Interstate Natural Gas Association of America

PUBLIC VERSION – DOES NOT CONTAIN CONFIDENTIAL BUSINESS INFORMATION SUBMITTED PURSUANT TO 40 C.F.R. PART 2

May 15, 2024

Via E-Mail

The Honorable Michael S. Regan, Administrator
U.S. Environmental Protection Agency
1200 Pennsylvania Avenue, N.W.
Washington, D.C. 20460

Re: Petition for Reconsideration of Final Rule or, in the Alternative, for New Rulemaking in "Standards of Performance for New, Reconstructed, and Modified Sources and Emissions Guidelines for Existing Sources: Oil and Natural Gas Sector Climate Review"; Docket ID No. EPA-HQ-OAR-2017-0317

Dear Administrator Regan:

The Interstate Natural Gas Association of America (INGAA), the national trade association addressing issues of importance to the natural gas pipeline industry in North America, respectfully requests that the Administrator of the U.S. Environmental Protection Agency ("EPA" or "Agency") reconsider parts of the final rule entitled "Standards of Performance for New, Reconstructed, and Modified Sources and Emissions Guidelines for Existing Sources: Oil and Natural Gas Sector Climate Review." The attached petition sets forth the reasons.

Please note that parts of Attachment B to the Petition are claimed as confidential and protected from disclosure under Exemption 4 and Exemption 6 of the Freedom of Information Act, 5 U.S.C. §552(b)(4) and (6), and as confidential business information (CBI) pursuant to 40 C.F.R. Part 2. Accordingly, we are submitting two versions of this petition – one including the CBI materials and bearing on this cover letter the heading "CONTAINS CONFIDENTIAL BUSINESS INFORMATION SUBMITTED PURSUANT TO 40 C.F.R. PART 2"; and a second, public version not including the CBIO materials and bearing on this cover letter the heading "PUBLIC VERSION – DOES NOT CONTAIN CONFIDENTIAL BUSINESS INFORMATION SUBMITTED PURSUANT TO 40 C.F.R. PART 2."

Thank you for your consideration of this request.

Interstate Natural Gas Association of America

Sincerely,

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PETITION FOR RECONSIDERATION OF FINAL RULE OR, IN THE ALTERNATIVE, FOR NEW RULEMAKING

STANDARDS OF PERFORMANCE FOR NEW, RECONSTRUCTED, AND MODIFIED SOURCES AND EMISSIONS GUIDELINES FOR EXISTING SOURCES: OIL AND NATURAL GAS SECTOR CLIMATE REVIEW

Docket ID No. EPA-HQ-OAR- 2021–0317
89 Fed. Reg. 16,820 (Mar. 8, 2024)

May 15, 2024

The Interstate Natural Gas Association of America ("INGAA"), a trade association that represents 26 members of the interstate natural gas pipeline industry, hereby requests that the Administrator of the U.S. Environmental Protection Agency ("EPA" or "Agency") reconsider the final rule entitled "Standards of Performance for New, Reconstructed, and Modified Sources and Emissions Guidelines for Existing Sources: Oil and Natural Gas Sector Climate Review" ("Final Rule").[1]

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.

Section 307(d)(7)(B) of the Clean Air Act ("CAA" or "Act") requires the Administrator to convene a reconsideration proceeding if a party objects to a final rule and if it was "impracticable to raise such objection" within the period for public comment or if "the grounds for such objection arose

[1] 89 Fed. Reg. 16,820 (Mar. 8, 2024).

after" that period, and if the objection "is of central relevance to the outcome of the rule."[2] In such a reconsideration proceeding, EPA must "provide the same procedural rights as would have been afforded had the information been available at the time the rule was proposed."[3]

INGAA is filing this petition for reconsideration to raise objections that could not have been raised during the public comment period and that are of central relevance to the outcome of this rulemaking. In the event that EPA determines that these issues are more appropriate for consideration through a petition for rulemaking under the Administrative Procedure Act, 5 U.S.C. § 553(e), INGAA asks, in the alternative, that this petition be considered under that provision of the Administrative Procedure Act.

I. Background

In the Final Rule, EPA takes three actions under section 111 of the CAA, 42 U.S.C. § 7411, with regard to new, modified, reconstructed, and existing sources in the oil and natural gas sector: (1) EPA modifies the new source performance standards ("NSPS") promulgated in 40 C.F.R. Part 60, Subpart OOOOa ("Subpart OOOOa"), which governs new, modified, and reconstructed sources that commence construction after September 18, 2015;[4] (2) EPA promulgates NSPS at 40 C.F.R. Part 60, Subpart OOOOb ("Subpart OOOOb") to govern new, modified, and reconstructed sources that commence construction after December 6, 2022, and includes performance standards for emission sources not previously regulated by EPA;[5] and (3) for the first time, EPA promulgates emission guidelines under section 111(d) of the CAA, 42 U.S.C. § 7411(d), at 40 C.F.R. Part 60, Subpart OOOOc ("Subpart OOOOc") to govern existing sources in the sector that commenced construction on or before December 6, 2022.[6]

EPA provided two notice and comment opportunities before issuing the Final Rule. EPA's first proposed rule, which was issued on November 15, 2021, was more akin to an Advance Notice of Proposed Rulemaking because it lacked specificity as to the key requirements and because of the absence of proposed regulatory text for Subparts OOOOb and OOOOc (the "2021 Partial Proposal").[7] A little more than a year later, EPA released a second proposed rule (the "Supplemental Proposed Rule") that made some changes in response to the comments the Agency received on the 2021 Partial Proposal.[8] Although the Supplemental Proposed Rule also did not include proposed regulatory text for Subparts OOOOb and OOOOc, EPA provided the proposed

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[2] 42 U.S.C. § 7607(d)(7)(B).

[3] *Id.*

[4] 89 Fed. Reg. at 16,826.

[5] *Id.*

[6] *Id.* at 16,827.

[7] 86 Fed. Reg. 63,110 (Nov. 15, 2021).

[8] 87 Fed. Reg. 74,702 (Dec. 6, 2022).

language in the rulemaking docket. INGAA filed comments on both the 2021 Partial Proposal[9] and the Supplemental Proposed Rule.[10] INGAA has participated in all of EPA's rulemakings and pre-rulemaking activity involving regulation of methane from the oil and natural gas source category.[11] In addition to filing regulatory comments, INGAA met with EPA staff both in-person and virtually to provide feedback and discuss concerns about the 2021 Partial Proposal and Supplemental Proposed Rule.

On March 8, 2024, the Final Rule was published in the Federal Register. Upon reviewing the Final Rule, it was clear EPA made several important and positive revisions that were responsive to INGAA's regulatory comments. In particular, the final standards for compressors were dramatically improved in the Final Rule by adopting work practice standards and clarifying that the volumetric rate applies on a per seal basis. Additionally, the delay of repair provision was improved substantially by the EPA's clarification that it applies to compressor stations, and by EPA's action to expand this provision to valve assembly supplies and custom fabricated parts. We appreciate that EPA considered INGAA's regulatory comments and made revisions that ensure a more practical and achievable regulation for INGAA members.

While we saw significant improvements in the Final Rule, there remain several areas of concern for INGAA members. To that end, INGAA now files this reconsideration petition, identifying the following issues for EPA's reconsideration or, in the alternative, new rulemaking:

Process Controllers. In both the 2021 Partial Proposal and the Supplemental Proposed Rule, EPA used the terminology "pneumatic controller" to describe the types of controllers that are included in the definition of affected facility, and thus the types of controllers that are subject to regulation under Subpart OOOOb and Subpart OOOOc.[12] In the Final Rule, however, EPA changed the terminology for pneumatic controllers to "process controllers."[13] EPA said this change was needed "[t]o assist with avoiding possible confusion about which types of 'controllers' are included in the definition of this affected facility…."[14] Further, the Agency noted, "[t]he term 'process controller' is *broader in scope* because it includes pneumatic controllers as well as other types of controllers that are not pneumatic."[15] As discussed in further detail below in Section II, this change has potentially led to consequences which EPA may not have understood and upon which INGAA was not provided the opportunity to comment. Indeed, this change has caused more confusion for INGAA members. In addition, EPA had unduly restricted the scope of the definition of Emergency

[9] Docket ID No. EPA-HQ-OAR-2021-0317-1391 (Jan. 31, 2022).

[10] Docket ID No. EPA-HQ-OAR-2021-0317-2483 (Feb. 13, 2023) ("INGAA Comments on Supplemental Proposed Rule").

[11] *See id.* at 1 n.3 (listing all of INGAA's comments on issues related to the regulation of methane from the oil and natural gas source category under section 111).

[12] 89 Fed. Reg. at 16,930.

[13] *Id.*

[14] *Id.*

[15] *Id.* (emphasis added).

Shutdown Devices ("ESDs") in the Final Rule. The Agency did not respond to some of INGAA's comments on this issue, and where EPA did respond, it proposed a solution – redundant ESD systems – without considering pre-existing regulations to which ESD systems are subject, or the cost-effectiveness of such a solution. Importantly, INGAA never had an opportunity to comment on or explain the implementation or cost effectiveness implications of such a solution.

Super Emitter Program. With regard to the Final Rule's Super Emitter Program, EPA appears to have misunderstood INGAA's comments about the serious problems posed by the 100 kilogram per hour ("kg/hr") threshold set by the Final Rule. At a minimum, EPA has failed to respond to INGAA's comments on this important issue. The program's inapt threshold will result in the inclusion of operational venting conducted for reliability and safety purposes (such as blowdowns) which are *not* super emitter events. Inclusion of blowdowns in the Super Emitter Program conflicts with EPA's recently issued Subpart W Final Rule where the Agency determined that remote measurements will produce highly inaccurate data on blowdowns which does not provide meaningful information. Also, while EPA included more detail in the Final Rule regarding the test methods needed to become an EPA-approved method for methane detection technology, more transparency regarding the process is needed. Finally, while EPA has slightly improved the process for the public posting of notices under the Super Emitter Program, problems remain.

Storage Vessels. Lastly, with regard to the portions of the Final Rule addressing storage vessels, INGAA commented that the Supplemental Proposed Rule's option that owners and operators obtain legally and practically enforceable limitations for de minimis sources, such as storage vessels in the transmission sector, is problematic because several states do not have the authority or the mechanisms to include these limits in permits. EPA's response, which was that the states should adopt whatever regulations are necessary to allow them to set such limits, opens a new set of issues on which INGAA could not comment. Namely, it is unclear what owners and operators should do in the interim while states undergo such changes to their regulations.

INGAA discusses each of these issues in more detail below and urges EPA to address them in a reconsideration proceeding or, in the alternative, a new rulemaking.

II. Process Controllers

A. The Change in Terminology from "Pneumatic Controllers" to "Process Controllers" in the Final Rule Increased Uncertainty and Potential Reliability and Safety Consequences for Transmission and Storage Compressor Stations.

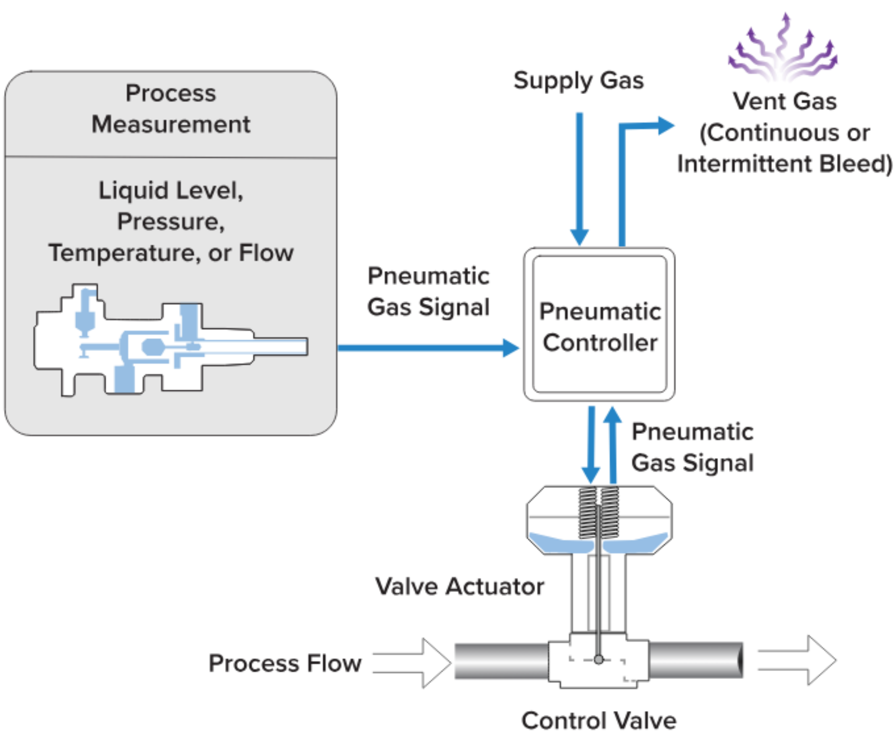
The Supplemental Proposed Rule included proposed requirements for a "pneumatic controller affected facility, which is the collection of natural gas-driven *pneumatic controllers* at a well site, centralized production facility, onshore natural gas processing plant, or a compressor station."[16] In the Final Rule, EPA says that it "noticed that not all commenters used the same terminology,"

[16] Proposed 40 C.F.R. § 60.5365b (emphasis added). Because the different Subparts of regulatory text proposed by EPA in the Final Rule have very similar language, we cite in this petition to the Subpart OOOOb provisions, but we intend to include any analogous provisions in Subparts OOOOa and OOOOc.

with regard to the scope of what was covered under the term "pneumatic controller."[17] Thus, "[t]o assist with avoiding possible confusion about which types of 'controllers' are included in the definition of this affected facility," EPA changed the terminology from "pneumatic controllers" to "process controllers," noting that the latter term "is broader in scope."[18]

The broadening of the terminology of an affected facility to encompass all "process controllers"[19] had the opposite effect; it created more uncertainty and failed to clarify the issue. Natural gas driven pneumatic process controller "systems" vary throughout the natural gas industry, resulting in significant differences in emissions, costs, and function across industry segments and applications.

Prior to the issuance of the final rule, INGAA and its members understood that a "pneumatic controller" was separate from an actuator or a valve. Indeed, EPA had articulated this view on its website with the following diagram[20] showing that the pneumatic controller is separate and distinct from the actuator or the valve:



[17] 89 Fed. Reg. at 16,930.

[18] *Id.*

[19] *See* 40 C.F.R. § 60.5365b.

[20] The diagram is presented on EPA's Natural Gas Star webpage at https://www.epa.gov/natural-gas-star-program/pneumatic-controllers.

The change of terminology and the reference to a "broader" term in the final rule created uncertainty as to what EPA intended to cover with the new terminology. A well-defined nomenclature and terminology are therefore imperative so that operators across the industry can adequately understand and ascertain what is within the scope of the rule and evaluate what actions are necessary to achieve compliance. Here, EPA has not adequately defined the affected source – of particular relevance to INGAA – as it relates to transmission and storage compressor stations ("T&S stations").[21]

The lack of clear EPA definitions for the affected source is exacerbated by the change to "process controller" in the Final Rule. For example, *process* controller could be interpreted to omit some *pneumatic* controllers, but include other devices not previously contemplated, including device types found at T&S stations such as large valve actuators, pilot valves, and associated parts (herein, "other system components").[22]

Support material for the Final Rule includes details and terminology that were not in previous rule material, and INGAA was not afforded the opportunity to comment on that material. Such an opportunity would have provided insight into EPA's analysis and intent with the new "process controller" terminology. Had INGAA been afforded that opportunity, it would have commented on the resulting uncertainty and furnished information regarding the devices in question, their associated emissions (very low) and the costs to comply (very high) for example applications at T&S stations not contemplated in EPA's analysis. Moreover, EPA failed to take the costs of the other system components into account in its technical support document ("TSD").

More specifically, INGAA members are concerned with the incorrect assumptions made when finalizing the rule regarding the controller devices in question as applied to their function and use at T&S stations, particularly as it relates to the associated emissions reductions from these devices and the cost impact of this broadened category of process controllers. EPA's model plants for T&S stations assumed relatively small, low-pressure pneumatic controllers would be affected by the rule. The rule could be interpreted as including large, high-pressure controller systems. Methane emissions from such large-pressure process controllers, which typically are actuated much less

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[21] INGAA member BHE GT&S specifically requested clarification on this point. Of note from BHE's comments: "Finally, BHE notes that the proposed definition of pneumatic controller may have intended to encompass only a certain type of application, "*Pneumatic controller* means an automated instrument used for maintaining a process condition such as liquid level, pressure, delta-pressure and temperature." Docket ID No. EPA-HQ-OAR-2021-0317-2366 (, 2023), at 9. From this definition it is assumed that other pneumatic valve operators whose function does not fit within this definition (e.g., opening or closing a valve) are *excluded* from this rule. BHE supports the current definition as it accurately describes the pneumatic controllers that should be the focus of this rule. EPA should clarify the intent of its definition." *Id*.

[22] To further the confusion, a study cited by EPA in the Final Rule seems to take a different position from EPA, finding that "emissions from pneumatic emergency shutdown, isolation, and pump devices…do not actively control process variables." Benjamin Luck, et al., *Multiday Measurements of Pneumatic Controller Emissions Reveal the Frequency of Abnormal Emissions Behavior at Natural Gas Gathering Stations*, Environ. Sci. Technol. Lett. 2019, 6, 348−352, Docket ID No. EPA-HQ-OAR-2021-0317-0014, Attach. 35, at 349.

frequently, are much lower than EPA assumed; however, the cost of providing compressed air at the pressures required for such controllers is very high, much higher than EPA assumed.

To illustrate the issue, three INGAA members have conducted analyses to estimate potential emission reductions from, and the costs of, replacing necessary system components for retrofit applications of process controllers at existing T&S stations. The analyses demonstrate both lower realized emissions reductions and significantly higher costs than EPA's scenarios for certain equipment, in particular situations that require replacing existing valve actuators due to differences in air systems and T&S natural gas-driven systems. The companies each performed an analysis using data representing realistic operating scenarios at T&S stations, aligned with certain variables consistent with EPA's TSD (e.g., 6-year compressor life, interest rate), applied costs based on recent equipment and service quotes, and calculated actual emissions based on valve actuation frequency, physical volume, and operating pressure. The results demonstrate two key findings: if EPA intended to include these types of controllers in its analysis for T&S station, (1) the actual emissions reductions are grossly overestimated by EPA in the final rule and (2) the cost assumptions made by EPA in its TSD grossly underestimate the cost to replace these types of process controllers used in T&S stations.

For example, an analysis of a small compressor station owned by INGAA member The Williams Companies, Inc., yielded a cost-effectiveness of $860,714 per ton of methane reduced based on average power gas pressure and a 6-year compressor life (consistent with EPA's assumptions in the rulemaking), and required valve actuator replacement.[23] This is *400 times larger* than EPA's estimates.

The analysis by Kinder Morgan, another INGAA member, based on INGAA's understanding of the Supplemental Proposed Rule, yielded a cost-effectiveness of $1,650 per ton of methane reduced for replacing only gas level pneumatic controllers – a number comparable to the cost-effectiveness figure that EPA calculated. But when Kinder Morgan subsequently analyzed the cost of replacing the valve actuators at the station, a required measure to convert the actuators from gas to air, the cost-effectiveness skyrocketed to $2,887,686 per ton of methane reduced.[24] Moreover, the total methane reduced by replacing actuators at the station is less than a ton per year total.

Another INGAA member, BHE GT&S, calculated a cost-effectiveness of $3,417,977 per ton of methane reduced for a group of 20 valve actuators at an active compressor station. This calculation includes initial capital costs only and does not include any ongoing operational or life cycle costs.[25] This cost effectiveness value is far above EPA's examples in the TSD.

B. EPA should clarify its definition to exclude components which are not cost-effective.

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[23] The Williams Companies Inc.'s analysis is provided in Attachment A.

[24] Kinder Morgan's analysis is provided in Attachment B.

[25] BHE GT&S's analysis is provided in Attachment C.

If EPA intended to regulate other system components, the Final Rule failed to analyze the associated emissions and retrofit costs to comply with the zero-emission standard. Conducting such an analysis would show that some T&S station applications (e.g., large, high-pressure valves that require replacement of the valve actuator) do not warrant replacement because they are not a cost-effective way to reduce methane emissions.

EPA needs to adequately assess whether the cost-effectiveness for T&S stations meets EPA's Best System of Emissions Reduction ("BSER") cost effectiveness requirements. For example, the Supplemental Notice TSD[26] refers to "actuation" on a limited basis when referring to the action that occurs in the control system, e.g., a valve opening or closing. The Final Rule TSD, however, introduces the term "valve actuator" and indicates that retrofit costs for an instrument air system do not include valve actuator or other peripheral component replacement costs.

> "This analysis includes only the costs of an instrument air system above the costs for a pneumatic system and does not include gas supply piping, control instruments or valve actuators, as these components would be used in either a pneumatic or a compressed gas system."[27]

These assumptions support a narrow interpretation of the components that fall under the definition of "process controller." EPA's lack of clarity is significant for T&S stations where the large pressure difference between the existing natural gas system and a new compressed air system requires wholesale replacement of the entire system, including the valve actuators.

Further, EPA did not properly account for the frequency of actuations as it pertains to emissions and over-estimates the magnitude of emissions from other system components that may be considered process controllers under the Final Rule. In fact, the Final Rule TSD *increases* emission estimates for T&S intermittent devices, while INGAA member review of actual operational data shows much lower emissions and actuation frequency.[28]

The source of this failure is the Agency's reliance on data characteristic of upstream segments. As INGAA has stated time and time again: upstream data does not typically translate to T&S stations, and this is especially true for many pneumatic controller applications. EPA's attempt to shoehorn T&S stations into an agency analysis focused on the upstream segment lays bare the failing of EPA's analysis. The estimated methane reduction costs of replacing systems at T&S stations, including valve actuators, *far exceed* EPA's reasonable cost threshold of $2,048/ton methane reduced for BSER.

EPA must clarify that it did not intend the term "process controllers" to include other system components to avoid imposing extremely burdensome costs on T&S stations that are not cost effective. In reconsidering this aspect of the Final Rule, EPA should clarify the definition of

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[26] EPA-HQ-OAR-2021-0317-1578.

[27] EPA-HQ-OAR-2021-0317-3198, page 2-24.

[28] For examples, see the emissions based on actuation frequency in Attachments A, B, and C.

process controller to more clearly define device types that are included and those that are excluded. In addition, EPA should ensure that adequate cost effectiveness analysis is included for the full breadth of controller types and applications when determining BSER. This may warrant additional subcategories, such as intermittent controllers in some T&S applications where emissions are very low (e.g., based on actuation frequency) and retrofit costs are very high (e.g., existing high-pressure systems that require major system upgrades including the valve actuator), while minimizing impacts on the reliability and safety of the natural gas system.

C. EPA Needs to Reconsider the Scope of its Exclusion for ESDs in the Final Rule.

EPA should also reconsider the scope of ESDs excluded from the definition of process controller affected facility in the Final Rule. In the Supplemental Proposed Rule, EPA proposed to define an ESD as a:

> device which functions exclusively to protect personnel and/or prevent physical damage to equipment by shutting down equipment or gas flow during unsafe conditions resulting from an unexpected event, such as a pipe break or fire. For the purposes of this subpart, an emergency shutdown device is not used for routine control of operating conditions.[29]

EPA rejected INGAA's comment that all ESDs and failsafe safety devices should be excluded from the definition on the ground that it is not the intent of this provision to exclude pneumatic controllers that are actuated frequently.[30] But EPA did not address ESDs that are only occasionally used for control of operating conditions. Indeed, a fair reading of the Final Rule is that ESDs that are not routinely used for control of operating conditions are excluded, because otherwise the second sentence of the regulatory definition would be entirely superfluous. However, "routine" versus "non-routine" control are not discussed or defined. EPA should, at a minimum, clarify the definition of ESD to specify how the line may be drawn between ESDs used for routine control of operating conditions and those used only occasionally or rarely to control operating conditions (i.e., non-routine control, such as venting prior to conducting major maintenance that may occur annually or even less frequently).

EPA suggests for the first time in the Response to Comments ("RTC") that "owners/operators could add a process controller such that one functions as an ESD and the other performs normal operations."[31] INGAA had no opportunity to comment on this approach, including on the cost-effectiveness and potential operational implications of such an approach. Additionally, it is unclear whether EPA evaluated its suggested remedy to this safety concern against the regulatory requirements regarding the design and safe operation of natural gas transmission and storage

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[29] Proposed 40 C.F.R. § 60.5430b.

[30] EPA, Response to Public Comments on the November 2021 Proposed Rule and the December 2022 Supplemental Proposed Rule, Docket ID No. EPA-HQ-OAR-2021-0317-4009, at II-7-20 (Nov. 2023).

[31] *Id.*

pipelines and compressor stations by the Pipeline and Hazardous Materials Safety Administration (PHMSA). PHMSA's regulations include specific design requirements (49 C.F.R. 192.167 for ESDs and 192.169 for overpressure protection - e.g., work-monitor pressure regulator) and operational inspection, testing and maintenance requirements for ESDs and over-pressure protection (192.739) and these must be taken into consideration when it comes to any redesign of an ESD system.[32] Redundant ESD systems will add significant costs which were not included in EPA's cost analysis. these systems will likely significantly exceed the cost effectiveness threshold, especially for T&S applications with low actuation frequency. Based on the information in the regulatory docket for the Final Rule, EPA has not considered any of these impacts on its suggested redundant ESD systems.

The issues for reconsideration relating to process controllers are of central relevance to the Final Rule and were ones on which INGAA could not comment. INGAA members are earnestly taking steps to comply with the requirements in OOOOb. However, this issue of process controllers is creating an operational conundrum and clarity is needed. As written, the Final Rule potentially requires highly costly controls for other system components at T&S stations which would provide minimal methane reductions, and unduly restricts the definition of ESDs.

D. EPA has not adequately analyzed the reliability impact of imposing the zero-emission standard on process controllers at T&S stations.

EPA must evaluate the reliability impact from requiring the zero-emission standard on all process controllers. The Final Rule provides twelve months for a compressor station that has triggered OOOOb to convert all process controllers in a process controller affected facility to comply with the zero-emission standard. This will place a significant demand on the equipment, supplies, and service vendors during the compliance time frame and add more strain to a supply chain that currently requires 12-18 months to deliver certain types of components necessary for the conversion of large natural gas driven controllers to an air driven system. Thus, if an operator is unable to complete the conversion due to reasons beyond its control, it will have to make a decision whether to continue operating but potentially in a non-compliant state or shut down that compressor station thereby reducing its ability to move gas during peak demand periods, pursuant to their FERC-approved tariffs.[33]

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[32] In addition, PHMSA's proposed Leak Detection and Repair (LDAR) Rule (88 Fed. Reg. 31,890) has recently been considered by the Gas Pipeline Advisory Committee (GPAC), and the agency is now working to finalize the LDAR Rule. It is noteworthy that the GPAC is comprised of a broad swath of stakeholders including the Environmental Defense Fund as well as the Federal Energy Regulatory Commission, and the Army Corps of Engineers. The proposed LDAR rule defined specific leak detection methods and frequencies as well as repair criteria to reduce and minimize emissions from natural gas pipeline operations. The GPAC unanimously provided sound technical recommendations to PHMSA to inform the final rule which is anticipated toward the end of 2024 or early 2025.

[33] *See* 18 C.F.R. § 284.12(b)(2)(iv) ("A pipeline must take all reasonable actions to minimize the issuance and adverse impacts of operational flow orders (OFOs) or other measures taken to respond to adverse operational events on its system. A pipeline must set forth in its tariff clear

Alternatives to the natural gas-powered controller introduce additional complexity into the system and potential unreliability. Compressed air, for example, depends upon the air compressors, electrical power, and dryer systems as opposed to the readily available and reliable compressed natural gas. Some of the concerns associated with compressed air 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. The addition of air pneumatic 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.

Finally, converting large natural gas driven controllers to an air driven system requires significant electrical demand due to the addition of electric air compressors. These are not small compressors – they have a significant power demand. Adding these units across the network of T&S stations will put additional electrical demand on a power grid that is already facing increased demand through data centers, conversion of natural gas appliances to electric, and electric vehicles, to name a few. Increased demand on the electric grid, in turn, places a higher demand upon power generation facilities, potentially leading to reliability issues for the system.

III. The Super Emitter Program

A. EPA Needs to Reconsider the Threshold for the Super Emitter Program and Address the Concerns Raised by INGAA.

The Supplemental Proposed Rule defined a super-emitter event as one that has a quantified emission rate of 100 kg/hr of methane or greater. Emissions above this rate can trigger the potential for an owner and operator to receive a notice from EPA of a potential super-emitter event, which in turn requires actions and explanations by the owner or operator. EPA acknowledged that there could be instances where emissions from normal operations might exceed the proposed threshold for a super-emitter event, but the Agency said it thought this would be unusual. INGAA commented that the threshold was too low and that the reporting of emissions from normal operations, like blowdowns, would not be an unusual occurrence. In addition, for Greenhouse Gas Reporting Program ("GHGRP") affected facilities, blowdowns are already reported for defined event types that include a "catch all" category that ensures blowdowns with emissions well less than 100 kg are already reported.

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standards for when such measures will begin and end and must provide timely information that will enable shippers to minimize the adverse impacts of these measures."); 18 C.F.R. § 284.13(d)(1) (requiring interstate pipelines to publicly post "all planned and actual service outages or reductions in service capacity").

In the Final Rule, EPA retained the 100 kg/hr threshold that defines a super-emitter event and does not consider event duration or total mass emissions. EPA's RTC, however, fails to address the thrust of INGAA's comments: Namely, that the 100 kg/hr threshold is too low and is easily exceeded due to operational venting conducted for reliability and safety purposes, like blowdowns; that such operations are not at all "unusual"; and that this very low threshold, without consideration for duration or total volume emitted, will sweep into the Super Emitter Program a very large number of operations that are *not* super emitter events. In the RTC, EPA responded with a non-sequitur, saying that it "revised the defined [sic] the owner or operators' requirements for responding to super-emitter notifications in Section X.C.2 and XI.C.4 of the preamble of the final rule."[34] EPA continues, saying that "[t]he goal of this program is not to prevent allowable maintenance or operational events from being conducted, but to inform an owner or operator when these large events occur, so an owner or operator can investigate, correct, and repair if necessary."[35]

These responses do not address INGAA's comments. Putting aside that an owner or operator does not need a third party to be "informed" that it has conducted a blowdown for operational, reliability, or safety purposes, and further putting aside the fact that such events need no investigation, correction, or repair, EPA's statements fail to even acknowledge, much less respond to, the practical problem INGAA raises – namely, that the 100 kg/hr threshold will result in too many instances in which super-emitter notices may be issued to, and have to be responded to by, owners or operators (and will need to be processed by EPA, potentially straining the Agency's and operator's resources unnecessarily).

Importantly, the emissions associated with blowdowns are miniscule in comparison to actual super emitter events, and blowdown emissions data are *already collected by EPA*. The statistics for blowdowns ultimately result in about 2,500 metric tons of carbon dioxide equivalent annually for all the larger T&S stations subject to the GHGRP. This is ten percent of the reporting threshold for the GHGRP and similar to the facility-level blowdown emission factor that EPA uses in its annual GHG inventory report.

In another part of the RTC, EPA specifically notes INGAA's comments that the threshold should be higher than 100 kg/hr because blowdowns will exceed the threshold.[36] The RTC recounts INGAA's comments, including examples INGAA provided and INGAA's discussion of alternative thresholds used by other jurisdictions.[37] In response to these detailed comments, however, EPA says only the following:

> "EPA acknowledges the commenters' input, [sic] we acknowledge that some super-emitter events will be larger than 100 kg/hr however limiting investigation to only higher-level emissions, negates the

[34] *Id*. at II-14-11.

[35] *Id.*

[36] *Id*. at II-14-59.

[37] *Id*. at II-14-60.

> potential emission reductions from emission events using the threshold of 100 kg/hr of methane in the NSPS."[38]

This response also fails to address the thrust of INGAA's comments. The comment is not that "some super-emitter events will be larger than 100 kg/hr"; it is that an event that exceeds a rate of 100kg/hr *for a short duration* should not constitute a super-emitter event. A threshold based solely on this rate is arbitrarily low, given that the Agency is aware that normal operations can routinely trigger or exceed the threshold in the Final Rule. As a result, there will be many events that are required for reliability and safety – thousands every year at T&S stations – that are perfectly allowable under the existing regulations that will exceed the 100 kg/hr threshold (at least for a short period of time). In contrast and as discussed below, data available to EPA from the EPA's own GHGRP show that the prevalence of large leaks from measured sources in the T&S stations is rare. Thus, routine and permissible events are going to be subject to unnecessary notices, leading EPA and owners or operators to have to take certain actions under the Super Emitter Program. These instances will not be unusual, and their inclusion will create unnecessary burden for owners or operators of T&S stations.

Indeed, as EPA acknowledges, "[d]ata from the GHGRP for 2016 compiled by the [Pipeline Research Council International ("PRCI")] showed an average compressor blowdown of approximately 500 kg per event, and an average scrubber blowdown of 1,700 kg per event."[39] EPA notes that the latter is "rare," but EPA says absolutely nothing about the frequency of compressor blowdowns.[40] Compressor blowdowns are not rare; they are used to maintain the safety of the pipeline system. Indeed, that exact same PRCI compilation of EPA data from the GHGRP for 2015-2016, including the report cited by EPA in the RTC and companion reports—reports prepared by PRCI (the "PRCI Reports")[41, 42, 43] and provided to EPA—shows the following with regard to T&S station blowdowns and large leaks:

- The PRCI Report includes 7,350 measurements of compressor isolation valve or blowdown valve leakage for 300 to 350 facilities over the first six years of the GHGRP Subpart W program (2011 to 2016).
- EPA required measurement due to the potential for larger leaks from these valves, and these leak measurements indicate that a total of 53 out of 7,350 measurements exceeded a rate of 100 kg/hr; this equates to, on average, about one out of every 35-40 facilities

[38] *Id.*

[39] *Id.* at II-14-59.

[40] *Id.*

[41] PRCI, PR-312-16202-R03, *Methane Emissions from Transmission and Storage Subpart W Sources* (Sept. 2019).

[42] PRCI, PR-312-16202-R02, *GHG Emission Factor Development for Natural Gas Compressors* (April 2018).

[43] PRCI, PR-312-18209-E01, *Methane Emission Factors for Compressors in Natural Gas Transmission and Underground Storage based on Subpart W Measurement Data* (Oct. 2019).

experiencing a "large leak" event annually; or less than nine large leaks a year across about 350 GHGRP reporting facilities.[44] These large leaks have been reduced since the 2011 – 2016 period due to voluntary and mandatory (e.g., state) LDAR programs and will reduce even further due to compliance with the new LDAR requirements.

- In contrast, for blowdowns, more than 95 percent exceed 100 kg with a total duration typically well less than an hour (so the short-term rate is over 100 kg/hr, but it persists over a very short period of time). Unlike the larger leaks noted above, blowdowns at a compressor station are not "unusual" or "rare." The PRCI Report showed blowdowns at about 323 facilities (in 2015) and 350 facilities (in 2016), which resulted in over 100 blowdowns per facility, per year (i.e., on average, 103 per facility in 2015, and 106 per facility in 2016). The average emissions per event were over 900 kg, and about 75 percent of these blowdowns are compressor blowdowns. Since blowdowns typically occur over durations less than one hour, the rate will almost always exceed the 100 kg/hr threshold based on an instantaneous or short-term measurement, but it will not persist for a substantial period as a leak typically would.

Using these EPA data from the GHGRP, we can expect about 100 blowdown events annually (a couple a week) per facility that can trigger a third-party super-emitter notification while about one in 36 of those facilities may have a large leak event that warrants a notice.

Blowdowns are not "unusual" or "anomalous" events that would be revealed by the Super Emitter Program, nor do blowdowns emit volumes of methane that warrant inclusion in the Super Emitter Program. In addition, because the leak data from the PRCI report are seven to twelve years old, large leaks are less prevalent now because voluntary and mandatory leak detection and repair ("LDAR") surveys have been implemented in the last decade. Blowdowns (compressor or otherwise) still occur as part of routine station operations.

B. EPA's Final Rule conflicts with its recently issued Subpart W Final Rule.

Blowdowns are subject to EPA reporting through the GHGRP reporting category, "blowdown vent stacks," In its recently released GHGRP rule (herein, "Subpart W Final Rule"),[45] EPA created a new GHGRP reporting category called "other large release events." The new reporting category is particularly relevant because it was designed by EPA to create parity between the GHGRP and the Super Emitter Program. Essentially, it creates a new GHGRP reporting category for super emitter events. And notably, EPA *excluded* blowdowns from it. The regulatory text for the "other large release events" category states:

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[44] This is calculated as follows: 53/6=8.83 events per year.

[45] Greenhouse Gas Reporting Rule: Revisions and Confidentiality Determinations for Petroleum and Natural Gas Systems, EPA-HQ-OAR-2023-0234; FRL-10246-02-OAR (prepublication version of the preamble and final rule is available at: https://www.epa.gov/system/files/documents/2024-05/subpart-w-final-preamble-rule-2024.pdf.

> "…*Other large release events* do not include blowdowns for which emissions are calculated according to the provisions in § 98.233(i)."[46]

EPA justifies its exclusion of blowdowns with the following reasons: (1) EPA already collects emissions data from blowdowns under the "blowdown vent stacks" reporting category in the GHGRP; (2) The emissions data collected via the "blowdown vent stack" category is accurate; and (3) Many remote measurements permissible under the Super Emitter Program will produce highly inaccurate data on blowdowns which does not meet EPA's rigor.[47]

EPA's determination that remote measurements of blowdowns will produce inaccurate data appears to have been ignored with the Super Emitter Program. This regulatory dichotomy leads to the untenable outcome that blowdowns are now reported under two EPA programs, creating duplication and waste of resources for all involved. Moreover, the Super Emitter Program data collected on blowdowns, by EPA's own admission, will not provide any meaningful information to the agency or the public at large.

EPA failed to consider its own GHGRP data in its analyses for the Super Emitter Program and failed to respond adequately to comments on this issue. EPA should reconsider relying solely on the 100 kg/hr threshold for super-emitter events to avoid the threshold being triggered regularly by the hundreds of operations, such as blowdowns, that are conducted for safety and reliability purposes throughout T&S stations, and which are already subject to EPA's oversight, and available to the public, through the GHGRP.

Failure to address and fix this issue by increasing the threshold or supplementing with a duration or total volume basis will result in EPA, owners, operators – and even third-party reporters – wasting resources to report, review, and investigate routine, permissible events. This result can be avoided by reconsidering the threshold, and/or including a duration, persistence, or total cumulative emissions basis to complement an emissions rate basis for the threshold. In the alternative, EPA could craft a Super Emitter Program exclusion for blowdowns, much as it has already done for the new GHGRP reporting category for "other large release events".

C. EPA Needs to Provide More Transparency Regarding the Process for Approval of Alternative Technologies for the Super Emitter Program.

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[46] See 89 Fed. Reg. at 42,323 (definition of "Other large release event").

[47] EPA states that "Specifically, the calculation methodology for blowdown vent stacks under 40 C.F.R. § 98.233(i) determines the total volume of between closed isolation valves and uses the pressure of the system at the start and end of the blowdown to calculate the amount of gas released, which we consider to be accurate even for large events. During a blowdown event, the emission rate will be highest at the start of the event (highest pressure) and consistently decline during the blowdown. Many remote measurements only determine the emission rate during a minute or two of observations, so projecting this instantaneous emission rate to estimate event emissions for blowdowns can be highly inaccurate. For these reasons, blowdowns will continue to be reported under blowdown vent stacks and not under other large release events, even for large emission rate events." 89 Fed. Reg. at 42,079.

In its comments on the Supplemental Proposed Rule, INGAA noted that there were a lack of standards and procedures with regard to the technologies and methods under the Super Emitter Program that are critical to the functioning of an effective program.[48] In response to these comments, EPA "revised the scope of the alternative test method program to now include the approvals for the Super Emitter Program."[49]

Under the Final Rule, approvals by EPA of any new methane detection technology or of any alternative test method that is broadly applicable are posted on EPA's website.[50] INGAA suggests that EPA broaden the scope of what it posts on its website to fulfill its intention that the Super Emitter Program "operate[] with a high degree of accuracy, integrity, and transparency."[51] In this regard, INGAA suggests that EPA not only post *approvals* of any new methane detection technology and alternative methods on its website but also any *disapprovals*. This will enable the public to see what types of technology and methods do and do not meet EPA's standards. It also will enable the public to see that EPA is acting consistently with regard to its approvals and disapprovals of applications for new technologies and alternative methods.

INGAA also suggests that EPA not only post approved alternative test methods that are broadly applicable on its website but also any site-specific methods. Having this information available could be useful to the public as new methods are developed, and it is possible that a site-specific method may be able to be used or readily adapted for use at another site.

D. Although EPA Has Acknowledged the Problems Associated with Being Identified as the Owner or Operator in Connection with a Potential Super-Emitter Event, EPA's Solution in the Final Rule Does Not Fully Solve these Problems.

In its comments on the Supplemental Proposed Rule, INGAA discussed the fact that reports from third-party reporters alleging a super-emitter event should not be placed on a public website, including EPA's website, until after EPA has verified the data and only when it has determined that an actual super-emitter event occurred that required corrective action by the owner or operator.[52] INGAA explained that "[i]f the alleged super-emitter event was the result of normal operations or maintenance, or if the third-party reporting entity made a mistake, the owner or operator will suffer reputational damage"[53]—even if it was later found that a mistake had been made or that the event was the result of normal routine activities, the owner or operator would suffer reputational harm.

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[48] INGAA Comments on Supplemental Proposal at 3-8.

[49] 89 Fed. Reg. at 16,918.

[50] 40 C.F.R. § 60.5398b(d), (d)(iii).

[51] 89 Fed. Reg. at 16,826.

[52] INGAA Comments on Supplemental Proposal at 13.

[53] *Id.*

In the Final Rule, EPA will now review a third-party notification before it is posted on its website and agreed with INGAA "that owners and operators should have the opportunity to refute the information provided by the third party" before being publicly identified.[54] Under the Final Rule, EPA shall review the notification from the third-party notifier to determine that "the notification is complete and does not contain information that the EPA finds to be erroneous or inaccurate to a reasonable degree of certainty."[55] Only after that step has occurred is the notification posted on the EPA website, and the identity of the owner and operator is not included in that initial posting.[56]

INGAA agrees with EPA's approach in the Final Rule of not identifying the owner and operator in the initial posting on the website. Had INGAA had the opportunity to comment on this version of the regulations, however, it would have noted that any other information in the report that could lead to the identification of the owner or operator, including the name of the facility, the latitude and longitude of the potential super-emitter event, and any images taken of the facility, should also be redacted in the initial website posting. If this information is included, the owner or operator will likely be able to be identified without too much difficulty in many cases, especially for rural locations common for T&S stations. INGAA suggests that EPA reconsider this aspect of the Final Rule and remove any and all information from the notification that could lead to the identification of the facility and thus its owner and operator. That identifying information should be released publicly only after EPA receives the super-emitter event report from the owner and operator and only after it has been confirmed that the event in question was in fact a super-emitter event.

IV. More Clarity is Needed on Storage Vessels.

The Supplemental Proposed Rule proposed to base applicability of the performance standards for storage vessel affected facilities on the affected facility's potential to emit ("PTE") methane. Specifically, a storage vessel affected facility with a PTE of more than 20 tons per year of methane is subject to the Final Rule. Accordingly, to avoid becoming an affected facility, owners and operators must obtain legally and practically enforceable ("LPE") limitations for methane emissions from the state permitting authority so as to limit the PTE of methane to less than the applicability threshold. INGAA submitted comments to EPA pointing out that many state permit programs do not allow the state to include methane limits for de minimis sources, such as storage vessels in the transmission sector. For this reason, INGAA asked EPA to eliminate applicability based on methane PTE, or to otherwise resolve the problem created by the disconnect between a PTE enforceability requirement that can be provided only by state agencies that may not have the mechanisms – or in some instances, the authority – to provide. EPA did not change the requirements for LPE methane PTE limitations. Instead, EPA suggested that any state without the necessary mechanisms or authority should adopt whatever regulations are necessary to allow them to set such limits.[57]

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[54] 89 Fed. Reg. at 16,922.

[55] 40 C.F.R. § 60.5371b.

[56] *Id.*

[57] *See, generally,* 89 Fed. Reg. at 16,976-78.

If this suggestion by EPA had been part of the Supplemental Proposed Rule, INGAA would have commented that this type of state action cannot occur instantly and that sources need to understand what they are expected to do in the interim while the states undergo their processes to change their regulations. EPA has not provided any guidance in the Final Rule as to how methane PTE could be effectively limited in the interim period. Nor did INGAA have an opportunity to offer comments on the resulting situation. For these reasons, EPA should reconsider this aspect of the Final Rule, and at least address on reconsideration (or, perhaps, in guidance associated with the Final Rule) how methane PTE can be effectively limited under the Final Rule in the period following the effective date of the rule until the applicable state permitting authority has taken steps to establish its authority and procedures to adopt such limitations under the state's programs.

V. Conclusion

For these reasons and due to the potential safety and reliability impacts on the natural gas system, EPA should grant reconsideration of these aspects of the Final Rule. Because it is anticipated these issues will require further discussion of a technical nature, INGAA would welcome the opportunity to meet with EPA to discuss these concerns further.

Respectfully submitted,

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ATTACHMENT A

Williams Exhibit for Petition for Reconsideration

Once the Final Rule was made available and industry learned that EPA did not address concerns raised about transmission and storage process controllers, The Williams Companies (Williams) undertook a comparative analysis of EPA's calculation methodology for a Small T&S Model Plant to understand EPA's assumptions in arriving at the single-pollutant cost effectiveness value of $1,924/ton CH4 in the Final Rule for retrofitting an existing facility with compressed air (Table 19). Once it understood the methodology, Williams identified a compressor station on one of its natural gas transmission pipelines with similar characteristics to those EPA outlined for a Small T&S Model Plant in the Final Rule calculation methodology. Williams undertook its own cost effectiveness evaluation using its familiarity with transmission and storage operational conditions and needs, two years of actual historized valve actuation frequency data and physical volumes of valve actuators, and recent pricing on equipment and contractor services to perform the work required. It was only through this exercise that Williams identified several faulty assumptions used by EPA in its methodology for existing sources at T&S Small (and Large) Model Plants, as well as its underestimation of the scope of a project required to convert these types of controllers from natural gas driven to zero emitting via compressed air (see table below). EPA seemingly had process controller operation and design information for control systems in an upstream segment(s) , and erroneously applied that information to process control systems at transmission compressor stations. As shown in the table below, the physical and operational differences that exist for process control systems at transmission compressor stations as compared to upstream facilities have a significant impact on the outcome of the analysis concerning emissions reduction impact and cost of reducing those emissions.

Comparison Table: Williams vs EPA Evaluation

Estimation Considerations	EPA TSD Existing CS - Gas to Air Conversion	Concern(s)	Williams Compressor Station Gas to Air Conversion
Emissions			
Controller count	30 controllers (22 intermittent, 7 low-bleed, 1 high-bleed)	Controllers at transmission compressor stations will predominantly be intermittent vent. Not all controllers with ESD function are exclusively ESD.	Facility has a total of 20 controllers; replacing gas controllers that do not meet exclusive ESD function exemption is 9 controllers.
Vented gas estimation	Proposed Subpart W emission factors used to determine gas loss.	EPA methodology can overestimate emissions especially for valves that stroke infrequently.	Engineering estimates used to determine volume of gas released for each actuation. Annual number of actuations based on 2 years of actual data at facility.
Methane content of gas	92.8% methane by volume		92.8% by volume

Annual CH4 emitted	Estimated total CH4 emissions = 22.1 tpy		Estimated total CH4 emissions = ~ 1 tpy
Capital Costs			
Compressor and associated equipment	EPA assumed a system with one 10 HP compressor would be required at a total cost of $33,992	Size and cost of required equipment to handle pneumatic load is severely underestimated.	Two 50 hp air compressors, one air drier, and two air receivers required: $287,154
Controllers	Does not include costs for new controllers.	Converting from high to low pressure gas actuation will require valve actuators to be replaced at significant cost.	Actuator unit replacement costs range from $13,370 to $66,625 per actuator. Total actuator replacement costs: $458,970
Instrumentation & fittings for retrofit	$1,487 per controller, for a total of $44,614	Electrical and piping upgrades required for air retrofits underestimated.	MCC section & buckets and transfer switch estimated at $110,000. Additional piping required for air system estimated at $33,000.
Emergency power supply	No consideration for emergency power supply when grid supplied power is down.	Back up power supply will be needed for air compressor systems given ESD function.	Current emergency power system is not sized to handle additional load of air compressors and new backup generator system will be required. 710 KW system estimated at $869,739.
Installation and engineering	Assumed 100% of equipment costs. Total = $78,606		Assumed 100% of equipment costs. Total $1,758,862
Annual Costs for Air System			
Annual compressor maintenance for air system	$3,159 per year. EPA assumed annual costs for compressor maintenance were 4% of total system cost. Note, incorrectly used system cost for large facility (i.e. $74,357 vs $33,992).	Cost of air compressor system is underestimated.	Used estimated cost of compressor system and EPA's annual maintenance assumption of 4% of total system cost for an estimate of $7,043 per year.
Annualized cost for air compressor replacement	$8,144 per year. Assumes compressor replacement cost of $48,863 every 6 years.	Cost is reasonable based on Williams historic quotes. A compressor life of 6 years is too	Compressor replacement cost of $53,083 and calculations run for a compressor life of 6 years and a more reasonable life expectancy of 15

		short; more reasonable is 15 years.	years. Annualized cost for 6 year life = $8,847. Annualized cost for 15 year replacement $3,539.
Electricity to run air compressor	$7,627 per year. Assumes two 10 hp compressors, one running at full capacity while the other is in standby. Electric use per compressor is 0.75 hp/kw at a cost of $0.0653/kw-hr.	EPA's capital costs were based on system with 10 hp compressor, where as electricity calculation assumed 20 hp compressors. Regardless, compressor size is underestimated.	Electric use estimated using EPAs methodology but increased compressor size to 50 hp for an estimate of $19,068 per year.
Annual Costs for Existing Natural Gas System (to be subtracted from costs of air system)			
Annual controller maintenance for natural gas system.	$4,200 per year. Assumes annual maintenance cost of $140 per controller.	EPA's assumption is based on "wet" supply gas. Supply gas at T&S facilities is dry. Condensation and corrosion are not typical.	Assumed no cost. Expect no difference in maintenance cost between air-driven and gas-driven process controllers.
Annualized cost to replace natural gas driven controllers	$5,190 per year. Assumes controllers are replaced once every 15 years. Assumes controller replacement cost of $2,595 per controller.	EPA's assumption is based on "wet" supply gas. Supply gas at T&S facilities is dry. Condensation and corrosion are not typical.	Assumed no cost. Expect no difference in life expectancy between air-driven and gas-driven process controllers.
Natural gas	Cost of natural gas that would have been vented to atmosphere is not included in EPA's estimate.	Should include cost of gas in analysis.	Cost of vented gas determined based on vented natural gas volumes and gas price of $3.13 per 1000 SCF: Between $143 to $175 per year for various scenarios.
Other			
Capital recovery timeframe	6 years	6 years is too short. 15 years is a more reasonable timeframe.	Scenarios presented for a compressor life of 6 years and a more reasonable life expectancy of 15 years.
Interest rate	7%		7%

Williams Cost Evaluation Summary

Single Mainline Compressor Convert Non-"Exclusive ESD" Actuators to Air 6 Year Project Life	Max power gas pressure (1440 psig)	Average power gas pressure (1242 psig)	
Air conversion capital cost	$ 3,517,725	$ 3,517,725	
Air conversion annual operation/maintenance cost	$ 34,957	$ 34,957	
Natural Gas annual operation/maintenance cost	$ -	$ -	
Natural Gas usage cost @ $3.13 per 1000 SCF	$ 170	$ 143	
Project life	6	6	years
Interest rate	7.00%	7.00%	
Annual cost of air conversion	$ 772,792	$ 772,818	
Annual natural gas emissions	54,159	45,812	scf
Annual methane emissions	50,260	42,513	scf
Annual methane emissions	1.061	0.898	ton
Annual cost per ton methane reduced	**$ 728,030**	**$ 860,714**	$/ton

Project Costs

Typical Valve Type & Size

Size	Valve type	Differential (psid)	Air supply pressure range (psig)	Controls	Quantity	Unit Cost	Total Cost	
36	Delta trunnion ball	1480	50-150	2 solenoid fail last	1	$ 66,625.00	$ 66,625.00	Mainline Block Valve
30	Delta trunnion ball	1480	50-150	3 solenoid fail closed	4	$ 66,625.00	$ 266,500.00	Unit suction valves, unit discharge valves
8	Nordstrom 2249	1480	50-150	Single solenoid spring return fail open	2	$ 28,690.00	$ 57,380.00	Unit blowdown valves
2	Nordstrom 2245	1480	50-150	Single solenoid spring return fail closed	2	$ 13,370.00	$ 26,740.00	Unit loading valves
				Total	**9**			

NOTE: Two Gas Cooler Block Valves and two Pig Trap Block Valves are manual control only and excluded from rule

NOTE: Two Station Blowdown Valves, two Gas Cooler Blowdown Valves, and two Sidegate Valves considered to be Exclusive ESD valves. OPP valve considered to be Process Safety Fail-Safe Valve.

Air Requirements

ft^3 double acting	Num simultaneous actuators*	volume for all simultaneous actuators (ACF)	volume safety factor	Actuation volume (acf)	Actuation volume (scf)	lbs air required	Receiver size (ft^3)	receiver size (gal)	Operate time (s)	Flowrate (SCFM)	Flowrate (ACFM)	Velocity limit (ft/s)	Header internal diameter	Air package size (SCFM)	Regeneration time (mins)
18.491	4.000	73.965	1.000	73.965	327.004	24.852	477.929	3574.913	30.000	654.009	147.931	20.000	4.754	360.000	0.908
	*2 unit suction valves, 2 unit discharge valves														

Item	QTY	Cost	Total	
3600 gal receiver	2.2	$ 42,492.00	$ 93,482.40	
Actuators	1.1	$ 417,245.00	$ 458,969.50	
Two 50hp air compressors & one air dryer	1.1	$ 176,065.00	$ 193,671.50	
Generator	1.1	$ 790,672.00	$ 869,739.20	
MCC section &buckets, transfer switch	1.1	$ 100,000.00	$ 110,000.00	
Piping	1.1	$ 30,000.00	$ 33,000.00	
		Total materials	$ 1,758,862.60	
		Installation	$ 1,758,862.60	100% of material cost
		Total Project	$ 3,517,725.20	

Operating Costs

	Small T&S (30) - 50 HP		
Item	$/unit	Annual $	
Compressor maintenance	$176,065	$7,043	Annual cost is 4% of system cost per EPA assumption
Replace compressors every 6 years	$53,083	$8,847	
Replace compressors every 15 years	$53,083	$3,539	
Electricity	**	$19,068	EPA provided equation - changed to 50 HP
Instrument Air System Total (6 year replacement)		$34,957	
Instrument Air System Total (15 year replacement)		$29,649	
NG system total - new and existing sites		$0	EPA assumption is gas controllers use wet gas & higher maintenance cost
			Williams' assumption lower maintenance and replacement costs due to dry gas service
EPA footnotes below:			
** Electrical cost = (Compressor Engine Power*Operating Hours*Operating factor * Electricity Cost)/electricity use per engine			
engine power = 5 HP; 10 HP; 20 HP			
operating hours = 8760 hrs/yr			
operating factor = 50% (one compressor is in standby while the other compressor runs at full capacity half the time)			
electricity cost = 0.0653/kwhr (2020 national average industrial cost of electricy from EIA - https://www.eia.gov/electricity/monthly/epm_table_grapher.php?t=table_5_06_a)			
electricity use per engine = 0.75HP/kilowatt (from Convert Gas Pneumatic Controls To Instrument Air Natural Gas Star Program			
Lessons Learned from National Gas STAR Partners, 2006. https://www3.epa.gov/gasstar/documents/ll_instrument_air.pdf)			

ATTACHMENT B

(Pages with Confidential Business Information Removed)

Kinder Morgan's Calculations and Methodology

In support of INGAA's petition for reconsideration of the EPA's NSPS Subpart OOOOb/c regulations, Kinder Morgan, Inc. (KM) has completed an evaluation of methane emission reduction and cost effectiveness ($ / ton of methane reduced) at our Tennessee Gas Pipeline (TGP) 32 compressor station. This existing station has 33 traditional process controllers and so is in between EPA's definition of small (less than 30 process controllers) and large (greater than 50 process controllers), for a transmission and storage (T&S) compressor station. The accompanying exhibits give relevant details and summarize the findings of Kinder Morgan's evaluation. These exhibits include:

1. Kinder Morgan TGP CS 32 Conversion of Gas Driven Controllers Estimate (30 Apr 2024).xls – contains cost totals and gas venting calculations. (*See* Appendix 1).
2. Kinder Morgan – Conversion of gas driven process controllers (TGP CS 32), 01 May 2024 –assumptions and final emission reductions and costs. (*See* Appendix 2).
3. Kinder Morgan – TGP CS 32 Overview – Marked up plot plan showing the compressor station details. (*See* Appendix 3).

Station Details

TGP CS 32 is an existing compressor station that is comprised of 20 compression units. All the station unit control valves are motor driven (electric). However, there are several (27) natural gas operated high pressure actuators on ball valves throughout the station. Eight of these actuators are part of the station ESD (Emergency Shutdown) system. At this compressor station, as for most of KM's compressor stations, the actuators and valves in the ESD system are not exclusive and are occasionally used for non-ESD functions. Additionally, there are six constant bleed natural gas driven process controllers used for liquid level control on separation equipment at the station. This evaluation includes the replacement of these devices to bring TGP CS 32 into compliance with the broadest interpretation of EPA's OOOOb/c definition of "process controller."

Methane Emission Estimates

The Original Equipment Manufacturer (OEM) documentation for the valve actuators was used to estimate the vented volume per stroke for each of the actuators. To account for the various miscellaneous components on the actuator control panels (*e.g.*, tubing, filters) a 1.5x factor was applied to vented actuator volume. Station operational data was reviewed to determine how many annual valve actuator cycles occurred. In 2023, TGP CS 32 experienced 6 station shutdowns. It was assumed that each of these shutdowns would require 2 valve actuations, for a total of 12 valve venting events for all 27 actuators. The gas powering the actuator was conservatively assumed to be 750 psig (pipeline MAOP) and consisting of 92.8% methane. Using this methodology, we estimate an annualized methane emission of only 0.27 tons at TGP CS 32 from all 27 actuators. The "Current Station Gas Emissions" tab in Appendix 1 contains detailed calculations.

OEM documentation stated the constant bleed rate of the L2 process controller is 1 scfh. The gas powering the process controllers was assumed to be 20 psig (controlled by pressure regulators) and consisting of 92.8% methane. Using this methodology, we estimate an annualized methane emission of 9.38 tons at TGP CS 32 from all 6 process controllers. The "Current Station Gas Emissions" tab in Appendix 1 contains detailed calculations.

Proposed Station Modifications - Replacement Equipment

In the case of the 27 valve actuators, KM analyzed what it would cost to replace the existing high-pressure actuators with low-pressure air actuators. A key factor in sizing the new air actuators is ensuring the actuators produce enough torque to safely open and close the valves. Quotes for the new air actuators were supplied by an approved KM distributor. See Appendix 4, Air Actuator Sizing and Quotation. A new air compressor was included in the estimate because the existing station air compressor was not sufficient to meet the demands of adding these additional air operated actuators. Additionally, since several of these new actuators will be installed on ESD valves, they were deemed essential and required a backup generator to be included in the estimate. An emergency generator would be necessary in case the power supply fails at any point so there is a backup source of power for the ESD system which serves a safety critical function. The KM cost estimating group (part of our Project Management department) provided installation and commissioning estimates. See Appendix 5, Construction, Installation, Commissioning Cost Estimate. These estimates included the cost of installing substantial lengths of air piping (see Appendix 3), installing fuel gas piping (supply for new backup generator), installing the new air compressor, installing the new backup generator, commissioning activities, and removing the gas actuators. The KM cost estimating group has compiled actual installation costs from completed projects and equipment purchases into a database to use for estimating costs of future projects. In KM's experience this database is highly accurate and the cost information it provides is within 10% (plus or minus) of the actual cost. This KM tool was used to estimate some of the installation costs. The "Station Modifications" tab in Appendix 1 contains detailed calculations and Appendix 5 Construction, Installation, Commissioning Cost Estimate contains details.

In the case of the process controllers used for liquid level control, KM evaluated replacing the existing constant bleed controllers with electric process controllers and level control valves. Quotes for the new equipment were supplied by an approved KM distributor. See Appendix 6 – Estimate for Electric Process Controllers. The "Station Modifications" tab in Appendix 1 contains detailed calculations.

List of Appendices

ATTACHMENT C

EPA has not given clear definitions or detail on the devices intended to be included in the rule. Below are suggested definitions which we believe to be useful for such a discussion.

a) EPA Process Controller Definition from 60.5430b
    i. "Process Controller means an automated instrument used for maintaining a process condition such as liquid level, pressure, delta-pressure, and temperature."
b) True (Traditional) Process Controller
    i. A device that is capable of actively controlling a process such as pressure, or temperature by use of a variable output, other means to provide throttling/variable control, or a snap acting output. Devices that only provide on/off logic or on/off outputs are not controllers. True process control devices commonly incorporate internal feedback loops, proportional and/or integral response adjustments, and other instrumentation common to control systems.
c) Piloted Valve Actuator
    i. A valve actuator (e.g. ball valve or gate valve) that is capable of making a determination to actuate when a given process condition reaches setpoint. This is accomplished via a mechanism integral to the actuator, such as a pilot. Often the actuation is made to direct gas flow, or stop flow entirely (e.g. over pressure protection), but not to throttle or incrementally control with variable output.
d) Remotely Controlled Valve Actuator
    i. A valve actuator that is not capable of making a determination to actuate; however, it is capable of actuating once a signal is received from an external control system (e.g. PLC or RTU). Often the actuation is made to direct the flow of gas, but not to throttle or control with variable output.
e) Dumb Valve Actuator
    i. A valve actuator (e.g. ball valve or gate valve) that is only capable of actuation when a local command is given, typically via a pneumatic push button or lever. This type of actuator is not capable of any control logic (remote or local) but may have limit switches installed such that valve position can be observed remotely.

Cost estimate associated with moving to zero bleed at an example station.

a) 20 devices are Shafer valve actuators that utilize full pipeline pressure to move valves quickly, usually in the range of 600-1400 psig. Readily available compressed air packages tend to become scarce above roughly 250 psig. Packages for a higher pressure compression option (1450 psig) is not readily available nor field tested for transmission pipeline pressure applications.

b) High pressure nitrogen bottles present multiple reliability, operational, and instrumentation challenges. In short, the EPA methane rule necessitates replacement of high pressure actuation with typical air pressure actuators (e.g. Bettis).

c) In the example, the scope of work includes replacing 20 actuators, installing new air lines to each new actuators, and adding the necessary associated equipment.

d) Bettis actuators were quoted by two different equipment vendors, and the lower cost option was used in the estimate. Specifications for these actuators were laid out to provide the closest functionality match as possible (e.g. manual override ability) as compared to the existing Shafer actuators.

Cost Summary for Example Compressor Station

Example costs to replace Shafer actuators with Bettis actuators Under EPA Methane rule		
Description	**Cost**	**Notes**
(2x) True Process Controllers	$10,000	Extend air lines
(4x) Piloted Valve Actuators	$164,102	All 4 of these are ESD actuators
(12x) Remote Control Valve Actuators	$516,773	Bettis actuators
(4x) Dumb Actuators	$167,560	Bettis actuators
Cost to install air lines across entire yard	$250,000	Budgetary estimate w/contractor & operations
(2x) Additional air tank/receivers in yard	$20,000	200 gallon tanks on concrete pads
Actuator installation cost	$100,000	Assume two installed per day
New Air Compression	$0	Existing air supply is adequate
Contingency (5%)	$61,422	5% of sub total
Grand Total	**$1,289,857**	

All Examples - Cost per metric ton calculation							
Description	**Total Gas Vented per year**	**Natural Gas Vented**	**Specific Volume**	**Kilograms**	**Metric ton natural gas**	**Cost to go Zero Bleed**	**Cost/ton**
	SCF/year	**m^3/year**	**m^3/kg**	**kg**	**ton**	**$**	
Example - True Process Controllers (4)	140,896	3,990	1.40	2,849.8	2.85	$10,500	**$3,684**
Example - Valve Actuators (20)	18,250	517	1.40	369.1	0.37	$1,279,357	**$3,465,870**
Example - Combined Total (24)	159,146	4,507	1.40	3218.9	3.22	$1,289,857	**$400,708**
EPA Reasonable Cost Effective Value							**$2,048**