UNITED STATES ENVIRONMENTAL PROTECTION AGENCY

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	)	**<u>Docket No. EPA-HQ-OAR-2023-0234</u>**
Greenhouse Gas Reporting Rule:	)	
Revisions and Confidentiality	)	*Via regulations.gov*
Determinations for Petroleum and	)	*October 2, 2023*[1]
Natural Gas Systems	)	
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	)	

We respectfully submit the following comments on EPA's proposed *Greenhouse Gas Reporting Rule: Revisions and Confidentiality Determinations for Petroleum and Natural Gas Systems*, 88 Fed. Reg. 50282 (August 1, 2023) on behalf of Environmental Defense Fund, Clean Air Task Force, Natural Resources Defense Council, Sierra Club, and Earthworks (together, "Environmental Commenters"). Our comments are informed by the urgent need to reduce emissions of methane and other harmful pollutants from the U.S. oil and natural gas sector and avoid the most catastrophic consequences of global warming by dramatically cutting greenhouse gas emissions. EPA's Greenhouse Gas Reporting Program (GHGRP) is important to understand the sources of emissions and approaches to mitigation. Ensuring the accuracy of information reported through the GHGRP can help to support policies that achieve the Biden Administration's commitment to reducing domestic greenhouse gas emissions by 50-52% from 2005 levels by 2030. Congress recently elevated the importance of accurate and empirically based reporting under subpart W of the GHGRP by enacting the Methane Emissions Reduction Program. We strongly support updates to subpart W, and we urge EPA to strengthen key provisions as discussed herein.

[1] Attachments submitted to Regulations.gov.

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INTRODUCTION

The GHGRP helps policymakers, stakeholders, and the public better understand domestic greenhouse gas emissions and how those emissions contribute to climate change. Data collected through the GHGRP, including the sources, magnitude, and distribution of greenhouse gas emissions across the country, inform decisions about how to address those emissions through legislation, regulation, and voluntary efforts. Emissions reported to the GHGRP cumulatively represent one of the largest drivers of global climate change. Understanding greenhouse gas pollution through high-quality, representative, and granular data is critical for developing effective policy solutions to abate this pollution. And reducing domestic greenhouse gas pollution is an urgent priority: the United States must cut emissions by at least half from 2005 levels by 2030 to remain on track for avoiding the most catastrophic effects of climate change.

The Inflation Reduction Act (IRA) is the most comprehensive congressional action to date addressing the climate crisis. This landmark legislation puts the U.S. on a path to achieve the Biden Administration's goal of cutting greenhouse gas emissions in half by 2030 and reaching net zero emissions by 2050. With the IRA's Methane Emissions Reduction Program (MERP), Congress acknowledged the major role that the oil and gas industry has played in the climate crisis, as well as the need to significantly reduce methane emissions from this sector to reach the Administration's climate goals. Congress thus established a new provision in the Clean Air Act (CAA)—section 136—which provides EPA with $1.55 billion to reduce methane emissions and establishes a waste emissions charge on methane emissions from applicable oil and gas facilities.[2]

Both components of MERP—the appropriations and the waste charge—assign implementation discretion and responsibility to EPA. The effectiveness of the waste charge, which is assessed on emissions reported to subpart W of the GHGRP, is contingent on the accuracy of reported data. In recognition of this, Congress included a directive in section 136(h) for EPA to update subpart W based on empirical data to ensure the accuracy of total emissions. We thank EPA for the work it has done to date to update subpart W, and the following comments provide additional suggestions to further strengthen the empirical basis and overall accuracy of reported emissions.

[2] 42 U.S.C. § 7436.

EXECUTIVE SUMMARY

- **Top-down data:** The incorporation of top-down, empirical data (site-level data and regional/basin-level estimates) is critical to assess the completeness and overall accuracy of emissions reporting. EPA can rely on this data to generate annual emission estimates that can inform further improvements to subpart W.
- **Large release events:** EPA should finalize reporting requirements for large release events, which contribute disproportionately to total emissions from oil and gas facilities and are not reflected through other reporting requirements. We urge EPA to ensure reporting of other large release events is required for all sites by expanding the types of information that would trigger reporting, supporting monitoring efforts, and developing a "k" factor for large releases.
- **Pneumatics:** EPA must mitigate concerns that would lead to inaccurate reporting by requiring all operators utilizing Calculation Methods 2 and 3 to install continuous metering for supply gas (i.e., Method 1) for a portion of their pneumatic equipment, and by requiring any operator to install additional continuous meters when deemed necessary by EPA. EPA should also strengthen measurement / monitoring standards for Calculation Methods 2 and 3.
- **Ownership transfer:** To track the emission impacts associated with ownership transfer, EPA should require sellers to continue reporting for retained and sold assets until certain conditions are met and track and publicly disclose all transactions.
- **Gathering pipelines:** EPA should adopt updated emission factors for gathering pipelines using newer studies that rely on measurements of gathering pipeline leaks. This will improve calculations of methane emissions from gathering pipeline leaks over the current and proposed approaches, which rely on older studies of gas distribution systems. EPA should likewise clearly specify that gathering pipelines are subject to reporting requirement for other large release events, as these events have been frequently observed from this infrastructure.
- **Plugged wells:** EPA should clarify how emissions from plugged wells will be accounted for, require operators to verify compliance with state and federal closure requirements before reporting a well as plugged, and apply its plugged well requirements to both onshore and offshore facilities.
- **Tanks, thief hatches, dump valves:** We support EPA's proposed approach to clarify and improve the treatment of open thief hatches and stuck dump valves. For open thief hatches, EPA should require the use of pressure monitoring systems to indicate that a thief hatch is open, as EPA has proposed to do for thief hatch sensors/alarms. EPA should consider requiring operators to utilize thief hatch sensors/alarms or pressure monitoring systems for a portion of their tank fleet, to increase the accuracy of emissions reporting for tanks. We do not support the addition of a new Calculation Method for tank emissions based on gas-to-oil-ratio (GOR).
- **Associated gas venting and flaring:** We strongly support requiring measurement of all gas directed to flares, especially for associated gas, which will avoid known issues and inaccuracies with using GOR to estimate volumes of gas flared.

- **Flare stack emissions:** We support the tiered approach to combustion efficiency, but EPA must ensure that operators using the higher combustion effectiveness in Tier 1 and Tier 2 demonstrate that they are properly implementing the standards required under NESHAP CC or OOOOb, respectively, whether those operators have a separate legal obligation to comply with those standards or not.
- **Compressors:** We support EPA's proposed revisions to reporting requirements for compressors.
- **Equipment leaks:** We largely support the proposed changes to equipment leak surveys and equipment leaks by population count, which will improve the accuracy of reported emissions from equipment leaks. For the leak survey method, EPA should require operators to measure and report emissions as a large release event if an operator has credible evidence or should reasonably suspect that emissions found during a leak survey would qualify as a large release event. We also encourage EPA to provide a pathway and set forth criteria for reporting emissions based on direct measurement by advanced technologies at the equipment level.
- **Offshore:** EPA should clearly extend the large release event reporting requirements to offshore facilities, where these events have been commonly observed and quantified by satellites. EPA should require operators to submit updated calculations for offshore facilities using BOEM's most recent calculation methods.
- **Throughput:** We support EPA's proposed updates to throughput reporting and calculation which will improve the accuracy and granularity of data.
- **Acid Gas Removal Units (AGRU)/Nitrogen Removal Units (NRU):** We largely support EPA's proposals for estimating emissions from AGRUs and NRUs. Methane emissions from AGRUs are a significant emissions source that companies were not previously required to report. And NRUs are also an important source of methane that were not previously accounted for. In both cases, the emissions calculation methodology should be clarified in specific ways to ensure consistency of reporting across operators.

LEGAL BACKGROUND

To ensure the waste emissions charge is accurately and effectively assessed on emissions from applicable facilities, Congress directed EPA to update methane emission reporting requirements under subpart W of the GHGRP.[3] The directive requires EPA to update subpart W to ensure that reporting is (1) "based on empirical data," (2) "accurately reflect[s] the total methane emissions and waste emissions from the applicable facilities," and (3) allows owners of reporting facilities "to submit empirical emissions data, in a manner to be prescribed by [EPA]."[4] EPA must satisfy these components to meet Congress's directive and fulfill the intent and requirements of MERP.

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[3] *Id.* § 7436(h).
[4] 42 U.S.C. § 7436(h). "Applicable facility" is defined in section 136(d) by cross reference to the facility definitions in subpart W of part 98 of title 40, Code of Federal Regulations. *Id.* § 7436(d).

In enacting MERP, Congress recognized that existing reporting requirements are inadequate for accurately estimating the emissions that are subject to the waste charge and sought to correct that through section 136(h).[5] Congress included a two-year timeline to ensure that emissions reporting rapidly moves to a more accurate approach in alignment with the timing of the waste charge. Congress also provided substantial funding to EPA under section 136(a), a portion of which can and should be used by the agency "to administer this section [including section 136(h)], prepare inventories, gather empirical data, and track emissions."[6] Consistent with the two-year timeline, EPA should move quickly to finalize the necessary updates. For the waste emissions charge to be most effectively and accurately implemented, reported emissions should align closely with actual observed emissions when the fee is assessed.

Even prior to the IRA's enactment, EPA had full authority under section 114 of the CAA to gather the information required under the GHGRP. That provision permits the Administrator to require emissions sources, persons subject to the CAA, or persons whom the Administrator believes may have necessary information to monitor and report emissions and provide such other information the Administrator requests "for the purposes of carrying out any provision [under the statute]."[7] The GHGRP is fully consistent with this authority. Section 136(h), however, goes further by *obligating* the Administrator to "revise the requirements of [subpart W of the GHGRP]" to ensure that MERP's waste charge provisions reflect "empirical data," including "the total methane emissions and waste emissions from the applicable facilities," and to "allow owners and operators of applicable facilities to submit empirical emissions data, in a manner to be prescribed by the Administrator[.]"[8] Thus, EPA *must* undertake a set of revisions to strengthen the subpart W, and must do so no later than August 16, 2024—that is, "2 years after the date of enactment of [the IRA]."[9]

METHANE REPORTING & ESTIMATION PRINCIPLES

Source-level data has been found to systematically underreport total emissions across the oil and gas supply chain.[10] While EPA's proposed empirically based calculation methodologies for

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[5] *See, e.g.*, Alvarez et al., *Assessment of Methane Emissions from the U.S. Oil and Gas Supply Chain*, 361 Science 186, (2018), https://science.sciencemag.org/content/361/6398/186; Amanda Garris, *Industrial Methane Emissions Are Underreported, Study Finds*, Cornell Chron. (June 6, 2019), https://news.cornell.edu/ stories/2019/06/industrial-methane-emissions-are-underreported-study- finds; International Energy Agency, *Methane Emissions From the Energy Sector Are 70% Higher Than Official Figures* (Feb. 23, 2022), https://www.iea.org/news/methane-emissions-from-the-energy-sector-are-70-higher-than-official-figures; Steven Mufson, *Oil and Gas Companies Under- reported Methane Leaks, New Study Shows*, Wash. Post (June 8, 2022), https://www.washingtonpost.com/climate-environment/2022/06/08/oilgas-methane-house-science-permian/.

[6] 42 U.S.C. § 7436(a)(4) (directing a portion of the $1.55 billion appropriation "to cover all direct and indirect costs required to administer this section, prepare inventories, gather empirical data, and track emissions.").

[7] *Id.* § 7414(a).

[8] *Id.* § 7436(h).

[9] *Id.*

[10] Alvarez et al., *supra* note 5; Brandt et al., *Methane Leaks from Natural Gas Systems Follow Extreme Distributions* (2016), https://pubs.acs.org/doi/10.1021/acs.est.6b04303; Zavala-Araiza et al., *Toward a Functional Definition of Methane Super-Emitters: Application to Natural Gas Production Sites*, 49 Env. Sci. Tech. 8167 (2015), https://pubs.acs.org/doi/pdf/10.1021/acs.est.5b00133.

individual sources will improve the quality and accuracy of emission estimates for those sources, incorporating top-down data at the regional and site-level is important for delivering comprehensive and accurate total emission estimates. Incorporating larger spatial scale, independent top-down empirical data (i.e., site-level and regional/basin-level estimates) is critical to assess the completeness and overall accuracy of reported emissions. Source-level emission estimates are valuable for supporting mitigation policies, but they do not fully capture total emissions at larger scales (e.g., all of the sites in a basin over the period of a year) since many emissions are from abnormal conditions (happening at a wide range of emission rates) that are difficult to categorize as a specific source.

As emissions change over time, empirically based, accurate reporting is needed to ensure that these changes are reflected in subpart W reporting. Currently, shifts in emissions are largely not included because most emissions are calculated using standard emission factors set by EPA. This will be addressed to some extent by the current proposal, which incorporates both required and optional measurement methods for many sources. However, EPA should continue to assess the adequacy of its reporting requirements by incorporating top-down data, collected through satellite, aerial, and other observational methods that ensure completeness across all sources of emissions. Using the top-down data as validation, EPA should propose additional updates to subpart W in the future to further improve accuracy and consistency with top-down measurement results. In this section, we describe principles and a framework that could guide EPA efforts to improve subpart W over time.

Role of top-down, regional-level estimates

Top-down empirical approaches can constrain total oil and gas emissions at the regional scale and are readily available for widespread deployment (i.e., aircraft, towers, and area-source data from satellites). When performed routinely (i.e., multiple measurements within one year),[11] they can provide the necessary assurance that aggregated emissions are accurately capturing all sources of emissions and are also reflecting emissions changes over time. There are also well-established methods of excluding methane emissions from non-oil and gas sources.[12]

Recent studies have highlighted the role of monitoring technologies in quantifying emissions from high-emitting point sources. These technologies are useful for understanding large point sources, as EPA has recognized with the proposed "other large release events" category, and also for guiding mitigation efforts. But the role of top-down technologies should not be restricted to characterization of single point sources. Data for high emitters is necessary but not sufficient since in many cases smaller sources contribute the bulk of the emissions across several basins. And if these smaller sources, which are below the detection limit of many technologies, are not

[11] Zavala-Araiza et al., *Toward a Functional Definition of Methane Super-Emitters: Application to Natural Gas Production Sites*, 49 Env. Sci. Tech. 8167 (2015), https://pubs.acs.org/doi/pdf/10.1021/acs.est.5b00133.
[12] Smith et al., *Exploring the influence of ancient and historic megaherbivore extirpations on the global methane budget*, 113 PNAS 874 (2015), https://www.pnas.org/doi/10.1073/pnas.1502547112; Neininger et al., *Coal seam gas industry methane emissions in the Surat Basin, Australia: comparing airborne measurements with inventories*, 15 Phil. Transactions of the Royal Soc. 379 (2021), https://pubmed.ncbi.nlm.nih.gov/34565226/.

adequately accounted for in existing emission factors or estimation techniques, they will be absent from the reported inventory.

Zavala-Araiza et al. (2017)[13] showed that in the Barnett Shale basin, production sites emitting less than 26 kg/hr (~99% of sites) accounted for two-thirds of total emissions from production sites. Notably, this study discusses the presence of abnormal conditions with emission rates well below 100 kg/hr, which are difficult to categorize as a specific source and are missing from inventories. Similarly, Omara et al. (2018)[14] estimated site-level emissions from production sites across several U.S. oil and gas production basins, finding that sites with emissions less than 100 kg/hr accounted for 90% of total emissions from production sites. They also found that 60% of total estimated emissions came from sites emitting less than 10 kg/hr. Incorporation of regional-level estimates is therefore needed to constrain total annual emissions and ensure that the contributions of all sources of emissions—large and small—are accurately captured.

Role of top-down, site-level measurements

Previous scientific studies have described how site-level data can be statistically aggregated and reconciled with basin-level top-down estimates.[15] While these methods will not provide information on the emissions of a particular site at a given time, they accurately characterize the emissions of group of sites in a given basin and should be considered for determining population-level emissions of subpart W facilities.

Scientific studies[16] have demonstrated how an accurate characterization of emissions distributions can be achieved when based on: 1) fit-for-purpose (e.g., low enough detection threshold to capture entire emissions distribution and not only high emitting sites); and 2) direct-measurement approaches that incorporate statistically representative and unbiased sampling to characterize (in the aggregate) the spatial and temporal variation in emissions across a population of sites.

While top-down site-level estimates for individual sites remain imprecise (i.e., due to temporal variability in emissions and other factors), readily available ground and airborne-based

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[13] Zavala-Araiza et al., *Super-emitters in Natural Gas Infrastructure Are Caused by Abnormal Process Conditions*, 8 Nat. Comms. 14012–21 (2017), https://www.nature.com/articles/ncomms14012. [hereinafter "Zavala-Araiza 2017"].
[14] Omara et al., *Methane Emissions from Natural Gas Production Sites in the United States: Data Synthesis and National Estimate*, 52 Env. Sci. Tech. 12915 (2018), https://pubs.acs.org/doi/10.1021/acs.est.8b03535.
[15] Alvarez et al., *supra* note 5; Zavala-Araiza et al., *supra* note 11.
[16] Omara et al., *Methane emissions from US low production oil and natural gas well sites*, 13 Nat. Comms. 2085 (2022), https://www.nature.com/articles/s41467-022-29709-3; Robertson et al., *New Mexico Permian Basin Measured Well Pad Methane Emissions Are a Factor of 5—9 Times Higher than U.S. EPA Estimates*, 54 Env. Sci. Tech. 13926—13934 (2020), https://pubs.acs.org/doi/abs/10.1021/acs.est.0c02927; Zavala-Araiza et al., *supra* note 11.

technologies can successfully characterize emissions distributions across the supply chain (e.g., for production sites,[17] compressor stations,[18] processing plants[19]).

Incorporation of site-level, population-based estimates is key to better constrain total emissions for different types of sites within a basin. For instance, this may include allocating emissions between production sites and gathering sites, or allocating emissions within different types of production sites.

Studies have also shown how these multi-scale reconciled data can then be used to assess completeness and improvements to source-level inventories.[20] Discrepancies provide information about larger uncertainties in terms of magnitude and location of emissions and help identify key sources that require further characterization, attention, and mitigation.[21] Thus, once the improvements in the current subpart W proposal have been implemented, EPA should compare the reported emissions to the top-down measurements (i.e., basin-level and site-level) and use the results of this assessment to guide future improvements to subpart W reporting. Notably, this could include improvements to specific source-level reporting requirements. Or, if there is no consensus on source-level improvements, basin-level or site-level scaling factors could be used to ensure that reported emissions match top-town measurements (i.e., similar to the "k" factor used for equipment leaks).

Multiscale top-down data can be used by EPA to produce empirically based, accurate, and complete emission estimates under subpart W

The following building blocks should be considered as a method for empirically and accurately characterizing total emissions:

1. **Independent quantification of total oil and gas emissions at the basin/sub-basin level:**
   - EPA and other federal agencies (e.g., NOAA) work to perform/coordinate/oversee routine (i.e., to characterize temporal variation of emissions and estimate yearly emissions) top-down measurements covering most oil and gas producing regions accounting for the overwhelming majority of oil and gas production.

[17] Robertson et al., *supra* note 16.
[18] Mitchell et al., *Measurements of Methane Emissions from Natural Gas Gathering Facilities and Processing Plants: Measurement Results*, 49 Env. Sci. Tech. 3219 (2015), https://pubs.acs.org/doi/10.1021/es5052809.
[19] *Id.*
[20] Rutherford et al., *Closing the Methane Gap in US Oil and Natural Gas Production Emissions Inventories*, 12 Nature Comms. 4715 (2021), https://www.nature.com/articles/s41467-021-25017-4#citeas; Zavala-Araiza 2017, *supra* note 13.
[21] Shen et al., *Satellite Quantification of Oil and Natural Gas Methane Emissions in the US and Canada Including Contributions from Individual Basins* 22 Atmos. Chem. Phys. 11203 (2022), https://acp.copernicus.org/articles/22/11203/2022/ (available at Attachment A); Alvarez et al., *supra* note 5; Neininger et al., *supra* note 12.

- Top-down approaches should be based on a set of previously peer-reviewed, scientifically robust approaches that characterize total regional emissions at the basin/sub-basin scale, including, aircraft,[22] towers,[23] and satellites.[24]
- Top-down approaches should incorporate robust attribution methods that allow separating emissions between oil and gas and other methane sources.

2. **Incorporation of population-based site-level empirical estimates:**
    - EPA coordinates the collection of site-level data.
    - Sampled sites should be stratified randomly within regions, industry segments, operator ownership, and types of sites to ensure representativeness. The number of samples should be sufficient to fully characterize—in the aggregate—the populations of emission sources.
    - EPA defines guardrails around what is considered high quality population-level empirical data.
    - Site-level measurement data is used to develop probabilistic, population-based models that characterize the entire emission distribution and extrapolate data to aggregate, regional emissions.

3. **EPA reconciles statistically aggregated site-level data with the regional-level data to produce robust and accurate basin default factors used by facilities in reporting.**

Top-down data is readily available (or soon will be) from a combination of independent research groups and service providers (e.g., MethaneSAT/MethaneAIR, Bridger Photonics, Scientific Aviation, Carbon Mapper). EPA should also consider intaking these data as part of its integration process to define the basin specific default factors.

Option for operators to provide self-reported site-level data

Operators could also be permitted to submit their own site-level empirical data, subject to specific requirements about data quality and previous validation of fit-for-purpose measurement-methods, as determined by EPA. These data could be used to prove that their company-level population-based emissions for a given basin are lower than the baseline average estimated by

[22] Karion et al., *Aircraft-Based Estimate of Total Methane Emissions from the Barnett Shale Region*, 49 Environ. Sci. Tech. 8124 (2015), https://pubs.acs.org/doi/full/10.1021/acs.est.5b00217; Peischl et al., *Quantifying Atmospheric Methane Emissions from the Haynesville, Fayetteville, and Northeastern Marcellus Shale Gas Production Regions*, 120 JGR Atmospheres 2119 (2015), https://agupubs.onlinelibrary.wiley.com/doi/full/10.1002/2014JD022697; Schwietzke et al., *Improved Mechanistic Understanding of Natural Gas Methane Emissions from Spatially Resolved Aircraft Measurements* 51 Environ. Sci. Tech. 7286 (2017), https://pubs.acs.org/doi/10.1021/acs.est.7b01810.

[23] Monteiro et al., *Methane, carbon dioxide, hydrogen sulfide, and isotopic ratios of methane observations from the Permian Basin tower network* 14 Earth Systems Sci. Data 2401 (2022), https://essd.copernicus.org/articles/14/2401/2022/.

[24] Shen et al., *supra* note 21.

EPA. Operators should be required to submit a sampling protocol—which should be approved by EPA before it is implemented—where they demonstrate that their sampling is statistically representative and unbiased and that the sampled site had no atypical abatement interventions prior to measurements. When such data is provided and utilized, it needs to be considered when the general basin-level emission factor is calculated to ensure that there is alignment with the top-down estimates and that basin-level accuracy is maintained. For example, if the emission estimates for one population of sites declines as a result of the operator's collection of site-level empirical data, the baseline factors for all other sites in the basin must increase to ensure consistency with wider-scale quantifications and to ensure accuracy.

RECOMMENDATIONS BY TOPIC & SOURCE

I. Incorporating Top-Down Data

In this section, we respond to questions posed by EPA about how top-down approaches can be used to generate annual emissions estimates for subpart W reporting facilities.[25] Top-down basin-level data can be used to estimate accurate annual emissions for subpart W reporting basins and facilities (including how to extrapolate to non-reporters and isolate segments). Below we respond to EPA's specific invitations for comment on this topic.

a. <u>How can snapshot in time top-down observations be used to estimate annual emissions?</u>

As with snapshot in time component-level observations that form the basis for emission factors, basin-level and site-level top-down observations can be reconciled and used to accurately estimate annual emissions across oil and gas production basins. Readily available aerial techniques using the mass balance approach can produce accurate annual emission estimates when based on multiple/frequent flights to characterize emissions from a given basin. While a basin-level estimate from a single airborne-based measurement (i.e., one single flight in one day) has significant uncertainty, Alvarez et al.[26] and Zavala-Araiza et al.[27] demonstrated how to reduce this uncertainty by performing multiple flights.

EPA should consider performing, coordinating, and overseeing routine overflights (i.e., multiple measurements within one year) to characterize temporal variation of emissions and estimate annual emissions. Similarly, studies have shown how satellite observations can be integrated across long periods of time (i.e., one year) to accurately estimate basin-level emissions.[28] In the near future, a next generation of satellites (e.g., MethaneSAT, Carbon Mapper, GOSAT-GW) with higher precision will further improve the characterization of basin-level emissions.

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[25] 88 Fed. Reg. 50291.
[26] Alvarez et al., *supra* note 5.
[27] Zavala-Araiza et al., *supra* note 11.
[28] Zhang et al., *Quantifying methane emissions from the largest oil-producing basin in the United States from space*, 6 Sci. Adv. 17 (2020), https://www.science.org/doi/10.1126/sciadv.aaz5120.

In addition, under appropriate conditions, EPA can employ the ergodic hypothesis, which assumes that measuring many similar sites at one point of time will be statistically equivalent to monitoring any one of those sites over a long period of time. Thus, with a large enough sample size at one point in time, you capture the net average emissions.[29] This would therefore be appropriate for estimating emissions from a basin with a large population of wells, assuming that the population was relatively homogenous with measurements conducted randomly. On the other hand, such a snapshot approach would not be appropriate for estimating emissions from a few large gas processing plants or a heterogeneous production basin. In the former case, multiple measurements would be required to accurately characterize emissions from a gas processing plant. And in the latter case, a stratified sampling strategy would be needed to ensure that each subgroup of production sites is relatively homogeneous.

b. <u>How can the data provided by top-down technologies at large spatial scales be disaggregated to the facility- or emission source-level?</u>

Characterization of total methane emissions can be done by reconciling basin-level and site-level emission estimates. Incorporation of top-down data does not need to be limited to the detection and quantification of high-emitting point sources. Basin-level data is also needed to constrain total emissions in a given basin. Site-level data can be used to characterize emissions for a population of sites, allowing disaggregation of emissions at the facility level while providing assurance that all emissions have been captured.

In the Permian basin, Robertson et al. collected site-level data that allowed for the characterization of two different populations of production sites: simple and complex.[30] Additional studies have provided constraints on total emissions from this production region based on basin-level estimates from satellite data[31] and towers.[32]

Alvarez et al. analyzed and synthesized site-level population-based data across several U.S. production basins (from production sites, compressor stations, and processing plants) and reconciled it with basin-level estimates.[33] Data was then used to derive accurate estimates of emissions characterizing facility-level emissions across basins. Further work from Rutherford et al. reconciled the top-down estimates with a source-level inventory.[34] This study compiled measurements at the source level and produced updated source-level emission factors that were reconciled with top-down data at the national scale. However, operational practices and the

[29] Veritas, *Measurement Protocol of Production Segment*, https://veritas.gti.energy/protocols (last visited Oct. 1, 2023).
[30] Robertson et al., *supra* note 16.
[31] Zhang et al., *supra* note 28. Shen et al., *supra* note 21.
[32] *See, e.g.,* Monteiro et al., *supra* note 23; Lyon et al., *Concurrent Variation in Oil and Gas Methane Emissions and Oil Price during the COVID-19 Pandemic*, 21 Atmospheric Chemistry and Physics 6605–26 (2021) https://doi.org/10.5194/acp-21-6605-2021.
[33] Alvarez et al., *supra* note 5.
[34] Rutherford et al., *supra* note 20.

proportional contribution of individual emissions sources can change over time, and verification from top-down data at larger spatial scales (i.e., site-level and regional/basin-level estimates), can be used to assess completeness and further ensure applied emission factors are representative.

The combination of basin-level and site-level data can ensure that overall emissions at the facility level are correct—in line with one of the main goals of the GHGRP. Disaggregating basin and site-level data to source-level is not needed to ensure the accuracy of total emissions. Discrepancies (between top-down and source-level data) provide information about larger uncertainties in terms of magnitude and location of emissions and help identify key sources that require further characterization and attention. While reconciliation between source-level and top-down data (i.e., reconciled basin-level and site-level) is useful for mitigation purposes—and can be achieved through a continuous improvement process—an accurate and empirical estimate of total emissions can be achieved based on the top-down data, in parallel to progressively reflecting updates and improvements in the source-level reporting.

c. <u>How can the different types of top-down data that have a wide range of detection limits and spatial resolution be reliably converted from point estimates to an annual emissions estimate as required by the GHGRP?</u>

Incorporation of top-down data should be based on peer-reviewed, previously validated, and fit-for-purpose technologies. At the basin-level, approaches should be able to capture total emissions from an entire region or basin. Studies have shown how this can be achieved with aircraft,[35] towers,[36] and satellites.[37]

At the site-level, approaches should be able to capture emissions from an entire population of sites. To achieve this, a statistically representative and unbiased sampling approach needs to be used and measurement technology should have sufficiently low detection thresholds to characterize the full emission distribution and not only the high emitting sites.

d. <u>How frequently do measurements need to be conducted to be considered reliable or representative of annual emissions for reporting purposes?</u>

The frequency of the measurements should be sufficient to characterize temporal variation of emissions and estimate annual emissions. Zavala-Araiza et al.[38] analyzed the uncertainty in top-down basin-level estimates resulting from daily variability in emissions in the Barnett Shale basin. They reported a significant reduction in uncertainty when shifting from single flights (i.e., snapshot measurement) to an estimate based on eight flights.

[35] Karion et al., *supra* note 22; Peischl et al., *supra* note 22; Schwietzke et al., *supra* note 22.
[36] Monteiro et al., *supra* note 23.
[37] Shen et al., *supra* note 21.
[38] Zavala-Araiza et al., *supra* note 11.

As discussed above, in the case of site-level measurements, the ergodic hypothesis can be employed to estimate emissions from a large number of relatively homogenous sites: measuring many similar sites at one point of time will be statistically equivalent to monitoring any one of those sites over a long period of time. But care should be taken to not over-apply the hypothesis in cases with small population sizes or heterogenous facilities—in those cases other sampling strategies must be employed.

e. What top-down approaches could be used to estimate annual emissions for any source categories under subpart W or for facility-level emissions?

Basin-level and site-level measurements can be used to estimate annual emissions at the facility level. Assurance and verification that all sources of emissions have been captured, can be achieved by incorporating site- and basin-level estimates. As mentioned earlier, allocating these top-down data to individual source-categories is useful for mitigation purposes and can be pursued through a continuous improvement process, however, the top-down data already provides on its own a complete and accurate picture of total emissions.

The main goal of the top-down data should be to produce a complete assessment of emissions across all sources. Specifically, approaches using aerial mass balance flights, vehicle-based measurements, tower networks, and satellite observations can be used to estimate total annual emissions. Some of these top-down approaches have the additional benefit—under certain conditions—of pinpointing a plume coming from a certain part of the facility or piece of equipment. When coupled with operational information, these detections can be used to improve source-based emissions estimates and measurements, as EPA has recognized.

f. What level of accuracy should be required for such use? Could the development of standards (either by the EPA or third party organizations) help inform this determination?

EPA can rely on peer-reviewed methods of estimating annual emissions at both the site and basin levels. These methods have been validated and used in multiple studies. EPA could work with other federal agencies, international bodies, and academic institutions to develop uniform methods and standards.

Development of guidelines and guardrails will be key for the operator's self-reported data (i.e., site-level data). These guidelines are needed to ensure that data collected by operators are sufficiently accurate. Operators should be able to demonstrate that their sampling protocol fully characterizes their population of sites.

g. In addition to the proposed use of top-down data to help identify and quantify super-emitter and other large emissions events, are there other appropriate uses of top-down data for the purposes of reporting under subpart W of the

<u>GHGRP? What types of emission sources and emission events could be captured and reported?</u>

As mentioned earlier, the main role of top-down data should not be limited to the characterization of super-emitters and large emission events, but also to provide an accurate and complete picture of total emissions (across all magnitudes of sources). This can be achieved by incorporating reconciled basin-level and site-level measurements.

In terms of identifying and quantifying large release events—as discussed in the following section— EPA could derive a "k" factor for other large release events based on top-down data characterizing the frequency, duration, and magnitude of these events across basins. EPA could then require reporters not monitoring for large release events to use the "k" factor in their reported emissions. As explained by EPA in the proposal, the other large release events category reflects emissions not reported through other provisions, and thus the addition of a "k" factor would likewise not lead to double counting.

h. <u>What are the best methods to estimate duration of events measured using top-down measurements and extrapolation to annual emissions?</u>

Methods to estimate duration typically involve repeat observations with enough precision and frequency to significantly reduce uncertainty. In the case of large emission events, studies have shown how this can be achieved based on satellite observations.[39] In the case of basin and site-level data—and as mentioned earlier—measurements performed with sufficient frequency can successfully characterize annual emissions.

i. <u>What associated modeling is necessary to incorporate top-down data and what are the associated uncertainties for calculating facility-level emissions?</u>

Several scientific studies have demonstrated how site-level measurements based on representative; unbiased sampling can be statistically analyzed to estimate emission distributions that can then be used to accurately estimate emissions at the facility level.[40] When these emission distributions are reconciled with basin-level measurements, they provide necessary assurance that all emissions on a given basin have been characterized. Alvarez et al. synthesized site-level data across several U.S. production basins and found, in the case of production sites, that the

[39] T. Lauvaux et al., *Global assessment of oil and gas methane ultra-emitters*, 375 Science 557 (2022), https://www.science.org/doi/10.1126/science.abj4351.
[40] Zavala-Araiza et al., *supra* note 11; Robertson et al., *supra* note 16; Alvarez et al., *supra* note 5; David R. Tyner & Matthew R. Johnson, *Where the Methane Is—Insights from Novel Airborne LiDAR Measurements Combined with Ground Survey Data*, 55 Environmental Science & Technology 9773–83 (2021), https://doi.org/10.1021/acs.est.1c01572.
Foteini Stavropoulou et al., *High Potential for CH 4 Emission Mitigation from Oil Infrastructure in One of EU's Major Production Regions* (Feb. 27, 2023) https://doi.org/10.5194/egusphere-2023-247. Omara et al., *supra* note 16.

resulting emission distribution had a relative uncertainty (95% confidence interval) of less than 30% from the central estimate.[41]

II. Large Release Events

We support the addition of a large release events reporting category and agree with EPA that these events are generally not captured through other reported sources. Large release events are part of the heavy tail present across the entire oil and gas supply chain, commonly referred to as "super-emitters." Large release events have a disproportionate contribution to total emissions from oil and gas facilities.[42] These events can be caused by malfunctions or from intentional operations, and it is well-documented in the scientific literature that they occur across the oil and gas sector and across site and equipment types.[43] Subpart W does not currently include calculation and reporting requirements for these large events, so the addition of this category is necessary to improve the accuracy of reported emissions.

a. Incentivizing monitoring and reporting

Requiring reporting of large release events that are observed through monitoring is necessary but not sufficient to ensure these emissions are fully captured in subpart W. Because methane monitoring across the oil and gas sector is currently limited to a small subset of sites and will not be required comprehensively across the sector for multiple years, limiting reporting for large release events to only those that are observed will continue to lead to underestimation. It may also disincentivize monitoring—if an operator can avoid reporting a large release, which may come with financial consequences once the waste emissions charge begins, the operator may avoid looking for those events in the first place. Operators using devices that do not immediately quantify emissions, like optical gas imaging (OGI) cameras, may also detect large release events but decline to quantify the emissions and avoid reporting. Third-party monitoring is likewise incomplete and occurs only in select basins at certain times, although it is expected to increase in coverage in the coming years.

To help ensure that reporting of large release events improves the accuracy and completeness of subpart W and encourages more monitoring and mitigation, we provide the following

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[41] Alvarez et al., *supra* note 5.
[42] *See, e.g.*, *id.*; Rutherford et al., *supra* note 20.
[43] Jacob et al., *Quantifying Methane Emissions From the Global Scale Down to Point Sources Using Satellite Observations of Atmospheric Methane*, 22 Atmos. Chem. Phys. 9617, 9617–46 (2022), https://acp.copernicus.org/articles/22/9617/2022/acp-22-9617-2022.pdf; Nat'l Aeronautics & Space Admin. Jet Propulsion Lab., *Methane 'Super-Emitters' Mapped By NASA New Earth Space Mission* (Oct. 25, 2022), https://www.nasa.gov/centers-and-facilities/jpl/methane-super-emitters-mapped-by-nasas-new-earth-space-mission/#:~:text=The%20plumes%20were%20detected%20by,20%20miles%20(32%20kilometers).&text=Methane%20absorbs%20infrared%20light%20in,with%20high%20accuracy%20and%20precision; Gorchov Negron et al., Airborne Assessment of Methane Emissions from Offshore Platforms in the U.S. Gulf of Mexico (2020), https://pubs.acs.org/doi/10.1021/acs.est.0c00179; Pandley et al., Satellite Observations Reveal Extreme Methane Leakage From A Natural Gas Well Blowout, 116 Proc. Nat'l Acad. Sci. 2376, 26376–81 (2019), https://www.pnas.org/doi/10.1073/pnas.1908712116; Zavala-Araiza 2017, *supra* note 13.

recommendations. First, EPA should broaden the scope of what is considered "credible information" that a large release event has occurred and must be reported. EPA should clearly include parametric monitoring data and other data available to the operator as credible information indicating an event. EPA has already recognized that this information can be used to determine the duration of a large release and should explicitly include it as credible information that would trigger the initial reporting obligation as well. Language in the proposal could be interpreted as only requiring reporting of large release events when they are detected using methane monitoring technologies, such as aerial or OGI surveys. However, many large release events will be discernable from other types of credible information, such as maintenance logs, tank pressure gauges, flow meters, and other types of operational data, as EPA has recognized. EPA should make clear in the final rule that if an operator has credible information that a large release event occurred through any type of operational data, monitoring data, or a combination, it must be reported. EPA should also make clear in the final rule that operators conducting leak surveys with Method 21 or OGI cameras must quantify leaks that could reasonably be large release events. For example, if an emission source saturates or exceeds the scale of a Method 21 instrument, that would be credible information that a large release event is occurring and should require measurement. Similarly, if an OGI operator observes a large plume, that would also be credible information and should require measurement to determine whether it is a large release event. We believe these clarifications will help align reporting requirements across sites that are monitored with various types of technologies and those that are not, improving accuracy and incentivizing monitoring.

Second, to ensure all reporters are required to report large release events, EPA should use funds appropriated through MERP to ensure comprehensive monitoring coverage across facilities and basins. Specifically, EPA should use MERP funds to support monitoring efforts (e.g., satellite remote sensing or aerial flyovers). Section 136(a)(4) specifically provides EPA with the directive to use a portion of the $1.55 billion appropriated to "prepare inventories, gather empirical data, and track emissions." EPA should focus these efforts on sites or regions known to have significant problems with large release events and those located near communities. EPA should work with entities monitoring methane emissions with satellites to ensure satellite detections are reflected in reported emissions. For example, EPA should work with satellite monitoring entities, such as NASA and the International Methane Emissions Observatory (IMEO), to ensure that large point source detections captured by satellite are included in reported emissions.

As another strategy to ensure accurate reporting of large release events across the sector, including from sites that are not regularly monitoring, EPA should develop a "k" factor for large release events. As EPA has recognized with equipment leaks, certain monitoring approaches are known to miss certain emissions and may require the use of a "k" factor to ensure completeness and accuracy. That is particularly true with respect to large release events due to the incomplete coverage of monitoring, as described above. Developing a "k" factor for large release events could be done by using basin-level emission estimates and leak rates or through an examination of recent scientific literature observing these events. Based on these data, EPA could discern the frequency of large release events at the site or facility level and develop a "k" factor representing the average size, duration, and frequency. For sites that are not regularly monitored, reporting large release events using the "k" factor would be required. This would help ensure that subpart W accurately reflects large release events from all facilities. EPA could likewise or alternatively require large release event reporting through a "k" factor at sites with equipment types that are known to cause large release events.

b. Defining "large release event"

EPA's proposed definition of "other large release event" specifies that it means "any planned or unplanned uncontrolled release to the atmosphere of gas, liquids, or mixture thereof, from wells and/or other equipment that result in emissions for which there are no methodologies" elsewhere in subpart W for estimating and reporting those emissions.[44] It also includes, but is not limited to, "well blowouts, well releases, pressure relief valve releases from process equipment other than hydrocarbon liquids storage tanks, storage tank cleaning and other maintenance activities, and releases that occur as a result of an accident, equipment rupture, fire, or explosion," as well as "failure of equipment or equipment components such that a single equipment leak or release has emissions that exceed the emissions calculated for that source using applicable methods" provided elsewhere in subpart W.[45] EPA has further specified that other large release events include planned releases, such as those associated with maintenance activities for which there are no emission calculation procedures in subpart W, like emptying, degassing, and cleaning a tank.

We support EPA's proposed definition because we believe it properly encompasses both emission sources and emissions of large magnitude that are not otherwise reflected in subpart W's reporting protocols (e.g., compressor slip far exceeding what would be calculated and reported through the applicable methodology). The proposed definition specifically excludes emissions that would be reported through methodologies for other sources and thus will not lead to any double counting of emissions. We believe the addition of large release events in subpart W, if reported accurately and comprehensively across the sector, will provide critical information that can be used to improve understanding of emissions and support mitigation of such large emitting point sources—especially those located nearby communities.

Offshore platforms and equipment should also be specifically subject to large release event reporting requirements. Large emission events have been observed at offshore platforms, and satellites and other top-down monitoring technologies are readily able to observe and quantify these events which should then be reported under subpart W. For example, a 2022 study using satellite observations quantified emissions from a 17-day ultra-emissions event at a Gulf of Mexico platform that released 40,000 metric tons of methane.[46] Another recent study

[44] Proposed 40 C.F.R. § 98.238.
[45] *Id.*
[46] Irakulis-Loitxate et al., *Satellites Detect a Methane Ultra-emission Event from an Offshore Platform in the Gulf of Mexico,* 9 Env. Sci. Tech. 520 (2022), https://pubs.acs.org/doi/pdf/10.1021/acs.estlett.2c00225.

demonstrated a technique to measure methane plumes as small as 180 kg/hr in the Gulf of Mexico off the coast of Louisiana using data from the GHGSat satellite constellation.[47]

c. Emission threshold

We support EPA's proposed 100 kg/hr emission threshold for large release events because it aligns with the scientific literature and with other regulatory programs, including the Super Emitter Response Program in EPA's proposed section 111 methane regulations for the oil and gas sector. An emission rate of 100 kg/hr is a very significant event and would not be reflected in calculation methods for other sources included in subpart W. These events are likewise the most harmful from an environmental and safety perspective and should be reported through the large release events category so that the public is aware and so operators are incentivized to eliminate them.

Data from satellites, which today generally have detection thresholds around 1000 kg/hr, would qualify as credible information requiring reporting under subpart W. We strongly support the inclusion of these data, as satellites can cover large geographic areas repeatedly, enabling highly accurate quantification of emissions by use of observed duration and magnitude through the entire course of the large release event. Satellite detection capabilities are also expected to improve over time, which would enable detection of large release events below 1000 kg/hr, further improving the accuracy of emissions reported under subpart W.

We agree with EPA that an event releasing 250 metric tons of CO_2e over the course of a few days or week should be considered a large release even if the rate is below 100 kg/hr and urge EPA to not increase this threshold. As EPA notes, the proposed threshold is equivalent to approximately 500,000 standard cubic feet (scf) of pipeline quality natural gas, which corresponds to the typical emissions associated with events EPA has defined as large releases. For example, uncontrolled completions often meet or exceed this threshold, as do well blowouts. The threshold also aligns with reporting requirements under subpart Y for petroleum refineries, and like those requirements, we urge EPA to include a time limit for large releases based on the cumulative mass threshold.

We recommend that EPA finalize the 100 kg/hr emission rate threshold, paired with the duration calculations, in defining large release events. EPA should likewise place a time limit on the proposed cumulative mass threshold definition for large release events.[48] Without defining a specific time period, the additional 250 metric tons of CO_2e threshold could cause confusion for operators about how to report when a small leak that has lasted for a significant period of time reaches this threshold. A cumulative mass threshold should be time-limited to avoid situations in

[47] MacLean, J.-P. et al., *Offshore methane detection and quantification from space using sun glint measurements with the GHGSat constellation,* EGUsphere [preprint] (2023), https://doi.org/10.5194/egusphere-2023-1772.
[48] For example, EPA could rely on the average duration of the events EPA cites as constituting large releases, like blowdowns and completions.

which a small leak that is more appropriately reported through other provisions may need to be reported as a large release event.

d. Duration

We support EPA's proposed duration assumptions and the flexibility and incentives provided to operators to identify duration through monitoring and operational data. EPA is proposing that the start time of the large release must be determined based on monitored process parameters, such as pressure or temperature, for which sudden changes in the monitored parameter signals the start of the event. If the monitored process parameters cannot identify the start of the event, EPA is proposing that reporters must assume the release started on the date of the most recent monitoring or measurement survey that confirms the source was not emitting at the rates above the other large release event reporting thresholds or assume the duration of the event was 182 days (six months), whichever duration is shorter. To identify the start date, EPA is proposing to allow monitoring or measurement surveys to include methods specified under the GHGRP as well as advanced screening methods such as monitoring systems mounted on vehicles, drones, helicopters, airplanes, or satellites capable of identifying emissions at the thresholds specified for a large release event.

We support EPA's proposed requirements surrounding the duration of large release events. Allowing operators to use monitoring data and reliable parametric data to identify the start of the event will allow for accurate quantification of these emissions. We encourage EPA to audit and carefully review the data used to support durations shorter than the default to ensure reliability. We likewise support EPA's default duration assumption. Without data supporting a shorter timeframe, it's possible that large release events could occur for even longer than the default duration. Large release events have commonly been observed to last long periods of time. Using 182 days is a reasonable timeframe and will help encourage operators to keep reliable data and conduct regular monitoring to ensure these events do not occur or are caught early. We support EPA's proposal to require a confirmed repair or end to the event as the end-date used in reporting.

e. Combustion assumptions

EPA has proposed that reporters must estimate the portion of the total volume of natural gas in a large release event that was combusted in an explosion or fire to determine the average composition of emissions released. For the portion of natural gas released via combustion in an explosion or fire, EPA is proposing a maximum combustion efficiency of 92% be assumed. We believe that combustion in fires and explosions is likely far lower than 92%, which is the average combustion efficiency of a flare that is designed to destroy methane. Unless there is evidence supporting a combustion assumption greater than zero for explosions and fires, such as an operator's own monitoring data, we recommend that EPA not allow use of a combustion efficiency assumption for large release events. If EPA decides to provide a combustion efficiency assumption, it should be 50% or less in the absence of evidence showing greater combustion.

f. Additional reporting requirements

We support the additional proposed reporting requirements for large releases because we believe they will provide valuable data to improve the accuracy of subpart W to help operators and other stakeholders to understand these events. Requiring reporters to provide the location, a description of the release, a description of the technology or method used to identify the release, volume of gas released, volume fractions of CO_2 and methane in the gas released, and CO_2 and methane emissions for each “other large release event” is all information critical to ensure the accuracy of reported emissions. This information should all be readily accessible and reportable as well, posing minimal burden to reporters.

Similarly, the start date and time of the release, duration of the release, and the method used to determine the start date and time are all essential pieces of information that must be reported to ensure accuracy and transparency. EPA is also proposing that reporters provide a general description of the event and indicate whether the event was also identified as a potential super-emitter emissions event under the proposed Super Emitter Response Program. We support these requirements and urge EPA to make clear that third-party notifications of large release events would require those events to be reported by the operator, regardless of whether the source causing the emission is formally subject to the Super Emitter Response Program. In this case, we also support EPA’s proposal to require the reporter to provide the name of the notifier, the remote sensing method used, the date and time of the measurement, the measured emission rate, and uncertainty bounds on the emission rate, if provided by the notifier.

We also support ensuring that reporters can only exclude from reported emissions those coming from third-party notifiers when the reporter provides valid, well-documented reasons for doing so. To do this, the reporter should be required to submit evidence of a site survey occurring shortly after the notification proving that the event did not occur or come from their site, including time-stamped parametric data from the site showing that normal operating conditions existed. If there is imagery that clearly shows an event at the reporter’s site with a quantified, time-stamped emission rate, it should not be rebuttable by the reporter. If the reporter seeks to exclude large release events stemming from a third-party notification, they should likewise be required to submit operational data and monitoring data for the entire site in support. If an operator claims the emissions are accounted for elsewhere in subpart W reporting, they should be required to submit parametric monitoring data and document where and how the emissions detected were reported to EPA.

III. Pneumatic Devices

Pneumatics are currently the largest reported source of methane from oil and gas under subpart W. Any changes to the reporting requirements for this emission source will have a potentially significant impact on overall emissions reported. Currently, emissions from pneumatics are calculated based on equipment counts, hours of operation, gas composition, and default emission factors for high, intermittent, and low bleed controllers. There are clearly shortcomings with this approach, although it has the benefit of being simple and allows comparison of emissions across companies (aside from the different interpretation of "operational hours", which EPA seeks to remedy in its current proposal and which we discuss below). Shifting from this emission factor approach to an estimation approach based on measurement can lead to a more comprehensive understanding of emissions from this source. In the case of emissions measured by continuously metering supply gas for pneumatic controllers (Calculation Method 1), these measurements will provide high quality data on emissions. But we have serious concerns about how these measurement methods, particularly those based on measurement or monitoring by operators (Calculation Methods 2 and 3), will be implemented.

Because of the importance of this source, it is essential that EPA's protocols lead to accurate assessment of emissions from the source, *in practice*, not just in theory. EPA must recognize that with the waste emissions charge in place, operators will have incentives to under-report emissions when the implementation of the rules can be manipulated or the rules can easily be broken. Therefore, we urge EPA to ensure that the final rule is robust with respect to under-reporting by operators. In addition, it must have procedures in place to audit and identify reports with anomalously low emissions from pneumatic equipment, and to meaningfully follow-up with reporters when, based on this information, there is reason to believe their individual reports are unrealistically low for this source. These measures should include approaches such as examining submitted data for outliers, requesting additional information from operators, inspecting facilities, and requiring operators to increase the use of continuous monitoring. EPA should also require that all operators install continuous monitoring meters on supply gas (Calculation Method 1) for a small, representative portion of their pneumatic controllers. Since emissions from these controllers can be compared to the emissions from other controllers, which are assessed using other Calculation Methods, this will provide valuable insight into how well operators are implementing the other Calculation Methods. Furthermore, and as we discuss further below, we suggest that EPA amend the regulatory language for Method 1 to allow EPA to require that individual operators install flow meters upstream of pneumatic controllers and/or pumps at certain sites, should it deem that to be necessary as a result of non-credible emissions reports or failure on the part of operators to adequately respond to questions from EPA about submitted data.

We strongly support EPA's goal of moving from default emission factors to measurement, although in a number of cases, we recommend strengthening EPA's proposed monitoring and measurement methodologies. While we recognize that this may increase cost, it is important that operators are able to choose among 4 methods at most sites.

It is likewise critical to consider that these methods, and the costs associated with using them to calculate emissions, are not applicable to *all* controllers. Operators that use non-emitting technology such as electric controllers/actuators/pumps or pneumatic equipment driven by compressed air instead of natural gas can entirely avoid the cost of monitoring, measurement, and reporting for pneumatics. Two states (Colorado and New Mexico) have already required operators to begin retrofitting venting gas-driven controllers at sites to eliminate emissions, and no longer allow installation of venting controllers at new sites. Moreover, EPA has proposed that almost all new and existing pneumatic controllers nationwide utilize such technologies (with a limited exception in Alaska). In addition to increasing the accuracy of reporting emissions associated with non-emitting equipment, replacing controllers with non-emitting technologies reduces maintenance costs, increases sales of gas that would otherwise be vented, and sizably reduces pollution levels.

Given the magnitude of emissions from controllers and the challenges in accurately quantifying them, and the in light of the feasibility of replacing controllers and the availability of other calculation methods under the rule, EPA should ensure that measurement methodologies are adequate.

a. Method 1: Support the addition of a continuous monitoring option

We support EPA's creation of a new Calculation Method 1 for pneumatic devices and pneumatic pumps that would give operators an option to measure emissions by metering the supply gas for the controller(s) and/or pump(s) at a site. This equipment has emissions that vary over time and can have significantly different emissions year to year or even hour to hour due to changes in production or other operating conditions. One study published in 2019 noted that "[s]ampling simulations also indicate that measurements of ≥24 h are necessary to quantify emissions to within 20% [11−31%] of a [pneumatic controller's] long-term average emissions."[49] Therefore, continuous monitoring of device supply gas is the best way to accurately measure these emissions. However, we recognize that it may be challenging or infeasible to rapidly implement continuous metering of supply gas at all sites with gas-driven pneumatic equipment, and therefore it is appropriate to provide additional methods that can be used to calculate these sources' emissions.

While we generally support the flexible approach that EPA has proposed, in the final rule, EPA should require all reporters to deploy Method 1 measurements at a small representative fraction of their pneumatic controllers. This representative sample should include high bleed, low bleed, and intermittent bleed controllers if operators have all three of them in operation at the facility, and amongst intermittent controllers, it should include controllers with high actuation frequency, low actuation frequency, and emergency shut down controllers (see more about these 3 categories of intermittent controllers in our comments on Methods 2 and 3, below). Information from these metered controllers can be used by EPA to refine default emission factors in future subpart W updates. In addition, it would provide a very valuable point of comparison when evaluating the accuracy of emission reports based on the other calculation methodologies (i.e., if

[49] Luck et al., *Multiday Measurements of Pneumatic Controller Emissions Reveal the Frequency of Abnormal Emissions Behavior at Natural Gas Gathering Stations*, 6 Environ. Sci. Technol. Lett. 348–52, at 348, https://pubs.acs.org/doi/10.1021/acs.estlett.9b00158.

there is a consistent pattern of controllers measured with Method 1 having different emissions than those calculated with other Methods EPA can propose ways to rectify). Additionally, EPA should clarify that it has discretion to require specific operators to increase the use of Method 1 (that is, install more supply gas meters) at specific sites or in general if, in EPA's judgment, those operators have submitted emissions reports that do not adequately represent all emissions or have failed to adequately respond to questions from EPA about submitted data.

At a minimum, if EPA provides default emissions factors for intermittent controllers under Calculation Method 4 (as we support) and given the serious concerns about data manipulation for Methods 2 and 3 that we discuss below, EPA should require any operator using Method 2 or 3 to meter a portion of their controllers. Under this approach, operators who find it infeasible or expensive to utilize supply gas metering could utilize Method 4.

b. Methods 2 and 3: Concerns about potential manipulation and abuse

Both Calculation Method 2 and Calculation Method 3 are quite vulnerable to manipulation of the methodology that would allow reporting that systematically and significantly underestimates emissions. Given the huge volume of emissions from pneumatic equipment, it is critical that EPA design this rule, and the program implementing it, to prevent as many forms of manipulation, gaming, or outright cheating as possible, and deal with it effectively when EPA discovers it.

We recognize the potential value of Methods 2 and 3 since, if implemented as intended, they should ultimately incentivize operators to maintain pneumatic equipment better in order to reduce emissions. (We note that those incentives will work much better under Method 1.) Nevertheless, the potential for abuse of these provisions is very concerning. Given what we know about the prevalence of malfunctions at intermittent pneumatic controllers, if EPA finalizes Calculation Method 2 and/or Calculation Method 3, it must conduct a thorough desk audit of company reports. EPA will have at its disposal a huge amount of data, including information on the total number of controllers and malfunctioning controllers at each facility (and well-pad). Footer et al. (2023) found a malfunction rate of 33-71%[50], Luck et al. (2019) found a malfunction rate of 63% (25 of 40),[51] and Tupper et al. (2019) found a malfunction rate of 38% (99 of 263).[52] Given these well-documented very high malfunction rates, if companies employing Method 2 or 3 report malfunction rates that do not comport with this previous science, EPA has a reasonable basis to question the validity of the reports and request more information. Operators may be able to point to increased controller maintenance that justifies the lower leak rate, which would be a welcome development, but EPA should not accept low

[50] Footer, T. L. et al., *Evaluating Measurement natural gas gathering emissions from pneumatic controllers from upstream oil and gas facilities in West Virginia,* 17 Atmospheric Environ. 100199 at Table 2 (2023), https://doi.org/10.1016/j.aeaoa.2022.100199. Both Category B and Category C are considered malfunctions. Range represents study's Low and High Limit assumptions.
[51] Luck et al., *supra* note 49.
[52] Tupper, P, *API Field Measurement Study: Pneumatic Controllers,* Presented at the EPA Stakeholder Workshop on Oil and Gas, Pittsburgh, PA (November 7, 2019) (available at Attachment B).

malfunction rate reports without adequate justification and documentation. If EPA is not satisfied by explanations provided by operators, the agency should further investigate the matter using the full range of its authorities, and, as described above, should consider requiring the operator to meter supply gas for some or all of its pneumatic equipment.

EPA must also strengthen the proposed rules to prohibit operators from artificially reducing their reported overall emissions by systematically reducing emissions from the specific subset of controllers that are to be measured or monitored in a particular year prior to undertaking the measurement or monitoring campaign. Given the five-year cycle for measurement or monitoring, this type of gaming could dramatically lower an operator's reported emissions, while the reductions that an operator makes (by reducing emissions through maintenance activities) would only slightly reduce emissions.

For example, under Calculation Method 2, an operator with 50 similarly sized sites would be required to measure emissions from controllers at 10 of these sites in the first year of application of the new subpart W rules. The operator might choose to carry out a “pre-inspection” of these 10 sites a short time before the formal measurements, which are needed to comply with the GHGRP pneumatics provisions, are carried out. If the operator discovers any problems during the pre-inspection and fixes them before the formal GHGRP measurements take place, then the problems will not be documented in the formal measurements. While there is a benefit from fixing some individual problematic controllers, the result is that the reported emissions from the operator’s pneumatics would be dramatically underestimated every time this occurs.

First, while the measured emissions would be accurate for the controllers as observed, the reported emissions would neglect the excess emissions that had occurred before the pre-inspection.

More importantly, the operator has not done anything to address excess emissions from controllers at the 40 sites that are not being measured during the first year, but due to the artificially low rate of reported malfunctions at the 10 measured sites, Calculation Method 2 will estimate low malfunction rates at these 40 sites (in addition to the 10 measured sites).

Similar manipulation could clearly occur under Calculation Method 3. To our understanding, this type of manipulation / gaming would not violate the proposed standards but would badly undermine the intention of the program.

This is not a far-fetched concern, because many of the ubiquitous pneumatic controller malfunctions are quite easy to fix. In Colorado, a survey of oil and gas producers subject to the state’s “find and fix” rules for pneumatic controllers found that, out of a sample of 193 identified malfunctions of controllers, 26% of malfunctions were repaired immediately, and 48% were repaired on the day the problems were identified.[53] Footer et al (2023) note that the frequency of

[53] CO. Dept. of Pub. Health and Environ., Pneumatic Controller Task Force Report to the Air Quality Control Commission (June 1, 2020) (available at Attachment C).

malfunctions in the controllers that they studied cannot be considered typical, because the controllers had been manually actuated a short time prior as part of LDAR inspections, and this simple act of manual actuation "resets" controllers in a fashion that often reduces continuous emissions from intermittent devices.[54] While it is not clear for how long these simple fixes actually reduce emissions (before malfunctions recur), it is probable that they reduce emissions for a few days—long enough for the measurements/monitoring required under Calculation Method 2 or 3 to occur.

To be clear, we do not in any way oppose genuine efforts to reduce emissions by fixing problems with pneumatic controllers, and it is important that if operators are able to reduce emissions systematically through careful application of voluntary measures or regulatory procedures such as those required under CAA Section 111 rules, those reductions should be reflected in GHGRP reports. Our concern is that under the current reporting standards, some of the reports EPA receives may be distorted for this source if operators carry out such repairs at the subset of sites subject to measurement / monitoring to comply with Method 2 or 3 in the period preceding the measurement / monitoring.

If EPA finalizes Method 2 or 3, it must strengthen the provisions to prohibit operators from distorting their reported data in at least the following ways:

- Directly address the issue of timing pre-inspections and repairs before formal measurement and monitoring efforts to comply with GHGRP are carried out, including repairs conducted to comply with state or federal regulations;
- Ensure that measurements are done randomly with respect to repairs; and
- Require operators to report the date of measurements / inspections performed for Calculation Method 2 or 3, and the date(s) of *any* repairs performed on pneumatic controllers, including "resetting" controllers by manually actuating them.[55] This includes repairs performed to comply with state or local regulations. While this information would not be used to calculate emissions, it would be essential to ensure that operators are not manipulating results of Calculation Method 2 or 3 by repairing malfunctioning controllers shortly before inspecting them or measuring their emissions.

As mentioned above, EPA should require all operators (and especially all operators utilizing Method 2 or 3) to meter the supply gas to a small sample of the operator's controllers, which will provide robust data on emissions from some of those devices. This can serve as a good comparison point for emissions assessed with Calculation Methods 2 and 3, giving insight into whether those results are reasonable.

c. Method 2: Volumetric flow rate based on 15-minute measurement

[54] Footer, T. L. et al., *supra* note 50.
[55] *Id.*

In its proposed Method 2, EPA allows operators to measure the volumetric flow rate of continuous- and intermittent-bleed pneumatic controllers for 15 minutes (or 5 minutes for isolation valves). If emissions are observed, EPA instructs operators to extrapolate measurements to the entire year based on the number of hours the controller is in service (i.e., pressurized).

We support this approach for continuous bleed controllers, although EPA must require operators to use proven measurement technologies/approaches, as described below, to prevent them from using inappropriate techniques or technologies that will tend to miss much of the emissions from controllers. Additionally, EPA must ensure that measurements are timed so that they are representative of average emissions from these devices and are not distorted by the repair timing issues discussed above.

For intermittent controllers, however, in addition to addressing the issues concerning measurement technology/approach and repair/measurement timing, EPA should lengthen the required measurement time. Should EPA choose to finalize Method 2 for intermittent controllers, it should significantly improve it to reduce these flaws. However, it is important to note that these flaws cannot be eliminated.

Measurement technologies/approaches

EPA proposes to allow measurement of emissions from pneumatic controllers using any one of the methods in (existing) 40 C.F.R. § 98.234(b), (c), or (d). The challenges of measuring emissions from all pneumatic controllers are well-documented, and result from factors such as the intermittency of emissions and the fact that emissions can emanate from many points on the controller, tubing, actuator, and housing for these devices. For instance, emissions may come from components with varied topology and orientation, that are physically connected with other devices in complex ways. To our knowledge, recent successful studies of pneumatic controller emissions have exclusively used either high flow samplers or metering upstream of the controllers to quantify emissions. In contrast, EPA proposes to allow operators to use temporary meters, calibrated bags, or high-volume samplers to measure emission rates from pneumatic controllers, without providing any appropriate criteria for the use of these measurement approaches. For example, the rule text does not require metering of gas to be performed upstream of the controller, even though it is very difficult to ensure that all gas from a controller is directed through a meter. The proposed rule text also does not limit the back pressure from meters, yet if this back pressure is too high, it will decrease the vent rate of some controllers. For calibrated bags, EPA has provided no criteria to ensure that operators use an appropriate size bag and capture all emissions from the bag are provided.

For measurements of either continuous or intermittent controller emissions, EPA should require that operators either use meters upstream of pneumatic equipment or high-volume samplers, in keeping with the methods that recent research has demonstrated to be effective for measuring emissions from this equipment. Furthermore, when flow meters are used, they should be accurate over the range of emission rates commonly seen from pneumatic equipment (i.e., below 1 scf per hour to over 150 scf per hour) without impeding flows at the higher flow rates.

Measurement time

Based on recent studies, the 15-minute measurement period is appropriate for continuous controllers. In Luck et al, of the 32 continuous bleed controllers studied, five were found to be malfunctioning, but in all five of these cases the malfunction would have been apparent in the first 15 minutes of observation.[56] This demonstrates that the chosen monitoring period is sufficient to capture continuous bleed controllers that are emitting more than they are designed to. Therefore, we support EPA's proposed measurement period in Calculation Method 2 for continuous bleed pneumatic controllers.

However, we have concerns that the same time period is inappropriate to capture abnormally operating intermittent controllers, given the varying time between those controllers' actuations. EPA has proposed to allow operators to estimate emissions for intermittent controllers with no emissions observed during the 15-minute period using a parametric approach: the volume of the controller, tubing, and actuator multiplied by the number of actuations per year, based on company records. This should be a reasonably accurate method for controllers that are functioning properly, but it would significantly underestimate emissions of controllers that are actually malfunctioning. To reiterate, malfunctions are very common for pneumatic controllers. Some intermittent controllers malfunction by emitting continuously, but others emit excessively during actuation and then return to emitting little or no gas between actuations. As described below in our comments on Method 3, Luck et al. (2019) observed this behavior in 20% of the intermittent controllers they studied.

Since it is important for the measurements used for Calculation Method 2 to properly account for emissions from malfunctioning controllers, it is important that the method require measurements that are long enough to observe a significant portion of malfunctions.

The frequency at which intermittent controllers actuate varies widely, based on their purpose, operating conditions, and other factors, from "minutes to hours" for gas processing unit liquid level controllers, to "hours to days" for temperature and pressure controllers, to "monthly to yearly" for emergency shutdown controllers. Rather than treating all intermittent controllers the same, EPA should increase the accuracy of and reduce uncertainty in its emission estimation protocol by taking actuation frequency into account, requiring longer measurements at controllers that actuate more frequently. To some extent, the function of the controller and/or the equipment it is installed on can be used as a proxy for actuation frequency. We summarize the approach we propose in Table 1.

[56] Luck et al., *Methane Emissions from Gathering and Boosting Compressor Station in the U.S. Supporting Volume 1: Multi-Day Measurements of Pneumatic Controller Emissions*, Co. State Univ. (2019), https://mountainscholar.org/handle/10217/194543. (see controllers I-2, J-2, J-6, D-3, and J-4.)

Table 1: Method 2 purpose-based measurement interval for intermittent controllers

Type	Number of actuations per year	Measurement interval required
High actuation frequency (e.g. gas processing unit liquid level controllers or separator dump valve)	>8,760	Until actuation cycle is observed
Low actuation frequency (e.g. temperature and pressure controller)	12-8,760	1 hour (or until actuation cycle is observed)
Emergency shutdown (ESD) controllers	<12	15 minutes (or until actuation cycle is observed)

Operators should assume that any controller associated with a gas processing unit or separator dump valve is high frequency unless they have evidence to the contrary. While this does not guarantee that every malfunctioning intermittent controller will be observed, it would increase accuracy and reduce uncertainty significantly.[57]

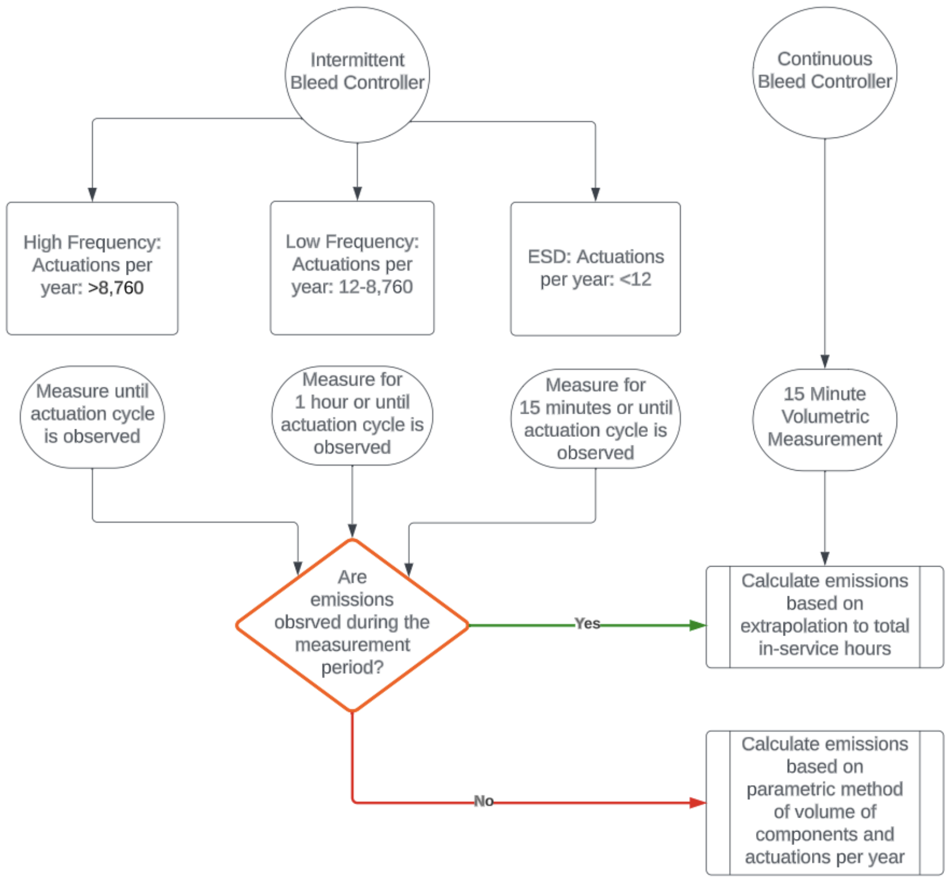
With these changes in measurement time, we support the balance of EPA's proposed methodology. For controllers with measurable emissions, operators calculate emissions using the volume of gas emitted during the measurement, the ratio of operating hours to the length of the measurement period, and gas composition. If no emissions are measured from the controller during the measurement period (this would now only apply for low actuation frequency and emergency shutdown device (ESD) controllers), the operator should calculate emissions based on parametric method of volume of components and actuations per year.

Along with the differentiated measurement intervals for intermittent controllers depending on the frequency of actuation, we propose a different survey cycle depending on frequency of actuation. For intermittent controllers with a high actuation frequency (i.e., more than 8,760 times per year), which have higher overall emissions and potential for malfunction, measurements should be conducted once a year. For all other intermittent controllers, EPA's proposed cycle length is appropriate. We recognize that this shortened cycle would significantly increase the

[57] We recognize that if perfectly implemented over a large number of controllers, Calculation Method 2 would obtain a valid estimate of emissions for the population of controllers. While it would miss actuation from many controllers that do not actuate in the period of observation, it should capture emissions from a small number of infrequently actuating controllers that happen to emit during the measurement period. When emissions for those controllers are extrapolated to the whole year, they will be very high (higher than actual), but when averaged with the many controllers not seen actuating (despite the fact that they do actuate at some point), the overall population emissions estimate should be correct. However, this methodology depends upon operators reporting these results accurately. We are concerned, because the operator is reporting emissions for a single controller that are much higher than expected from that controller. It is questionable whether all operators will carry this out faithfully.

measurement requirement. However, this increase would only be required at intermittent controllers with very high actuation rates — that is, more than 8,760 times per year. Furthermore, there are cost-effective solutions to replace gas-driven controllers with non-emitting options. This has been required in two states (Colorado and New Mexico) and would also be required by EPA's OOOOb/c proposal.

This flow chart describes the proposed measurement requirements for pneumatic controllers using Method 2:



EPA would then need to modify Equation W-1A and W-1B to reflect the three subtypes of intermittent controllers.

d. Method 3: Leaker factor for intermittent pneumatic controllers

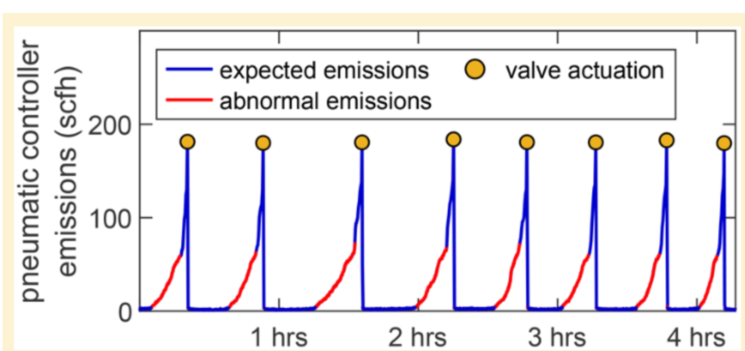
EPA has proposed a Method 3 for intermittent pneumatic controllers that would allow operators to inspect their controllers and apply a different emission factor based on whether or not the controller is found to be malfunctioning. As CATF and EDF noted in our 2022 comments (and we expand upon in these comments), this leaker factor method creates incentives to underestimate emissions, contrary to the goals of GHGRP, because it is very easy for operators using a method such as OGI to intentionally underestimate the count of pneumatic malfunctions by simply not recording observations of emissions. Given the cost implications for the operator under the methane waste emissions charge of each observed malfunctioning controller, there is a large potential for abuse of Calculation Method 3 by operators. This concern is additional to the issues discussed above in which operators could manipulate results for Calculation Methods 2 and 3 by repairing controllers prior to inspection. These concerns underscore the need for EPA to conduct robust auditing and require all operators to meter the supply gas to a representative portion of their pneumatic controllers.

At the same time, we note that EPA's current proposal is an improvement from its 2022 proposal. However, further improvement is still needed. For most intermittent controllers, EPA should increase the monitoring times to determine whether the controller is malfunctioning. The monitoring time should be based on the actuation frequency of the controller. Furthermore, EPA should switch from using a default emissions factor for controllers that are not malfunctioning to estimating emissions using the internal volume of the controller, actuator, and tubing and the number of actuations in a year, similar to the methodology for intermittent controllers where no emissions are measured that EPA proposes under Calculation Method 2.

EPA has proposed to require operators to observe intermittent controllers for up to two minutes to determine whether a malfunction is occurring. This is an improvement from the 2022 proposal, which allowed the operator to use their standard LDAR protocol, which would have meant an observation of only a few seconds. Clearly, the longer the controller is observed, the more confidence the operator can have about its leak/no-leak determination.

However, as noted above, two minutes is not long enough to sufficiently show that the intermittent controller is operating normally. In most cases, an inspector can quickly determine whether an intermittent controller is continuously emitting, but he or she can only tell if it is functioning properly while actuating if an actuation is observed. Critically, a significant portion of malfunctioning intermittent controllers only malfunction during actuation, as illustrated by Luck et. al. in the figure below.

Figure 1: Emissions trace from a malfunctioning intermittent controller.



In the figure above, although the controller's emissions return to near-zero or zero between actuations, the emissions per actuation are far higher than the design value for the device. This behavior can only be observed if an actuation is observed.

Luck et al. reported this phenomenon in a significant portion of controllers: 8 of the 40 intermittent controllers (20%) they studied exhibited this behavior.[58] (A total of 25 of these intermittent controllers were malfunctioning.)[59]

Therefore, EPA should require longer monitoring of controllers, to increase the chances that malfunctions will be observed. This is particularly important for frequently actuating intermittent controllers. Footer found that 33-76% of "frequently actuating" intermittent controllers were malfunctioning. This was true even after controllers were manually actuated, reducing the incidence of malfunction.[60] This elevated malfunction rate illustrates the need for thorough survey methods. And, if a controller is emitting excessively during actuation, the emissions impact is more severe if the controller actuates more frequently.

Therefore, similar to our recommendation for Method 2, EPA should require different observation intervals depending on the controller's purpose and frequency of actuation, as shown in Table 2. The operator must observe for the prescribed time, or until either evidence of a malfunction is observed or an actuation is observed. If they observe an actuation with no evidence of malfunction, they can be reasonably sure that the intermittent controller is operating properly. These maximum observation times are a more reasonable balance between keeping observation time short to limit cost to operators and extending the observation time to get more accurate assessments of real emissions from the malfunctioning controllers that are clearly ubiquitous in the current fleet.

Table 2: Method 3 Variable observation interval for intermittent controllers based on actuation frequency

Actuation frequency category	Number of actuations per year	OGI Observation interval required
High actuation frequency (e.g. Gas processing unit liquid level controllers or separator dump valve)	>8,760	Until actuation or malfunction is observed
Low actuation frequency	12-8,760	15 minutes (or until

[58] Luck et al., *Boosting Compressor Station in the U.S. Supporting Volume 1*, *supra* note 56, at 25 Table S1-2. Controllers H-1, O-6, P-5, T-4, T-5, T-6, U-5, and U-6.
[59] *Id*. at 348.
[60] Footer et al., *supra* note 50 at Section 2.1. "As part of normal LDAR survey procedures for these sites, the LDAR inspector manually actuated many (potentially all) of the indoor GPU liquid level IPC pilots to clear and reset the pilot. For this reason, the "as-found" state of the GPU liquid level IPCs could not be determined in this study. It is generally assumed that an IPC reset reduces continuous emissions by clearing accumulated seal debris and reducing closed bleed rate emissions from the as-found state, but this has not been systematically studied."

(e.g. temperature and pressure controller)		actuation or malfunction is observed)
Emergency shutdown (ESD) controllers	<12	2 minutes (or until actuation or malfunction is observed)

Operators should assume that any controller associated with a gas processing unit or separator dump valve is in the high actuation frequency unless they have evidence to the contrary.

For intermittent controllers where no malfunction is observed in the time periods specified above, instead of using a standard non-leaker emission factor, EPA should require operators to estimate emissions using the parametric method described for Method 2: the volume of the controller, tubing, and actuator multiplied by the number of actuations per year, based on company records. This will ensure that they are neither overestimating emissions for infrequently actuating controllers nor underestimating emissions for frequently actuating controllers. However, if EPA finds that this approach is too burdensome for Method 3 (despite proposing it for Method 2), it could alternatively create different emission factors for non-malfunctioning controllers for each of the three actuation frequency categories of intermittent controllers listed in Table 2.

If a malfunction is seen during the appropriate observation interval, we support EPA's proposed calculation methodology using a leaker emissions factor. However, the leaker emissions factor EPA has proposed for these devices, 16.1 scfh (based on a DOE's Gathering and Boosting Study) does not reflect the average emissions from malfunctioning controllers in the literature. In its June 2022 GHGRP revisions proposal, EPA proposed a leaker emission factor of 24.1 scfh based on the Tupper study.[61] Footer et al. sorted malfunctioning controllers into two categories, B and C, and found an emission factor of 15.8 scfh (upper limit 27.3 scfh) for "Category B" controllers and an emission factor of 36.5 (upper limit 79.4 scfh) for "Category C" controllers.[62] The weighted average (accounting for the number of controllers observed in each state) emission factor for Category B and C malfunctioning controllers is 29.4 scfh (upper limit 59.9 scfh). Because of the wide variability in emissions from malfunctioning intermittent controllers, EPA should base its emission factor on a combination of these studies and continue to reassess as new data becomes available.

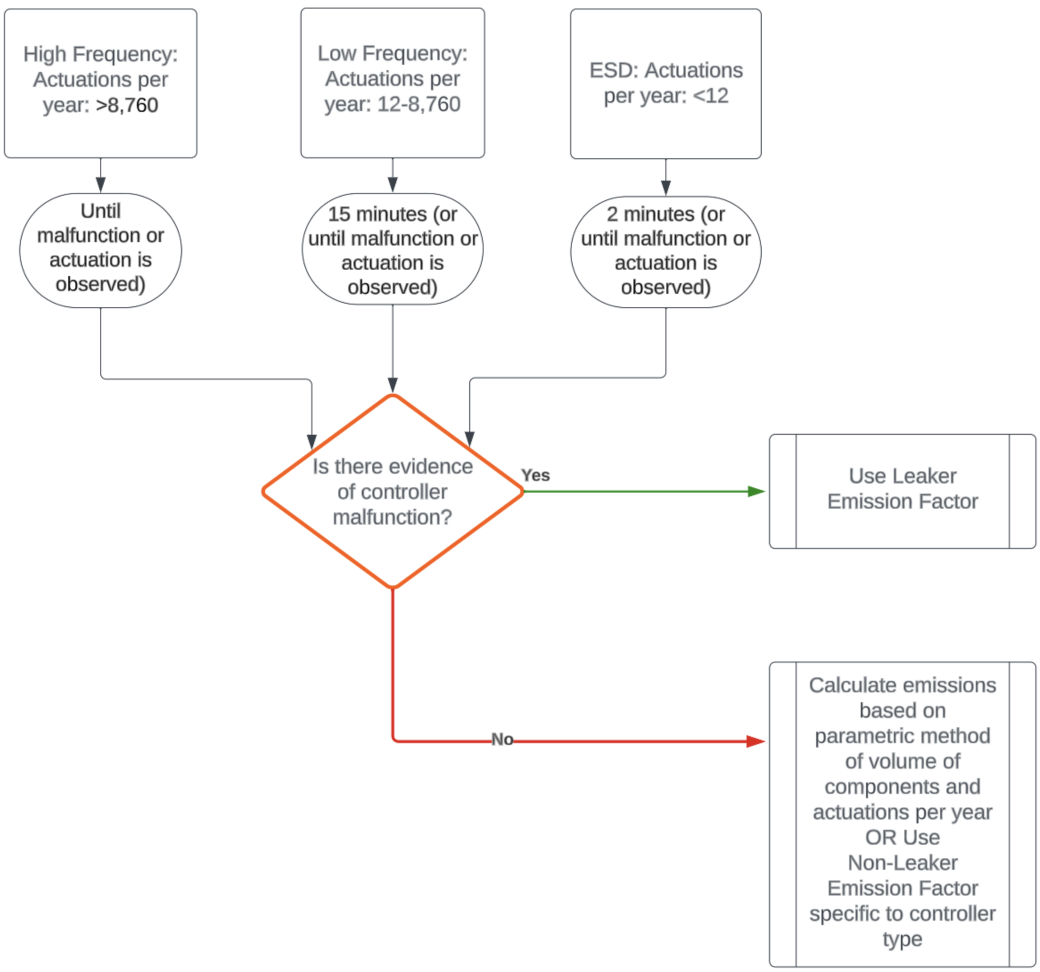
Along with the differentiated measurement intervals for intermittent controllers depending on the frequency of actuation, we propose a different survey cycle depending on frequency of actuation. Intermittent controllers with a high actuation frequency (i.e., more than 8,760 times per year),

[61] P. Tupper, *supra* note 52.
[62] Footer et al., *supra* note 52 at Table 2. Category B: Complex temporal behavior where IPC pilot(s) can achieve a low closed bleed rate between actuations, but emissions are higher than expected due to suboptimal settings or maintenance. May exceed IPC emissions factor. Category C: Dominated by elevated continuous emissions, indicating significant IPC maintenance or underlying process issues. Typically in exceedance of emissions factor.

which have higher overall emissions and potential for malfunction, should be monitored once a year. For all other intermittent controllers, EPA's proposed monitoring cycle length is appropriate. We recognize that this shortened cycle would significantly increase the monitoring requirement. However, we note the following:

- Increased measurement would only be required at intermittent controllers that actuate very often (more than 8,760 times per year)
- There are cost-effective solutions to replace gas-driven controllers with non-emitting options, removing the need for any measurement, monitoring, or reporting for controllers, as mentioned above
- Operators have other options for calculating emissions under EPA's proposal.

This flow chart describes our proposed measurement requirements for intermittent pneumatic controllers using Method 3:



Perverse incentives stemming from leaker factor method

With the passage of the waste emissions charge in the Inflation Reduction Act, many operators will be required to pay a charge of $900–$1,500 per metric ton of methane emissions for all emissions above segment-specific thresholds set by the Act. Based on simple analysis of past GHGRP reports, it is possible that a substantial number of onshore oil and gas production operators will have reported emissions above the Act's threshold, and therefore will be required to reduce their emissions or pay $900 per metric ton of methane emissions in 2024, $1200 per ton in 2025, and $1500 per ton in 2026 and thereafter.

An operator reporting the presence of a malfunctioning controller, emitting 16.1 scfh of whole gas, will therefore be reporting over 141 mcf for the entire year. Assuming that the gas is about 80% methane by volume, 141 mcf of gas contains 2.2 metric tons of methane. Therefore, under EPA's proposal, operators who identify a malfunctioning controller in 2025 (the first year the revised GHGRP rules will apply) would be required to pay about $2,630 for 2025 emission for that single malfunctioning controller, provided the operator's total emissions exceed the emissions threshold for the facility. The amount will rise in future years.
While some operators will reduce emissions (for instance by replacing high-emitting and malfunctioning devices), others may under-report the occurrence of malfunctioning controllers (and therefore, their emissions). Given the nature of OGI inspections, this issue must be addressed.

If EPA does decide to allow operators to use the leaker method, the agency must conduct a thorough desk audit of company reports. EPA will have at its disposal a huge amount of data, including information on the total number of controllers and malfunctioning controllers at each facility (and well-pad). As mentioned above, Footer et al (2019) found a malfunction rate of 33-71%[63], Luck found a malfunction rate of 63% (25 of 40),[64] and Tupper (2019) found a malfunction rate of 38% (99 of 263).[65] Stovern et al. (2020) observed that 11.6 – 13.6% of the intermittent controllers were malfunctioning, but this study underestimates malfunctions because it was based on OGI camera inspections of pneumatic controllers and was designed to be a "snapshot in time" to determine whether an intermittent controller was malfunctioning,[66] demonstrating even further the inadequacy of short intervals for determining proper operations of intermittent controllers. Even the 2 minute inspection time proposed by EPA in this rulemaking is an improvement from this "snapshot" approach, and would be expected to find more malfunctions. Thus, if companies employ Method 3 to estimate emissions from intermittent pneumatic controllers, but report malfunction rates that do not comport with this previous science, EPA has a reasonable basis to question the validity of the reports and seek more information. Operators may be able to point to increased controller maintenance that justifies the

[63] *Id*. at Table 2. Both Category B and Category C are considered malfunctions. Range represents study's low and high limit assumptions.
[64] Luck et al., *supra* note 49.
[65] P. Tupper, *supra* note 52.
[66] Michael Stovern et al., *Understanding oil and gas pneumatic controllers in Denver-Julesburg basin using optical gas imaging*, 70 J. Air & Waste Management Ass'n 9 (2020), https://doi.org/10.1080/10962247.2020.1735576.

lower leak rate, which would be a welcome development, but EPA should not accept low malfunction rate reports without justification.

As mentioned above, EPA should also require operators to meter the supply gas for a small, representative portion of their pneumatic controllers. This would provide a valuable comparison point for emissions from other controllers assessed using Calculation Methods 2 and 3.

In addition, whether the cycle is five years (as proposed by EPA), or one year for frequently actuating controllers and five years for controllers with less frequent actuation (as we propose), the inspections for Method 3 are most likely to take place during or in coordination with regular LDAR inspections. A well production site that contains a gas-driven pneumatic controller, whether continuous-bleed or intermittent, will automatically fall into the Quarterly OGI bucket (based on EPA's 2022 Supplemental proposal) once the site is subject to approved state implementation plans or a federal implementation plan (or NSPS OOOOb for new/modified sites). A typical OOOOb/c inspection of an intermittent controller will last only a few seconds, which, as we note above, is typically not long enough to definitively determine whether the controller is malfunctioning. However, these inspections do reveal some malfunctions. EPA should clearly require that when operators perform OOOOb/c inspections at a site in coordination with GHGRP monitoring (that is, performing both surveys on the same day or within a few days of each other), any pneumatic identified as malfunctioning by either inspection must be counted as a malfunction under GHGRP Method 3.

e. Method 4: Population emissions factors

EPA has also proposed changes to population emissions factors for pneumatic devices. The proposal includes updates to emissions factors for continuous high bleed pneumatic devices in different industry segments and removes default factors for intermittent pneumatic devices.

Updates to emissions factors for continuous bleed devices:

For continuous low-bleed pneumatic devices, EPA proposes an emissions factor of 6.8 standard cubic feet per hour per device (scf/hr/device) based on the available measurement data. This emissions factor was proposed for all applicable industry segments. For continuous high bleed devices, EPA proposes an emissions factor of 21 scf/hr/for units in Production and G&B, and an emissions factor of 30 scf/hr/device for devices in Processing, Transmission Compression, Storage, and Distribution.

As discussed in CATF and EDF's comments to the previous subpart W update,[67] we see the updated emissions factors as an improvement due to their incorporation of more recent measurement data.

[67] Clean Air Task Force, Comments on Revisions and Confidentiality Determinations for Data Elements Under the Greenhouse Gas Reporting Rule (Oct. 6, 2022), Doc. ID No. EPA-HQ-OAR-2019-0424-0248 (available at

Table 3: Pneumatics Emissions Factors for Production and G&B.

(scfh)	CATF/EDF Proposed Updated Emission Factor	EPA Proposed Updated Emission Factor	Old Subpart W Emission Factor
Low Bleed	7.6	6.8 **(or 7.6)**	1.39
High Bleed	19.3	21.2 **(or 23.7)**	37.3

While this is an improvement from the 2022 proposal, we recommend that EPA update emission factors based on the results of the DOE G&B Study, rather than averaging emission factors from studies of varying qualities. We have discussed the potential for error from short measurement periods in depth in previous sections and find that the DOE G&B study presents the most complete data. While the DOE G&B Study focused on gathering and boosting stations, we believe it is appropriate to apply these emission factors to the production segment as well. EPA has historically used the pneumatic emission factors from the production segment for gathering and boosting as well, and we believe it is appropriate to continue doing so here. While our recommendation is for EPA to employ DOE G&B emissions factors, the alternative proposed factors (bolded above) are an improvement from the original proposed factors.

Table 4: Pneumatics Emissions Factors for Processing, Transmission Compression, Storage, and Distribution

(scfh)	EPA Proposed Updated Emission Factor	Old Subpart W Emission Factor
Low Bleed	6.8	1.37
High Bleed	30	18.2

We support EPA's proposed update to pneumatic device emission factors in the transmission and storage industry segments. However, we encourage EPA to seek measurement data for pneumatic devices in these industry segments, and to revise the emission factor upwards to account for possible malfunctions.

Updates to emissions factors for intermittent bleed devices

EPA should retain the use of default population emission factors as an alternative calculation methodology for intermittent controllers, thus providing an option for sites not to conduct measurements or monitoring for intermittent bleed devices. This may be useful for operators that are planning to replace these devices with non-emitting alternatives, and do not wish to create a measurement or monitoring program for the short time before they finish replacing the emitting

Attachment D). Environmental Defense Fund, Comments on Revisions and Confidentiality Determinations for Data Elements Under the Greenhouse Gas Reporting Rule (Oct. 6, 2022), Doc. ID No. EPA-HQ-OAR-2019-0424-0312 (available at Attachment E).

controllers. In addition, as we argue above, it is important that operators that utilize Method 2 or 3 use Method 1 on at least a small representative sample of their controllers. Operators may wish to opt to use default factors for all controllers as a way to avoid installing these supply gas meters.

Table 5: Emissions Factors for Intermittent Bleed Pneumatic Devices

(scfh)	CATF/EDF Proposed Updated Emission Factor	EPA Proposed Updated Emission Factor	Old Subpart W Emission Factor
Production and G&B	11.1	8.8 (or 10.3)	13.5
Processing, Transmission Compression, Storage, and Distribution	2.3	2.3	2.35

In the June 2022 Proposal, EPA proposed updated emissions factors for intermittent bleed pneumatic devices based on more recent measurement data. While this represented an improvement, we agree with EPA's stated concerns surrounding the short measurement periods of certain studies. Consistent with our recommendations for continuous bleed devices in production and G&B, we recommend EPA update emissions factors for intermittent pneumatic devices in production based on the results of the DOE study. While our recommendation is for EPA to employ DOE G&B emissions factors, the alternative proposed factor (bolded above) is an improvement from the original proposed factor.

For intermittent devices in Processing, Transmission Compression, Storage, and Distribution, we support the proposed emissions factor. However, EPA notes that "if these intermittent bleed devices are subject to malfunction emissions, the intermittent bleed pneumatic device emission factor used in subpart W for the transmission and storage industry segments would not include excess emissions caused by worn or malfunctioning devices."[68] We are concerned about potential device malfunctions and encourage EPA to pursue measurement data on intermittent pneumatic devices in these industry segments. In addition, because the default emission factors for intermittent controllers in these segments do not account for malfunctioning controllers, EPA should make it clear that excess emissions from controllers should be treated as "large emissions events" if the operator has credible information that their emissions are above the set threshold.

[68] U.S. EPA, Greenhouse Gas Reporting Rule: Technical Support for Revisions and Confidentiality Determinations for Data Elements under the Greenhouse Gas Reporting Rule; Proposed Rule – Petroleum and Natural Gas Systems (January 2022) (available at Attachment F).

In addition, EPA should use data collected by operators deploying Method 1 to develop a more accurate default emission factor for intermittent bleed controllers. Or better, EPA could develop 3 different default emission factors for intermittent controllers based on actuation frequency category (high, low, and ESD). This would only be possible, however, if EPA follows our recommendation of requiring all operators to deploy Method 1 at a small representative sample of sites, including intermittent controllers in each of these 3 categories. Note that if EPA creates default emission factors for the 3 categories of intermittent controllers, these would be different from the emission factor that we suggest for non-malfunctioning controllers in Method 3. In contrast, default emission factors appropriate for Method 4 would account for both malfunctioning and normally operating controllers in each of the categories.

f. Other key revisions

Clarify operational hours for pneumatics as "in service" not "in operation" to correct misinterpretations

We support EPA's proposal to revise the definition of variable "Tt" in Equation W-1 and the corresponding reporting requirement in 40 C.F.R. 98.236(b)(2) to use the term "in service (i.e., supplied with natural gas)" rather than "operational" or "in operation." This clarification is important because it would prohibit operators from reporting their controllers as operating for the brief moments that they emit gas. Bloomberg News reported that several companies have reported their controllers as in operation for less than ten minutes per day, leading to significant underestimates of emissions.[69] By updating this definition to "in service," EPA can close this reporting loophole and more accurately quantify emissions.

Additional reporting elements

We support EPA's proposal to include flared emissions from pneumatic devices and pumps in the calculation for total flared emissions. We also support EPA's decision to combine emissions from pneumatics routed to a combustion unit with other fuel types as part of the total emissions from the combustion. We also support EPA's proposal not to mandate reporting when a device is routed to a vapor recovery unit and not subsequently to a combustion device.

We strongly support EPA's updates to reporting count requirements. These changes to reporting requirements for the total number of pneumatic devices will provide higher quality data for verification of annual reports to subpart W. Further, data on pneumatics routed to flare, combustion, and VRU will provide improved information about the prevalence of types of controlled pneumatics.

[69] Zachary Midler, *Methane 'Loophole' Shows Risk of Gaming New US Climate Bill*, Bloomberg News (Aug. 10, 2022), https://www.bloomberg.com/news/articles/2022-08-10/methane-loophole-shows-risk-of-gaming-new-us-climate-bill.

IV. Ownership Transfer

We generally support EPA's proposed revisions for reporting in cases of ownership transfer applicable to facilities in Onshore Petroleum and Natural Gas Production; Onshore Petroleum and Natural Gas Gathering and Boosting; Natural Gas Distribution; and Onshore Natural Gas Transmission Pipeline. We respectfully encourage EPA to strengthen its proposed approach by incorporating the recommendations described below to ensure that operators do not evade reporting emissions due to ownership transfers that strategically occur to cause emissions to go unreported, and when that does occur incidentally, that it is documented and disclosed.

Ownership transfer is common in the oil and gas sector due to market volatility and other factors. Increasingly, companies are divesting high-emitting assets as a method of achieving emission reduction targets and ESG goals. This type of divestment only reduces emissions on paper and may lead to even greater emissions as the purchasing company may lack environmental standards and commitments. A recent report by EDF analyzes global upstream oil and gas merger and acquisition data from 2017 through 2021, including specific high-risk transactions and the climate implications of oil and gas asset sales.[70] It finds that:

- **A significant amount of upstream oil & gas dealmaking has taken place in recent years**. Deal value in 2021 totaled $192 billion, exceeding annual deal value in 2015, 2016, 2018, and 2020. Additionally, the aggregate number of deals in 2021 rose to 498, surpassing 2015, 2016, and 2020.

- **Assets are flowing from public to private markets at a significant rate**. Over the last five years, the number of public-to-private transfers exceeded the number of private-to-public transfers by 64%. In each year during this period, public-to-private transfers comprised the largest share of deals.

- **Assets are increasingly moving away from companies with environmental commitments**.[71] In 2018, deals that moved assets away from companies with environmental commitments accounted for only 10% of transactions. By 2021, these deals accounted for 15% of transactions. During this same period from 2018 through 2021, more than twice as many deals moved assets away from operators with net zero commitments than the reverse.

- **Stewardship risk in upstream oil and gas appears to be rising**. The movement of upstream oil and gas facilities to private markets with traditionally less

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[70] EDF, *Transferred Emissions: How Risks in Oil and Gas M&A Could Hamper the Energy Transition* (2022), https://business.edf.org/insights/transferred-emissions-risks-in-oil-gas-ma-could-hamper-the-energy-transition/.
[71] Corporate commitments as of Q1 2022 were applied retroactively to transactions over the last five years. For example, if a company had a net zero commitment as of Q1 2022, it would be listed as a net zero buyer or seller in a 2017 transaction, even if it did not have a net zero pledge in 2017.

> transparency and to companies with reduced environmental commitments suggests that a growing number of assets are at risk of weak climate stewardship.

In some circumstances, these transfers may be motivated in part by forthcoming regulations, corporate environmental commitments, and the methane waste charge recently enacted by Congress. And in recent years, stakeholders have grown increasingly concerned that oil and gas mergers and acquisitions may undermine emission reduction efforts. If assets move from industry leaders in reducing emissions to companies without clear commitments and strong practices, emissions could increase and transparency could decrease, regardless of why the transactions take place. Traditional oil and gas dealmaking—blind to the climate implications of asset transfer—may not be compatible with a net zero world that demands sustained and proactive climate stewardship. Given the potential ramifications of oil and gas dealmaking, the "transferred emissions problem" has become increasingly important, especially as demand for decarbonization incentivizes companies to sell high-emitting assets.

These risks are also important to consider in light of Clean Air Act section 136(f)(6), which provides that "for facilities under common ownership or control, the Administrator shall allow for the netting of emissions by reducing the total obligation to account for facility emissions levels that are below the applicable thresholds within and across all applicable segments[.]" Operators may choose to purchase or sell facilities to take advantage of this exception. Operators might also split up high-emitting facilities and sell them to multiple purchasers to reduce liability. Given these concerns, we encourage EPA to track these transfers to the greatest extent possible under subpart W.

EPA's proposed changes cover four scenarios of ownership transfer:

1. When the entire facility is sold to a single purchaser and the purchaser does not already report to the GHGRP in that industry segment, then the purchaser would be responsible for submitting the facility's annual report for the entire reporting year in which the acquisition occurred and would include any previously owned applicable emission sources in the same geographic area as part of the purchased facility beginning with the reporting year in which the acquisition occurred.

2. When the entire facility is sold to a single purchaser and the purchaser already reports to the GHGRP in that industry segment (and basin or state, as applicable), then the purchaser would merge the acquired facility with their existing facility for purposes of reporting under the GHGRP.

3. When the selling owner or operator retains some of the emission sources and sells the other emission sources of a facility to one or more purchasers, the seller would continue to report for the retained emission sources unless and until that facility meets one of the criteria in 40 C.F.R. § 98.2(i) and complies with those provisions. For purchasers, existing reporters must combine applicable emissions

sources to their existing facility and new reporters must report as a new facility for the entire reporting year for acquired emissions sources combined with other applicable emissions sources previously owned.

4. When the seller does not retain any of the emission sources and sells all of the facility's emission sources to more than one purchaser, then the seller would notify the EPA within 90 days of the transaction and new reporters would begin reporting their acquired applicable emission sources as a new facility, while existing reporters would add the acquired applicable emission sources to their existing facility (if they already report).

We are most concerned with the application of scenarios 3 and 4. The proposed changes, and EPA's prior interpretation of reporting requirements in cases of ownership transfer,[72] do not address ownership transfer risks and are ambiguous in situations where the transaction causes the facility to be divided such that portions fall below the reporting threshold and are not merged into existing facilities. These types of transactions are the most concerning because it is likely to lead to unreported emissions and could result in gaming of otherwise applicable requirements.

We recommend EPA clarify that when a transaction causes a facility to become split between multiple owners such that each portion falls below the reporting threshold, the seller must continue reporting for retained and sold emissions sources until the conditions in 40 C.F.R. § 98.2(i) are met. Alternatively, or in situations where the seller will cease to exist, the purchasers should continue reporting for three to five years, as specified in 40 C.F.R. § 98.2(i)(1)-(2). 40 C.F.R. § 98.2(i) contemplates continued reporting for operators whose facilities no longer meet the original definition of a reporting facility under subpart A - including after they have sold assets,[73] and is therefore a suitable provision to apply in cases of ownership transfer. Finally, EPA should require owners and operators to notify EPA when *any* type of transaction occurs. Although EPA is in some cases requiring sellers and purchasers to update e-GGRT identifiers to reflect transactions and notify EPA of transactions, EPA has not proposed these requirements for all scenarios. Because new regulatory requirements, corporate environmental commitments, and the methane waste charge will result in at least some strategic asset transfers to avoid otherwise applicable requirements, EPA should more closely track and publicly disclose these transactions.

We also encourage EPA to set forth clear guidance outlining how operators should evaluate whether their facility is required to report, especially before the proposed updates to subpart W go into effect. There are likely facilities that are near the reporting threshold now that will be required to report once the updates take effect. The owners and operators of these facilities may avoid determining whether they meet the threshold or may truly not know they are required to

[72] EPA, *Frequently Asked Questions*, https://ccdsupport.com/confluence/pages/viewpage.action?pageId=198705183 visited Oct. 2, 2023).
[73] 40 C.F.R. § 98.2(i) provides that "Except as provided in this paragraph, once a facility or supplier is subject to the requirements of this part, the owner or operator must continue for each year thereafter to comply with all requirements of this part, including the requirement to submit annual GHG reports, even if the facility or supplier does not meet the applicability requirements in paragraph (a) of this section in a future year."

report. EPA should both analyze this universe of facilities and provide clear guidance to all operators for how they should assess whether their facility meets the reporting threshold.

V. Gathering Pipelines

There is notable evidence demonstrating that gathering pipeline leak emissions are significantly higher than previously reported and estimated. Analysis by EDF estimates that fugitive emissions from gathering lines range from 482,000 to 1,890,000 metric tons of methane per year, which is 4 to 15 times greater than EPA's 2022 GHGI estimate.[74]

For gas gathering pipelines, EPA proposes to "revise the gathering pipeline population emission factors . . . to use the leak rates from Lamb et al. (2015)," and is "not proposing to update the activity data (leaks per mile of pipeline) portion of the emission factors," and thus to continue relying on the 1996 GRI/EPA study for activity data.[75] EPA should update the methodology for reporting gathering pipeline emissions because new studies provide measurements of gathering pipeline leakage, and because the distribution pipeline leak data from Lamb et al. (2015) and 1996 GRI/EPA are not necessarily representative of gathering pipelines.

Under subpart W, operators are required to calculate and report their gathering pipeline methane emissions using EPA-defined emission factors (standard cubic feet of methane / hour / mile of pipeline) applied to the pipeline material and mileage in an operator's system.[76] The emission rates defined by EPA for gathering pipelines are from an EPA/GRI 1996 study that relies on a small sample of measured data obtained from distribution pipeline mains (only 64 leaks), and an EPA-generated estimate for the number of leaks per mile of gathering pipelines by material. Thus, current GHGRP methods for estimating emissions from gathering pipeline leaks are not based on any direct leak measurement of gathering lines. Similarly, EPA proposes to use leak rate estimates from Lamb et al. (2015), another study that only includes leaks on distribution pipelines, and that reviewed direct measurements of 230 leaks.

a. <u>Distribution and gathering pipelines are not interchangeable</u>

While gathering lines transport unprocessed gas mixtures from well sites to processing facilities, distribution pipelines transport pipeline-quality natural gas to customers. Distribution and gathering pipelines serve distinct purposes and are subject to varying levels of oversight, and because of the differing levels of minimum maintenance standards applicable to each, leak data for one type of pipeline system is not necessarily representative of another.
Local gas distribution systems deliver gas to end users and therefore are, by design, in close proximity to homes, businesses, and densely populated areas; gathering infrastructure tends to be located in more remote oil and gas production areas (though gathering lines can be near population centers too). Distribution pipelines are generally subject to heightened requirements

[74] R. McVay, *Methane Emissions from U.S. Gas Pipeline Leaks*, Environmental Defense Fund (Aug. 2023), https://www.edf.org/sites/default/files/documents/Pipeline%20Methane%20Leaks%20Report.pdf.
[75] 88 Fed. Reg. 50353 (Aug. 1 2023).
[76] *See* 40 C.F.R. § 98.233(r).

for leak management in light of their geographic location. The U.S. Department of Transportation, Pipeline and Hazardous Materials Safety Administration ("PHMSA") requires that distribution pipelines in business districts be surveyed for leaks once per year, and all other distribution pipelines be surveyed for leaks at least every 5 years.[77] By contrast, most gathering pipelines are federally unregulated and are not subject to any leak survey and repair requirements.[78] Out of about 435,000 miles of U.S. onshore gathering pipelines, only about 12,000 miles have historically been subject to leak survey standards.[79] PHMSA is expected to begin enforcing leak survey standards for an additional ~20,000 miles in May 2024, and has proposed to further expand leak survey standards to about 100,000 total miles of gathering lines.[80] Even with these developments, the federal requirements for leak management are significantly less protective for gathering lines compared with distribution lines. And while many states have additional leak management standards for distribution pipeline operators, far fewer have done so for gathering pipeline operators.[81]

b. New studies provide relevant emission factors across geographies

Yu et al. (2022) uses measurements collected as part of the PermianMAP project, where oil and gas infrastructure was surveyed in four aerial campaigns during 2019-2021 using aircraft equipped with a sensor capable of imaging and quantifying large plumes of methane.[82] The flights surveyed more than 10,000 miles of gathering pipelines in each campaign, identifying hundreds of high-emitting pipeline sources.

Another study, Cusworth et al. (2022), also identified gathering pipeline emissions sources. The multi-basin aerial study finds significant gathering line emissions in regions beyond the Permian, using the same instrument that was deployed in several of the aerial measurement campaigns

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[77] 49 C.F.R. § 192.723(b)(1)-(2).
[78] *See generally* PHMSA, Final Rule: *Pipeline Safety: Safety of Gas Gathering Pipelines: Extension of Reporting Requirements, Regulation of Large, High-Pressure Lines, and Other Related Amendments,* 86 Fed. Reg. 63266 (Nov. 15, 2021); PHMSA, Regulatory Impact Analysis, Pipeline Safety: Expansion of Gas Gathering Regulation Final Rule (Nov. 2021), https://www regulations.gov/document/PHMSA-2011-0023-0488.
[79] *See* PHMSA, Annual Report Mileage for Natural Gas Transmission & Gathering Systems (last updated Sept. 1, 2023), https://www.phmsa.dot.gov/data-and-statistics/pipeline/annual-report-mileage-natural-gas-transmission-gathering-systems.
[80] *See* PHMSA, *Proposed Rule: Pipeline Safety: Gas Pipeline Leak Detection and Repair*, 88 Fed. Reg. 31890 (May 18, 2023); PHMSA, Notice of Limited Enforcement Discretion for Particular Type C Gas Gathering Pipelines (July 8, 2022), https://www.phmsa.dot.gov/sites/phmsa.dot.gov/files/2022-07/Gas%20Gathering%20Enforcement%20Discretion%20Notice%20-%20July%202022.pdf; PHMSA, Final Rule: *Pipeline Safety: Safety of Gas Gathering Pipelines: Extension of Reporting Requirements, Regulation of Large, High-Pressure Lines, and Other Related Amendments,* 86 Fed. Reg. 63266 (Nov. 15, 2021).
[81] According to data provided by NAPSR, at least 22 states have requirements for prioritizing leak repairs that add to or exceed federal requirements—most of which are for distribution pipelines. *See* NAT'L ASS'N OF PIPELINE SAFETY REPS., *Compendium of State Pipeline Safety Requirements & Initiatives Providing Increased Public Safety Levels compared to Code of Federal Regulations* (3rd ed. 2022), http://nebula.wsimg.com/77f8f2a14d467fbe1e56cbafaf9e8a8b?AccessKeyId=8C483A6DA79FB79FC7FA&disposition=0&alloworigin=1.
[82] Yu et al., *Methane Emissions from Natural Gas Gathering Pipelines in the Permian Basin*, 9 Environ. Sci. Technol. Lett. 969–974 (2022), https://doi.org/10.1021/acs.estlett.2c00380.

referenced in Yu et al.—the AVIRIS-NG instrument.[83] Although Cusworth et al. does not incorporate activity data to derive an emissions factor for observed gathering pipeline emissions, the application of similar methods used in Yu et al. allows for the comparison of basin-specific pipeline emission factors across the U.S., shown below.

Table 6: 2021 Gas Gathering Pipeline Methane Emissions and Emission Factors. (Uncertainty is reported as ± the 95% confidence interval)

Basins	Observed Gathering Pipelines (km)	Total gathering pipeline point source emissions (t h^{-1})	Emissions Factor (t y^{-1} km^{-1})
Marcellus (SW PA)	1669	0.6 ± 0.2	3.3 ± 1.2
Uinta	1191	2.1 ± 1.0	15.3 ± 7.0
Denver-Julesburg	4891	0.2 ± 0.1	0.4 ± 0.1
Permian	16000	6.7 ± 3.2	3.7 ± 1.7

Methods for Table 6: Emission factors were calculated by dividing proportion of total point source emissions attributed to gathering pipelines in Cusworth et al. and Yu et al. by the total length of pipelines flown. Since Cusworth et al. reports two emissions totals from separate campaigns in July 2021 and September 2021 for the Denver-Julesburg basin, the average attributed emissions across the two campaigns are reported and applied here. Correspondingly, the persistence-weighted emissions for sources with at least three overflights across the two 2021 Permian campaigns in Yu et al. are averaged and applied here. Gathering pipeline data was used from Enverus Prism and accessed March 3, 2023. Yu et al. applies an uncertainty measure to the observed gathering pipeline length by evaluating the difference between the Enverus Prism and DrillingInfo data sources. However, in testing Yu et al. reports that the difference between the two was negligible, so we disregard this uncertainty calculation and only apply the Enverus Prism data.

The gathering line observations in regions like the Marcellus are similar to those in the Permian, though regions like the Denver-Julesburg basin have proportionally few gathering pipeline emissions sources in this study. The Permian Basin emission factor is not completely exceptional, and the Marcellus is a close match. Even though these are characteristically very different basins (oil production vs. gas production), the pipeline emission factors for either are surprisingly representative.

The results in Uinta appear anomalously high and may not completely represent the emissions. Results from Yu et al. indicate that derived emission factors can vary greatly—from 2.7 t y^{-1} km^{-1} up to 10 t y^{-1} km^{-1}—due to the dynamic nature of O&G activity and emissions and how well aerial surveys capture the intermittency of pipeline sources. By limiting the number of sources to those observed more than three times over multiple days, Permian emissions factors from a single time period could decrease up to ~5 t y^{-1} km^{-1}.

Using repeated observations of the same sources more accurately accounts for the contribution of sources that are highly emitting for a very short duration, and often lowers the emission factor

[83] Cusworth et al., *Strong methane point sources contribute a disproportionate fraction of total emissions across multiple basins in the United States*, 38 PNAS 119 e2202338119 (2022), https://doi.org/10.1073/pnas.2202338119.

and narrows the range of uncertainty. Not only source coverage, but also temporal variation in the basin can also affect emissions. When looking at only sources with at least three overflights across multiple days, the difference between the fall and summer 2021 emission factors was 2.1 ± 1.3 t / y km. It is likely that one of these two factors contributes to the anonymously high emission factor for the Uinta.

The lower emission factor of the Denver-Julesburg relative to other basins is possibly driven by a strong environmental regulatory environment in Colorado. If this is the case and the state or local regulatory environment significantly affects gathering pipeline emissions, this would suggest our national emissions factor estimate is conservative given that over half (~55%) of gathering pipelines nationally are in Texas.

c. Coverage of national gas gathering pipelines by basin and state

This table shows the top six basins and states, from greatest to smallest, by mileage of active gas gathering pipelines according to Enverus Prism. The Denver-Julesburg and Uinta basins are not in the top six but are relevant for comparison to Table 6 above.

Table 7: Gathering Pipelines by Basin and State

	Basin	Percent of National Gas Gathering Mileage	State	Percent of National Gas Gathering Mileage
1	PERMIAN	24.6	TX	55.7
2	WESTERN GULF	16.8	OK	14.8
3	ANADARKO	10.7	NM	6.3
4	FORT WORTH	6.7	ND	3.1
5	ARK-LA-TX	6.4	WY	3
6	MARCELLUS-UTICA	5.6	KS	2.9
	DENVER-JULESBURG	2.1	CO	2.7
	UINTA	0.5	PA	1.6

These results confirm that, like other oil and gas sources, gas gathering pipeline emission factors can differ significantly across basins. Because the majority of nationwide gathering lines are located in Texas, the same local regulatory environment as the Permian, and lower-emitting areas such as the Denver-Julesburg basin have a small fraction of gathering lines, the Yu et al. 2022 gathering line emission factor is appropriate to apply nationwide, until more empirical data is available. For future research, the highest value would be to understand gathering pipeline emissions in the Anadarko, then the other Texas and Louisiana basins.

d. Replacement is not the only solution

EPA states that one limitation of the Yu et al. emission factors is that "inability to report by [pipeline] material could limit a reporter's ability to pursue emission mitigation projects (e.g., pipeline replacement) and recognize the associated emission reductions."[84] This conclusion overlooks the fact that replacement is not the only solution—and may often not be the most cost-effective solution—to mitigate methane leakage from pipelines. Leak *repair* is widely viewed as a worthwhile practice across oil and gas infrastructure to reduce methane emissions and improve facility safety, and there is no reason to disregard its utility for gathering pipelines. For example, in reporting on unregulated ("Type R") gathering lines that happened for the first time in 2023, 87 operators reported repairing or scheduling for repair over 4,300 leaks on federally *unregulated* gathering lines.[85] That operators are conducting leak repair on gathering pipelines not subject to mandatory leak survey and repair standards is a positive indication that this infrastructure can readily be repaired.

Furthermore, pipe material data for gathering pipelines is not available publicly or even through industry databases like Enverus, rendering it less likely that public interest survey campaigns and academic research can compile this information into analyses. If EPA views this as a key impediment to updating pipeline emission factors, then the agency should prioritize collection and release of the relevant information in order to facilitate development of more granular emission factors. And as discussed elsewhere in this comment, the most important solution to ensure that operators can demonstrate emission reductions over time is through incorporation of effective and regular real-world measurements.

e. Gathering lines should report large release events

Gathering pipeline operators should be specifically required to report large release events. Yu et al. and Cusworth et al. demonstrated that emissions from gathering pipelines are characterized by notable super-emitter sources. Gathering lines can have super-emitting leaks and can also release large volumes of methane during operational events such as pigging and blowdowns. PHMSA found that in order to transport greater volumes, "some gas gathering lines are now constructed with large-diameter pipe and operating pressures comparable to large, interstate gas transmission pipelines," and these lines "are susceptible to the same types of integrity threats as transmission pipelines, including corrosion, excavation damage, and construction defects."[86]

[84] U.S. EPA, Greenhouse Gas Reporting Rule: Technical Support for Revisions and Confidentiality Determinations for Data Elements Under the Greenhouse Gas Reporting Rule; Proposed Rule – Petroleum and Natural Ga*s Systems* (June 2023) at 111.
[85] K. Roberts, *Natural Gas Gathering and Hydrogen Pipeline Reported Data*, Environmental Defense Fund (Aug. 2023), https://www regulations.gov/comment/PHMSA-2021-0039-26522; PHMSA, Gas Distribution, Gas Gathering, Gas Transmission, Hazardous Liquids, Liquefied Natural Gas (LNG), and Underground Natural Gas Storage (UNGS) Annual Report Data, https://www.phmsa.dot.gov/data-and-statistics/pipeline/gas-distribution-gas-gathering-gas-transmission-hazardous-liquids (last accessed Aug. 7, 2023).
[86] PHMSA, Final Rule: *Pipeline Safety: Safety of Gas Gathering Pipelines: Extension of Reporting Requirements, Regulation of Large, High-Pressure Lines, and Other Related Amendments,* 86 Fed. Reg. 63266, 63267 (Nov. 15, 2021).

VI. Plugged Wells

EPA is proposing to require that onshore operators report the number of wells permanently shut-in and plugged during the calendar year for the basin as a whole.[87] It is also proposing to require reporting of the quantities of natural gas (in thousand cubic feet), crude oil (in barrels) and condensate (in barrels) produced that is sent to sale from or through the facility during the reporting year for each onshore and offshore well that is permanently shut-in and plugged at a facility and those same quantities for all producing wells on each onshore well-pad with a well that was permanently shut-in and plugged.[88] To measure quantities operators must use a flowmeter that satisfies the requirements of § 98.234(b).[89]

We strongly support EPA adding new reporting requirements for plugged wells. These proposed data elements will be essential to implementation of MERP. In order for EPA to calculate whether a facility meets MERP's waste emissions threshold, EPA must have production data for plugged wells for any time the well was producing in the previous year, as well as production data for wells that were producing the entire year. Together, production data from plugged wells and wells that continue to produce will constitute the production level that emissions must be compared to when calculating fee applicability for facilities.

Collecting data on plugged wells, including the date of plugging and production while still producing, is also essential for implementation of the plugged well exemption under Clean Air Act section 136(f)(7), which provides that "[c]harges shall not be imposed with respect to the emissions rate from any well that has been permanently shut-in and plugged in the previous year." As a result, it is important for subpart W to collect data on plugged wells to accurately implement the exemption.

EPA can improve its reporting framework for plugged wells in several ways. First, EPA must ensure that operators submit not just production data, but also emissions data for plugged wells during the time those wells were producing. EPA should clarify in the plugged well section how operators will ensure emissions data from these sources are accounted for, whether that be in a separate section of subpart W or embedded within plugged well requirements. Emissions data is equally important for calculating the MERP threshold and methane waste charge.

Second, EPA should clarify that operators must plug wells in accordance with federal and state closure requirements before they can report wells as plugged under subpart W. EPA should require operators to submit verification that they have plugged wells by providing relevant certificates from state entities and an indication as to whether they have completed closure and post-closure requirements under OOOOb/c. After operators submit their annual reports, EPA

[87] 88 Fed. Reg. 50434 (Aug 1. 2023). EPA does not specify the same requirement for offshore operators. *See id.* at 50435.
[88] *Id.* at 5030, 50434–5.
[89] *Id.* at 50434

should coordinate with staff implementing OOOOb/c to ensure that, for wells reported as plugged under subpart W, operators have submitted required closure plans and conducted their post-closure OGI survey.[90] If EPA finds that either state or federal closure requirements have not been met, it should disallow an operator from reporting a well as plugged under subpart W. These measures will ensure accurate implementation of the plugged well exemption under MERP.

Finally, EPA should apply its onshore reporting requirements to offshore facilities. This would entail also requiring offshore facilities to report (1) the number of producing wells and the number of plugged and permanently shut-in wells, and (2) required quantities for all producing wells on each offshore well pad with a well that was permanently shut-in and plugged. EPA should also require verification that wells have been plugged at offshore facilities in line with our recommendations above. Research in the North Sea has documented leaks from plugged offshore wells near shallow gas formations indicating the need for reporting and monitoring of offshore wells even after decommissioning.[91] MERP applies to offshore facilities as well, so it is equally critical to the proper functioning of that program that EPA require the above recommended framework for offshore facilities.

VII. Tanks, Thief Hatches, Dump Valves

a. Open thief hatches

We generally support EPA's proposed clarifications and requirements related to the calculation of emissions that result from thief hatches that are open or not properly closed. These revisions will provide more accuracy in the reporting of emissions, especially with the consideration of periods of reduced capture efficiency when emissions are vented directly to the atmosphere instead of captured and controlled in a vapor recovery system or flare. We also agree that these revisions clarify the original intent of the calculation methodologies for atmospheric storage tanks in 40 C.F.R. § 98.233(j). EPA should go further and *require* operators of larger tanks, which have the potential to emit more methane when a thief hatch is open or not properly sealed, to utilize either a thief hatch sensor or a pressure monitor, to ensure accurate emissions estimates from the hatches on those tanks. As discussed below, we recommend several additional revisions

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[90] The section 111 proposed standards would allow operators to cease fugitive monitoring once they submit a well closure plan within 30 days of the cessation of production, including: (1) the steps necessary to plug; (2) the financial requirements and disclosure of financial assurance to complete closure; and (3) the schedule for completing all activities in the closure plan. Owners and operators would also have to report any changes in ownership at individual well sites so that it is clear who is responsible until the site is plugged and closed. 87 Fed. Reg. 74736 (Dec. 6, 2022). The section 111 proposal also requires ongoing fugitive monitoring, recordkeeping, and reporting until wells are properly plugged and post-closure OGI surveys for to demonstrate that plugging has been effective. *Id.* at 74736 (requiring owners to "conduct a survey of the well site using OGI...to ensure there are no emissions identified.").

[91] Bottner et al., *Greenhouse gas emissions from marined decomissioned hydrocarbon wells: leakage detection, monitoring and mitigation strategies*, 100 Int'l J. of Greenhouse Gas Control 103119 (2020), https://doi.org/10.1016/j.ijggc.2020.103119.

that would further increase the accuracy of emissions reporting for atmospheric storage tanks that are found with a thief hatch that is open or not properly closed.

Revisions related to reduced capture efficiency due to open thief hatches

We support EPA's proposed clarification and edits to the calculations proposed as 40 C.F.R. § 98.233(j)(4) for reduced capture efficiency of vapor recovery systems and flares used for controlling emissions from atmospheric storage tanks. We further agree with EPA's statement that these proposed revisions "emphasize the original intent of the rule and ensure the accuracy of reported data"[92] and that the emissions that are not captured must be considered when using any of the calculation methodologies for atmospheric storage tanks.

We also agree with EPA's proposal that an assumption of 0% control is appropriate during times when a thief hatch is open or not properly closed. In a storage tank system utilizing vapor capture and recovery or control, vapor capture is dependent on maintaining the design pressure and an open or improperly closed thief hatch changes the pressure of the system, allowing vapors to bypass the capture system and preventing them from reaching the control device. Therefore, the assumption of 0% control is appropriate to recognize this bypass of the system and venting of emissions directly to the atmosphere, regardless of which calculation methodology is used to calculate emissions. We further support the addition of this clear statement within the regulatory text at 40 C.F.R. § 98.233(j)(4)(i)(C).

Methods for determining the duration of time a thief hatch is open or not properly closed

We support EPA's proposed monitoring requirement to determine how long the thief hatch has been open or not properly closed. However, we recommend specific changes that would improve the accuracy of this determination. First, as EPA has proposed, operators should be required to use thief hatch sensors or alarms where they are already installed and operating, and capable of transmitting and logging data whenever the thief hatch is open or not properly closed. Additionally, we recommend that EPA explicitly mandate that the information from these sensors or alarms must be used to determine the duration of time the thief hatch was open or not properly closed when sensors are present and operating. Information collected from these systems is more accurate, and less subjective, than a visual inspection.

In addition to thief hatch sensors and alarms, we recommend that EPA require the use of pressure monitoring systems on atmospheric storage tanks where they are present and operating, if those tanks do not have a thief hatch sensor/alarm in service. In general, the operation of vapor capture systems requires close monitoring of system pressures to maintain the system integrity and prevent venting of emissions through over-pressurization. Pressure monitoring of vapor control systems for atmospheric storage tanks is a common practice, especially where those tanks are subject to control requirements through OOOO, OOOOa, or an operating permit or other

[92] *See* 88 Fed. Reg. 50326 (Aug. 1, 2023).

requirement established under a federal, state, local, or tribal authority. EPA has a record of identifying emissions from controlled atmospheric storage tanks, and has incorporated additional requirements for pressure monitoring into various settlements.[93] For example, the Consent Decree entered between EPA, New Mexico, and Matador Resources in March 2023, requires Matador to "install, calibrate, maintain, and operate one electronic pressure monitor . . . that shall record data at least once every minute and, every five minutes, shall transmit five pressure measurement records . . . to a central monitoring station."[94] Like thief hatch sensors and alarms, pressure monitoring will provide more accurate information on the duration of time a thief hatch is open or not properly closed. Therefore, we recommend that EPA require the use of this technology in its updated subpart W provisions.

Given the much higher accuracy of emissions estimates from tanks with thief hatch sensors/alarms and/or pressure monitoring systems, EPA should require operators of larger tanks to install one of these systems on tanks with larger potential emissions (*i.e.*, tanks with higher throughput that would lead to higher methane emissions if a thief hatch were not sealed), if they do not have one of these systems already. This would provide accurate emissions reporting from tanks caused by open or unsealed hatches and would best notify operators to diligently and consistently work to ensure that hatches are kept sealed, in keeping with the intent of MERP.

EPA might also consider requiring operators to utilize sensors or pressure monitoring on a representative portion or sample of their tanks. In addition to providing the most accurate data for when hatches are open on the tanks which have pressure monitors or sensors, the information from those sensors would give insight into the accuracy of the reported data for thief hatch status for tanks *without* sensors. If an operator reports that thief hatches on tanks without sensors are open significantly less than on tanks with sensors, this might suggest that an operator is failing to record all instances of open hatches, or under-reporting the length of open hatches, warranting further enquiry by EPA into the discrepancy.

When thief hatch sensors and pressure monitoring systems are not in use, we support the required use of inspections to determine when a thief hatch is open or not properly closed. However, we recommend specific additions to the visual inspection requirement that would improve the accuracy of the information obtained from these inspections. We recommend the use of methane detection technologies in place of visual inspections to determine when a thief hatch is open or not properly closed. There are several methane detection technologies that have been used to identify emissions from controlled atmospheric storage tanks. These technologies include handheld OGI cameras, drone-mounted OGI or TDLAS systems, fixed OGI cameras, and aerial LiDAR systems. There is an abundance of information available, including many peer-reviewed studies, EPA and state enforcement actions, EPA and state aerial survey campaigns, and operator

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[93] *See, e.g.*, Consent Decree at 38, United States et al. v. PDC Energy, Inc., No. 1:17-cv-1552 (D. Colo. Oct. 31, 2017), https://www.epa.gov/sites/default/files/2017-10/documents/pdc-cd.pdf; Consent Decree at 33, United States et al. v. Noble Energy, Inc., No. 1:15-cv-00841 (D. Colo. April 23, 2015), https://www.epa.gov/sites/default/files/2015-04/documents/noble-cd.pdf.

[94] Consent Decree at 27, United States et al. v. Matador Production Company, No. 1:23-cv-00260-JFR-GJF (D.N.M. March 27, 2023), https://www.epa.gov/system/files/documents/2023-03/matador-cd.pdf.

data that demonstrate the effectiveness of these technologies in identifying emissions from thief hatches on atmospheric storage tanks.[95] Given the wide use of these technologies, it is vital that EPA require the use of information obtained during any of these types of surveys in determining the presence of an open or improperly closed thief hatch. Additionally, if EPA finalizes NSPS OOOOb/c as proposed, then all sites with controlled storage tanks will be subject to quarterly OGI inspections of the cover and closed vent system on controlled storage tanks. Therefore, we recommend that EPA explicitly require the use of information obtained during any methane detection event for determining when a thief hatch is open or not properly closed, and the duration of time the thief hatch has been in that position.

Finally, we recommend more frequent visual inspections than the frequencies proposed if EPA finalizes the use of visual inspections. EPA has proposed visual inspections to determine if a thief hatch is open or not properly closed at frequencies consistent with the audio, visual, and olfactory (AVO) inspection frequencies proposed for sites subject to fugitive emissions monitoring in OOOOb/c. Where sites are not subject to fugitive emissions surveys, EPA proposed annual visual inspections. The relevant proposed AVO inspection frequencies in OOOOb/c are monthly for compressor stations and bimonthly for well sites and centralized production facilities. However, EPA has failed to also consider the monitoring requirements for covers and closed vent systems associated with controlled storage tanks in OOOOa, in which monthly AVO inspections are required. Where sources are not subject to AVO inspections, we recommend visual inspections of thief hatches at least bimonthly to ensure timely identification of an open (or not properly closed) thief hatch and to provide for more accurate reporting of reduced capture efficiency from vapor recovery systems and controls on atmospheric storage tanks.

Accounting for the full duration of time a thief hatch is open or not properly closed

The duration of time a thief hatch is open or not properly closed directly impacts the amount of emissions vented to the atmosphere from atmospheric storage tanks. Therefore, it is critical that reporters account for this duration as accurately as possible. We support EPA's proposal to extend the duration back to the last inspection, thief hatch sensor record, or pressure monitoring

[95] *See, e.g.*, Lyon et al., *Aerial surveys of elevated hydrocarbon emissions from oil and gas production sites*, 50 Env't. Sci. Tech. 4877 (2016), https://pubs.acs.org/doi/full/10.1021/acs.est.6b00705; Colorado Air Pollution Control Division, *Field Inspection Report* (Nov. 15, 2021), https://drive.google.com/file/d/1kemWoGHzFl3krnFR5zAD8b2RO8Cy-Cd8/view; EPA, *EPA Announces Clean Air Act Violations for Permian Basin Company* (March 22, 2023), https://www.epa.gov/newsreleases/epa-announces-clean-air-act-violations-permian-basin-company; Bridger Photonics, *Measuring and Managing Flare, Tank, and Compressor Emissions*, https://www.bridgerphotonics.com/blog/measuring-and-managing-flare-tank-and-compressor-emissions.; EPA, *EPA Announces Clean Air Act Violations for Permian Basin Company* (March 22, 2023), https://www.epa.gov/newsreleases/epa-announces-clean-air-act-violations-permian-basin-company; Bridger Photonics, *Measuring and Managing Flare, Tank, and Compressor Emissions*, https://www.bridgerphotonics.com/blog/measuring-and-managing-flare-tank-and-compressor-emissions; EPA, *EPA Announces Clean Air Act Violations for Permian Basin Company* (March 22, 2023), https://www.epa.gov/newsreleases/epa-announces-clean-air-act-violations-permian-basin-company; Bridger Photonics, *Measuring and Managing Flare, Tank, and Compressor Emissions*, https://www.bridgerphotonics.com/blog/measuring-and-managing-flare-tank-and-compressor-emissions.

system record that demonstrates when the thief hatch was properly closed. However, we recommend that EPA further strengthen the requirements to ensure the full duration is accounted for in the reported emissions.

First, we recommend that EPA include a forward-looking element to the duration of time the thief hatch is open or not properly closed. This forward-looking element allows accounting for duration of vented emissions until the thief hatch is properly closed. While the proposal clearly defines how to determine when the thief hatch started venting emissions, EPA does not address the fact that emissions will continue to be vented until the thief hatch is properly closed. We therefore recommend that EPA define the duration of time a thief hatch is open or not properly closed to include a start date as the day after the last documented day the thief hatch was properly closed and extending until the thief hatch is again properly closed after it has been identified as open or not properly closed.

Second, we recommend that EPA expand the start date of the open thief hatch prior to the beginning of the reporting year if the reporter identifies that the start date spanned reporting years because the thief hatch was not closed during the previous reporting year. In this scenario, we recommend that reporters update their previous reporting year emissions as necessary to reflect that emissions were vented instead of captured in a vapor recovery system or controlled by a flare. Accounting for these vented emissions in the previous reporting year will yield more accurate calculations.

Reporting of open thief hatches and total volume of gas vented through an open thief hatch

We support EPA's proposed requirements to report the number of controlled atmospheric storage tanks with open or not properly closed thief hatches within the reporting year, and the total volume of gas vented directly to the atmosphere through the open (or not properly closed) thief hatch. We further support this reporting regardless of which calculation methodology is used to calculate emissions from atmospheric storage tanks. We agree with EPA that this information would provide opportunities to better understand the impact of open thief hatches on emissions and enhance the data quality. However, we recommend that EPA also requires the reporting of each instance a thief hatch is found open or not properly closed and the total volume of emissions from that individual event in order to provide more granularity on the data and improve EPA's ability to understand individual event contributions to emissions. An individual thief hatch may be identified as open or not properly closed multiple times during a reporting year, and we believe that reporting each instance will allow EPA to identify if updates to the calculator methodologies are appropriate in future revisions to subpart W or the impact of the duration of the open thief hatch on the total volume vented.

b. <u>Malfunctioning dump valves</u>

We generally support EPA's proposed clarifications and requirements related to the calculation of emissions that result from malfunctioning separator dump valves. These revisions will provide more accuracy in the reporting of emissions. We also agree that these revisions are clarifications to the original intent of the calculation methodologies for atmospheric storage tanks in 40 C.F.R. § 98.233(j).

Methods for determining the duration of time a separator dump valve is malfunctioning

We support EPA's proposed requirement to perform visual inspections of the gas-liquid separator for the purpose of determining if the liquid dump valve is stuck open (or partially open). However, like our recommendations for open thief hatches, we recommend that EPA include additional methods to determine the duration of time a separator dump valve is malfunctioning beyond the proposed annual visual inspections.

There are several additional indicators that could be used to determine if a separator dump valve is stuck or malfunctioning. These other indicators are downstream from the separator itself and associated with the atmospheric storage tank, vapor recovery system, or control device. EPA could include these other indicators as additional methods for determining the duration of time a separator dump valve is malfunctioning. For example, an operator may have flow metering on their flare or enclosed combustion device. When the flow meter measures an increased volume of gas flow to that flare, that information could indicate the separator dump valve has malfunctioned. Information from the flow meter could provide a date and time stamp of when the increased flow began (and ended), thus providing a duration for the malfunction if the separator dump valve was the cause of the increased flow. Other indicators that EPA could include relate to tracking frequent open/closed cycling of thief hatches and other pressure relief devices.

c. <u>Applicability and selection of appropriate calculation methodologies for atmospheric storage tanks</u>

Extension of calculation methods 1 and 2 to tanks with throughput <10 bbl/day

We generally support EPA's proposal to allow the use of calculation methodologies 1, 2, or 3 for atmospheric storage tanks that have a throughput of <10 bbl/day. Current subpart W reporting requires the use of method 3 only, which relies on population count emission factors. The inclusion of methods 1 and 2 will allow for more accurate accounting of emissions where these other methods are used.

EPA should undertake a review of the appropriateness of allowing operators to use calculation method 3 for any tank with throughput below 10 bbl per day, given the large number of these tanks, the relatively high threshold for use of a default factor, and the many changes that have occurred in the oil and gas production industry in the time since this emissions factor was developed.

Extension of reporting requirements to floating roof tanks

We support EPA's proposal to extend emissions reporting requirements to floating roof tanks as these sources also contribute to emissions vented to the atmosphere. While floating roof tanks are not widely used by the upstream production segment of the industry, they are used in other segments and their emissions should be accounted for in reporting under subpart W. Emissions occur whenever a liquid is withdrawn from the tank as a result of clingage loss. This occurs when liquid remains on the walls of the tank and is exposed to the atmosphere as the tank roof lowers with the liquid level inside the tank. Therefore, we support the inclusion of these emissions where floating roof tanks are used.

d. Potential new calculation method based on laboratory GOR results

We do not support the use of gas-to-oil (GOR) laboratory results for calculating emissions from atmospheric storage tanks, and we recommend that EPA clearly prohibit this approach. The GOR ratio is typically calculated by dividing the volume of gas produced from an oil well by the volume of oil produced over a specific period of time. In a laboratory or small-scale environment, GOR can be determined by carefully measuring the volume of gas and oil under controlled conditions (in this case, the pressure and temperature of the tank). Lab-scale GOR calculations can provide more accurate results compared to field GOR estimates, as they allow for controlled measurements of both oil and gas volumes under specific conditions. However, they may not capture all the complexities and variations encountered in real-world oil and gas operations, including fluid dynamics, changing process conditions, flow rates, and gas compositions. Therefore, lab-scale GOR calculations are typically used for research, quality control, or analytical purposes rather than for estimating emissions from oil and gas process equipment, where field measurements and more comprehensive methodologies are necessary for accurate assessments.

Furthermore, atmospheric storage tanks pose specific challenges that make GOR calculations even less appropriate for emissions estimation:

1. Variability in Gas Composition: The GOR calculation assumes a fixed ratio between the volume of gas and the volume of oil produced. However, the precise composition of the stream can vary between different wells, reservoirs, processing facilities, and throughout the time of the operation. Different hydrocarbon compounds, impurities, and non-hydrocarbon gases may be present, all of which have different emission factors. This variability makes it challenging to accurately estimate emissions without considering the gas composition.

2. Tank-Specific Parameters: Atmospheric storage tanks have tank-specific parameters such as size, design, and venting systems that are critical in determining emissions. GOR calculations are unable to account for these tank-specific factors, making them inadequate for accurate emissions estimation from storage tanks.

3. Control Measures: Storage tanks may be equipped with control measures like vapor recovery units (VRUs) or gas blanketing systems to minimize emissions. These systems can significantly reduce the release of emissions, including volatile organic compounds (VOCs) into the atmosphere. However, GOR calculations do not consider the presence or efficiency of these control measures, leading to inaccurate estimates of emissions reductions achieved through mitigation efforts.

4. Tank Breathing or Evaporation Losses: Atmospheric storage tanks are particularly susceptible to breathing losses due to flashing, which can vary depending on factors such as product type, temperature, and tank design. GOR calculations do not account for these variations, resulting in unreliable emissions estimates.

In summary, while GOR calculations provide a simple formula for estimating gas-to-oil ratios in oil production, they are not appropriate for estimating emissions from atmospheric storage tanks in oil and gas facilities because they lack consideration for essential engineering parameters that significantly impact emissions. It is imperative to adopt more tailored and comprehensive methodologies that account for tank-specific parameters, control measures, and breathing losses to ensure accurate emissions estimates and regulatory compliance.

VIII. Associated Gas / Flare Stacks

a. Associated gas venting and flaring calculation

Subpart W currently requires reporters to calculate annual emissions from associated gas venting and flaring using equation W-18. Equation W-18 uses the GOR (gas-to-oil ratio), volume of oil produced, and volume of associated gas sent to sale to calculate the volume of gas vented or flared. Associated gas venting emissions are then calculated using the results of equation W–18 and the gas composition. Associated gas flaring emissions are calculated using the results of equation W–18 and the methodology for calculating flaring emissions from flare stacks for a given volume of flared gas.

EPA is proposing several significant changes to this methodology. Most importantly, EPA proposes to no longer require or allow operators to use equation W-18, based on GOR, to calculate the volume of associated gas flared from well production facilities. The proposed approach requires operators to use the methodologies used for flare stacks, based on "direct flow meters or other parameter monitoring systems combined with engineering calculations, such as line pressure and burner nozzle dimensions" to measure the volume of flared gas.[96] For vented associated gas, EPA proposes new provisions in 40 C.F.R. § 98.233(m)(3) to specify that if the reporter measures the flow to a vent using a continuous flow measurement device, then the reporter must use the measured flow volumes to calculate the volume of gas vented rather than

[96] 88 Fed. Reg. 50397 (Aug. 1, 2023).

using equation W-18.[97] Reporters would then not be required to report W-18 inputs. If reporters do not measure flow to a vent using a continuous flow measure device, they would continue to apply EPA's current approach (*i.e*., use equation W-18).[98]

We strongly support EPA's proposal to require operators to measure the volume of associated gas sent to flares using flare stack methodologies instead of a GOR. Using a GOR to calculate the volume of gas that is vented[99] or flared[100] is quite problematic, because gas production from wells (and therefore GOR) varies by large factors over time scales from minutes to years. Therefore, quite simply, the GOR changes too rapidly for measurements carried out over short times to be accurate and reliable. Even accurate measurements of average GOR (carried out with precise measurement over long periods of time) may only be accurate for a well for a few months, as the GOR changes over months.[101]

For venting, EPA should consider placing a limit on the volume of vented gas that can be calculated using GOR – above this amount, operators would be required to use the metering/parametric monitoring calculation methodology. Given the large pollution levels that come from venting oil wells, operators should not be allowed to use the unreliable GOR method to estimate larger volumes of venting of associated gas.

Additionally, EPA must set criteria for conducting GOR tests for venting wells. Canadian federal regulations require GOR tests to run from 24 to 72 hours,[102] and has standards for metering during the test.[103] Given the huge variability of GOR, it is appropriate for EPA to require measuring GOR over a multi-day period. In addition, GOR can clearly change over long time periods, so EPA should require GOR to be re-measured at least once per year.

As a clarification, EPA should change the name of § 98.233(m) to "Associated Gas Venting," since the paragraph no longer covers flaring of associated gas. Likewise, EPA should change the name of section 98.233(n) to "Associated Gas Flaring and Other Flare Stacks."

b. <u>Associated gas venting reporting</u>

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[97] 88 Fed. Reg. 50332 (Aug. 1 2023).
[98] *Id.*
[99] *See, e.g.*, Festa-Bianchet et al., M*ethane Venting from Uncontrolled Production Storage Tanks at Conventional Oil Wells – Temporal Variability, Root Causes, Implications for Remote Measurements, and Recommendations*, 11 Elem. Sci. Anth. 1 (2023), https://doi.org/10.1525/elementa.2023.00053.
[100] *See* Carbon Limits, *Improving utilization of associated gas in US tight oil fields*, at 17, https://cdn.catf.us/wp-content/uploads/2015/04/21094438/CATF_Pub_PuttingOuttheFire.pdf.
[101] *Id.*
[102] Environment and Climate Change Canada, *Regulations Respecting Reduction in the Release of Methane and Certain Volatile Organic Compounds (Upstream Oil and Gas Sector)*, § 24, https://laws-lois.justice.gc.ca/eng/regulations/SOR-2018-66/FullText.html.
[103] *Id.*

EPA has proposed changes to the way operators can report associated gas venting emissions. Specifically, EPA is proposing to require that reporters indicate whether or not a continuous flow monitor or continuous composition analyzer was used to measure the volume of gas vented. EPA's proposal would also require reporters to report the flow-weighted mole fractions of methane and CO_2 and the total volume of associated gas vented from the well, in standard cubic feet for all wells, regardless of whether a continuous flow measurement device was used. Additionally, EPA has clarified that for those volumetric emissions determined through a continuous flow measurement device, reporters would not be required to report the inputs to equation W-18.

We support EPA's proposed changes to associated gas venting reporting. Because continuous flow monitoring is a more comprehensive and accurate method for measuring emissions, it is reasonable that operators using those devices should not have to report equation W-18 inputs. However, EPA should clarify that reporting W-18 inputs—including GOR, volume of oil produced, and volume of gas sent to sale—is still required for operators who choose to continue using the existing GOR approach.

While we strongly support EPA's proposed approach to require measurement of all gas sent to flares, we note that EPA provides no criteria for carrying out these measurements accurately and precisely. Operators can use flow meters or parametric approaches such as using measurements of pressure and orifice size, together with engineering calculations, to calculate the volume of gas sent to flares. The highly variable flow from wells can be quite challenging to measure, and not all meters or parametric monitors will accurately capture phenomena such are spikes in flow.[104] EPA must carefully examine the reports of flared gas volumes, comparing these reports to independent assessments of flared gas volume such as those derived from satellite observations, to assess whether operators are utilizing accurate methods to measure the volume of gas sent to flares.

c. Calculating and reporting emissions from flare stacks

Although EPA currently allows reporters to assume a default combustion efficiency of 98% in calculating flare stack emissions, it is now proposing a tiered approach. In Tier 1, a default combustion efficiency of 98% would be allowed where the reporter conducts flare monitoring consistent with the procedures specified in 40 C.F.R. §§ 63.670 and 63.671 (NESHAP for petroleum refineries, or "NESHAP CC"). Section 63.670 requires flare operators to use a pilot flame at all times when regulated material is routed to a flare; specify the smokeless design capacity of each flare; operate with no visible emissions; monitor the flare tip velocity and ensure the average flow rate every 15 minutes does not exceed the maximum velocity determined by the vented gas's net heating value; maintain the net heating value of flare combustion zone gas at or above 270 Btu/scf; continuously monitor the presence of the pilot flame; conduct an initial visible emissions demonstration using an observation period of 2 hours

[104] *See, e.g.*, Festa-Bianchet et al., *supra* note 99, at 13.

using Method 22; and operate a monitoring system capable of continuously measuring, calculating, and recording the volumetric flow rate in the flare header as well as any flare supplemental gas that is used. Under NESHAP CC, it is presumed that complying with these flare requirements achieves at least 98% reduction in emissions.

In Tier 2, a default combustion efficiency of 95% would be allowed if the reporter is required to or elects to comply with the monitoring specified in proposed 40 C.F.R. § 60.5417b(d)(1)(viii) of OOOOb. The standard in OOOOb is 95%, and it is presumed that this standard is met when the specified monitoring is conducted and the corresponding activity data limits are met. OOOOb requires operators to continuously monitor at least 1 time every 5 minutes with a device capable of detecting a flame (thermocouple, ultraviolet beam sensor, infrared sensor); use a continuous Parameter Monitoring System to measure flow unless a backpressure preventer is in place or the operator is using pressure assisted flare; and continuously determine the NHV of inlet gas using a calorimeter unless the NHV exceeds the applicable operating limit (5414(f)(1)(vii)(B)(1)) or the operator continuously determines the NHV of inlet gas using a calorimeter. EPA's reporting elements to demonstrate compliance with OOOOb require operators to "indicate" whether they are subject to that rule or electing to comply with its flare monitoring requirements. For those merely electing to comply, operators must "indicate whether [they] use a calorimeter to continuously determine net heating value (NHV) or if [they] have demonstrated according to the methods described in § 60.5417b(d)(1)(viii)(C) of this chapter that the NHV consistently exceeds the operating limit specified in § 60.18 of this chapter (or that it consistently exceeds 800 Btu/scf for a pressure assist flare)."[105]

Tier 3, a default combustion efficiency of 92%, would apply if Tier 1 or 2 requirements are not met and before a flare owner is required to implement those requirements per other regulations. EPA states that a 92% assumption is based on the low end of the range of empirical results observed in testing over an extensive area in three of the most active basins in the US.

We generally support EPA's tiered approach. Research from Plant et al. illustrated that the combustion efficiency in the field varies significantly and is on average lower than the prior assumption of 98%. In this proposal, EPA correctly applies average combustion efficiency measurements from lit flares, and does not apply the effective combustion efficiency values in the Plant et al. study (which take into account the contribution of unlit flares) since unlit flares are accounted for elsewhere in the reporting. Therefore, EPA is not double counting by both lowering the default combustion efficiency and requiring improved reporting of time periods when the flare is unlit. The Tier 3 combustion efficiency of 92% was determined by the lowest average combustion efficiency of the three basins measured by Plant et al. For Tier 2, EPA applies the combustion efficiency of 95%, which was the average across all basins in Plant et al. This measured value is consistent with the minimum control requirements in OOOOb. Lastly, the Tier 1 assumption of 98% combustion efficiency—the prior EPA assumption—requires operators to demonstrate compliance with NESHAP CC. Because that regulation requires

[105] 88 Fed. Reg. 50429 (Aug. 1 2023).

continuous monitoring of the pilot light, flow rate, flare tip velocity, and NHV to ensure suitable conditions for proper combustion, a 98% assumption for Tier 1 is reasonable.

Overall, we find that EPA's tiered approach incorporates insights from the most recent flaring science, and simultaneously rewards reporters for demonstrating compliance, or equivalency, with robust regulatory standards that have been demonstrated to increase the effectiveness of flares.

Although we support EPA's overall framework, we are concerned that operators who report voluntary compliance with NESHAP CC or OOOOb for the purpose of applying a higher combustion efficiency may not comply with flaring operational standards as fully as operators who are directly legally required to apply those standards to their flares. EPA should therefore improve the proposal by strengthening reporting requirements to ensure operators who claim they fall under Tier 1 or 2 are in fact meeting associated assumptions. EPA's proposal currently allows operators to monitor the flare as specified under those rules to estimate the combustion efficiency from flares because those separate rules each *require* a combustion efficiency of 98% or 95% for flares covered under the respective regulations. This is insufficient for subpart W reporting.

As an initial matter, EPA should require operators subject to NESHAP CC and OOOOb to submit relevant compliance reports under both rules to EPA GHGRP staff so that staff can verify actual compliance with those rules. Additionally, we note that operators that are required to comply with NESHAP CC and OOOOb are subject to more than just monitoring requirements to ensure the 98% and 95% requirements are met. For example, flares used as a control device under OOOOb are required to design the flares consistent with 40 C.F.R. § 60.18 and, in many cases, also undertake performance testing under 40 C.F.R. § 60.5412b(d). Similarly, under NESHAP CC, operators must also comply with requirements under 40 C.F.R. 40 C.F.R. § 63.11. This additional level of oversight provides a necessary verification that the assumed combustion efficiencies under those rules are met. While this is not an issue for reporters that are subject to those standards, it creates a stark divide with those that elect to voluntarily comply with 40 C.F.R. §§ 63.670 and 63.671 (for Tier 1) or 40 C.F.R. § 60.5417b(d)(1)(viii) (for Tier 2).

To bridge that gap, EPA should also require reporters that elect to follow the respective monitoring requirements for Tier 1 or 2 to submit documentation that they comply with the flare requirements under the general provisions of the NESHAP, 40 C.F.R. § 63.11, or the NSPS, 40 C.F.R. § 60.18. Those that elect to be in Tier 1 or 2 should also be required to keep and maintain records consistent with the recordkeeping requirements under the respective NESHAP, OOOOb, and approved state plan requirements. For Tier 1, we recommend the recordkeeping requirements under 40 C.F.R. § 63.655(i)(9); for Tier 2 we recommend the recordkeeping requirements consistent with 40 C.F.R. § 60.5420b)(c)(3)(ii)(A)-(H). Maintaining such records will allow EPA staff to verify additional compliance with the respective flare requirements to ensure more accurate emissions reporting.

d. Associated gas flaring should be reported separately from other flaring

As described above, in its current proposal, EPA requires all emissions from flaring to be calculated using the methodologies in section 98.233(n), which requires measurement of the volume of gas sent to the flare (with a meter or parametric monitoring). As we detailed above, this is an important improvement over the current requirements, in particular for the most important source of flared gas, associated gas. We strongly support this key improvement. However, in the current proposal, EPA would no longer require clearly separate reporting of emissions (or other parameters) for associated gas flaring. Rather, operators report all parameters (volumes of gas flared, combustion efficiency, gas composition, flare type, and emissions) in aggregate for each flare, if they do not meter the different flows to the flare separately. In this case, associated gas can be mingled with other gas sources for the purposes of reporting. Operators *are* required to report *estimated* disaggregated emissions of methane, CO_2 and N_2O attributed to each source type,[106] but this will be just an estimate and this provision does not require disaggregation of the critical other parameters reported under section 98.236(n). Furthermore, we are concerned that this provision may lead to emissions reports that are challenging to clearly disaggregate into emissions from associated gas flaring and other types of flaring, due to potential inconsistencies in designations operators use in reporting categories under section 98.236(n)(19).

Associated gas flaring, specifically, is a very large source of emissions that has been targeted for mitigation by a number of jurisdictions and regulatory authorities. EPA should modify the reporting requirements to require operators to clearly report all parameters required under section 98.236(n) separately for both associated gas flaring and other types of flaring. This may require modification of section 98.233(n) to require that associated gas volumes be measured separately from other gas flared at vent stacks.

e. Calculating and reporting emissions from unlit flares

In its current proposal, EPA would require operators to follow one of several options to monitor whether a flare is unlit "using a device (including, but not limited to, a thermocouple, ultraviolet beam sensor, or infrared sensor) capable of detecting that the pilot or combustion flame is present at all times"[107] and directs the operator to calculate the fraction of feed gas sent to an unlit flare. It then uses this value in Equation W-19 for calculating CH4 emissions from flaring: "ZU = Fraction of the feed gas sent to an unlit flare determined from both the total time the flare was unlit as determined by monitoring the pilot flame or combustion flame as specified in paragraph (n)(2) of this section and the volume of gas routed to the flare during periods when the flare was unlit as determined by the flow measurement required by paragraph (n)(1) of this section." Thus, CH4 emissions from the unlit flare are reported together with CH4 emissions from methane slip at the flare. Requiring reporting of emissions from unlit flares based on actual measurement and observation is an improvement over the existing reporting requirement in

[106] Proposed § 98.236(n)(19).
[107] 88 Fed. Reg. 50398 (Aug. 1, 2023).

which unlit flare fraction is based on "engineering estimates and process knowledge based on best available data and operating records." Operators report the value for ZU, but they do not directly report the methane emissions from the unlit flare. We ask EPA to modify the reporting requirements to separately report CH4 from slip at the flare and CH4 from the unlit flare. This would significantly increase transparency and auditability for this important emissions source.

EPA is also proposing to require a few new flare-specific reporting elements to help better understand the state of flaring in the industry and to improve data quality, such as an indication of the type of the flare (*e.g.,* open ground-level flare, enclosed ground-level flare, open elevated flare, or enclosed elevated flare) in 40 C.F.R. § 98.236(n)(4) and the type of flare assist (*e.g.,* unassisted, air assisted with indication of single-, dual-, or variable-speed fan, steam assisted, or pressure-assisted) in proposed 40 C.F.R. § 98.236(n)(5). These additional data elements are extremely important for understanding emissions from flaring.

The proposed requirements for continuously monitoring flared gas volumes and the pilot light will increase the accuracy of reported emissions during periods while a flare is unlit. Meanwhile, revisions to the combustion efficiency assumption will reflect flared gas emission estimates that are closer to what has been observed through recent scientific research. However, there are still cases where flares may temporarily have reduced combustion efficiency, due to causes such as improper amounts of air-assistance or crosswinds[108] inhibiting proper combustion. Emissions from lit flares during these periods could exceed a 100 kg/h CH4 emission rate[109] or a similarly large threshold and is not represented by the calculation frameworks in this section. Therefore, we recommend that EPA clarify to reporters that if observed combustion efficiency is reduced below their combustion efficiency tier, or if a survey detects a large emission source from a lit flare, this should be considered credible information for including these excess emissions from that period in the large release events category.

IX. Compressors

We generally support the changes that EPA has proposed for reporting on compressors, which will increase the accuracy of the reporting program. In addition to the points articulated below, we also support EPA's proposals to (1) update the emission factors for uncombusted methane emissions in exhaust (i.e., "methane slip") from compressor engines; (2) add an emission source category for crankcase venting; (3) require reporting of the number of dry seals on centrifugal compressors and the reporting of emission measurements made on the dry seals; (4) remove acoustic leak detection from the screening and measurement methods allowed for manifolded groups of compressor sources and; (5) require operators to report the total number of centrifugal

[108] Burtt et al., *A methodology for quantifying combustion efficiencies and species emission rates of flares subjected to crosswind*, 104 J. Energy Inst. 124 (2023), https://doi.org/10.1016/j.joei.2022.07.005.
[109] Examples of large CH4 emissions from processing plant, available at: https://edf-permian-data.s3.amazonaws.com/videos/Flaring_August_2021/S6M_0330 mp4. Examples of large methane emissions from central tank battery, available at: https://edf-permian-data.s3.amazonaws.com/videos/Flaring_December_21/S8R_0480.mp4.

compressors at the facility and the number of centrifugal compressors that have wet seals, along with the total number of reciprocating compressors at the facility.

a. Alignment with OOOOb/OOOOc

We support EPA's efforts to align subpart W with forthcoming regulatory requirements. A significant portion of subpart W reporting facilities and emission sources will become subject to LDAR requirements under the proposed OOOOb/c regulations in the coming years, with little added burden to report gathered data through subpart W. We therefore support EPA's proposal to require these facilities to report data gathered through monitoring surveys, and the option to do so voluntarily for facilities or portions of facilities not subject to fugitive monitoring regulatory requirements.

b. Use of emission factors derived from Zimmerle et al. (2019)

We support EPA's proposal to amend the methane and CO_2 population emission factors for compressors. Adjusting these emission factors to a population emission factor based on the average population emission rate measured by Zimmerle et al. (2019) will greatly improve the accuracy of reporting using equation W-29D. The Zimmerle study is more comprehensive than the previously used data from 1996, as it includes a nationally representative field assessment with a sample size of rod packing vent measurements that is much larger than that of the 1996 study.

c. Addition of dry seal vents to reporting requirements

We also support EPA's proposal to add dry seal vents to the defined compressor sources for centrifugal compressors and require measurement of volumetric emissions from the dry seal vents in both operating mode and in standby pressurized mode. As EPA notes, while dry seal compressors have lower emissions than wet seal compressors, these emissions are not negligible and thus should be accounted for. Additionally, EPA correctly observes that the measurement crew will already be at the centrifugal compressor to make the "as found" measurement for blowdown valve leakage, so they can also measure the emissions from the dry seal while they are onsite.

d. Other changes to mode-source reporting

We support EPA's proposal to include reporting in standby pressurized mode for reciprocating and wet seal oil degassing vent in centrifugal compressors. While the standby pressurized mode is less common, emissions do occur during this mode, and adding this will provide clear guidance to operators. Furthermore, we support requiring measurement of rod packing emissions for reciprocating compressors when found operating in standby pressurized mode, which will increase the accuracy of overall reporting. As EPA notes, recent studies indicate that rod packing emissions can occur while the compressor is in standby pressurized mode. Similar to the consideration for dry seal vents, measurement crew will already be at the compressor to make the "as found" measurement for blowdown valve leakage, so they can also measure the emissions from the dry seal while they are onsite.

X. Equipment Leaks

Environmental Commenters largely support the proposed changes to equipment leak surveys and equipment leaks by population count, which will improve the accuracy of reported emissions from equipment leaks. For the leak survey requirements, EPA should require operators to measure and report emissions as a large release event if an operator has credible evidence or should reasonably suspect that emissions found during a leak survey would qualify as a large release event. We also encourage EPA to incorporate a pathway and set forth criteria for reporting emissions based on direct measurement by advanced technologies at the equipment level.

a. <u>Equipment leak surveys</u>

Revisions and Addition of Default Leaker Emission Factors

We support EPA's proposal to amend the leaker emission factors in Table W–1E for production and gathering and boosting facilities to include separate emission factors for leakers detected with OGI. EPA's proposed emission factors were developed by combining the data from Zimmerle et al. (2020) and Pacsi et al. (2019), and represent an improvement from the outdated factors currently being used. Because EPA excluded venting sources on compressors and tanks (e.g., blowdown vent, common multi-unit vent, common single-unit vent, pocket vent, rod packing vent, and starter vent) when creating OGI leaker factors based on Zimmerle (2020), if an operator finds emissions from those sources during an OGI survey they should be reported in the appropriate category or as a large release event if appropriate.

We also agree that using the same leaker emission factor for components detected with OGI and Method 21 with a leak definition of 10,000 ppm, as is currently done in subpart W, likely understates the emissions from leakers detected with OGI. We also support a requirement to use OGI leaker emission factors to quantify the emissions from the leaks identified using other monitoring methods, and support a pathway for identifying alternative technology specific factors in future.

EPA proposes to estimate leak duration based on the following assumptions:

> If one leak detection survey is conducted in the calendar year, assume the component was leaking for the entire calendar year. If multiple leak detection surveys are conducted in the calendar year, assume a component found leaking in the first survey was leaking since the beginning of the year until the date of the survey; assume a component found leaking in the last survey of the year was

> leaking from the preceding survey through the end of the year; assume a component found leaking in a survey between the first and last surveys of the year was leaking since the preceding survey until the date of the survey; and sum times for all leaking periods. For each leaking component, account for time the component was not operational (i.e., not operating under pressure) using an engineering estimate based on best available data.[110]

Similar to our recommendations for open thief hatches above, we recommend that EPA include a forward-looking element to the duration of time calculated for the leak until the date of leak repair. In other words, if the leak is not actually repaired on date of the leak survey when it is detected, time until actual repair should be included in the emissions reporting. While the leak duration assumptions EPA proposes are otherwise reasonable, EPA could also consider an approach similar to that of the Alberta Energy Regulator. AER uses half the time between the previous survey and the leak repair date. If there is no previous survey, then AER assumes a duration of 8760 hours. If the leak is not repaired in that calendar year, the end date for emissions is in the calendar year found for reporting purposes, and the leak is then treated as a new leak in the next calendar year with a duration lasting until repair. This approach appropriately considers the date of repair, not just the date a leak is found during a survey. EPA could utilize a similar approach.

We also support EPA's proposal to apply the "OGI enhancement" factor identified from measurement study data in the onshore production and gathering and boosting industry segments to the leaker emission factors for the other subpart W industry segments as a means to estimate an OGI emission factor set. EPA's rationales for proposing these factors for the production segment apply equally to other segments, and EPA's proposal to apply the enhancement factor is therefore reasonable and will lead to more accurate estimates.

We strongly support a requirement to report the major equipment type (e.g., wellhead, compressor, dehydrator) at which the component-level leak is found, in addition to continuing to collect activity data on a per component basis. Including major equipment type will provide important information for assessing emissions and reduction efforts, while only imposing a de minimus additional reporting burden. EPA should also consider requiring emissions reported under the leak surveys option to be based on major equipment emissions factors that account for large emission events, in line with its proposed update to the emission factors for the population count method for reporting equipment leaks.

Finally, as discussed above in the large release event section, if an operator has credible evidence or should reasonably suspect that emissions found during a leak survey would qualify as a large release event (for example, an emission source which saturates or exceeds the scale of a Method 21instrument), the operator should be required to measure emissions and report as a large release event if it meets the threshold, rather than as a leak.

[110] 88 Fed. Reg. 50405.

Addition of undetected leak factor for leaker emission estimation methods

We support EPA's proposal to provide a method specific adjustment factor, k, for the calculation methods leaks (i.e., OGI, Method 21 with a leak definition of 500 ppm, and Method 21 with a leak definition of 10,000 ppm) used to quantify emissions from equipment. We also support EPA's proposal for alternative methods to use the OGI k factor for adjustment. Lastly, we support EPA's proposal to have adjustment factors apply across the leak survey options including the default and proposed site-specific adjustment factors, as well as the direct measurement method.

Based on Pacsi et al., EPA finds that OGI observes 80% of emissions from measured leaks, Method 21 at a leak definition of 10,000 ppm observes 65% of emissions from measured leaks, and Method 21 at leak definition of 500 ppm observes 79% of emissions from measured leaks. In order to account for the quantity of emissions that remain undetected by each screening method, EPA proposes that an adjustment factor, k, is needed. The proposed k factor is derived by dividing 100% by the method-specific percent of emissions observed. For example, for OGI, the proposed undetected leak factor, k, is calculated as 100/80 or 1.25. Following this same method, the proposed undetected leak factor for Method 21 at a leak definition of 10,000 ppm is 1.55 and for Method 21 at a leak definition of 500 ppm is 1.27. We agree with EPA that these adjustment factors will improve the accuracy of reported emissions data. Additional scientific studies have documented that handheld monitoring technologies, including OGI, fail to see certain types of leaks,[111] and EPA's proposal to account for these missed emissions based on empirical data from Pacsi et al. will help improve accuracy.

Addition of method to quantify emissions using direct measurement

We support EPA's addition of an option to quantify equipment leak emissions by directly measuring leaks using one of the existing subpart W measurement methods in 40 CFR 98.234(b) through (d), such as calibrated bagging or a high volume sampler. We strongly agree with EPA that for this option, operators must be required to measure *all* leaks identified during a complete leak detection survey to avoid cherry-picking by only measuring the smallest leaks at a site or leaks expected to measure below the default leaker factors.

As discussed below, there are technologies that are capable of identifying and quantifying leaks at the equipment level. EPA could incorporate the reporting of emissions from equipment leaks that are detected and quantified by these technologies (e.g., TDLAS, point sensors, open path technologies, aerial LiDAR) as they would represent direct measurement of emissions and would be consistent with EPA's shift to equipment-based factors elsewhere in subpart W. To incorporate these methods, EPA should ensure that that technologies are capable of both (1) quantifying emissions based on an appropriate level of measurement sensitivity by establishing

[111] *See, e.g.*, Tyner & Johnson, *supra* note 40; Ravikumar et al., *Are Optical Gas Imaging Technologies Effective For Methane Leak Detection?*, 51 Env. Sci. Tech. 718 (2017), https://pubs.acs.org/doi/10.1021/acs.est.6b03906.

criteria in a final subpart W rule and (2) identifying the individual piece of equipment with the emissions, in line with criteria for detection established for alternative technologies in OOOOb/c.

Addition of a method to develop site-specific component-level leaker emission factors

We support EPA's proposal to include a method to develop site-specific component-level leaker emission factors. We believe EPA's proposal to require a use of a minimum of 50 measurements of a particular leaking component and leak detection method is appropriate to ensure the site-specific leaker factors are statistically representative. In EPA's 1995 emission factor protocol for LDAR, the agency recommended at least 30 measurements (bagged emissions) if someone wanted to develop unit-specific correlation equations across all ranges for Method 21 readings.[112] Less is known about the quantification of leaks identified by OGI compared to Method 21. OGI surveys have varying degrees of performance based on many factors, including wind speed/direction, ambient temperature, sky conditions, and the experience of the operator.[113] For these reasons, at least 50 samples should be measured to ensure sufficient representation in the sampling for developing site-specific leaker factors.

Amendments related to oil and natural gas standards and emissions guidelines in 40 C.F.R. Part 60

We support EPA's efforts to align subpart W with forthcoming regulatory requirements for fugitive emissions surveys. All subpart W reporting facilities will become subject to fugitive emissions survey requirements under NSPS OOOOb and 40 CFR part 62 state plans implementing EG OOOOc regulations. We therefore support EPA's proposal to require these facilities to report data gathered through compliance with the required OGI monitoring surveys because this will present little added burden for subpart W reporting.

EPA should clearly state that the monitoring results from all surveys conducted in compliance with NSPS OOOOb or 40 CFR part 62 state plans must be included when reporting emissions from leaks. If finalized as proposed, both forthcoming regulatory actions would require either semiannual or quarterly OGI surveys depending on the type of site (wellsite, centralized production facility, or compressor station) and the type and count of equipment at the site. We support EPA's proposal that emissions would be calculated based on the use of the revised leaker factors and assumed leak durations based on the survey frequency.

AVO inspections

EPA fails to include requirements related to the estimation of emissions from equipment leaks that are identified during AVO inspections. In the 2022 supplemental proposal for NSPS OOOOb and EG OOOOc, EPA proposed frequent AVO inspections to allow for the faster

[112] U.S. EPA, *Protocol for Equipment Leak Emission Estimates at* 2-42 (1995), https://www.epa.gov/sites/default/files/2020-09/documents/protocol_for_equipment_leak_emission_estimates.pdf.
[113] Zimmerle et al., *Detection Limits of Optical Gas Imaging for Natural Gas Leak Detection in Realistic Controlled Conditions*, 54 Environ. Sci. Technol. 11506 (2020), https://pubs.acs.org/doi/10.1021/acs.est.0c01285.

identification of larger emissions sources (e.g., surface casing valves).[114] Because these emissions can be identified without the need for specialized training or equipment, it is reasonable to assume these are larger emissions that should be accounted for in the reported emissions for subpart W and any subsequent waste emissions charge. Therefore, we recommend that EPA specify that reporters either perform a voluntary OGI or Method 21 survey at the individual site level (wellsite, centralized production facility, or compressor station) and use the leaker emission factors to estimate those emissions, or reporters estimate emissions using the population count method at the individual site level where emissions are detected through AVO inspections.

Screening surveys using approved alternative technologies

The 2022 proposed NSPS OOOOb and EG OOOOc included provisions that would allow the use of advanced methane detection technologies and continuous monitoring systems after EPA approves alternative test methods.[115] We recommend that EPA also incorporate language for subpart W to allow the use of results from the follow-up OGI and Method 21 surveys for purposes of calculating and reporting emissions from equipment leaks.

Equipment leaks from onshore natural gas processing facilities

We support EPA's proposal to allow use of the results from LDAR surveys conducted in compliance with NSPS OOOOb and 40 CFR part 62 state plans at onshore natural gas processing plants. These surveys provide critical information on the number of leaks detected throughout the year and duration of individual leaks at the component level. We further support EPA's proposal to use all information from each survey and the requirement to conduct a complete survey at least once during the reporting year. We believe these surveys, in conjunction with the leaker emission factors, provide for accurate reporting of emissions from equipment leaks at these facilities, and ensure that all components are monitored for emissions each year.

Additional methods or advanced technologies that can identify individual leaking components

EPA requests comment on other methods or advanced technologies that can identify leaks from individual components. While there are many technologies available, most advanced technologies have focused on the identification and quantification of emissions at the equipment level. As discussed above, EPA could incorporate the reporting of emissions from equipment leaks that are detected and quantified by these technologies as they would represent direct measurement of emissions and would be consistent with EPA's shift to equipment-based factors elsewhere in subpart W. To incorporate these methods, EPA should ensure that that technologies are capable of both (1) quantifying emissions based on an appropriate level of measurement sensitivity by establishing criteria in a final subpart W rule and (2) identifying the individual piece of equipment with the emissions, in line with criteria for detection established for

[114] *See* 87 Fed. Reg. 74732 (Dec. 2, 2022).
[115] *See* 87 Fed. Reg. 74740 (Dec. 6, 2022).

alternative technologies in OOOOb/c. This approach could provide for more accurate reporting of the emissions dependent on the method used and the accuracy of the emissions quantification.

b. Equipment leaks by population count

Onshore production and G&B population count method

We strongly support EPA's proposal to provide emission factors that are on a major equipment basis rather than a per component basis. We believe this feature of the proposal will reduce reporter error by eliminating the step of estimating the number of components, and that use of major equipment factors should be required whenever it is possible. We also believe this would reduce reporter burden as well as the number of errors in the calculation of emissions, leading to better overall emissions estimates.

We further strongly support EPA's proposal to use Rutherford et al. (2021) to provide population emission factors by major equipment and site type (i.e., natural gas system or petroleum system). The Rutherford model accounts for large emission events when developing bottom-up emission factors using a bootstrap resampling statistical approach. This represents an improvement over relying solely on the study data from Zimmerle et al. (2020) and/or Pacsi et al. (2019) to provide the population count emission factors by major equipment because emission factors based solely on those data do not adequately account for intermittent, large emission events. In contrast, the Rutherford study is based on greater measurement data and robustly accounts for infrequent, large emission events.

The Rutherford study and estimation tool undertakes two sequential extrapolations: first from the component to the equipment-level, and second from the equipment to the national or regional-level.[116] The approach utilized in the bottom-up estimation tool begins with a database of component-level direct emissions measurements (e.g., component-level emission factors). The authors generate component-level emission factor distributions from a literature review building on prior work and adding new publicly available quantified measurements. The resulting database includes around 3,700 measurements from six studies across a 12-fold component classification scheme. They then derive equipment-level emission factors through random resampling (i.e., bootstrapping, with replacement) from the component-level database according to component counts per equipment and fraction of components emitting. Some of the studies relied on by Rutherford et al. also calculate equipment-level emission factors, but these are not used as inputs. Instead, the authors take the combined component-level emission data, component counts, and fraction of components found to be leaking, and derive values different from those calculated in the underlying studies. The authors then use these emission factors to construct a bottom-up inventory that largely aligns with the top-down literature and estimates.

[116] Rutherford et al., *supra* note 20.

The Rutherford estimation tool provides a useful example of how emission factors can be derived that reflect and align with top-down literature and observed emissions. For the default subpart W emission factors to provide useful estimates that give an accurate picture of actual observed emissions, it is critical they incorporate super-emitter events. If they do not, the reporting program could disincentivize operators from using advanced measurement technologies and reporting better data because doing so will lead to higher reported emissions than they would calculate using the existing and proposed emission factors.

EPA appropriately excluded data from the Rutherford sample for venting from tanks, liquids unloading, flare slip and other sources that are reported under other sources covered by subpart W to avoid double reporting of those emissions.

XI. Offshore

Offshore facilities account for 30% of global oil and natural gas production but produce a higher quantity of emissions relative to production when compared to onshore facilities. According to a recent study published by Carbon Mapper, the University of Michigan, and the University of Arizona, offshore facilities have a methane loss rate (*i.e.*, the measure of emissions relative to production) of 23% to 66%, while onshore facilities in places like the Permian basin have a methane loss rate of 3.3% to 3.7%.[117] According to the GHGI, offshore petroleum and natural gas production facilities account for 4% of total production emissions.[118] As current and proposed onshore oil and gas methane regulations are implemented, offshore emissions could comprise a proportionately even larger share of total US oil and gas methane emissions. Methane venting and flaring are primary contributors to offshore emissions.[119]

Further, like onshore emissions, offshore emissions reported through the GHGI are under-estimated. A recent study comparing BOEM's inventory (which is used by the EPA GHGI) to observational data found that methane emissions are underestimated when compared to inventories at the site level, even when accounting for intermittent hourly emissions.[120] The study found that "[p]latforms in shallow waters, especially central hubs, are most responsible for the gap in reported CH_4 emissions."[121] Given the high loss rate associated with offshore facilities compared to onshore facilities and that emissions are highly under-estimated, it's essential that EPA help improve reporting requirements for offshore facilities under the GHGRP.

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[117] Ayasse et al., *Methane remote sensing and emission quantification of offshore shallow water oil and gas platforms in the Gulf of Mexico*, 17 Environ. Res. Lett. 084039 (2022), https://iopscience.iop.org/article/10.1088/1748-9326/ac8566.
[118] U.S. EPA, *Inventory of U.S. Greenhouse Gas Emissions and Sinks: 1990-2021*, EPA 430-R-23-002, https://www.epa.gov/ghgemissions/inventory-us-greenhouse-gas-emissions-and-sinks-1990-2019.
[119] NASA, *Mapping Methane Emission Plumes Using Sunglint-confingured Imagery for Monitoring Offshore Oil & Gas Activity* (2022), https://appliedsciences nasa.gov/what-we-do/projects/mapping-methane-emission-plumes-using-sunglint-configured-imagery-monitoring.
[120] Negron et al., *Excess methane emissions from shallow water platforms elevate the carbon intensity of US Gulf of Mexico oil and gas production*, 120 Earth, Atmospheric, and Planetary Scis. 1 (2023) https://www.pnas.org/doi/full/10.1073/pnas.2215275120.
[121] *Id.* at 5.

Subpart W currently requires offshore production facilities to report emissions consistent with methods published by BOEM. On the years where both BOEM and EPA require reporting, facilities that report data to BOEM may submit that same data to fulfill subpart W requirements, and facilities that don't report to BOEM must use the most recent calculation methods published by BOEM. During the years that BOEM doesn't require reporting, facilities that report to BOEM must use their most recent BOEM data submission and adjust emissions based on operating time, while operators that don't report to BOEM must again use BOEM's most recent calculation methods.

EPA is proposing two changes to reporting requirements during the years that operators do not submit to BOEM. First, operators can use their most recent BOEM submission and adjust based on operating time as before but would be required to report two new data elements: operating hours in the current year, and the facility's operating hours from the BOEM emission study publication year that is the basis for the reported emissions. Second, whether or not operators report to BOEM already, they can calculate emissions anew using the most recent monitoring and calculation methods published by BOEM referenced in 30 C.F.R. § 550.302 through 304. EPA has concluded that this alternative will improve data quality through the use of more empirical data.

While we support some aspects of these changes—including additional reporting elements under the first reporting option—we encourage EPA to, as with onshore facilities, incorporate top-down approaches discussed earlier in these comments for offshore facilities.

This type of reporting framework is feasible for offshore facilities. Emission inventories for production platforms in federal waters of the Gulf of Mexico have extremely detailed public information available about intermittency from oil and gas sources. For the platforms, BOEM has developed an emissions inventory that reports source-by-source emissions data for individual offshore platforms, on a monthly basis.[122] Approximately 1,100 platforms in the Gulf of Mexico reported emissions through the Gulfwide Offshore Activities Data Systems (GOADS) in 2017.[123]

Further, a recent partnership between BOEM and NASA demonstrates how remote sensing can complement current bottom-up methane emission assessments.[124] In this study, NASA used several satellites and sensors, including Landsat 8 OLI, Sentintel-2 MSI, PRISMA, Landsat 9 OLI-2, and Suomi NPP VIIRS, to identify and quantity methane plumes from flaring and venting at offshore facilities using sunglint configured imagery.[125] The study concluded that its analyses

[122] Chen et al., *Reconciling Methane Emission Measurements for Offshore Oil and Gas Platforms with Detailed Emissions Inventories: Accounting for Emission Intermittency*, 3 ACS Environ. 88 (2023), https://www.ncbi.nlm.nih.gov/pmc/articles/PMC10125359/pdf/vg2c00041.pdf.
[123] *Id.*
[124] NASA, *Gulf of Mexico Health & Air Quality: Mapping Methane Emission Plumes Using Sunglint-configured Imagery for Monitoring Offshore Oil and Gas Activity* (2022), https://ntrs.nasa.gov/citations/20220016789.
[125] NASA, *Gulf of Mexico Health & Air Quality: Mapping Methane Emission Plumes Using Sunglint-configured Imagery for Monitoring Offshore Oil and Gas Activity* (2022) at Slide 6 (available at Attachment G).

served as “a proof of concept for the utility of remote sensing for methane emission monitoring offshore, which can complement regulator emission inventories and validate self-reported operator records.”[126]

While conducting measurements offshore requires additional considerations and methods relative to onshore, there are numerous available technologies that would enable the GHGRP to use multi-scale top-down data for offshore reporting. Site-level measurements are available through downwind boat-based observations[127], aircraft mass balance[128], and aerial[129] and satellite remote sensing[130]. Additionally, regional top-down emissions can be estimated through statistically aggregated site-level data.[131] Current satellite capabilities[132] already enable monitoring for offshore large emission events and direct measurements of regional emissions in the near future.[133] BOEM’s upcoming project, Carbon Mapper and Air Measurements in the Gulf of Mexico, is a model of how governmental agencies can coordinate to collect multiscale empirical data for building complete emission estimates.[134]

If EPA chooses to retain its general proposed framework, we recommend that it require all offshore facilities to calculate their emissions each year using BOEM’s most recent calculation methods. BOEM is actively working to incorporate top-down data into its reporting framework, which EPA acknowledges is “expected to improve data quality through the use of more empirical data.” EPA should ensure that as BOEM calculation requirements incorporate empirical methods, operators use those same methods to report to EPA each year. To permit operators to submit their most recent BOEM submissions would mean operators are submitting data that is both outdated (by potentially three years) and not reflective of BOEM’s updated methods.

XII. Throughput

We support EPA’s proposed changes to throughput quantity reporting. We support the general changes made to align with CAA section 136 across all segments including adding “natural” in

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[126] NASA, *Mapping Methane Emission Plumes Using Sunglint-confingured Imagery for Monitoring Offshore Oil & Gas Activity*, (2022), https://appliedsciences.nasa.gov/what-we-do/projects/mapping-methane-emission-plumes-using-sunglint-configured-imagery-monitoring.
[127] Riddick et al., *Methane emissions from oil and gas platforms in the North Sea*, 19 Atmospheric Chem. Phys. 9787 (2019), https://doi.org/10.5194/acp-19-9787-2019.
[128] Negron et al., *supra* note 43.
[129] Ayasse et al., *supra* note 117.
[130] GHGSat, *GHGSat achieves breakthrough in offshore emissions measurement from space* (Sept. 22, 2022), https://www.ghgsat.com/en/newsroom/ghgsat-achieves-breakthrough-in-offshore-emissions-measurement-from-space/.
[131] *Excess methane emissions from shallow water platforms elevate the carbon intensity of US Gulf of Mexico oil and gas production, supra* note 120.
[132] Irakulis-Loitxate et al., *supra* note 46.
[133] MethaneSAT, *Bridging the Gap*, https://www methanesat.org/satellite/ (last visited Oct. 2, 2023).
[134] BOEM, *Studies Development Plan* at 214, https://www.boem.gov/environment/environmental-studies/studies-development-plan-2023-2024.

front of “gas,” clarifying the definitions of oil/crude oil, “sent to sales,” and “through the facility,” and the additional measurement of quantities sent to sales/through the facility.
For the Onshore Petroleum and Natural Gas Production and Offshore Petroleum and Natural Gas Production segment, we support the separation of crude oil and condensate throughput reporting, as well as the changes proposed to make Offshore Petroleum and Natural Gas Production reporting elements analogous to those in Onshore Production. We believe that EPA should continue to retain the existing reporting elements in addition to the proposed new data elements to allow direct comparison of the impacts of the proposed change in requirements.[135]

For Onshore Petroleum and Natural Gas Gathering and Boosting, we strongly support the proposed amendments that will clarify the previous definitions as this will lead to greater data accuracy and completeness for the segment. We support the clarification in 40 C.F.R. § 98.236(aa)(10)(ii) and (iv) that the downstream endpoints listed in the current reporting elements are examples of potential destinations and the specification that the reported quantities should be the *total* natural gas or hydrocarbon liquids, respectively, transported to downstream operations such as one of those endpoints. We also support adding storage facilities to the list of downstream operations to make the list of examples more comprehensive, as well as the specification that reported quantities should include all natural gas and hydrocarbon liquids transported downstream from the facility (i.e., leaving the basin or leaving the gathering system owner or operator). Additionally, we strongly support the amendment to the definition of “Gathering and boosting system” and “Gathering and boosting owner or operator” in 40 C.F.R. § 98.238 to specify that these systems may receive natural gas and/or petroleum from one or more other onshore petroleum and natural gas gathering and boosting systems in addition to production facilities as this will rectify the previous exclusion of those facilities.

For Onshore Natural Gas Processing we support the proposed changes to maintain consistency with subpart NN and reduce the burden for reporters, including the addition of a new reporting element to capture all natural gas processed and/or passed through the facility. For EPA’s proposed amendments to Onshore Natural Gas Processing and Natural Gas Distribution throughputs also reported under subpart NN, we support the proposal to reduce redundancy for facilities also reporting under subpart NN as long as facilities that both fractionate NGLs and report as a supplier under subpart NN continue to report those data elements that do not overlap with subpart NN reporting. Currently, we do not see an issue with the removal of the reporting elements for the volume of natural gas used for operational purposes and natural gas stolen, however we would like to know if/how these quantities are used by stakeholders aside from EPA.

Lastly, we do not see any issues with the proposed replacement of the term “in-system” and clarification around underground natural gas storage and LNG storage facilities within the Onshore Natural Gas Transmission Pipeline Storage segment.

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[135] *See* Infra section on well-level reporting of throughputs associated with permanently shut-in and plugged wells.

XIII. Acid Gas Removal Units / Nitrogen Removal Units

a. Nitrogen removal units

We support EPA's proposal to add new requirements for calculating and reporting methane emissions from nitrogen removal units (NRUs) used in the Onshore Petroleum and Natural Gas Production, Onshore Natural Gas Processing, Onshore Petroleum Natural Gas Gathering and Boosting, LNG Storage, and LNG Import and Export Equipment industry segments. Oil and gas reservoirs are highly heterogenous, both in terms of composition and geologic characteristics. Nitrogen levels in hydrocarbon streams can range widely depending on the source and location of extraction. Inclusion of nitrogen rejection units in emissions reporting acknowledges this variability and allows EPA to better account for the diverse nitrogen challenges the industry faces. Incorporating NRUs into the list of source types for which specific industry segments must report emissions is essential for a more comprehensive and accurate assessment of the industry's emissions. The oil and gas industry is continuously evolving, with new technologies emerging to reduce emissions and improve efficiency. By including nitrogen rejection units in reporting, EPA can track the adoption of advanced technologies, as demonstrated by GasSTAR program,[136] and incentivize their use. This promotes innovation within the industry in efforts to reduce emissions.

Specific industry segments reporting

We further support EPA's proposed list of industry segments mandated to report NRU vent emissions. Nitrogen rejection units are most prevalent in the upstream and midstream segments of the oil and gas industry, where they are used to treat natural gas streams to remove nitrogen and other impurities. Nitrogen can be found in varying concentrations in natural gas reservoirs. In some regions, such as the Williston Basin,[137] Powder River Basin, and Permian Basin,[138] the gas can contain a significant amount of nitrogen. More broadly, in the U.S., approximately 16% of known gas reserves are contaminated with nitrogen.[139] Nitrogen rejection units are commonly used at wellheads and production facilities to treat natural gas before it enters pipelines. Nitrogen rejection units are often integrated into natural gas processing plants to separate and remove the remaining nitrogen from the gas before sending it to market via transmission pipelines. Furthermore, in the LNG production process, nitrogen removal is essential to meet the stringent quality requirements for LNG liquefaction and transportation.

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[136] EPA, Natural Gas STAR Program, *Nitrogen Rejection Unit Optimization Unit,* https://19january2017snapshot.epa.gov/natural-gas-star-program/nitrogen-rejection-unit-optimization_.html (last visited Oct. 2, 2023).

[137] Timothy O. Nesheim, North Dakota Geological Survey, *Review of Production, Completions, and Future Potential of the Lower Tyler Formation – Central Williston Basin, North Dakota* (2019), https://www.dmr.nd.gov/ndgs/documents/Publication_List/pdf/GEOINV/GI-222.pdf.

[138] Membrane Technology and Research, Inc., *Nitrogen Removal from Natural Gas Phase II Draft Final Report* (1999), https://www.osti.gov/servlets/purl/780455/.

[139] Kuo, J. C. et al., *Pros and cons of different Nitrogen Removal Unit (NRU) technology,* 7 J. of Natural Gas Sci. Engineering 52–59 (2012), https://doi.org/10.1016/j.jngse.2012.02.004 (available at Attachment H).

Calculation methods for NRU vents

We support EPA's proposal to use current emissions calculation methods applied to AGR (Acid Gas Removal) vents for methane emissions originating from Nitrogen Rejection Units (NRUs). We also agree with EPA's proposal for nitrogen removal unit vents routed to a flare to follow the calculation and reporting requirements as other flared emission source types. However, we urge EPA to provide clearer definitions regarding nitrogen gas vent streams from NRUs, as these streams, containing mostly nitrogen with 1-3% methane,[140] often used to purge equipment between semi-batch processes, such as Acid Gas Recovery. Eventually, they are still vented into the atmosphere through low-pressure (LP) vent pipelines (not covered under current reporting rule).

Insufficient clarity in this regard could result in operators only accounting for partially vented emissions from NRUs. Therefore, it is imperative for EPA to introduce clear guidelines that ensure comprehensive reporting of all methane emissions released during the nitrogen removal process. Our recommendation is for EPA to provide more clarification on the definition of NRU vent stream(s) and require operators to report both the methane content and flowrate of the primary vent stream or the sum of the flowrates from all vent streams exiting the NRU, before any pipe branching that route the flow into other processes occurs into other processes, in the case when this flow is not entirely directed to a flare. This data should then be used to subtract the amount of methane that is either recycled or consumed in downstream processes. This approach ensures a more accurate and inclusive representation of methane emissions stemming from nitrogen removal processes.

b. Acid gas removal (AGR) units

We strongly support EPA's proposed amendments regarding the reporting of methane emissions from AGRs and the associated revisions. EPA's recognition of the need to revisit the assessment made in the 2010 subpart W Technical Support Document (TSD) regarding methane emissions from AGR vents is essential. With the current data indicating a substantial increase in the number and size of AGRs, methane emissions from these sources have been significantly underestimated in the past. These proposed changes represent a significant step towards ensuring the completeness and accuracy of subpart W reporting.

Proposed changes in calculation methodologies for CH4 emissions from AGR vents:

We strongly support EPA's proposal to amend regulations and require the reporting of methane emissions from AGR vents. Regarding the calculation methods, we believe Calculation Method 2, 3, and 4 are most appropriate for calculating methane emissions from AGR vents. The proposed revisions to specify that reporters should calculate both CO_2 and methane emissions

[140] U.S. Environmental Protect. 2005. *Optimizing Nitrogen Rejection Units, Lessons Learned from Natural Gas STAR*, Presented at Processors Technology Transfer Workshop (Apr. 22, 2005), https://www.epa.gov/sites/default/files/2017-09/documents/rejection_units.pdf.

using Calculation Method 2 when a vent meter is installed and provide additional parameters, such as inlet and outlet methane content, for Calculation Method 4 are appropriate.

Furthermore, the proposal to require reporters to select a standardized solvent type and composition is a change that will enhance data quality and consistency. We agree that collecting information regarding the specified parameters will allow EPA the opportunity to verify the accuracy of the simulation results, when using Calculation Method 4, for more robust emissions inventorying and management.

In line with our comments regarding the need for more precise definition of NRU vents, we also extend this consideration for AGR vents. AGR vent pipes in many facilities may encompass multiple vent streams and even aggregate various vent pipes originating from other processes. The variation in equipment design and facility layout may lead to partial reporting of emissions if sufficient clarification is not provided.

We therefore recommend that EPA clarify the definition of AGR vent streams and require operators to report both the methane content and flowrate of the primary vent streams as it exits the AGR or the total of all the vent streams existing the AGRUs (in the case that AGR unit has multiple vent streams), before any pipe branching occurs that route the flow into other processes, in the case when this flow is not entirely directed to a flare. This data should then be used to subtract the amount of methane that is either recycled or consumed in downstream processes. This approach will ensure a more accurate and inclusive representation of methane emissions stemming from acid gas removal processes.

Lastly, we support treating AGR vents routed to flares or engines similarly to other emission source types, eliminating special provisions. This approach simplifies reporting and ensures consistency in calculating and reporting emissions.

Feedback on reporting elements for Methods 1, 2, and 3

We support EPA's efforts to require reporting of the temperature and pressure information corresponding to flow rates reported under Calculation Methods 1, 2, or 3 is a more robust approach to ensure data accuracy. This aligns reporting with technical standards and will simplify the verification process. Additionally, we support standardizing the units reported for the total annual feed rate in MMscf per year as it further improves data integrity and accuracy.

* * *

Thank you for your consideration of these comments.

Respectfully submitted,

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