements that have the effect of making optical gas imaging (OGI) nearly infeasible without any additional environmental benefit. As written, proposed Appendix K will have the effect of operators not being able to use OGI technology and being forced to opt for Method 21 surveys instead. INGAA recommends a re-write of the entire method, with appropriate stakeholders being included in the process. OGI is a critical and efficient tool for finding and fixing leaks, and it will continue to be a necessary tool even as technology advances. INGAA is willing to offer assistance to EPA in this effort.

- INGAA looks forward to providing comments in the future and to participating in a process to evaluate whether the use of information from communities and others is appropriate and, if so, under what conditions. INGAA emphasizes, however, that such a process is truly nascent at this time. Accordingly, INGAA urges EPA to recognize that this is the start of a process and not to seek to propose, much less finalize, regulations for the use of information from communities and others in this rulemaking. Indeed, EPA, along with stakeholders, must thoughtfully and carefully evaluate how such use can: (1) dovetail with and not duplicate monitoring that is otherwise required under the rule; and (2) be well-defined and rigorous in its requirements of methods and quality assurance and quality control so that it does not impose costs with little to no benefit and continues to support operators maintaining focus on identifying emissions events and responding as appropriate.

- The applicability dates for both proposed OOOOb and proposed OOOOc are incorrect. The date that EPA publishes the proposed regulatory text in the Federal Register will be the applicability date for OOOOb. Until that publication occurs, EPA has not "prescrib[ed] a standard of performance" as required by section 111 of the Clean Air Act. Similarly, the applicability date for proposed OOOOc is incorrect. OOOOc should apply to those sources that commenced construction on or before September 18, 2015, which is the date that OOOOa was proposed. Any source that commenced construction after that date was a "new source" and complied with the standards of performance set forth in OOOOa.

- EPA solicits comment and information regarding pigging operations. In these comments, INGAA explains that pigging is different in the transmission segment, where pigging typically occurs for safety purposes. Pigging also occurs far less frequently in the transmission segment. As a result of these differences, the emissions from pigging operations in the transmission segment are extremely low. The Pipeline and Hazardous Materials Safety Administration (PHMSA) is also examining options to reduce methane emissions associated with pigging operations, and EPA should consider deferring to PHMSA on this issue.

DETAILED COMMENTS

INGAA's detailed comments are provided below.

I. It is difficult to provide EPA with meaningful comments on proposed OOOOb and OOOOc in the absence of proposed regulatory text.

A. The lack of proposed regulatory text in a proposed rule is unusual and is inconsistent with the intent of the Administrative Procedure Act.

As EPA notes in the Proposed Rule, it "plans to issue a supplemental proposal and supplemental [regulatory impact analysis (RIA)] for the supplemental proposal to provide regulatory text for the proposed OOOOb and … OOOOc."[7] EPA states that it views this "[a]s a further step in the rulemaking process" and will be "solicit[ing] additional public input" at that time.[8] As a result, these portions of the Proposed Rule do not include rule language and are more akin to an Advance Notice of Public Rulemaking, and as discussed further below, it makes meaningful comment on certain aspects of the Proposed Rule impossible.

It is highly unusual for an agency to purposefully exclude proposed regulatory language in a proposed rule, especially one of this magnitude. The Administrative Procedure Act requires that an agency's proposed rule must provide "either the terms or substance of the proposed rule or a description of the subjects and issues involved."[9] Courts have interpreted the notice requirement of the Administrative Procedure Act to require that a final rule be a "logical outgrowth" of the proposed rule.[10] The issue of whether or not mere vague discussion of the issues involved is sufficient to satisfy the logical outgrowth test has not yet been decided by the courts.

INGAA urges EPA to follow through on its plan to issue a supplemental proposal and supplemental RIA along with the proposed regulatory text for OOOOb and OOOOc and further urges EPA to allow sufficient time for comment on these important documents. In addition, EPA should not foreclose comment on aspects of the overall proposal on the grounds that comment was allowed here as part of this Proposed Rule. The ability to review the proposed regulatory text should provide clarity on issues that are unclear and could even reveal some areas in which the understanding by INGAA members was incorrect. In these cases, it is important that INGAA be able to comment and correct any misperceptions that it may have had.

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[7] 86 Fed. Reg. at 63,115.

[8] *Id.*

[9] 5 U.S.C. § 553(b)(3).

[10] *See, e.g.*, *Fertilizer Inst. v. EPA*, 935 F.2d 1303, 1311 (D.C. Cir. 1991); *see also* Phillip M. Kannan, *The Logical Outgrowth Doctrine in Rulemaking*, 48 ADMIN. L. REV. 213 (1996).

In particular, seeing the regulatory text is imperative as the specific words matter. As EPA knows, how a statute or a regulation is interpreted by courts and by EPA can be affected by such benign things as the placement of a comma or a word as seemingly innocuous as "any."[11]

B. The lack of regulatory text makes comment on certain aspects of the Proposed Rule impossible.

The lack of regulatory text makes comment on certain aspects of the Proposed Rule difficult, if not impossible, because it is unclear what EPA intends to do. For example, in numerous places in the Proposed Rule, EPA discusses the regulation of emissions from wells, but it is unclear whether EPA intends to regulate production wells, storage wells, or both. In Table 2 of the Proposed Rule, EPA lists "well liquids unloading" as an affected source and proposes a BSER of zero methane or VOC emissions.[12] This BSER can be applied only at hydraulically fractured wells. It is possible that EPA understands this and intends that this performance standard apply only to hydraulically fractured wells, but without the proposed regulatory text, INGAA members have no way of confirming that. The issue of what type of wells certain proposed standards of performance apply to is a core, fundamental issue, and without knowing this with certainty, INGAA members cannot evaluate the proposal and provide EPA with meaningful feedback. Without clear definitions being provided, it is impossible to understand the scope of the Proposed Rule.

Another area in which the lack of regulatory text makes meaningful comment difficult concerns the timing of state plan submissions and compliance times. As EPA notes, when state plans will be due to be submitted to EPA is an open question following the D.C. Circuit's recent decision in *American Lung Association v. EPA*.[13] EPA states that it "is committed to publishing this proposed timeline for comment when available."[14] The problem, however, is that in the absence of this information it is impossible to say whether a compliance timeline of two years following the state plan submittal deadline is reasonable because commenters have no idea what the state plan submittal deadline will be. Under the original implementing regulations for section 111(d), this deadline was nine months.[15] That would not provide enough time. If the deadline for state submittal of plans is longer, then it may provide enough time. But in the absence of this key piece of information, meaningful comment is simply not possible.

Another important piece of information that is missing with regard to state plans is the amount of time that EPA will have to approve or disapprove the state plan following submittal. Until a state plan has been approved, regulated entities may be hesitant, or even limited in their ability, to invest significant time, resources, and capital into compliance until they are sure that the requirements in the state plan are indeed what they will need to meet. Under the original implementing regulations

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[11] *New Jersey v. EPA*, 517 F.3d 574, 582 (D.C. Cir. 2008); *New York v. EPA*, 443 F.3d 880, 885 (D.C. Cir. 2006).

[12] 86 Fed. Reg. at 63,119 Table 2.

[13] *Id.* at 63,255 (citing *Am. Lung Assoc. v. EPA*, 985 F.3d 914, 991 (D.C. Cir. 2021)).

[14] *Id.*

[15] 40 Fed. Reg. 53,340, 53,347 (Nov. 17, 1975) (40 C.F.R. § 60.23(a)(1)).

for section 111(d), EPA had four months to approve or disapprove a plan,[16] which would have made the compliance deadline of two years from the deadline for plan submission more reasonable. Establishing a two-year deadline for compliance while leaving the EPA review period for state plans undefined is unreasonable. These unknowns, again, make commenting meaningfully challenging.

An important factor with regard to the timing deadlines for state plan submission and, in turn, compliance, is that the proposed requirements for OOOOc will take time to implement. Sufficient time needs to be provided under OOOOc to give operators the needed time to: research, plan, develop, and implement the required programs and strategies; hire and train personnel; enter into contracts with third-party service providers to conduct monitoring; procure additional monitoring equipment; and establish recordkeeping procedures. All of these things, collectively, will be crucial for proper implementation.

Moreover, OOOOc will involve implementing new requirements on *thousands* of existing sources, which will be a time intensive endeavor. It takes time to procure parts and the skilled labor necessary to implement these changes, and this is even more significant when considering the current supply chain disruption issues. With regard to work practice standards, it takes time to make these changes and to train operators and contractors properly. For all of these reasons, INGAA supports a phased-in approach for existing sources. INGAA generally agrees with EPA "that it may be appropriate to require different compliance times for different designated facilities" and that "[t]here may not be a one-size-fits-all approach to compliance times that is appropriate for all designated facilities,"[17] but needs to see the actual timing that is proposed before it can meaningfully comment.

INGAA looks forward to reviewing the proposed regulatory text once it becomes available and asks the Agency to provide a reasonable amount of time for comment on that text and all related aspects of the Proposed Rule as it will likely give rise to many new issues that cannot be identified now in the text's absence.

II. INGAA generally supports EPA's proposed revisions to OOOOa.

As a general matter, INGAA supports EPA's proposed revisions to OOOOa. First, INGAA agrees with EPA that the Technical Amendments Rule provisions should be extended to apply to methane emissions from all segments of the source category, including the transmission and storage segments.[18]

Second, INGAA supports the Proposed Rule's proposal to apply the delay of repair provisions in the 2020 Technical Amendment Rule to the transmission and storage segments for both VOC and methane emissions.[19] This provision allows repairs that require a unit shutdown to be delayed until

[16] *Id.* at 53,348 (40 C.F.R. § 60.27(b)).

[17] 86 Fed. Reg. at 63,256.

[18] *See id.* at 63,158.

[19] *Id.* at 63,164.

the next scheduled shutdown for maintenance. As EPA notes, these maintenance shutdowns occur on a regular schedule, and it makes sense to do the repairs during these shutdowns to avoid unnecessary methane venting and disrupting the reliability of gas transmission.[20]

Third, INGAA also generally supports the following amendments to OOOOa:

- Extending the deadline for conducting initial monitoring from 60 to 90 days for both VOC and methane emissions at all well sites and compressor stations;[21]
- Amending the OOOOa provisions associated with applications for use of an alternate means of emissions limitation (AMEL) for methane work practice standards at well sites and gathering and boosting compressor stations and VOC and methane work practice standards at compressor stations in the transmission and storage segment;[22]
- Finding that state fugitive emission standards for methane and VOCs in California, Ohio, Pennsylvania, and Texas for compressor stations in the transmission and storage segment are "equivalent with, if not better than, the Federal requirements";[23] and
- Aligning the methane standards of OOOOa with the Technical Amendment Rule to allow certification of technical infeasibility by either a professional engineer or an in-house engineer with expertise on the design and operation of the pneumatic pump.[24]

All of these amendments made sense when they were done as part of the 2020 Technical Amendments Rule for the reasons expressed there, and INGAA supports extending these provisions to the transmission and storage segment and to methane emissions.

III. EPA should provide for a delay of repair that is caused by the lack of availability of parts in OOOOc.

The Proposed Rule solicits comment on delay of repair (DOR) requirements to address the availability of replacement parts for existing compressor stations, an important matter that is of particular concern to INGAA and its members. As explained in INGAA's Pre-Rulemaking Comments, which are included here as Attachment 4 and incorporated by reference, the parts necessary to repair a leak are not always readily available or in stock.[25] OOOOc needs to contain a DOR provision for parts availability to avoid reliability impacts to customers and system disruptions. Including a DOR provision for parts availability is a practical necessity, sound policy,

[20] *Id.*

[21] *Id.*

[22] *Id.* at 63,166.

[23] *Id.* at 63,167.

[24] *Id.* at 63,162.

[25] *See* INGAA Pre-Rulemaking Comments at 4-7 & Apps. A, B.

and is protective of the environment. INGAA's recommendations on DOR are modeled after regulations adopted by several states, including Colorado and Maryland.[26]

Specifically, INGAA is requesting that the DOR provisions for availability of parts in OOOOc mirror the DOR provisions in OOOOa as follows:

- If parts are not available and need to be ordered, repair may be delayed until they are received.
- Once parts have been received, operators will need to schedule the repair after receipt of the replacement part to ensure that adequate skilled labor is available, the parts have been integrity tested, and the timing of the repair will not impair reliability of the natural gas system.
- If the leak cannot be repaired without a shutdown or blowdown, then EPA should allow operators to delay making a repair until the next scheduled shutdown for maintenance that occurs after the parts have been received, not to exceed two years from discovery of the leak.

In the Proposed Rule, EPA solicits comment on several specific issues related to a replacement part DOR provision:

> The EPA is soliciting comment and data to better understand [1] the *breadth of this issue* with replacement parts for existing compressor stations. Additionally, we are soliciting comment on [2] *whether 30 days following receipt of the replacement part is appropriate* for completing delayed repairs at existing compressor stations, [3] whether there should be *any limit on delays* in repairs under these circumstances, and [4] whether this compliance flexibility *should be limited or disallowed based on the severity of the leak* to be repaired.

86 Fed. Reg. at 63,174 (emphasis added). Each of these issues is addressed below.

A. The breadth of the issue posed by replacement parts necessitates the inclusion of a DOR provision in OOOOc related to parts availability.

Equipment utilized for gas transmission is high specialized and is made to stringent engineering specifications. The parts necessary to repair a leak are not always readily available or in stock. Not only do parts come in various sizes, but parts are not interchangeable between different manufacturers, models, or even different vintages of the same equipment. Some existing source compressors may be more than 50 years old, and compressors have changed over time. If a part breaks on an older piece of equipment, the comparable part that is used for new compressors may not be the right size or configuration for that older equipment. For example, the specifications of an older compressor valve might not be standard, the system associated with an older unit might have additional connections for recirculation piping, or there might be additional changes that the

[26] *See* 5 COLO. CODE REGS. § 1001-9:D.I.L5. (allowing DOR if parts are unavailable or for other good cause); MD. CODE REGS. 26.11.41.03.A(9)(c)(i) (allowing DOR if parts or equipment need to be ordered or delivered).

operator needs to make to that system to address other regulatory requirements, such as PHMSA regulations. In such cases, the appropriate parts for that equipment will need to be custom ordered and/or manufactured, and it may take several months to fabricate such parts.

The delivery time on receiving such equipment can also be prolonged because some parts are manufactured overseas. As has been seen in recent months, supply chain delays have lengthened the times for overseas products to be delivered, and even if a part is manufactured in the United States, it could be affected by supply chain delays because the materials needed to manufacture the part are delayed. While operators can control the ordering of needed parts and can ensure this is done in a timely fashion, they cannot control how quickly that part will arrive. System reliability should not suffer because of supply chain delays.

The occurrence of situations where the need for replacement parts that are not readily available and for which a DOR allowance will be appropriate is nevertheless likely to be a relatively rare occurrence, and thus the emissions associated with these occurrences are therefore likely to be small. Below is a list of the types of parts that are most likely to be required for replacement, and the general timeframes for acquiring them:

- **Valves (ball, plug, gate, check).** Valves that are 16 inches and below are typically available; valves over 16 inches are more likely to take longer.
- **Regulators/Relief Valves.** Valves that are 16 inches and below are typically available; valves over 16 inches are more likely to take longer.
- **Compressor Packing.** This is typically available.
- **Parts with unique design requirements.** The need for these parts is rare, but they need to be special ordered and can typically take up to 12 months.

Another INGAA member currently reports that the typical lead-times for smaller valves (i.e., those are between 8 and 12 inches) are in the neighborhood of 16 to 20 weeks. The lead time for large bore valves are approximately 40 weeks, and the lead time for new valve actuators are approximately 20 to 24 weeks. All lead times are subject to change based on market conditions.

An analysis of INGAA members' affected sources reveals that there are over 20 different engine manufacturers and over 100 different models, each with their own model-specific parts. Further, these various engines span a wide range of vintages, such that even parts from a single supplier can vary significantly from model year to model year. Likewise, there are several different turbine manufacturers and dozens of different turbine models. The complications arising from different model year equipment requiring different parts applies with equal force to turbines. All of this equipment, moreover, is itself composed of many unique sub-assemblies, potentially comprising thousands of sub-components for each facility. Any one of these thousands of components and subcomponents could be required to repair a leak and need to be replaced.

Appendix B to INGAA's Pre-Rulemaking Comments helps to further explain the enormity of the challenge posed by part availability for existing compressor stations by providing examples of the types of equipment and potential leak sources that are most likely at compressor stations. As Appendix B explains, a typical compressor house will have multiple compressors within the building and a compressor station may have several compressor houses.[27] The appendix provides photographs and diagrams of just some of the key equipment located in these compressor houses to illustrate the scale and breadth of the issue for the industry. The examples reviewed in Appendix B begin with integral reciprocating compressors, which are common in gas transmission.[28] These units include flanges, cover plates, and bolted surfaces encasing natural gas, and each of these components is a potential leak source and piece of equipment that may need to be replaced.[29] Looking at a cross-section of the integral reciprocating compressor itself, Appendix B further identifies the engine fuel system and compressors, and the flanges and cover plates associated with the compressor variable valve pockets and distance piece as additional potential leak sources.[30]

Looking more in-depth into just one category of these potential leak sources—valves—the appendix explains that each type of valve is itself made up of dozens of components, "including: the valve stem packing, grease nipples, bleed ports, valve body seals (e.g., where the bonnet bolts to the valve body, retainer connections), packing guide, and any monitoring ports on the stem packing system."[31] As explained above, and as further described in Appendix B, the number of these potential leak sources must be multiplied by the different sizes, manufacturers, and model years for the equipment in use at the source to fully appreciate the number of pieces of equipment that could require replacement and the enormity of the stockpile of spare parts that would be needed for each facility.

An argument often given against DOR for parts availability is that operators should keep an inventory of parts on hand. This argument simply does not understand the scope and scale of the issue. Given the number of engines and turbines and the considerable variation in design among manufacturers and across model years, it is not feasible for individual companies or facilities to stockpile every type and size valve or part that might be needed to repair a leak. An operator has no reasonable way to predict which parts will need to be replaced and when, particularly considering that the operator's initial attempts to stop the leak using other repair methods may be successful.

For the same reason and because of generally low demand for what are often relatively unique or uncommon parts, manufacturers cannot be expected to maintain an inventory of parts ready for rapid shipment when a facility discovers a part must be replaced. Maintaining such an inventory would have considerable tax and cash flow implications because the parts may never sell due to low demand. In addition, many parts have a shelf-life that limits the time they can remain in inventory, and an operator may question whether a part may have been sitting on the shelf for too long and is still good for use. In INGAA's experience, manufacturers limit their inventory to items that move quickly or are more commonly required, which means there is not a ready inventory of

[27] INGAA Pre-Rulemaking Comments, App. B at 13.

[28] *Id*.

[29] *Id*. at 15.

[30] *Id*. at 16.

[31] *Id*. at 18.

expensive, unique, or obsolete parts. Because it is not feasible to keep a complete stockpile of all possible equipment that may need to be replaced to address a leak, allowing a DOR to provide time for acquisition of replacement parts is necessary.

Given that the number of parts that may potentially require replacement at any given facility is enormous and given that the time to obtain some of these parts can be several months, the only reasonable solution that preserves reliability of the gas supply is to include in OOOOc a DOR provision related to parts availability.

B. The appropriate amount of time for making a repair once a replacement part is received

Once all of the necessary replacement parts are received, the appropriate amount of time needed to make a repair depends on whether a shutdown or blowdown is needed. If a shutdown or blowdown is needed, then OOOOc should provide that the repair may be delayed until the next scheduled shutdown for maintenance, not to exceed two years from leak discovery, as is allowed under OOOOa. This approach would also be consistent with EPA's approach to natural gas processing plants. There, EPA acknowledged the importance of making repairs during planned shutdowns and when parts are available.[32] This requirement was rational and safe for natural gas processing plants, and EPA should adopt a similar approach in OOOOc.

Where a shutdown or a blowdown is not needed to make the repair, then at least 30 days from receipt of all of the parts is needed to make the repair. This amount of time is needed to ensure operators have adequate time to develop a plan that ensures safety, minimizes system disruptions, and manages the necessary logistics. In particular, safe installation of a replacement part may require the following:

- Pre-job safety analyses must be conducted to ensure that the repairs can be completed without harm to personnel, equipment, or the environment.
- The operator may need to weld pieces of pipe in or hydrotest before the valve can be replaced.
- The operator may need to x-ray or test the welds.
- The operator may need to ensure that specific heavy equipment is available to hold the pipe up during replacement.
- The operator may need to schedule an entire crew of welders to make the repair (not just the station welder) if all the welds need to be made at one time to close the line up quickly.

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[32] *See* 48 Fed. Reg. 279, 289-90 (Jan. 4, 1983) (explaining the basis for allowing DOR in Subpart VVa); 40 C.F.R. § 60.481a. Subpart VVa also provides additional clarification that shutdowns, or partial unit shutdowns, that are less than 24 hours in length are *not* considered a process unit shutdown for natural gas processing plants and thus do not trigger repair obligations for natural gas processing plants under Subpart OOOO. *See* 40 C.F.R. §§ 60.481a, 60.5430.

- Special tooling or equipment may be required because piping components can move as a result of being cut, which can lead to difficulties getting alignment before a new part can be installed.
- Special contractors may be needed, and their availability may be limited.
- The leaking valve may be buried and need to be excavated before the repair can be made.
- The unit/station may need to remain in operation during a specific timeframe to fulfill air emissions testing requirements.
- Repairs must be coordinated in advance based on supply and demand to avoid causing disruptions to natural gas supply. Outages must often be delayed in the winter heating or summer cooling months to avoid disruptions. In the northeast, for example, unless there is an emergency, it is almost impossible to take an outage during these times.
- Weather can also be a factor and may prevent or delay work where access (e.g., wet ground, steep slopes) or buried facilities is an issue.

As discussed previously,[33] EPA is proposing to amend OOOOa to allow repairs in the transmission and storage segments that require a shut down or blowdown to be delayed until the next scheduled shutdown for maintenance, not to exceed two years from discovery of the leak.[34] INGAA is recommending that an identical approach be followed with regard to DOR due to availability of parts in OOOOc. In situations when the repair in question would require a shut down or blowdown, instead of adhering exclusively to a "30-day from date of receipt" repair requirement for delays based on acquisition of replacement parts, EPA should allow for such repairs to be made during the next scheduled shutdown for maintenance, not to exceed two years from discovery of the leak. Such an approach has the benefit of avoiding unnecessary blowdown emissions.

C. Limits on DOR related to replacement part availability are not warranted.

EPA asks for comment on whether there should be any limit on delays in repairs when needed to acquire replacement parts, and specifically whether a limit is appropriate based on the severity of the leak to be repaired.[35] In general, limiting the availability of the DOR for replacement parts will not have a beneficial effect. The delay envisioned by this provision would be to account for the *unavailability* of the means by which to make a repair in the allotted timeframe. It is not intended to alleviate a burden, create efficiencies, or manage challenging logistics, all of which are themselves appropriate reasons for providing DOR relief.

The purpose of the replacement part DOR provision is to ensure that companies are not penalized for circumstances they cannot control or alter. Indeed, a rule that would impose such consequences is arguably arbitrary and capricious and contrary to EPA's authority. Including the replacement part DOR provision would therefore strengthen any final EPA rule. Accordingly, because a limit

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[33] *See supra* Section II.

[34] 86 Fed. Reg. at 63,164.

[35] *Id.* at 63,174.

on the replacement part DOR provision, even one based on the severity of the leak, would do nothing to speed the repair or change the availability of the necessary replacement part, such limits are not appropriate or useful.

IV. The functionality exemption for pneumatic controllers needs to be continued for safety and reliability reasons.

When EPA promulgated OOOO and OOOOa, it properly recognized that there should be an exemption to the 6 cubic feet per hour (cfph) emission limitation "based on functional needs, including but not limited to response time, safety, and positive actuation."[36] EPA is now proposing for OOOOb and OOOOc that pneumatic controllers have a methane and VOC rate of zero and states that because of this fact the Agency "do[es] not believe that the reasons related to the use of low bleed controllers are still applicable."[37] This reasoning does not make any sense. The exact same rationale that applied in 2011 when EPA promulgated OOOO—and again in 2016 when it promulgated OOOOa—remains relevant today. Functional requirements related to safety and reliability warrant the use of gas-driven pneumatic controllers in some cases. As a result, INGAA strongly disagrees with EPA's proposal not to maintain this exemption. As discussed below, all of the reasons why EPA gave the exemption in OOOO and OOOOa still exist and remain valid.

As EPA recognized in 2011, "[t]here may be situations where high-bleed controllers and the attendant gas bleed rate greater than 6 [cfph], are necessary due to functional requirements, such as positive actuation or rapid actuation."[38] As EPA also recognized in 2011, "[t]here are certain situations in which replacing and retrofitting are not feasible, such as instances where a minimal response time is needed, cases where large valves require a high bleed rate to actuate, or a safety isolation valve is involved."[39] All of this remains true and is unchanged today. EPA has not identified anything in the Proposed Rule that shows why it has changed its position on this important safety and reliability issue. Moreover, because EPA is proposing to regulate existing sources for the first time through OOOOc, the fact that, as EPA acknowledged in 2011, replacing and retrofitting is not feasible in many circumstances becomes even more germane.

It is important to note that the exemption in OOOO and OOOOa is limited and does not apply to all pneumatic devices. In some circumstances, safety concerns and system reliability dictate that high-bleed controllers or gas-driven (both low-bleed and intermittent) controllers be used. This is particularly the case for emergency shutdown valves on pipelines entering or exiting compression

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[36] *Id.* at 63,203.

[37] *Id.*

[38] 76 Fed. Reg. 52,737, 52,761 (Aug. 23, 2011).

[39] U.S. EPA, *Oil and Natural Gas Sector: Standards of Performance for Crude Oil and Natural Gas Production, Transmission, and Distribution: Background Technical Support Document for Proposed Standards*, EPA-453/R-11-002, at Section 5.4.1.1 (July 2011) (Technical Support Document accompanying Proposed OOOO) (Docket ID No. EPA-HQ-OAR-2010-0505-0045).

stations[40] or on pipeline isolation valves. Indeed, PHMSA is undergoing a rulemaking right now that proposes "standards for valve installation, rupture recognition and timely mitigation, and valve shut-off and location requirements for segment isolation."[41] The purpose of these new requirements is "to minimize consequences from ruptured pipeline segments and improve the effectiveness of emergency response."[42] EPA needs to be aware of this rulemaking and needs to coordinate with PHMSA to be sure that the requirements contemplated here do not conflict with PHMSA. The Fall 2021 Regulatory Agenda lists an anticipated date of February 2022 for a final rule from PHMSA.[43]

The following sections of the comments will provide background to EPA on the types of equipment that could achieve zero emissions and the safety and reliability issues that are raised in some limited circumstances. INGAA will also provide examples for EPA regarding why gas-driven pneumatics are needed at some sites because of the lack of a reliable electric power source and for safety reasons. Most importantly, EPA needs to understand that emissions from gas-driven pneumatics in the transmission sector are small. Thus, preserving the exemption for use in limited safety and reliability instances will have only a negligible environmental impact.

A. Background

At the outset, EPA needs to understand that there are three types of options for powering pneumatic valves: (1) electric; (2) air; and (3) gas. Electric valves have reliability concerns. If the power gets disrupted, the valve will not work, which presents a safety and reliability issue. Air valves can also have reliability and safety issues. Air compressors produce significant amounts of water, which freezes in cold weather, making the compressors inoperable. In humid areas, dryers are needed to remove moisture from air compressors, and issues arise as to what to do with the water that results from the humidity at these locations.

To achieve zero-emissions on existing equipment, INGAA members have the following options:

- **Switching from natural gas to compressed air.** This is a solution that may work in specific applications but does not present a broad design solution. The first issue is that compressed air is currently not available at all locations. At locations where air is supplied, the air pressure available varies, and the required power gas pressure for the actuators varies. It is unlikely that any large actuators used on applications with pipeline pressure will work with less than 350 pounds per square in gauge (psig) air pressure. Typical air systems currently operate in the range of 125 psig to 250 psig. With regard to reliability, the power gas supply of air will now depend upon the air compressors, electrical power, and dryer systems as opposed to the readily available compressed natural gas. Some of

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[40] *See* 76 Fed. Reg. at 52,761 (EPA acknowledging that an example where high-bleed controllers are necessary "would be controllers used on large emergency shutdown valves on pipelines entering or exiting compression stations.").

[41] 85 Fed. Reg. 7162, 7168 (Feb. 6, 2020).

[42] *Id.*

[43] DOT/PHMSA, Fall 2021 Unified Agenda and Regulatory Plan, RIN No. 2137-AF06.

these air supply concerns can be mitigated with storage tanks for emergency use systems but, even then, there will be a limit to how frequently the valves can operate. Compressed air for smaller actuators can be used where less pressure is needed to provide required torque. Finally, when gas-driven pneumatics are replaced with air pneumatics, a higher level of complexity is introduced to the system because of the additional complex compressed air systems that are needed to produce the compressed air. The addition of these systems increases the number of single points of failure that can lead to unreliability. The compressed air systems also require higher use of electrical power (either utility or site-produced) and require a greater need for added capacity of backup power to power the double redundant type of air compressor system designs that are necessary for equivalent and continued robustness and reliability of instrumentation gas for safe and reliable service.

- **Replacing a gas-powered hydraulic central system with an electric-powered hydraulic central system.** This option is most applicable for replacing existing central systems, which are found only at legacy compressor stations. The electric-powered hydraulic option prevents natural gas from being vented by using an enclosed nitrogen blanket with hydraulic pressure. An electric pump is used to store energy by compressing against the nitrogen blanket. This system would be an improvement over the legacy central system with added instrumentation and simplicity. New electric power loads will be required, however, and could be a concern should a station already operate at the limit of available power. Should the station lose electrical power, the unit can be designed to allow for emergency valve operation. This is not a preferred option, however, when compared to unitized actuators. If the central system fails, then all the actuators cannot operate, which creates a safety and reliability issue.

- **Vendor specific zero-emissions options.** There are zero-emissions systems available for some unitized power gas actuators. One example uses a single electric pump to hydraulically move a piston. This piston has natural gas on one side that is charged for use. When operating, the piston moves the hydraulic fluid but never has to vent gas. This option does add additional hardware to the system, which would result in a lower reliability than the typical natural gas-powered actuator. Moreover, the costs to modify the actuator units and run electrical feeds to small pumps would be expensive. Using solar panel options gives rise to reliability and maintenance concerns with the required batteries.

- **Accumulator and recompression/flare.** This option would allow for any vented gas to be captured and either recompressed or flared. INGAA members have investigated these options the least due to the added equipment and maintenance. It is believed that accumulators would not be possible due to the back pressure put on the actuator vent.

- **Electric actuators.** With large ball valves or plug valves, electric actuators require high voltage due to the high level of torque. These systems have given rise to safety and reliability concerns in the past and have even been replaced because of those issues. These actuators are completely dependent on the electrical system and maintaining 480V equipment.

Most of the above options would add multiple levels of complexity to the system, resulting in expanded training requirements, lower reliability, higher maintainability necessities, and extensive conversion costs. Some of these options are still in the experimental stages. Every situation has a list of specificities that will result in the operator not being able to use blanket level designs. The additional complexity of these systems can lead to reduced reliability and, should the system fail in an emergency, consequences such as fire or loss of containment.

Issues are also raised for implementing these zero-emissions options outside of compressor stations, particularly at smaller, less developed, and more remote facilities like meter stations that are likely to be unmanned. At a minimum, excluding devices outside of compressor stations from the zero-emissions requirement would help alleviate at least some of the significant safety and feasibility concerns associated with the Proposed Rule.

Use of these zero-emissions options can also actually result in unintended, additional emissions. For example, if valves are converted to electric operated valves, this would require installing emergency generators at all sites to ensure that reliability and safety issues can be met. The installation of a combustion source defeats the intent of the Proposed Rule to minimize emissions. This source would be subject to Subpart JJJJ and would require routine maintenance and testing. This means increased visits to remote sites, which results in increased vehicle emissions.

Simply put, the design choice of using gas-driven pneumatic devices has provided a constant and reliable source of energy to provide proper valve orientation, blowdowns, and emergency shutdowns as needed. Gas-driven pneumatics are a proven technology that has served well for over 50 years because it is the simplest design and because compressed natural gas is readily available and can dependably and reliably provide the power needed for high torque applications.

B. The exemption for sites where electric power is unavailable should apply throughout the entire United States and not just in Alaska.

EPA proposes to allow an exemption for pneumatic controllers in Alaska at sites without electric power.[44] This exemption should also apply in other areas of the United States outside of Alaska where electric power is unavailable. It is arbitrary and capricious that the exemption that applies within Alaska would not also apply to areas in the other 49 states where the same situation exists.

As an example, one INGAA member operates a pipeline in a very remote part of a state forest in Pennsylvania where electric power is unavailable.[45] Installation of an electric transmission line is not feasible given the distance to the site. Additionally, installation of solar panels is problematic because of the forest. A large amount of state forest would need to be cleared to install the panels, and it is unclear that the state would allow this. Several INGAA members operate in state forests with similar challenges.

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[44] 86 Fed. Reg. at 63,203.

[45] Pipelines being located in forest land is not unusual. Installation of electric power lines or solar panels on forest land will involve the clearing of acres of forest that may not be permitted by the applicable forest authority.

Moreover, the experience of INGAA members with solar panels has been problematic. The panels get used for target practice and frequently get stolen (along with the site's batteries). The panels are also susceptible to damage from weather events. It is also important to note that replacing a gas-driven pneumatic with an air-powered device may require a larger footprint (and more deforestation) and additional buildings that need electric power and generator backup.

At a different location in Pennsylvania, some of the metering stations could have power installed to them without too much issue. In some instances, however, electrical lines over 10 miles long in remote areas would need to be installed. The reliability of a power line that long and remote is suspect and creates a safety issue.

The pipeline does not need to be in a remote area for there to be problems with providing electric power to a site. For example, in Texas, one INGAA member operates a pipeline on land where the landowner is not welcoming to any future development. The INGAA member has attempted for years to add power to the site, but all efforts have failed. Although the INGAA member was able to borrow a spare circuit from an adjacent transmission operator and run it a couple of hundred feet into the fence, that circuit only provides enough power to run some low power equipment. The site has nothing close to the power needed to run electric actuators or air compression. In addition, there is not enough space to install a solar panel system that would be sizeable enough and that would still have the reliability issues discussed above. These types of landowner issues can make safe and reliable operation almost impossible without the use of gas-driven equipment.

C. Situations exist where the use of gas-driven pneumatic controllers is necessary for safety reasons.

Even where electric power is available, there are situations where the use of electric pneumatic controllers is ill-advised for safety reasons. If electric supply gets disrupted, important safety equipment such as emergency shutdown valves still need to work. If gas-driven controllers have been replaced with electric-driven controllers to be able to achieve the zero-emissions requirement, this raises a significant safety issue. At a compressor station, a catastrophic failure can cause control systems, power systems, and compressed air systems to fail. If battery limit valves (those needed to isolate and blow down the facility) are depending on any of those systems, it becomes impossible to shut down and isolate the station from its associated transmission lines, resulting in a much worse accident. Battery limit valves that are gas powered function independently from the above systems and are usually actuated to a safe position by loss of a gas pilot signal. Many have power storage tanks to ensure that they are able to operate even when supply pressure to the actuator is removed or disrupted.

The bottom line is that the only 100 percent reliable method for powering important safety valves is stored energy available from the pressurized natural gas in the transmission line. For an operating transmission pipeline that requires a controller to perform a function such as closing a safety valve or modulating line pressure, the stored energy available from the pressure within the line ensures that there is a constant high-energy source available (i.e., high pressure gas within the pipeline) to actuate the valve using a natural gas-driven pneumatic controller. Reliability is not assured for electric systems or other (e.g., compressed air) systems unless multiple redundancies are built into the system.[46] Additionally, the immediately available, high energy motive force from high-pressure pipeline gas that may be needed for some functions (e.g., torque and time response to operate a large high-pressure valve) may be very difficult to achieve with electric or compressed air systems.

D. Emissions from gas-driven pneumatic controllers in the transmission and storage segment are small.

EPA expresses concern that "[t]he emissions from natural gas-powered pneumatic controllers represent a significant portion of the total emissions from the Oil and natural Gas Industry."[47] This is not the case for the transmission and storage segment,[48] and EPA's own data confirm this. As summarized in the following table, Table 8-2 of EPA's October 2021 Technical Support Document (TSD)[49] shows that pneumatic controller emissions are relatively significant for upstream operations (i.e., greater than 20 percent of methane emissions from all affected segments), while pneumatic controller emissions from the transmission and storage segment are very minor and insignificant.

Pneumatics Contribution to Natural Gas Operations Methane Emissions from TSD Table 8-2					
Segment(s)	**Emissions (kilotons methane)**			**Pneumatics % of Total**	
	Total CH_4 Emissions	**All Pneum. Controllers**	**Intermittent Controllers**	**All Pneum. % of Total**	**Intermittent % of Total**
All Emissions (Production through T&S)	5,745	1,352	1189.5	23.5%	20.7%
T&S Pneumatic Emissions (T&S segment total CH_4)	1,478	24	0.5	1.6%	0.03%
T&S Pneumatic Emissions (All segments total CH_4)	5,745	24	0.5	0.4%	<0.01%

As the above table shows, methane emissions from pneumatics in the transmission and storage segment comprise less than one percent of the total methane emissions from pneumatics in the source category (from production through the transmission and storage segment).

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[46] As discussed above in Section IV.A, building in these multiple redundancies adds multiple levels of complexity to the system and results in expanded training requirements, lower reliability, higher maintainability necessities, and extensive conversion costs.

[47] 86 Fed. Reg. at 63,203.

[48] This is another example of where there is a lack of clarity due to the lack of proposed regulatory text. It is unclear whether EPA intends to include intermittent pneumatic controllers along a pipeline in the regulation. Replacing intermittent pneumatics along a pipeline, which are present for safety and reliability purposes, is an extensive cost that results in very little environmental benefit.

[49] U.S. EPA, *Background Technical Support Document for the Proposed New Source Performance Standards (NSPS) and Emissions Guidelines (EG)*, at Table 8-2 (Oct. 2021) (Docket ID No. EPA-HQ-OAR-2021-0317-0166).

The TSD data are based on information from EPA's annual GHG inventory report, and further documentation that pneumatic device methane emissions are low for the transmission and storage segment and for transmission and storage intermittent devices is available to EPA from Subpart W of the GHG Reporting Program (GHGRP).

In November 2019, INGAA met with EPA staff associated with the EPA annual GHG inventory report and Subpart W of the GHGRP. INGAA provided EPA with a report by the Pipeline Research Council International that presents an analysis of six years of Subpart W reporting data for transmission and storage sources.[50] That report includes a review of pneumatic controller data for hundreds of facilities that report annually. The data indicate that methane emissions from pneumatic controllers in the transmission and storage segment are more than 13 percent lower than the value presented in the EPA annual GHG inventory, based on a compressor station-level emission factor. Thus, the relatively low emission levels discussed above are even lower based on more recent data available from the GHGRP.

An INGAA member operates a station in South Carolina that highlights this point. This station, which sits in a remote area without an electrical power, protects a 22-mile stretch of 8-inch pipe with a lower maximum operating pressure than its upstream source. There are two regulators and two monitors with gas-driven pneumatics at the station. The regulators are redundant, with only one regulator operating under normal conditions and the other regulator serving as a backup. The regulators are controlled with Becker pilots, which will bleed only when the regulator needs to move. The backup regulator does not move unless it has to meet downstream pressure requirements. The two monitors are also driven by Becker pilots and only come into service if there was a primary or secondary regulator failure. The monitors will not bleed in normal operating conditions – only in the event of a failure. Even if there was a regulator failure, these monitors bleed far less gas than a relief valve would. This example demonstrates that much of the equipment in the transmission segment does not emit frequently because it serves only a backup function.

In other words, although pneumatic controllers may be a significant contributor to methane emissions from the source category overall, they are not a significant contributor from the transmission and storage segment. As a result, the Proposed Rule would introduce pipeline and compressor station safety risks for a nominal emission reduction. Therefore, at a minimum, EPA should keep the exemption in place for the transmission and storage segment.

[50] Pipeline Research Council International (PRCI) White Paper, *Methane Emissions from Transmission and Storage Subpart W Sources*, PRCI Catalogue No. PR-312-16202-R03 (Aug. 2019). This report is attached to these comments as Attachment 6.

V. Any standard for existing wet seals, if appropriate, should exclude low-emitting and low-utilization wet seal compressors, and should be based on an updated BSER analysis.

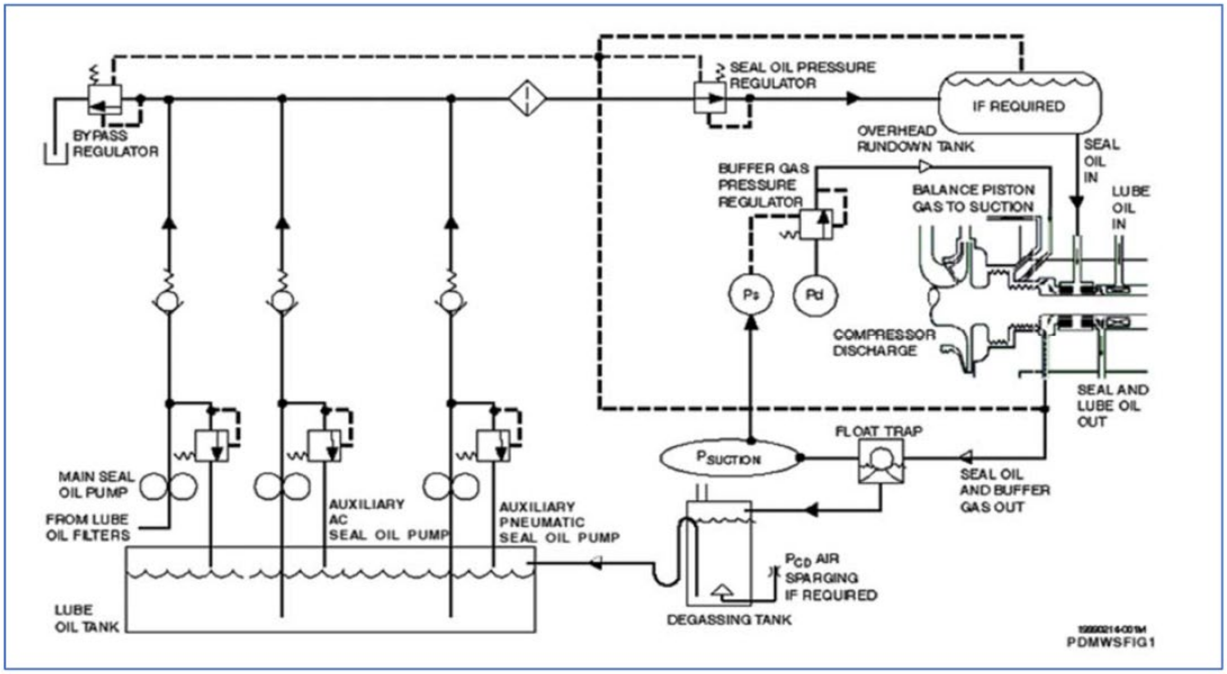
A. Low-emitting and low-utilization wet seal compressors should be excluded from OOOOb and OOOOc.

EPA has generally targeted wet seal centrifugal compressors for regulation under OOOOa, and now under proposed OOOOb and OOOOc because EPA perceives that these types of compressors invariably lead to high emissions from degassing emissions vented to the atmosphere. EPA's perception and estimates of wet seal emissions, however, are based on compressors of a certain type and vintage that *are not representative* of most wet seal compressors in the transmission and storage sector.

Prior to the invention of dry gas seal systems in the 1990s, most centrifugal compressors utilized wet seals based on pressurized lubricating oil as the internal gas sealing mechanism. With wet seal-based systems very little natural gas escapes the oil seal face. As pressurized oil contacts process gas, however, hydrocarbons in the natural gas are absorbed and entrained in the seal oil. This entrained gas is purged from the seal oil for safety and system reliability. These "de-gas" emissions, when vented to the atmosphere, are the source of emissions from wet gas compressors.

A basic wet-seal system overview is shown in Figure 1 below. Gas compressors are lubricated from the main lube oil system, and this lube oil is also used for the compressor wet seal. Seal oil pumps raise the oil pressure to a level of about 15 psig above the compressor suction pressure. At the wet seal face where the oil contacts natural gas, some gas is absorbed and entrained in the oil.

Figure 1. Typical Wet Seal System Diagram (provided by Solar Turbines).



In a basic configuration, the oil/gas medium is sent from the seal mechanism to an oil recirculation system where hydrocarbons are released from the oil. EPA's requirements for wet seal compressors assume this basic configuration, and that the degassing emissions are vented to the atmosphere.

The process for that degassing step varies, however, and some manufacturers, such as Solar Turbines, have included a configuration that is essentially a closed process that ports the degassing emissions into the natural gas line at the compressor suction. This typically includes a primary chamber where initial degassing occurs (and is recovered), and chamber(s) with air sparging to release and recover residual gas volumes entrained in the oil. For example, a separate de-gassing module with multiple seal oil traps and/or air sparging systems may be in place to recover the de-gas emissions. Rather than venting all of the de-gassing volumes (i.e., the configuration considered by EPA in its analysis for wet seals), the de-gas emissions are routed back to suction directly from the degassing / sparging chambers; the oil is ultimately recycled to the lube oil tank where any small amount of residual gas is released through a vent. Field evaluation is not feasible for this closed system configuration, but Solar Turbines' testing and modeling demonstrates that the residual natural gas volume vented is very small, and much less than 1% of the total degassed natural gas volume.

EPA should make clear that these types of compressors already incorporate one of the control options required under the Proposed Rule, namely collection and routing to a process. Indeed, EPA seems to recognize that in the TSD, where it describes this control option as follows: "Routing to a process would entail routing emissions via a closed vent system to any enclosed portion of a process unit (e.g., compressor or fuel gas system) where the emissions are *predominantly* recycled, consumed in the same manner as a material that fulfills the same function in the process, transformed by chemical reaction into materials that are not regulated materials, incorporated into a product, or recovered."[51] EPA should incorporate a similar description, including that the emissions are "predominantly" recirculated, in the regulatory language.

Another type of low-emissions wet seal utilized in compressors in the transmission and storage sector is a mechanical seal, in which metal (tungsten carbide) is seated against carbide, with oil pressing against the outside of the actual seal. One such mechanical wet seal is manufactured by Kaydon and utilized on DeLaval compressors. (Information for the Kaydon mechanical wet seal is provided in Attachment 7.) Because the oil is not in contact with the natural gas, these wet seals have generally zero degassing emissions. It makes no sense to subject such a zero-emissions wet seal to control requirements. Accordingly, EPA should exclude compressors utilizing mechanical wet seals from the requirements otherwise applicable to west seal compressors.

More generally, the rule for existing compressors should provide a procedure that would allow owners or operators to demonstrate that a particular wet seal configuration results in no or very small degassing emissions (for example, less than 3 standard cubic feet per minute (scfm) per wet seal,[52] which is half the average emission rate for dry seal compressors (6 scfm), which EPA found too small to regulate previously) and thus be excluded from the control requirements for high-emitting wet seals under OOOOb and OOOOc.

In addition, many wet seal compressors remain in service at compressor stations merely to accommodate "peak flow" days and these compressors operate very infrequently. One INGAA member reports that 60 percent of its wet seal fleet fits this category. The 3-year average (2019-2021) of operating time for these wet seal compressors is 31 operating hours per year per compressor (utilization of 0.36 percent). By their nature, these limited-use compressors result in minimal actual emissions of methane and VOC; therefore, imposing control requirements for these units has an astronomical $/ton value that is far beyond what would be considered reasonable. Accordingly, INGAA urges EPA to adopt a de minimis exemption from installation of controls for wet seal compressors that have very low utilization, because it is not cost effective to require such controls in these circumstances. INGAA proposes a cutoff for such a de minimis exemption at 500 hours of operation per year, based on a 3-year average of actual operation.

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[51] TSD at 7-30 to 7-31 (emphasis added).

[52] We note that the California Air Resources Board (CARB) recently issued a regulation that set forth a 3 scfm threshold for emissions from each wet seal at a centrifugal compressor as an alternative to controls similar to those required in the Proposed Rule (i.e., vapor collection and flaring or routing to a process). *See* CAL. CODE REGS. tit. 17, § 95668(d)(6) (requiring wet seal compressors *either* to install controls similar to OOOOa—i.e., vapor recovery with degassing emissions routed to a flare or a process—*or* annual monitoring and repair where the leak rate is more than 3 scfm per wet seal).

B. EPA's BSER analysis is flawed, particularly for retrofitting existing wet seal compressors.

EPA relies exclusively on the BSER analysis it undertook for wet seal compressors in the OOOOa rulemaking to propose the same controls for OOOOb and OOOOc. Those controls require capturing leaking gas from wet seals and routing it to (1) a combustion device (flare), or (2) the process. In reality, this BSER analysis is largely theoretical under OOOOa (and OOOOb) for *new* centrifugal compressors, because virtually all compressors installed after the 1990s are dry seal compressors. And, even assuming that certain particular circumstances would necessitate the installation of a new wet seal compressor, such a compressor would be designed from the outset to have controls consistent with OOOOa (e.g., a wet seal compressor with a closed system, as described in Section V.A, above, for some wet seal compressors manufactured by Solar Turbines).

In this proposal, EPA adopts these same controls for existing wet seal compressors under OOOOc without any additional analysis, on the grounds that the Agency "has not identified any costs associated with applying these controls at existing sources, such as retrofit costs, that would apply any differently than, or in addition to, those costs assessed above regarding application of the identified controls to new sources."[53] EPA's conclusion is flawed for two reasons.

First, EPA based its previous BSER analysis in OOOOa on an inflated emission factor for wet seal compressors, as demonstrated by review of the TSD and related analyses in 2010 and 2016 for previous Subpart OOOO and Subpart OOOOa rules. TSD Table 7-13 relies on the most recent (2019) EPA annual GHG inventory report for total methane emissions from natural gas systems and the contribution from wet seal compressors. The reported 2019 data reflect an update to the emission factor for wet seal compressors that EPA adopted in April 2016[54,55] and used in every subsequent annual GHG inventory report. In the BSER analysis here, however, EPA relies on 2010 and 2016 Subpart OOOO/Subpart OOOOa analyses that use a much older, inaccurate emission factor to estimate baseline emissions for wet seal compressors. That emission factor is more than five times higher than the updated compressor emission factor, which EPA itself recognized and adopted in 2016. In addition, the compressor emission factor is a composite of several leak sources associated with the unit, and the portion of the compressor emission factor attributable to the wet seal degassing vent is over ten times lower in the updated emission factor.

In addition, based on a detailed review of the TSD emissions estimates analyses, it appears that there are errors in the analysis, and/or EPA has included assumptions or calculation corrections that are not apparent or stated. Several examples follow:

- TSD Table 7-13 presents information clearly based on the EPA annual inventory report and Annex 3.6 data and calculations.

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[53] 86 Fed. Reg. at 63,224.

[54] U.S. EPA, *Inventory of U.S. Greenhouse Gas Emissions and Sinks 1990-2014: Revisions to Natural Gas Transmission and Storage Emissions*, EPA 430-R-16-002 (April 2016).

[55] U.S. EPA, *Annexes to the Inventory or U.S. GHG Emissions and Sinks*, Annex 3.6, Table A-137, (April 2016).

- Emission factors presented in Table 7-15 erroneously convert the emission factors for the baseline emission estimates. It appears the emission factors have been converted to a metric ton basis rather than a short ton/U.S. engineering unit basis.
- Emission factors presented in Table 7-14 (based on older, outdated, and inflated emission factors for wet seals) are similar to but not equivalent to the EPA historical emission factors. Since detailed calculation are not provided, it appears that this is due to one or more of the following:
  - Erroneous conversion between metric and standard engineering units;
  - Unstated calculation assumptions relating to annual turbine operating hours (i.e., time that seals are pressurized);
  - Unstated calculation assumptions relating to the fraction of the *composite* compressor emission factor that is attributed specifically to the wet seal oil degassing vent;
  - Other calculation errors (e.g., converting from volumetric (SCF) to mass basis).

Moreover, Subpart W reporting has provided even more reliable data. In addition to the data EPA used to update the wet seal compressor emission factor, a PRCI White Paper[56] previously provided to EPA by INGAA provides a detailed review of the wet seal compressor emission factor based on analysis of GHGRP Subpart W data. The Subpart W dataset includes hundreds of measurements for wet seal compressors that provide an improved emissions estimate. The dataset is from the existing fleet of transmission and storage wet seal compressors, and the PRCI paper shows an emission factor that is even lower than the updated emission factor currently used by EPA in the annual GHG inventory report. The detailed results presented in the PRCI report show a composite wet seal compressor emission factor 85 percent lower than the inflated, circa 2010-2015 emission factor used by EPA in the TSD, with the emissions specific to the regulated source (degassing vent) over 90 percent lower. These items alone would increase the cost effectiveness ($ per ton) by more than an order of magnitude.

Second, EPA's estimates of cost for the BSER analysis are unsupported. As an initial matter, there are no new wet seal centrifugal compressors that have been constructed since well before the OOOO and OOOOa rules were promulgated, because all new centrifugal compressors use dry seals. Accordingly, EPA's purported estimate of control costs for new wet seal centrifugal compressors in the OOOO and OOOOa rulemakings are not based on any real-world application of such controls; certainly, they have not been demonstrated. In adopting the same cost estimates for proposed OOOOc, EPA says it did not identify additional "retrofit costs that would apply any differently than, or in addition to, those costs assessed above regarding application of the identified controls to new sources."[57] But there is nothing in the TSD that indicates EPA actually looked at

[56] Pipeline Research Council International (PRCI) White Paper, *Methane Emission Factors for Compressors in Natural Gas Transmission and Underground Storage based on Subpart W Measurement Data*, PRCI Catalogue No. PR-312-18209-E01 (Revision 1, January 2020).

[57] 86 Fed. Reg. at 63,224.

actual retrofits of similar controls on existing wet-seal centrifugal compressors to reach this conclusion.

As early as the OOOO rulemaking in 2011, INGAA commented: "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.… As discussed at the October 20, 2011 INGAA meeting with EPA, existing units with wet seals that become subject to Subpart OOOO could be faced with extraordinary costs."[58] INGAA reiterated those concerns in the OOOOa rulemaking.[59] EPA has not addressed these comments in the context of existing wet seal compressors, and it should not proceed with finalizing any control requirements for such compressors until it has done so.

It would be arbitrary and capricious for EPA to use for the BSER evaluation for wet seal compressor emission estimates based on emission factors that the Agency itself later recognized is more than an order of magnitude larger than reality, and that the recent, more accurate Subpart W data demonstrate is clearly wrong. EPA should not rely on calculations that are not transparently provided in the record for the rulemaking. And EPA should not rely on cost estimates for proposed controls at existing wet seal compressors that do not have some basis in actual costs incurred for actual construction of these types of controls. INGAA respectfully recommends that EPA reevaluate its BSER evaluation, in particular for *existing* wet seal centrifugal compressors (the only kind that exists, actually, since no one is constructing new wet seal compressors). In such evaluation, EPA should use the most current, representative emission factors and related data for wet seal degassing vent emissions, and cost estimates for control technologies that bear some relationship to actual experience with these controls. To provide transparency for EPA's evaluation, EPA should include in the record of the supplemental notice a new TSD (or technical memorandum) that presents EPA's analysis within one document rather than citing two previous TSDs, and that clearly and transparently states all assumptions associated with the calculations.

VI. EPA should adopt both a fixed schedule option and a condition-based option as alternative standards for the replacement of rod packing for reciprocating compressors.

In the OOOOa rulemaking, EPA adopted a fixed-schedule rod packing replacement standard. EPA determined that a standard requiring the replacement of rod packing for reciprocating compressors on a fixed schedule, every 3 years or 26,000 hours of operation, was BSER.[60] In that rulemaking, INGAA suggested that a condition-based standard, similar to the standard that California had proposed at the time, should be adopted as an *alternative* to the fixed schedule standard because such an approach may extend the operation of functional rod packing, precludes premature and wasteful rod packing maintenance/replacement, and encourages the development of innovative

[58] INGAA OOOO Comments at 21 (Nov. 22, 2011).

[59] *See* INGAA OOOOa Comments at 37-38 (Dec. 4, 2015).

[60] *See* 86 Fed. Reg. at 63214-15 (describing BSER determination in 2016 rulemaking).

rod packing technologies.[61] In effect, INGAA's suggestion was based on its view that a condition-based standard would be more, or at least as, cost-effective as the fixed schedule standard adopted in OOOOa.

Because EPA adopted in OOOOa only the fixed schedule option, many companies have since instituted voluntary programs for their reciprocating compressors—including many existing compressors, which are not subject to OOOOa—that are modeled on the OOOOa fixed schedule standard. For example, the EPA Methane Challenge Program includes a fixed schedule program from reciprocating compressor rod packing based on OOOOa criteria as an accepted Best Management Practice (BMP)[62] for the program. EPA's website indicates that over 200 facilities voluntarily implemented reciprocating compressor reductions in 2019.[63] That represents a subset of facilities that have implemented a fixed schedule program for rod packing. Other operators and facilities that are not under the Methane Challenge Program purview have also implemented such a program. Many states have also adopted standards or permitting requirements (e.g., general permits) of their own for reciprocating compressors and have modeled these rules on the fixed schedule approach in OOOOa.

In the Proposed Rule, EPA agrees that a condition-based standard—requiring annual monitoring and replacing of the rod packing if the measured flow rate for an individual cylinder exceeds 2 scfm—is also BSER for reciprocating compressors.[64] But EPA proposes to adopt this standard under OOOOb and OOOOc instead of—not in addition to—the fixed schedule standard previously adopted under OOOOa. As EPA's analysis shows, however, both of these standards are cost-effective and can be considered BSER. EPA nonetheless adopted the condition-based standard as the only BSER based on its assumption that the condition-based standard would result in more emission reductions (in the first year after it occurs) than the fixed schedule option. The baseline emissions rates that EPA used in the OOOOa BSER analysis (for the fixed schedule option) and in this Proposed Rule (for the condition-based option) differ and include substantial uncertainty. In addition, the effect of a condition-based standard on timing for replacement is not known at this time (and can only be assumed for the purpose of estimating potential emission reductions). If the average interval of replacement in the condition-based option is roughly the same as that in the fixed schedule option, the emission reductions cannot be very different (considering that the cost effectiveness is close). And if the average interval of replacement in the condition-based option is significantly longer than that in the fixed schedule option, then while the former may result in a larger reduction in the first year after replacement, that is only because the baseline is higher. With significant uncertainty in assumptions regarding potential emission reductions, it is not possible to

[61] INGAA OOOOa Comments at 36 (Dec. 4, 2015).

[62] U.S. EPA, *Natural Gas STAR Methane Challenge Program: BMP Commitment Option Technical Document*, at 14 (July 2020) https://www.epa.gov/sites/default/files/2020-07/documents/mc_bmp_technicaldocument_2020-07.pdf.

[63] U.S. EPA, *Methane Challenge Program Accomplishments*, https://www.epa.gov/natural-gas-star-program/methane-challenge-program-accomplishments (last visited Jan. 30, 2022).

[64] 86 Fed. Reg. at 63,215-20.

determine at this time that one method offers higher reductions than the other. Thus, one method should not be presumed as the preferred BSER.

Given the uncertainties of the assumptions underlying the BSER evaluations for the two options, and that, in the end, the cost effectiveness of the two options are very close, INGAA urges EPA to provide flexibility to affected facilities by adopting both standards as BSER alternatives, rather than a one-size-fits-all approach that would require facilities to switch from their voluntarily adopted or currently applicable fixed schedule standard—which EPA agrees qualifies as BSER—to a condition-based standard in all cases.

In addition, and assuming that EPA goes forward with a condition-based standard (whether as the only allowed standard, or in the alternative), EPA should address in the regulatory language the timing for the rod packing replacement that would be required when annual monitoring yields a measured flow rate for an individual cylinder that exceeds 2 scfm.[65] Specifically, because rod packing replacement is a major maintenance activity that can be undertaken only during a shutdown, EPA should make clear in the regulatory language that rod packing replacement would be required at the next planned shutdown for maintenance after such a measurement.

The precise application of the proposed condition-based rod packing standard is unclear without regulatory text. INGAA requests that the standard be adopted as a per cylinder standard (for example, 2 scfm/cylinder) for each reciprocating compressor unit. Most reciprocating compressor units have more than one cylinder, with the rod packing emissions from each individual cylinder being emitted through a vent that is common to all cylinders on the unit. Measurements of rod packing vent emissions for such units are typically made at the common vent, so they measure the aggregate leakage from all of the cylinders that vent through the common vent. To accommodate these types of common vents, the condition-based standard should allow for measurement at the common vent and the standard should have an option to be based on the total rod packing vent emissions for a unit. For example, a reciprocating compressor unit with four cylinders would have a condition-based standard of 8 scfm for the common vent, which is the equivalent of 2 scfm/cylinder times 4 cylinders. Measuring the rod packing leakage from each cylinder should remain an option, however, if such measurement can be made, with a 2 scfm standard applied to each cylinder.

VII. Proposed Appendix K is overly burdensome and would preclude or severely hinder the ability of operators to conduct OGI leak surveys.

Proposed Appendix K outlines the proposed procedures would need to be followed to identify emissions using OGI. Unfortunately, the proposed requirements in Appendix K do not add any environmental benefits and are inordinately excessive and impractical, which makes OGI under these conditions nearly infeasible. INGAA is concerned that Appendix K as currently written will

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[65] INGAA reserves the right to provide additional comments on the proposed 2 scfm threshold, if and when such a threshold is proposed in regulatory language. In the meantime, we note that the data in the Regulation Background Documentation within the CARB rule are limited and appear insufficient to support a nationwide rule that impacts thousands of units.

result in far less use of OGI technology for leak surveys, with operators being forced to opt for Method 21 surveys instead.

The following are a handful of examples of the issues with proposed Appendix K:

- Hundreds of hours (and sites) of training for operator certification are required, with estimates for training exceeding $200,000 and very few experts available to oversee the training.
- Oversight is required by a senior operator/expert, and very few people qualify for this designation. For example, one INGAA member uses internal resources to conduct OGI. That member's personnel have conducted consistent quarterly leak detection and repair (LDAR) surveys for three years and would not qualify for this designation.
- Onerous requirements including quarterly audits after certification, viewing requirements that would increase survey time at least four-fold, extensive recordkeeping requirements (including video, which involves massive files that would require multiple SD cards to save and upload each time without added benefit).
- There is confusion regarding whether the requirements apply to the original equipment manufacturers or to the operators.
- There are inconsistencies with regard to detection limits. For example, proposed Appendix K lists 17 g/hr, but OOOOa has a requirement of 10,000 ppm at a flow rate less than or equal to 60 g/hr.
- The requirements regarding operator fatigue are very onerous. Twenty minutes is a short time and would result in a huge increase in time to perform LDAR surveys.
- Proposed Appendix K has specific meteorological weather data requirements that limit the use of current equipment that satisfies OOOOa requirements.

The issues with proposed Appendix K are so severe that INGAA recommends a re-write of the entire method, with appropriate stakeholders being included in the process. INGAA emphasizes the importance of including transmission and storage operators in the stakeholder process in addition to other parties. In many instances, operators use internal employees to operate OGI cameras in lieu of hiring contractors to do this work. OGI is a critical and efficient tool for finding and fixing leaks, and it will continue to be a necessary tool even as technology advances. INGAA would be happy to offer assistance to EPA in this effort and has the following initial recommendations:

- We support training and auditing requirements that are simplified and streamlined.
- The obligations for OEM (in factory) versus ongoing operator requirements need to be appropriate, clarified, and specified.
- For the transmission and storage segment, only a methane evaluation is warranted for pre-test QA/QC (i.e., butane screening should not be required).
- The viewing and recordkeeping requirements need to be simplified and streamlined.

Furthermore, based on the wide variety of methane detection techniques and technologies available, each of which serves a defined purpose, INGAA strongly advises that the method developed to replace Appendix K be divided into five distinct technology categories: (1) hand-held; (2) fixed fence line monitoring; (3) drones; (4) fixed wing; and (5) satellites.

The costs associated with implementing proposed Appendix K are significant, and notably, EPA did not include these costs in its OOOOb and OOOOc analysis. The Agency needs to do so.

The issues with Appendix K go beyond stifling OGI. The stringency and burdensome nature of Appendix K has implications for the adoption and implementation of other imaging or infrared-based technologies that are integral to the Proposed Rule (e.g., any new technologies such as remote or fence line monitoring should have similar methods). Methods such as this would preclude technology deployment and is in direct conflict with EPA's desires to expand technologies available to both operators and communities. If EPA wants pathways to new technology that will offer more continuous monitoring or more transparency to communities, Appendix K is not the way to achieve those goals. Because these types of programs require some type of standardization, Appendix K will preclude progress on these important issues. It is incumbent on EPA to prepare methods that are simple, streamlined, easily replicated, and developed for all stakeholders.

INGAA strongly recommends that EPA re-write Appendix K and engage with stakeholders and operators with experience in OGI to do so.

VIII. It is premature for EPA to propose or finalize in this proceeding any provisions for the "use of information from communities and others," and EPA should do so only after the Agency and stakeholders have thoughtfully and carefully evaluated how such use of information may be appropriate in the future.

EPA states that it "learned during the Methane Detection Technology Workshop, industry, researchers, and NGOs have utilized advanced methane detection systems to quickly identify large emission sources and target ground based OGI surveys," and EPA thus "is seeking comment on how to take advantage of the opportunities presented by the increasing use of these technologies to help identify and remediate large emission events (commonly known as 'super-emitters')."[66] While INGAA looks forward to providing comments here and in the future and to participating in a process to evaluate whether such use is appropriate and, if so, under what conditions, we emphasize that such a process is truly nascent at this point in time. Accordingly, INGAA urges EPA to recognize that this is the start of a process and not to seek to propose, much less finalize, regulations for the use of information from communities and others in this rulemaking. Indeed, EPA, along with stakeholders, must thoughtfully and carefully evaluate how such use can (1) dovetail with and not duplicate monitoring that is otherwise required under the rule; and (2) be well-defined and rigorous in its requirements of methods and quality assurance and quality control so that it does not impose costs with little to no benefit and continues to support operators maintaining focus on identifying emissions events and responding as appropriate.

INGAA provides the following comments on the specific subjects in EPA's Proposed Rule on this issue:

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[66] 86 Fed. Reg. at 63,177.

Emission thresholds and technologies. INGAA suggests that any use of information from third parties should not supplant or duplicate requirements that owners and operators are already required to use. Nor should such information change the frequency of monitoring required under the rule, because any such change necessarily changes the cost and burdens of the rule. INGAA agrees, therefore, that the use of such information should be limited to large emission events. A threshold of 100 Kg/hr—which EPA says is a threshold that is "visible by satellite"—makes sense, as satellite technologies are best suited to detect and identify large emission events. As discussed further below, in the event EPA eventually decides to adopt a program that allows use of information in the way EPA envisions in the Proposed Rule, it will be critical for EPA to define very precisely and stringently the type of technology that can be used for this purpose, and to ensure that technology results in replicable and reliable results and is not susceptible to operator error, quality concerns, or even discretionary judgment in interpreting the results.

Another concern that the transmission and storage sectors believe ought to be considered in setting the threshold is whether the threshold would be useful in distinguishing between large emission events that require corrective action—which EPA envisions as those "attributable to malfunctions or abnormal process conditions"[67]—and other events that are attributable to normal, if infrequent, events, such as a large, but very short, emergency blowdown.

Follow-up actions triggered by notification of a large emissions event. EPA's solicitation appears to assume, almost categorically, that any large emissions event detected would require a root cause analysis and corrective action. But that is not necessarily the case, especially if the selected threshold and technology might identify activity that is not in the nature of fugitive emissions "attributable to malfunctions or abnormal process conditions." Therefore, among the actions that should be required after notification of an event should be the possibility of a determination that no further action is necessary because the emissions are consistent with the regulations.

In addition, it will be important to provide sufficient time for each action that may have to be undertaken.

Guidelines for credible and actionable data. This is, by far, the most critical issue regarding the potential use of monitoring data produced by third parties. If EPA eventually adopts such a requirement, the Agency must define, in detail, every aspect of the process used to obtain and maintain the data, including clear and specific protocols, quality assurance, and maintenance of data integrity. If the third parties include anyone other than regulating agencies (e.g., EPA and state agencies), it will be important for these protocols for collecting data and maintaining integrity to be clear and precise, and also foolproof in terms of potential operator error and susceptibility to differing interpretation or manipulation. Operators must be trained and certified, pursuant to a training and certification process set forth and administered by EPA.

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[67] *Id.*

IX. The applicability dates for both OOOOb and OOOOc in the Proposed Rule are incorrect.

In the Proposed Rule, EPA states that proposed OOOOb will govern new, modified, and reconstructed sources that commence construction after November 15, 2021, and that proposed OOOOc will govern existing sources that commenced construction on or before November 15, 2021. Both of these dates are incorrect as a matter of law.

Section 111(a) of the Clean Air Act defines a "new source" as "any stationary source, the construction or modification of which is commenced after the publication of regulations (or, if earlier, proposed regulations) prescribing a standard of performance under this section which will be applicable to such source."[68] As discussed further in Section I above, the Proposed Rule does not contain any proposed regulatory text and is more akin to an Advance Notice of Proposed Rulemaking. As a result, the Proposed Rule does not "prescrib[e] a standard of performance" that would apply to new sources. Once EPA issues its supplemental proposal that includes proposed regulatory text, then it will have "proposed regulations" that "prescribe[e] a standard of performance." Until that happens, sources that commence construction must comply with OOOOa. When the supplemental proposal and proposed regulatory text are published in the Federal Register, that date will be the one that will provide the applicability date for OOOOb, and any sources that commence construction after that date will have to comply with OOOOb.

With regard to OOOOc and existing sources, section 111(a) defines an "existing source" as "any stationary source other than a new source."[69] Sources whose methane emissions were subject to OOOOa are considered "new sources"—and thus cannot be existing sources—because those sources were subject to a standard of performance under section 111. As a result, "existing sources" for the purpose of proposed OOOOc are those sources that commenced construction on or before September 18, 2015, which is the date that the OOOOa was proposed. Any source that commenced construction after that date was a "new source" and complied with the standards of performance set forth in OOOOa.

This makes sense within the context of section 111(d), which is to ensure that certain pollutants (those like methane that are not regulated under the national ambient air quality standard program or the hazardous air pollutants program) are regulated either as new sources under section 111(b) or as existing sources under section 111(d).[70] There is no need to regulate sources that commenced construction after September 18, 2015, under the existing source program of section 111(d) because those sources have already complied with new source performance standards under section 111(b).

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[68] 42 U.S.C. § 7411(a).

[69] *Id.*

[70] *See id.* § 7411(d).

For these reasons, EPA needs to change the applicability date for OOOOb to sources that commence construction after the date the proposed regulatory text is published in the Federal Register and needs to change the applicability date for OOOOc to those sources that commenced construction on or before September 18, 2015.

X. Pigging operations are essential for pipeline safety, and INGAA and its members are working to minimize methane emissions from these operations.

EPA states that it is "considering including additional sources as affected facilities under the proposed NSPS OOOOb and the proposed EG OOOOc," including "the potential for establishing standards applicable to … pipeline pigging and related blowdown activities."[71] EPA makes clear that it is not proposing NSPS or emissions guidelines for these activities but is "soliciting comment and information that would better inform the EPA as [it] continue[s] to evaluate options for these sources."[72]

As EPA acknowledges, pigging operations are vital to maintaining the integrity of the pipeline.[73] As such, PHMSA has numerous safety regulations with which INGAA members must comply. In recent years, PHMSA has also been examining options to reduce methane emissions associated with pigging operations. For example, it issued a proposed rule in 2016 that would have regulated blowdown emissions from pipelines.[74] Although the proposed rule has not been finalized, PHMSA has made it clear in response to President Biden's executive orders on climate change that it will be examining methane emissions from pipelines.[75] EPA needs to be aware of these PHMSA efforts and coordinate with that agency to avoid duplicative or conflicting regulations. EPA should consider deferring to PHMSA on the issue of pigging emissions and supplement that only if PHMSA's regulations are proven to be lacking.

At the outset, it is important for EPA to understand two key points. First, the purpose of pigging differs in each segment of the oil and gas industry, and these differences impact the potential for emissions. Second, emissions from pigging operations depend on a variety of factors, including the frequency of pigging.

With regard to the first point, pigging is different in the transmission segment as compared to the gathering and boosting segment. The general function of a pig is either to clear a pipeline of liquids

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71 86 Fed. Reg. at 63,240.

72 *Id.*

73 *Id.* at 63,242.

74 81 Fed. Reg. 20,722, 20,741 (Apr. 8, 2016) (noting "proposed rule is expected to prevent incidents, leaks, and other types of failure that might occur, thereby preventing future releases of greenhouse gases … to the atmosphere, thus avoiding additional contributions to global climate change" and estimating "net GHG emissions abatement over 15 years of 69,000 to 122,000 metric tons of methane").

75 *See, e.g.*, 86 Fed. Reg. 31,002 (June 10, 2021) (PHMSA Advisory Bulletin requiring pipeline operators "to address eliminating hazardous leaks and minimizing releases of natural gas … from their pipeline facilities").

and debris to avoid reduced gas flow or to monitor the condition of the pipeline for safety purposes. It is the latter reason that pigging typically occurs in the transmission and storage segment.

With regard to the second point, pigging happens far less frequently in the transmission segment. The transmission segment involves the movement of pipeline quality gas, which means that the gas has already been cleaned of most impurities at the gas plant and contains far fewer liquids. Thus, pigging to clear the transmission pipeline of liquids and debris occurs far less frequently than it does in the gathering and boosting segments. For example, in the gathering and boosting segments, gathering lines in some areas might be pigged on a weekly or even a daily basis. In contrast, one member of INGAA reports that it sometimes mechanically pigs its pipelines annually—and at least every three years—for maintenance purposes. That member also typically conducts an in-line "smart pig" inspection of the pipeline for safety purposes once every five to seven years.[76] In addition, emissions from pigging operations involve emissions only from blowdowns of the pigging barrels—not the entire segment of the pipeline.

These key points result in methane and VOC emissions from pigging operations in the transmission segment being extremely low. EPA cannot assume that all pigging operations are similarly situated, and the Agency must undertake segment-specific analysis as it continues to evaluate options for these sources.

Pigging provides information to operators about the structural characteristics of the pipeline for safety and maintenance purposes. INGAA and its members recognize the need to reduce emissions from pigging operations while conducting integrity and maintenance-related work, where practical. These emissions can be reduced in many instances, but the safety of the public, employees, contractors, and assets must remain priorities. Before considering any additional action, EPA should further investigate the characteristics of emissions for pigging in the transmission and storage segment. INGAA and its members are working to produce a white paper of best practices that will identify various strategies to reduce emissions from the interstate natural gas pipeline network.

With regard to blowdown emissions from pipelines, INGAA members have three sets of options that they take to minimize emissions from these activities. First, members eliminate the need for a blowdown for anomaly repair work or project tie-ins, when possible, by using other repair options such as composite wraps or full encirclement "split" sleeves, and using hot taps for the project work. Using these repair procedures and in-service welding methods can eliminate the need for a blowdown. Second, when a blowdown is required for anomaly repair work or project tie ins, INGAA member companies typically reduce the emissions by using customer and company compression to lower the pressure prior to the blowdown. Third, members generally use company-owned or third-party portable compression and/or flares to further lower the pressure and reduce

[76] PHMSA regulations require that all transmission pipelines within High Consequence Areas (i.e., those areas with sufficient population close to the pipeline) are required to be assessed for integrity at least once every seven years. 49 C.F.R. § 192.937(a). These assessments are usually accomplished by an in-line pigging inspection.

emissions prior to the blowdown. These options may eliminate methane emissions and will, at a minimum, reduce them by 75 percent.

It should be noted, however, that there are factors that can influence what options can be implemented. For example, in some situations, there is limited time because of the need to quickly address potential integrity concerns. Depending on the significance of the pipeline integrity anomaly, PHMSA may require an immediate excavation to inspect and repair the anomaly. When this occurs, there is not sufficient time to significantly reduce blowdown emissions. Whether the pipeline has a single line or parallel lines to compress the natural gas in the same right-of-way also affects the ability to reduce emissions. A parallel line in the right-of-way makes using the second and third options above much more effective and efficient. Finally, other factors that can affect the ability to minimize blowdown emissions include limited time because of customer commitments (particularly on cold winter or hot summer days), constrained rights-of-way, and population, environmental, and highway considerations.

XI. Conclusion

INGAA thanks EPA for its consideration of these comments and looks forward to providing the Agency with comments on the upcoming supplemental proposal and proposed regulatory text.

To the extent that EPA has questions about these comments or would like to engage in further dialogue, INGAA is happy to provide follow-up information. My contact information is below.

Regards,

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