United States
Environmental Protection
Agency

Summary of Public Comments and Responses for 2024 Final Revisions and Confidentiality Determinations for Petroleum and Natural Gas Systems under the Greenhouse Gas Reporting Rule

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Summary of Public Comments and Responses for 2024 Final Revisions and Confidentiality Determinations for Petroleum and Natural Gas Systems under the Greenhouse Gas Reporting Rule

U. S. Environmental Protection Agency
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List of Acronyms and Abbreviations

AGR	acid gas removal unit
AMLD	Advanced Mobile Leak Detection
API	American Petroleum Institute
ASTM	American Society for Testing and Materials
AVO	audio, visual, and olfactory
BOEM	U.S. Bureau of Ocean Energy Management
BRE	Bryan Research & Engineering
BSER	best system of emissions reduction
Btu/scf	British thermal units per standard cubic foot
CAA	Clean Air Act
CBI	confidential business information
CE	combustion efficiency
CEMS	continuous emissions monitoring system
CenSARA	Central States Air Resources Agency
CFR	Code of Federal Regulations
CH_4	methane
CO_2	carbon dioxide
CO_2e	carbon dioxide equivalent
CRR	cost-to-revenue ratio
DE	destruction efficiency
DI&M	directed inspection and maintenance
DRE	destruction and removal efficiency
e-GGRT	electronic Greenhouse Gas Reporting Tool
EG	emission guidelines
EIA	U.S. Energy Information Administration
EOR	enhanced oil recovery
EPA	U.S. Environmental Protection Agency
FAQ	frequently asked question
FLIGHT	Facility Level Information on Greenhouse gases Tool
FR	*Federal Register*
FTIR	Fourier transform infrared
GHG	greenhouse gas
GHGRP	Greenhouse Gas Reporting Program

GOR	gas to oil ratio
gpm	gallons per minute
GRI	Gas Research Institute
GT	gas turbines
HHV	higher heating value
ICR	information collection request
ID	identification
IRA	Inflation Reduction Act of 2022
IVT	Inputs Verification Tool
kg/hr	kilograms per hour
LDAR	leak detection and repair
LDC	local distribution company
LNG	liquefied natural gas
m	meters
MDEA	methyl diethanolamine
MEA	monoethanolamine
MMBtu/hr	million British thermal units per hour
MMscf	million standard cubic feet
mt	metric tons
$mtCO_2e$	metric tons carbon dioxide equivalent
N_2O	nitrous oxide
NAICS	North American Industry Classification System
NGLs	natural gas liquids
NRU	nitrogen recovery unit
NSPS	new source performance standards
NYSERDA	New York State Energy Research and Development Authority
O&M	operation and maintenance
OCS AQS	Outer Continental Shelf Air Quality System
OEL	open-ended line
OEM	original equipment manufacturer
OGI	optical gas imaging
OMB	Office of Management and Budget
OTM	other test method
PBI	proprietary business information

PHMSA	U.S. Pipeline and Hazardous Materials Safety Administration
ppm	parts per million
ppmv	parts per million by volume
PRA	Paperwork Reduction Act
PRD	pressure relief device
psig	pounds per square inch gauge
PTE	potential to emit
RFA	Regulatory Flexibility Act
RFI	Request for Information
RICE	reciprocating internal combustion engines
RY	reporting year
SCADA	supervisory control and data acquisition
scf	standard cubic feet
scf/hr/device	standard cubic feet per hour per device
TCEQ	Texas Commission on Environmental Quality
THC	total hydrocarbon
TOC	total organic carbon
TSD	technical support document
U.S.	United States
UMRA	Unfunded Mandates Reform Act of 1995
VISR	Video Imaging Spectro-Radiometry
VOC	volatile organic compound(s)
WEC	waste emissions charge
WWW	World Wide Web

Introduction

This document provides the U.S. Environmental Protection Agency (EPA)'s response to public comments on Greenhouse Gas Reporting Rule: Revisions and Confidentiality Determinations for Petroleum and Natural Gas Systems. The EPA proposed amendments to subpart W on June 21, 2022 (87 FR 36920) (hereafter referred to as the "2022 Proposed Rule"). The EPA published a Notice of Proposed Rulemaking in the Federal Register on August 1, 2023 (88 FR 50282, hereafter referred to as the "2023 Subpart W Proposal"). The preamble to the 2023 Subpart W Proposal explained that the EPA did not intend to finalize the revisions to subpart W that were proposed in the 2022 Proposed Rule and that the final amendments to subpart W would include consideration of public comments on the 2023 Subpart W Proposal.

The EPA proposed to amend requirements that apply to the petroleum and natural gas systems source category of the Greenhouse Gas Reporting Rule consistent with CAA section 136(h) to ensure that reporting is based on empirical data, accurately reflects total methane emissions and waste emissions from applicable facilities, and allows owners and operators of applicable facilities to submit empirical emissions data that appropriately demonstrate the extent to which a charge is owed. The EPA also proposed changes to requirements that apply to the general provisions, general stationary fuel combustion, and petroleum and natural gas systems source categories of the Greenhouse Gas Reporting Rule to improve calculation, monitoring, and reporting of greenhouse gas data for petroleum and natural gas systems facilities. Finally, the EPA proposed to establish and amend confidentiality determinations for the reporting of certain data elements to be added or substantially revised by the proposed amendments.

During the 60-day public comment period, the EPA received comment letters from industry representatives and associations, environmental organizations, technology manufacturers and vendors, and private citizens in response to the August 1, 2023 proposal. This document provides the EPA's responses to public comments regarding the proposal. The verbatim text of each comment extracted from the original comment letters is included in this document, arranged by subject. For each comment, the identity of the commenter and the document control number (DCN) assigned to the comment letter are provided. Where possible, the EPA separated comments on specific topics into categories. Within categories, similar comment excerpts from multiple commenters were combined into a group of comments with a single response. However, in some cases, commenters made broad statements about the proposed revisions to subpart W or general comments on the approach that could not be easily separated by topic or category without potentially affecting the intended meaning of the commenter's statements. In such cases, we referred the reader to the response to another similar comment.

The EPA's responses to comments are generally provided immediately following each comment. In some cases, the EPA provided responses to specific comments or groups of similar comments in the preamble to the final rulemaking. Rather than repeating those responses in this document, the EPA has referenced the preamble to the final rule. In some cases, a commenter incorporated by reference the comments of another company or organization. Rather than repeat these comment excerpts for each commenter, the EPA has listed the comment excerpt only once under the name of the person, company or organization who submitted the comment and included a list of commenters who indicated their support for that comment in a footnote to the List of Commenters.

On November 15, 2021 (86 FR 63110), the EPA proposed under CAA section 111(b) standards of performance for certain new, reconstructed, and modified oil and natural gas sources (40 CFR part 60, subpart OOOOb) (hereafter referred to as "NSPS OOOOb"), as well as emissions guidelines under CAA section 111(d) for certain existing oil and natural gas sources (40 CFR part 60, subpart OOOOc) (hereafter referred to as "EG OOOOc"). On December 6, 2022, the EPA issued a supplemental proposal to update, strengthen and expand the standards proposed on November 15, 2021 (87 FR 74702). Multiple commenters resubmitted their comments on theNSPS OOOOb and EG OOOOc proposal and/or supplemental proposal as part of their comments submitted on this proposed rulemaking. Comments on the proposed NSPS OOOOb and EG OOOOc are out of scope of this rulemaking. The List of Commenters lists the commenters on this rulemaking and notes in a footnote which commenters included comments on the NSPS OOOOb and EG OOOOc that are not individually responded to in this document.

Multiple commenters resubmitted their comments on the non-rulemaking docket (Docket ID No. EPA-HQ-OAR-2022-0875) as part of their comments submitted on this proposed rulemaking. The EPA opened the non-rulemaking docket (Docket ID No. EPA-HQ-OAR-2022-0875) for public input on the Methane Emissions Reduction Program, including, but not limited to revisions to subpart W. The EPA received $1.55 billion to reduce methane emissions from the oil and gas sector by providing financial assistance (grants, rebates, contracts, loans, and other activities) and technical assistance as well as implementing a statutorily required waste emissions charge. The goal of this non-rulemaking docket and other public engagement efforts was to gather perspectives from a broad group of stakeholders to assist the EPA in the guidance, planning, and implementation of the Methane Emissions Reduction Program, including financial and technical assistance provisions, waste emission charge, and revisions to subpart W. With regards to the comments resubmitted from the non-rulemaking Docket ID No. EPA-HQ-OAR-2022-0875 on this rulemaking, we have considered and responded to all of the comments relevant to this rulemaking. The List of Commenters lists the commenters on this rulemaking and notes in a footnote which commenters included the comments they submitted to the non-rulemaking docket that are not individually responded to in this document.

In the preamble to the 2023 Subpart W Proposal, the EPA stated that "commenters who would like the EPA to further consider in this rulemaking any relevant comments that they provided on the 2022 Proposed Rule regarding proposed revisions at issue in this proposal must resubmit those comments to the EPA during this proposal's comment period." Multiple commenters resubmitted their comments on the 2022 Proposed Rule (Docket ID EPA-HQ-OAR-2019-0424) as part of their comments submitted on this proposed rulemaking. To the extent that the resubmitted comments are still relevant and the commenters provided enough information in their new comment for the EPA to determine the relevancy of their resubmitted comments, these comments have been addressed in this document. For comments not individually addressed in this document, many commenters did not specify which portion of their comments were still relevant. To the extent that these commenters did provide explanation as to why these comments are still relevant, they may not have provided sufficient specificity on why their previous comments were relevant. The List of Commenters lists the commenters on this rulemaking and notes which commenters included resubmitted comments from the 2022 Proposed Rule that are not individually responded to in this document.

Copies of all comments submitted are available electronically through http://www.regulations.gov by searching Docket ID. No. EPA-HQ-OAR-2023-0234.[1]

[1] See also: https://www.epa.gov/dockets

List of Commenters

Document Control Number	Commenter
EPA-HQ-OAR-2023-0234-0182	Project Canary, PBC
EPA-HQ-OAR-2023-0234-0183	Anonymous
EPA-HQ-OAR-2023-0234-0184	GPA Midstream Association
EPA-HQ-OAR-2023-0234-0185	Petroleum Alliance of Oklahoma, Independent Petroleum Association of America and Western Energy Alliance
EPA-HQ-OAR-2023-0234-0186	Marcellus Shale Coalition (MSC)
EPA-HQ-OAR-2023-0234-0187	Differentiated Gas Coordinating Council (DGCC)
EPA-HQ-OAR-2023-0234-0188	American Exploration and Production Council (AXPC)
EPA-HQ-OAR-2023-0234-0189	Anonymous
EPA-HQ-OAR-2023-0234-0190	Protect PT
EPA-HQ-OAR-2023-0234-0191	Peter Furcht
EPA-HQ-OAR-2023-0234-0192	Physicians for Social Responsibility Pennsylvania (PSR)
EPA-HQ-OAR-2023-0234-0193	John Sonin
EPA-HQ-OAR-2023-0234-0194	Planetary Emissions Management Inc.
EPA-HQ-OAR-2023-0234-0195	Kathryn Westman
EPA-HQ-OAR-2023-0234-0196	SLB
EPA-HQ-OAR-2023-0234-0197	Interstate Natural Gas Association of America (INGAA) et al.
EPA-HQ-OAR-2023-0234-0198	Bridger Photonics, Inc.
EPA-HQ-OAR-2023-0234-0199	American Petroleum Institute (API)
EPA-HQ-OAR-2023-0234-0200	Project PT
EPA-HQ-OAR-2023-0234-0201	State of Wyoming, Office of the Governor
EPA-HQ-OAR-2023-0234-0202	Anonymous
EPA-HQ-OAR-2023-0234-0203	Clean Air Council
EPA-HQ-OAR-2023-0234-0206	Alaska Oil and Gas Association (AOGA)
EPA-HQ-OAR-2023-0234-0207	American Petroleum Institute (API)
EPA-HQ-OAR-2023-0234-0208	GPA Midstream Association
EPA-HQ-OAR-2023-0234-0224	Subpart W Public Hearing Transcript
EPA-HQ-OAR-2023-0234-0226	Physicians for Social Responsibility Pennsylvania (PSR)
EPA-HQ-OAR-2023-0234-0227	Marlene Adkins
EPA-HQ-OAR-2023-0234-0228	Kathairos Solutions, Inc.
EPA-HQ-OAR-2023-0234-0229	EnerVest Operating, LLC
EPA-HQ-OAR-2023-0234-0230	Riverside Energy Group
EPA-HQ-OAR-2023-0234-0230	Energy Workforce & Technology Council
EPA-HQ-OAR-2023-0234-0232	Chevron
EPA-HQ-OAR-2023-0234-0233	AQC Environmental Brokerage Services, Inc.
EPA-HQ-OAR-2023-0234-0234	Terra Energy Partners (TEP)
EPA-HQ-OAR-2023-0234-0235	David Allen
EPA-HQ-OAR-2023-0234-0236	Ceres, Inc.
EPA-HQ-OAR-2023-0234-0237	Anonymous
EPA-HQ-OAR-2023-0234-0238	Nevada Nanotech Systems

Document Control Number	Commenter
EPA-HQ-OAR-2023-0234-0239	National Tribal Air Association (NTAA)
EPA-HQ-OAR-2023-0234-0240	Kairos Aerospace
EPA-HQ-OAR-2023-0234-0241	Alaska Oil and Gas Association (AOGA)
EPA-HQ-OAR-2023-0234-0242	Interfaith Center on Corporate Responsibility (ICCR)
EPA-HQ-OAR-2023-0234-0243	David Allen
EPA-HQ-OAR-2023-0234-0244	Teledyne FLIR, LLC
EPA-HQ-OAR-2023-0234-0245	American Petroleum Institute (API)
EPA-HQ-OAR-2023-0234-0246	Matt Walker
EPA-HQ-OAR-2023-0234-0247	Terri Yeager
EPA-HQ-OAR-2023-0234-0248	Kathy Bradley
EPA-HQ-OAR-2023-0234-0249	Jesse Crouse
EPA-HQ-OAR-2023-0234-0250	Alicia Clifton
EPA-HQ-OAR-2023-0234-0251	Barbara Abraham
EPA-HQ-OAR-2023-0234-0252	Debra Wontor
EPA-HQ-OAR-2023-0234-0253	Gerritt and Elizabeth Baker-Smith
EPA-HQ-OAR-2023-0234-0254	Elizabeth Watts
EPA-HQ-OAR-2023-0234-0255	Kevin Rolfes
EPA-HQ-OAR-2023-0234-0256	S. E. Williams
EPA-HQ-OAR-2023-0234-0257	Steven Vogel
EPA-HQ-OAR-2023-0234-0258	Russ Allen
EPA-HQ-OAR-2023-0234-0259	Ronald Gulla
EPA-HQ-OAR-2023-0234-0260	Sandy Field
EPA-HQ-OAR-2023-0234-0261	JL Angell
EPA-HQ-OAR-2023-0234-0262	Stephen Dutschke
EPA-HQ-OAR-2023-0234-0263	Fred Granlund
EPA-HQ-OAR-2023-0234-0264	Paula Shafransky
EPA-HQ-OAR-2023-0234-0265	Independent Petroleum Association of America (IPAA)[a,q,r]
EPA-HQ-OAR-2023-0234-0266	Clean Connect AI Inc.
EPA-HQ-OAR-2023-0234-0267	Diversified Energy Company
EPA-HQ-OAR-2023-0234-0268	Jaquelin Camp
EPA-HQ-OAR-2023-0234-0269	Beth Jones
EPA-HQ-OAR-2023-0234-0270	Paul Roden
EPA-HQ-OAR-2023-0234-0271	Kathy Bradley
EPA-HQ-OAR-2023-0234-0272	Jesse Reyes
EPA-HQ-OAR-2023-0234-0273	Dale Foote
EPA-HQ-OAR-2023-0234-0274	Scott Trees
EPA-HQ-OAR-2023-0234-0275	Marcellus Shale Coalition (MSC)[b]
EPA-HQ-OAR-2023-0234-0276	Occidental (Oxy)[q]
EPA-HQ-OAR-2023-0234-0277	Tomas Rodriguez
EPA-HQ-OAR-2023-0234-0278	Joanne Hall
EPA-HQ-OAR-2023-0234-0279	SENSIA Solutions S.L.

Document Control Number	Commenter
EPA-HQ-OAR-2023-0234-0280	Ellie Rotz
EPA-HQ-OAR-2023-0234-0281	Don Hawkins
EPA-HQ-OAR-2023-0234-0282	Lori Vest
EPA-HQ-OAR-2023-0234-0283	Anonymous
EPA-HQ-OAR-2023-0234-0284	Isabel Melvin
EPA-HQ-OAR-2023-0234-0285	Spencer Koelle
EPA-HQ-OAR-2023-0234-0286	Jennifer Bett
EPA-HQ-OAR-2023-0234-0287	Tracy Foster
EPA-HQ-OAR-2023-0234-0288	James Stanton
EPA-HQ-OAR-2023-0234-0289	Jill Greer
EPA-HQ-OAR-2023-0234-0290	Theresa Kardos
EPA-HQ-OAR-2023-0234-0291	Lucyna de Barbaro
EPA-HQ-OAR-2023-0234-0292	Clean Air Council[c]
EPA-HQ-OAR-2023-0234-0293	Sensirion Connected Solutions
EPA-HQ-OAR-2023-0234-0294	Sensirion Connected Solutions
EPA-HQ-OAR-2023-0234-0295	American Exploration and Production Council[d,e]
EPA-HQ-OAR-2023-0234-0296	Anonymous
EPA-HQ-OAR-2023-0234-0297	National Association of Manufacturers (NAM)
EPA-HQ-OAR-2023-0234-0298	Michigan Oil and Gas Association (MOGA)
EPA-HQ-OAR-2023-0234-0299	GPA Midstream Association[f,p,q,r]
EPA-HQ-OAR-2023-0234-0300	Lee Schondorf
EPA-HQ-OAR-2023-0234-0301	Carbon Mapper and RMI[r]
EPA-HQ-OAR-2023-0234-0302	Linda Myers
EPA-HQ-OAR-2023-0234-0303	James Ploger
EPA-HQ-OAR-2023-0234-0304	Joann Koch
EPA-HQ-OAR-2023-0234-0305	Timothy Mullen
EPA-HQ-OAR-2023-0234-0306	Paul Roden
EPA-HQ-OAR-2023-0234-0307	Barbara Hogan
EPA-HQ-OAR-2023-0234-0308	Dale Foote
EPA-HQ-OAR-2023-0234-0309	Brad Snyder
EPA-HQ-OAR-2023-0234-0310	Dan Perry
EPA-HQ-OAR-2023-0234-0311	Wendy Schroeder
EPA-HQ-OAR-2023-0234-0312	Norma Kline
EPA-HQ-OAR-2023-0234-0313	Torunn Sivesind
EPA-HQ-OAR-2023-0234-0314	Don Hawkins
EPA-HQ-OAR-2023-0234-0315	Paul Palla
EPA-HQ-OAR-2023-0234-0316	Matt Gribble
EPA-HQ-OAR-2023-0234-0317	Ethan Frank
EPA-HQ-OAR-2023-0234-0318	Kathryn Lemoine
EPA-HQ-OAR-2023-0234-0319	Vic Bostock
EPA-HQ-OAR-2023-0234-0320	Alison Rupert

Document Control Number	Commenter
EPA-HQ-OAR-2023-0234-0321	Barney McComas
EPA-HQ-OAR-2023-0234-0322	Tara Strand
EPA-HQ-OAR-2023-0234-0323	Carol Claus
EPA-HQ-OAR-2023-0234-0324	Constantina Hanse
EPA-HQ-OAR-2023-0234-0325	Anonymous
EPA-HQ-OAR-2023-0234-0326	Abigail Gindele
EPA-HQ-OAR-2023-0234-0327	Megan LeCluyse
EPA-HQ-OAR-2023-0234-0328	Laura Horowitz
EPA-HQ-OAR-2023-0234-0329	Jessica Bellas
EPA-HQ-OAR-2023-0234-0330	Jeanne Weber
EPA-HQ-OAR-2023-0234-0331	Catherine Hunt
EPA-HQ-OAR-2023-0234-0332	Nancy Drain
EPA-HQ-OAR-2023-0234-0333	Edward Lynch
EPA-HQ-OAR-2023-0234-0334	Diane DiFante
EPA-HQ-OAR-2023-0234-0335	American Lung Association
EPA-HQ-OAR-2023-0234-0336	National Federation of Independent Business, Inc. (NFIB)
EPA-HQ-OAR-2023-0234-0337	Independent Petroleum Association of New Mexico (IPANM)[q]
EPA-HQ-OAR-2023-0234-0338	Antero Midstream Corporation
EPA-HQ-OAR-2023-0234-0339	Ascent Resources, LLC[q]
EPA-HQ-OAR-2023-0234-0340	Konica Minolta Sensing Americas, Inc.
EPA-HQ-OAR-2023-0234-0341	Heath Consultants Inc.
EPA-HQ-OAR-2023-0234-0342	Enerplus Resources (USA) Corporation[q]
EPA-HQ-OAR-2023-0234-0343	INNIO Waukesha Gas Engines, Inc.[p,r]
EPA-HQ-OAR-2023-0234-0344	Peoples Natural Gas Company LLC
EPA-HQ-OAR-2023-0234-0345	BP America Inc.[p,q]
EPA-HQ-OAR-2023-0234-0346	Permian Basin Petroleum Association (PBPA)[p,q]
EPA-HQ-OAR-2023-0234-0347	California State Teachers' Retirement System CalSTRS
EPA-HQ-OAR-2023-0234-0348	Project Canary, PBC[q,r]
EPA-HQ-OAR-2023-0234-0349	Texas Commission on Environmental Quality (TCEQ)[q]
EPA-HQ-OAR-2023-0234-0350	Ovintiv Inc.[q,r]
EPA-HQ-OAR-2023-0234-0351	Taxpayers for Common Sense (TCS)
EPA-HQ-OAR-2023-0234-0352	Truck & Engine Manufacturers Association (EMA)
EPA-HQ-OAR-2023-0234-0353	Stephen Gliva
EPA-HQ-OAR-2023-0234-0354	M. Port
EPA-HQ-OAR-2023-0234-0355	Carolyn Lange
EPA-HQ-OAR-2023-0234-0356	Ret Turner
EPA-HQ-OAR-2023-0234-0357	Alan Peterson
EPA-HQ-OAR-2023-0234-0358	Tika Bordelon
EPA-HQ-OAR-2023-0234-0359	Frances Gilmore
EPA-HQ-OAR-2023-0234-0360	Devon Energy[q,r]
EPA-HQ-OAR-2023-0234-0361	Gerard Tessier

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EPA-HQ-OAR-2023-0234-0362	John Sonin
EPA-HQ-OAR-2023-0234-0363	Joseph Wenzel
EPA-HQ-OAR-2023-0234-0364	Encino Environmental Services
EPA-HQ-OAR-2023-0234-0365	K. Danowski (no first name provided)
EPA-HQ-OAR-2023-0234-0366	Anonymous
EPA-HQ-OAR-2023-0234-0367	Chestnut Hill United Church
EPA-HQ-OAR-2023-0234-0368	Damascus Citizens for Sustainability (DCS)
EPA-HQ-OAR-2023-0234-0369	Gry Nuns of the Sacred Heart
EPA-HQ-OAR-2023-0234-0370	Providence Photonics, LLC
EPA-HQ-OAR-2023-0234-0371	Evangelical Environmental Network (EEN)
EPA-HQ-OAR-2023-0234-0372	EOS at Federated Hermes Limited (EOS) (United Kingdom)
EPA-HQ-OAR-2023-0234-0373	Colorado Department of Public Health and Environment (CDPHE)
EPA-HQ-OAR-2023-0234-0374	ConocoPhillips
EPA-HQ-OAR-2023-0234-0375	Honeywell International Inc.
EPA-HQ-OAR-2023-0234-0376	Duke Energy
EPA-HQ-OAR-2023-0234-0377	Physical Sciences Inc. (PSI)
EPA-HQ-OAR-2023-0234-0378	Marathon Oil Company
EPA-HQ-OAR-2023-0234-0379	Edison Electric Institute (EEI)
EPA-HQ-OAR-2023-0234-0380	Miller/Howard Investments, Inc.
EPA-HQ-OAR-2023-0234-0381	Endeavor Energy Resources, L.P.
EPA-HQ-OAR-2023-0234-0382	Arkansas Independent Producers and Royalty Owners (AIPRO)
EPA-HQ-OAR-2023-0234-0383	Baker Hughes
EPA-HQ-OAR-2023-0234-0384	Gas Turbine Association (GTA)
EPA-HQ-OAR-2023-0234-0385	Pioneer Natural Resources USA, Inc.[g]
EPA-HQ-OAR-2023-0234-0386	Qube Technologies, Inc.
EPA-HQ-OAR-2023-0234-0387	Interstate Natural Gas Association of America (INGAA)[h,i,p,q]
EPA-HQ-OAR-2023-0234-0388	Wyoming Department of Environmental Quality (WDEQ)[p,q,r]
EPA-HQ-OAR-2023-0234-0389	Kirk Frost
EPA-HQ-OAR-2023-0234-0390	Sensirion Connected Solutions Inc. (SCS)
EPA-HQ-OAR-2023-0234-0391	Oceana
EPA-HQ-OAR-2023-0234-0392	MiQ[q]
EPA-HQ-OAR-2023-0234-0393	CrownQuest Operating[q]
EPA-HQ-OAR-2023-0234-0394	Williams Companies, Inc.
EPA-HQ-OAR-2023-0234-0395	Step2compliance
EPA-HQ-OAR-2023-0234-0396	Downstream Natural Gas Initiative
EPA-HQ-OAR-2023-0234-0397	Range Resources Corporation
EPA-HQ-OAR-2023-0234-0398	The Petroleum Alliance of Oklahoma[q]
EPA-HQ-OAR-2023-0234-0399	Western Energy Alliance[q]
EPA-HQ-OAR-2023-0234-0400	Chesapeake Energy Corporation
EPA-HQ-OAR-2023-0234-0401	Environmental Defense Fund et al.

Document Control Number	Commenter
EPA-HQ-OAR-2023-0234-0402	American Petroleum Institute (API) et al.[j,k,p,q]
EPA-HQ-OAR-2023-0234-0403	American Petroleum Institute[l]
EPA-HQ-OAR-2023-0234-0404	American Petroleum Institute (API)[m]
EPA-HQ-OAR-2023-0234-0405	Lambda Energy Resources
EPA-HQ-OAR-2023-0234-0406	Atmos Energy Corporation
EPA-HQ-OAR-2023-0234-0407	Bridger Photonics, Inc.
EPA-HQ-OAR-2023-0234-0408	Encino Energy (EAP Ohio, LLC)[q]
EPA-HQ-OAR-2023-0234-0409	Offshore Operators Committee (OOC)[n]
EPA-HQ-OAR-2023-0234-0410	LongPath Technologies, Inc.
EPA-HQ-OAR-2023-0234-0411	Pipeline Safety Trust
EPA-HQ-OAR-2023-0234-0412	Picarro Inc.
EPA-HQ-OAR-2023-0234-0413	Environmental Defense Fund, et al.[q,r]
EPA-HQ-OAR-2023-0234-0414	Kirk Frost
EPA-HQ-OAR-2023-0234-0415	Differentiated Gas Coordinating Council (DGCC)[q]
EPA-HQ-OAR-2023-0234-0416	VERITAS - GTI Energy
EPA-HQ-OAR-2023-0234-0417	North Dakota Petroleum Council (NDPC)[q]
EPA-HQ-OAR-2023-0234-0418	American Gas Association (AGA) and American Public Gas Association (APGA)[o,p]
EPA-HQ-OAR-2023-0234-0419	Planetary Emissions Management Inc. (PEM)
EPA-HQ-OAR-2023-0234-0421	Ute Indian Tribe of the Uintah and Ouray Reservation
EPA-HQ-OAR-2023-0234-0422	Protect PT

[a] The comments by IPAA were also supported by AIPRO (Docket ID No. EPA-HQ-OAR-2023-0234-0382), Pioneer Natural Resources (Docket ID No. EPA-HQ-OAR-2023-0234-0385).

[b] The comments by MSC with respect to flare destruction efficiency were also supported by Chesapeake Energy Corporation (Docket ID No. EPA-HQ-OAR-2023-0234-0400).

[c] The comments by Clean Air Council were also supported by DCS (Docket ID No. EPA-HQ-OAR-2023-0234-0368).

[d] The comments by the American Exploration and Production Council were also supported by MSC (Docket ID No. EPA-HQ-OAR-2023-0234-0275), Devon Energy (Docket ID No. EPA-HQ-OAR-2023-0234-0360), Marathon Oil Company (Docket ID No. EPA-HQ-OAR-2023-0234-0378), Pioneer Natural Resources (Docket ID No. EPA-HQ-OAR-2023-0234-0385), NDPC (Docket ID No. EPA-HQ-OAR-2023-0234-0417).

[e] The comments by the American Exploration and Production Council with respect to flare destruction efficiency were also supported by Chesapeake Energy Corporation (Docket ID No. EPA-HQ-OAR-2023-0234-0400)

[f] The comments by GPA were also supported by MSC (Docket ID No. EPA-HQ-OAR-2023-0234-0275).

[g] Pioneer Natural Resources indicated that they supported the comments submitted by the Harvard Methane Roundtable but no comments on the rulemaking were received from that organization.

[h] The comments by INGAA were also supported by MSC (Docket ID No. EPA-HQ-OAR-2023-0234-0275).

[i] The comments by INGAA with respect to proposed revisions for natural gas transmission, storage, and LNG operations as applied to both interstate and intrastate gas utility facilities and comments with

respect to crankcase venting were also supported by AGA and APGA (Docket ID No. EPA-HQ-OAR-2023-0234-0418).

[j] The comments by API with respect to flares were also supported by IPAA (Docket ID No. EPA-HQ-OAR-2023-0234-0265).

[k] The comments by API were also supported by MSC (Docket ID No. EPA-HQ-OAR-2023-0234-0275), Devon Energy (Docket ID No. EPA-HQ-OAR-2023-0234-0360), Marathon Oil Company (Docket ID No. EPA-HQ-OAR-2023-0234-0378), AIPRO (Docket ID No. EPA-HQ-OAR-2023-0234-0382).

[l] Comment was submitted separately but is an annex to comment submitted as Docket ID No. EPA-HQ-OAR-2023-0234-0402.

[m] Comment was submitted separately but is supporting information for the comment submitted as Docket ID No. EPA-HQ-OAR-2023-0234-0402.

[n] The comments by OOC were also supported by API (Docket ID No. EPA-HQ-OAR-2023-0234-0402).

[o] The comments by AGA and APGA were also supported by Peoples Natural Gas (Docket ID No. EPA-HQ-OAR-2023-0234-0344).

[p] These commenters resubmitted their comments on the proposed NSPS OOOOb and EG OOOOc rule as part of their comments submitted on this proposed rulemaking.

[q] These commenters resubmitted their comments on the non-rulemaking docket (Docket ID No. EPA-HQ-OAR-2022-0875) for the Methane Emissions Reduction Program as part of their comments submitted on this proposed rulemaking.

[r] These commenters resubmitted their comments on the 2022 Proposed Rule (Docket ID EPA-HQ-OAR-2019-0424) as part of their comments submitted on this proposed rulemaking.

1 Empirical Data

Commenter: Downstream Natural Gas Initiative
Comment Number: EPA-HQ-OAR-2023-0234-0396
Page(s): 8

Comment 1: DSI requests EPA to provide a definition of "empirical data." DSI expects that by defining additional terms, EPA can reduce future requests from reporters seeking clarification and can reduce the burden of compliance.

Response 1: It is unclear why the commenter believes it is necessary to include a definition of empirical data in the regulatory text, as the commenter did not supply examples on what terms would need clarification without such a definition and the provisions in this final rule provide clarity on what methodologies are allowed or required. In the August 1, 2023, proposal preamble the EPA provided an interpretation of what empirical data means for the purposes of this rulemaking, which the EPA used in determining revisions to subpart W consistent with the directives in CAA section 136(h). Specifically, the EPA stated the following:

> "For purposes of this action, the EPA interprets empirical data to mean data that are collected by conducting observations and experiments that could be used to accurately calculate emissions at a facility, including direct emissions measurements, monitoring of CH_4 emissions (e.g., leak surveys) or measurement of associated parameters (e.g., flow rate, pressure, etc.), and published data.[2]"

In the final rule, the EPA maintains the interpretation of empirical data as described at proposal. The EPA does not find it necessary to incorporate an exact definition in the regulatory text of Subpart W and believes our interpretation of empirical data as described in the preamble is clear, and that the final provisions also provide sufficient clarity for compliance.

Commenter: Physicians for Social Responsibility Pennsylvania (PSR)
Comment Number: EPA-HQ-OAR-2023-0234-0192
Page(s): 1

Commenter: Public Hearing Transcript
Comment Number: EPA-HQ-OAR-2023-0234-0224
Page(s): 8 (Asa Carre-Burritt), 13-14 (Lisa Beal), 34 (Dr. Dakota Raynes)

Commenter: Physicians for Social Responsibility Pennsylvania (PSR)
Comment Number: EPA-HQ-OAR-2023-0234-0226
Page(s): 1

[2] 88 FR 50286 (August 1, 2023).

Commenter: Chevron
Comment Number: EPA-HQ-OAR-2023-0234-0232
Page(s): 1-2

Commenter: Kairos Aerospace
Comment Number: EPA-HQ-OAR-2023-0234-0240
Page(s): 3-5

Commenter: Marcellus Shale Coalition (MSC)
Comment Number: EPA-HQ-OAR-2023-0234-0275
Page(s): 4

Commenter: Occidental (Oxy)
Comment Number: EPA-HQ-OAR-2023-0234-0276
Page(s): 3

Commenter: GPA Midstream Association
Comment Number: EPA-HQ-OAR-2023-0234-0299
Page(s): 2-3

Commenter: National Federation of Independent Business, Inc. (NFIB)
Comment Number: EPA-HQ-OAR-2023-0234-0336
Page(s): 2

Commenter: Colorado Department of Public Health and Environment (CDPHE)
Comment Number: EPA-HQ-OAR-2023-0234-0373
Page(s): 1-2

Comment 2: Commenter 0192: As a Public Health professional I ask that the EPA ensures the reporting of the following to the Subpart W of the Greenhouse gas Reporting Program:

1. Reports are based on empirical data.

2. Reports accurately reflect total methane emissions from applicable facilities.

3. Reports allow operators to submit empirical emissions data in a manner prescribed by EPA.

Commenter 0224: The EPA is proposing many amendments to incorporate additional empirical data in emissions reporting for the purpose of improving accuracy. Bridger is in support of providing operators with the option to use empirical data for emissions reporting.

…

I think first consistent with the Inflation Reduction Act mandate, INGAA supports the development of amendments to the GHGRP Sub-W that incorporate more empirical data. INGAA generally believes operator should have the option to use measured data or other methods in Subpart W. This proposal adds those options or adds options to use measured data which we fully support.

…

Emissions calculations as compared to direct measurements should only be used as a last resort, and the EPA should do everything in its power to ensure that such calculations are the result of robust statistical analysis that is based on real world measurements of pollution.

Commenter 0226: As a Public Health professional I ask that the EPA ensures the reporting of the following to the Subpart W of the Greenhouse Gas Reporting Program:

1. Reports are based on empirical data.

2. Reports accurately reflect total methane emissions from applicable facilities.

3. Reports allow operators to submit empirical emissions data in a manner prescribed by EPA.

Commenter 0232: Through the Greenhouse Gas Reporting Program (GHGRP), the U.S. Environmental Protection Agency (EPA) has been a global leader in mandatory reporting and transparency for greenhouse gas (GHG) emissions across sectors. Chevron has reported to the GHGRP including under Subpart W for Petroleum and Natural Gas Systems and appreciates the opportunity to provide public comments on the proposed Subpart W changes. The GHGRP includes important elements regarding:

- Comparability – Emissions reporting under the GHGRP requires the use of specific emission calculation methods and factors that are the same for all reporters in the segment.
- Transparency – Nearly all reported GHG emissions are publicly accessible through EPA's websites.
- Relevance – Most segments under the GHGRP include source level information for specific assets. This allows for the direct comparison of emission intensity performance across similar types of assets and provides granular emission information for interested stakeholders at the asset or facility level.

Requirements to report methane emission data under Subpart W over the last decade have helped Chevron focus on specific methane emission sources within our operations, inform our efforts to reduce methane emission intensity through facility design changes and implementation of best practices, and benchmark performance directly against peers through publicly available data. We continue to design, construct, and operate facilities with strategies to help prevent methane emissions. We agree with EPA that there are opportunities to improve the quality of data provided under the GHGRP. For the proposed revisions to Subpart W, we appreciate EPA's efforts to update methane emission factors using the latest field measurement studies, including work on equipment leaks and pneumatic controllers that was co-authored by our expert. If there are questions on studies in which Chevron has participated, we would be pleased to meet with EPA during the rulemaking process.

In our view and based on our experience, methane reporting under the GHGRP should move toward the use of empirical data for measurement-informed reporting, including the use of available advanced quantitative technologies. This shift would require the use of both advanced technologies for direct measurement of methane that work at-scale across dispersed assets in the U.S. oil and gas sector and data processing and reporting protocols for consistent incorporation of data from advanced technologies into emission inventories. At Chevron, we have trialed fourteen advanced methane detection devices across aircraft, drone, satellite, and continuous monitoring platforms to understand how these devices work across different assets and geographic locations. We have also supported a multi-stakeholder initiative with Veritas, a GTI Energy Methane Emissions Measurement and Verification Initiative[1], that aims to develop the technical protocols for measurement, reconciliation, and verification that would enable consistent, measurement-informed emission reporting. We believe that the GHGRP will need the flexibility to include multiple options for the collection of empirical data, including updated emission factors based on new information from studies (e.g., gas-driven pneumatic controllers), operator-specific source information, and data collected using advanced technologies such as flyovers (where they can be deployed) to increase the quality, accuracy, and transparency of data collected as part of the program.

Footnote:

[1] https://veritas.gti.energy/

Commenter 0240: Measurement Data is Necessary to Improve the Overall Accuracy of EPA's Greenhouse Gas Inventory

The proliferation of basin scale, source level measurement of emissions from oil and gas infrastructure, combined with continuous or near-continuous emissions measurement in recent years has reshaped our understanding of methane emissions from the oil and natural gas sector. Historically, measuring tens or hundreds of thousands of sites per year was an expensive and logistically daunting task. Today, it is happening routinely across the United States.

This rapid increase in measurement has been revealing in a few keyways. First, measured emission totals routinely do not match reported emissions volumes and in some cases, by a wide margin. Second, the sources of measured emissions at the equipment in the field do not always align with the expected contribution of a particular process or equipment type based on inventory estimates.

On the first point that measured emission totals often do not align with Inventory results, Sherwin et al. examined aerial methane leak survey results from CarbonMapper and Kairos aerospace, and found that while there was substantial regional variation, measured emissions could be as much as nine times higher the EPA Inventory in some basins. Chen et al. looked specifically at the Permian Basin in New Mexico and found measured emissions to be 6.5 times higher than the Inventory.

Cusworth et al. 2021, used NASA Jet Propulsion Laboratory methane detection technology to generate similar findings in the Permian Basin[8]. Over 55,000 sq km were surveyed across the Delaware and Midland Basins. The study found a similar "heavy tailed" distribution of methane emissions, with a relatively small fraction of sites emitting most of the total flux of methane emissions.

This is not a Permian-only phenomenon, or even a US-only phenomenon. Johnson et al. examined aerial data collected by Bridger Photonics and compared it to the GHG inventory in British Columbia. They concluded measured emissions were 1.7 times higher than the Province's bottom-up inventory.

On the second point that sources within the Inventory itself do not match measured contributions, Johnson et al. evaluated where emissions were detected through measurement and compared the measured emission contributions of those source categories to the Inventory. They found several notable differences, shown in Figure 1. For example, there were notable discrepancies between inventory-recorded emissions from storage tanks and compressors and measured emissions for those equipment types.

[Figure 1: Comparison of estimated and measured sources contributing to the total upstream oil and gas methane inventory in BC. (a) Assumed source breakdown in the most recent (2020) official inventory (SCVF = Surface casing vent flow; Dehys. = Glycol Dehydrators). (b) Source breakdown from the presently derived 2021 measurement-based methane inventory.]

We support EPA's decision to incorporate more direct measurement of emissions, which will help close the gap between GHGRP-reported emissions and actual emissions in the field. Closing this gap will ultimately help EPA, other agencies, and businesses make better decisions about how to manage emissions as the EPA Inventory is one of the key tools at the heart of a wide range of climate policies and initiatives.

Footnote:

[8] Daniel H. Cusworth, Riley M. Duren, Andrew K. Thorpe, Winston Olson-Duvall, Joseph Heckler, John W. Chapman, Michael L. Eastwood, Mark C. Helmlinger, Robert O. Green, Gregory P. Asner, Philip E. Dennison, and Charles E. Miller 2021. Intermittency of Large Methane Emitters in the Permian Basin. Environ. Sci. Technol. Lett. 2021, 8, 7, 567–573 https://pubs.acs.org/doi/10.1021/acs.estlett.1c00173 ("Cusworth et al. 2021")

Commenter 0275: The MSC believes the intention of the IRA's requirement to incorporate empirical data into Subpart W revisions for the Oil and Gas sector was to allow for additional accuracy in reporting if an operator needed this accuracy. The MSC supports not understating emissions in an emission inventory. However, it should not be a requirement to generate the most accurate inventory possible without considerations such as cost and additional personnel hours. In general, the MSC's comments support a final rule that provides flexibility to report emissions as accurately as practical. This approach satisfies the needs of small operators, large operators, and the IRA, as it would not result in under-reporting emissions for tax purposes. The MSC appreciates and supports several changes proposed by the U.S. EPA that result in options for more accurate reporting of emissions. The MSC provides examples of additional improvements in the technical comment sections of this letter.

Commenter 0276: **Oxy supports EPA efforts to improve the accuracy of reported emissions.**

Oxy supports EPA's proposed amendments to the petroleum and natural gas systems source category of the Greenhouse Gas Reporting Rule to improve reporting accuracy by providing more options to calculate emissions using empirical data. The inclusion of these empirical methodologies will refine and improve the quality of data reported under the Greenhouse Gas Reporting Program (GHGRP). Although EPA has proposed to expand the ability to use empirical data, not all emission sources were provided options to use empirical data. Oxy encourages EPA to allow for empirical data to be used for all sources and to ensure the rule accounts for future innovations in emissions measurement.

Additionally, Oxy encourages EPA to allow for various technical solutions through the proposed rule. For example, Oxy utilizes Tank Emissions Monitoring Systems (TEMS) on atmospheric storage tanks to prevent the over pressurization and subsequent venting of the tanks, where applicable. This system utilizes onsite automation to actively monitor tank pressure and control upstream governing flow devices to automatically reduce or stop flow to the tank system if the pressure approaches the system's designed vent pressure. This system, and other similar systems, should be allowed in addition to thief hatch sensors that are mentioned in the proposed rule.

Lastly, Oxy recommends EPA adopt a similar approach to that of state and voluntary programs to allow for representative sampling when measuring emissions from large quantities of similar equipment. Representative sampling ensures enough data is collected to report quality data to the GHGRP and takes into consideration the geographic breadth of upstream operations and the large numbers of individual equipment. Requiring sampling of every emission point is inconsistent with existing state and voluntary programs and would create logistical challenges limiting an operator's ability to maximize the benefits of empirical data.

Commenter 0299: More extensive comments are provided in this letter, but to highlight our key areas of concern the following summary is provided:

…

- Use of Empirical Data – EPA has accommodated use and incorporation of empirical data for some, but not all, emission source categories, in direct conflict with Congress's explicit direction that emissions reported under Subpart W be based on empirical data. EPA needs to allow the use of any relevant empirical data, such as engine stack tests and flare performance tests, and should not pick and choose where empirical data may be used. Further, EPA should not introduce requirements that are completely untethered to real-world data, such as the proposed "undetected leaks" factor that forces reporters to report phantom emissions.

…

Subpart W should be the "source of truth" for venting, fugitive, and flaring methane emissions accounting. This can be accomplished only if: (1) there is robust coordination within and between federal agencies to ensure consistent requirements; (2) Subpart W is technology agnostic and does not disincentivize or otherwise preclude advancement of emission detection/reduction technologies due to overly specific requirements; and (3) Subpart W has built-in flexibility that allows reporters to incorporate all relevant empirical data.

Commenter 0336: Section 136(h) of the Clean Air Act requires the Administrator to issue rules to ensure that emissions reporting under subpart W, and the calculations of methane charges, are based on accurate empirical data. While the EPA Administrator has no discretion with respect to the methane charge -- the statute requires the Administrator to collect it -- the Administrator may have some leeway in crafting the regulations designed to ensure use of accurate empirical data. The Administrator should use that leeway, to the maximum extent possible, to minimize or avoid hikes in the cost to consumers of fossil-fuel energy.

Commenter 0373: CDPHE supports EPA's proposed addition of methods that require (where feasible) direct measurement of emissions and/or actual operating condition data to better characterize GHG emissions.

Monitoring in support of determining actual emissions, whether by direct measurement, parametric monitoring or other method, is generally preferable over a default emission factor method (though not appropriate for all emission types, sizes, or sources). Technologies are developing rapidly and are varied in their useability. CDPHE encourages the use of multi-scale measurements (satellite, aerial, ground, intermittent and continuous) as each technology provides valuable information that supports an improved and more accurate inventory.

Response 2: The EPA acknowledges the commenters' support of the use of empirical data such as data that are collected by observation and experiment and has further improved upon ways to ensure subpart W is based on empirical data and to incorporate use of empirical data to the extent it is feasible and appropriate in accurately quantifying GHG emissions under Subpart W. In the final rule, the EPA has maintained and improved upon ways to incorporate empirical data in reporting of emissions. For example, Section II.B of the preamble discusses the expanded use of direct measurement, including for the calculation of emissions from equipment leaks, combustion slip, crankcase venting, associated gas, compressors, natural gas pneumatic devices, and equipment leaks from components at transmission company interconnect metering and regulating stations. For this final rule, the EPA considered currently available information, including comments on the proposed methods, and in some cases is finalizing methods that are different from proposed as appropriate, increasing availability of methods that utilize facility measurements. For example, the EPA proposed one calculation method for crankcase venting based on an emission factor, but we are finalizing an additional method based upon unit-specific measurement (see Section III.C.5 of the preamble to the final rule for additional information). See Section III.K of the preamble for comments related to thief hatch sensors.

With respect to one commenter's recommendation that EPA allow for representative sampling when measuring emissions from large quantities of similar equipment, we note that the final rule allows this approach or similar approaches that achieve the same goal in several instances, including:

- Measurements of pneumatic device emissions for facilities in segments other than onshore production and gathering and boosting and with more than 26 devices may be conducted over multiple years while applying each year's measurements to the non-measured pumps. For onshore production and gathering and boosting segments, facilities are allowed to select different calculation methods for each well pad site or gathering and boosting site and, therefore, are not required to measure all of their devices.
- Measurements of pneumatic pump emissions may be conducted over multiple years while applying each year's measurements to the non-measured pumps.
- Measurements of liquid unloading emissions for representative wells applied to non-measured wells.
- Measurement of emissions from representative well completions and workovers with hydraulic fracturing applied to non-measured events.
- Using "as found" measurements of compressor venting emissions to develop reporter-specific emission factors to apply to non-measured modes of operation for the compressors.
- Development of facility-specific leaker factors based on a minimum of 50 measurements for each component type and measurement method combination.
- Measurement of mud degassing emissions from representative wells applied to non-measured wells.

Section III.B.2 of the preamble notes advanced technology, in addition to other types of empirical data, can be used to calculate emissions and/or estimate the duration of events under the other large release events source type. Advanced screening methods including monitoring systems mounted on vehicles, drones, helicopters, airplanes, or satellites, capable of identifying methane emissions at 100 kg/hr with a 90 percent probability of detection can be used to estimate the total volume of release during such an event. The EPA finds that existing remote sensing approaches are suitable to supplement the other requirements for periodic measurement and calculation of annual emissions for large discrete events, as they are capable of having suitable detection limits for the identification of the presence of large anomalous events. However, our assessment at this time is that existing remote sensing approaches currently are not able to appropriately estimate annual emissions from other sources under subpart W. The EPA is also finalizing the option to use advanced technologies to measure data that are inputs to emissions calculations for flares and completions and workovers with hydraulic fracturing.

Under CAA section 136(h), Congress directed the Administrator to revise the requirements of subpart W to ensure that reporting of CH_4 emissions under subpart W (and corresponding waste emissions charges under CAA section 136) is based on empirical data, accurately reflects the total CH4 emissions (and waste emissions) from applicable facilities, and allows owners and operators to submit empirical emissions data, in a manner prescribed by the Administrator, to demonstrate the extent to which a charge is owed under CAA section 136. The revisions being finalized are consistent with these directives, ensuring that (1) reporting of methane emissions under subpart W are based on empirical data, (2) accurately reflect total methane emissions (and waste emissions) and (3) allow owners and operators to submit appropriate empirical data. The EPA estimated burden in the analysis, *Assessment of Burden Impacts for Greenhouse Gas Reporting Rule Revisions for Petroleum and Natural Gas Systems*, which is available in the docket to this rulemaking and briefly summarized in section VI of the preamble. Considering the improvements to the GHGRP contained in this final rule as well as the need to comply with CAA section 136(h) and the anticipated costs of this rule in the context of this industry, the EPA concludes that the anticipated costs are reasonable and support the final rule.

For comments related to coordination between federal agency, see Sections 27.6 and 28.4 of this document.

With regard to one commenter's specific request that EPA allow use of flare performance tests and engine stack tests, see EPA's discussion and response on these matters in Sections III.N.1.b and III.S.2.b of the preamble to the final rule, respectively. In addition, see Section III.P.2.b of the preamble to the final rule for EPA's response to comment that the "undetected leaks" factor should not be used.

Commenter: GPA Midstream Association
Comment Number: EPA-HQ-OAR-2023-0234-0299
Page(s): 14-15

Commenter: Devon Energy
Comment Number: EPA-HQ-OAR-2023-0234-0360
Page(s): 2-3

Commenter: American Gas Association (AGA) and American Public Gas Association (APGA)
Comment Number: EPA-HQ-OAR-2023-0234-0418
Page(s): 5, 7

Commenter: Permian Basin Petroleum Association (PBPA)
Comment Number: EPA-HQ-OAR-2023-0234-0346
Page(s): 3-4

Commenter: Antero Midstream Corporation
Comment Number: EPA-HQ-OAR-2023-0234-0338
Page(s): 1

Commenter: Marcellus Shale Coalition (MSC)
Comment Number: EPA-HQ-OAR-2023-0234-0275
Page(s): 1-2

Commenter: Michigan Oil and Gas Association (MOGA)
Comment Number: EPA-HQ-OAR-2023-0234-0298
Page(s): 3

Commenter: Step2compliance
Comment Number: EPA-HQ-OAR-2023-0234-0395
Page(s): 3-4

Commenter: Honeywell International Inc.
Comment Number: EPA-HQ-OAR-2023-0234-0375
Page(s): 3

Commenter: Arkansas Independent Producers and Royalty Owners (AIPRO)
Comment Number: EPA-HQ-OAR-2023-0234-0382
Page(s): 2

Commenter: Project Canary, PBC
Comment Number: EPA-HQ-OAR-2023-0234-0348
Page(s): 5-8

Commenter: Qube Technologies, Inc.
Comment Number: EPA-HQ-OAR-2023-0234-0386
Page(s): 4-5

Commenter: Differentiated Gas Coordinating Council (DGCC)
Comment Number: EPA-HQ-OAR-2023-0234-0415
Page(s): 5-6

Commenter: Sensirion Connected Solutions
Comment Number: EPA-HQ-OAR-2023-0234-0293
Page(s): 2

Commenter: Sensirion Connected Solutions
Comment Number: EPA-HQ-OAR-2023-0234-0293
Page(s): 10-12

Commenter: Western Energy Alliance
Comment Number: EPA-HQ-OAR-2023-0234-0399
Page(s): 3-5

Commenter: Pioneer Natural Resources USA, Inc.
Comment Number: EPA-HQ-OAR-2023-0234-0385
Page(s): 1-2

Commenter: Kairos Aerospace
Comment Number: EPA-HQ-OAR-2023-0234-0240
Page(s): 3-5

Comment 3: Commenter 0299: **GPA generally supports EPA's interpretation of what constitutes "empirical data" but additional options to use empirical data must be included.**

In the proposed rule, EPA notes that "[t]here are many forms of empirical data that can be used to quantify [greenhouse gas ("GHG")] emissions" and that for the purposes of its revision of Subpart W, it "interprets empirical data to mean data that are collected by conducting observations and experiments that could be used to calculate emissions at a facility, including direct emissions measurements, monitoring of [methane] emissions (e.g., leak surveys) or measurement of associated parameters (e.g., flow rate, pressure, etc.), and published data."[37] As a general matter, GPA supports EPA's interpretation. In particular, GPA supports EPA's proposal to include emission factors in Subpart W where appropriate, and not mandating direct measurement of every emission source, but optionally "allow[ing] for the development of site-specific emission factors for equipment leaks and pneumatic devices based on data collected from direct measurement at the facility."[38] As discussed further in in the comments listed below, however, EPA misses many opportunities to incorporate additional pertinent empirical data. Per the mandate of the IRA, EPA must include additional options to determine emissions using this data, including cases where direct measurement should be allowed, cases where emission factors should be allowed, and cases where other data should be allowed to determine emission duration/cessation such as:

- Allow large release event duration to be assessed by more than "monitored process parameters" or "monitoring or measurement survey"; for example, operator inspection logs should be an accepted credible limit on large release event duration [Comment 19]
- Allow original equipment manufacturer ("OEM")/manufacturer specification data for natural gas driven pneumatic devices and pumps [Comment 24]
- Allow reporters to demonstrate some capture efficiency for open or not properly seated tank thief hatches [Comment 42]
- Allow demonstration of thief hatch emission repair [Comment 43]
- Allow tank pressure sensors to determine if a thief hatch is open [Comment 45]
- Allow manufacturer guarantees or test data for flare destruction efficiency [Comments 53 and 61]
- Eliminate the "undetected leak factor" for fugitive component leaks [Comment 66]
- Allow actual gas composition to be used when calculating transmission and underground storage equipment leak emissions [Comment 68]
- Allow operators to account for equipment leak repair [Comment 71]
- Allow direct measurement of engine crankcase emissions [Comment 75]
- Allow use of stack test data for engines combusting field gas [Comment 80]

Footnotes:

[37] Id. at 50,286.

[38] Id. at 50,289.

Commenter 0360: **EPA should ensure Subpart W allows operators to utilize empirical data across every source category in order to facilitate and incentivize accurate reporting of emissions.**

When Congress enacted the Inflation Reduction Act (IRA) and corresponding Methane Emissions Reduction Program, EPA was mandated to revise Subpart W to ensure that reporting and calculation of the methane emissions waste charge: "are based on empirical data . . . , accurately reflect the total methane emissions and waste emissions from the applicable facilities, and allow owners and operators of applicable facilities to submit empirical emissions data, in a manner to be prescribed by the Administrator, to demonstrate the extent to which a charge is owed." The IRA's waste charge is assessed upon emissions reported in accordance with Subpart W standards.

In the proposed Subpart W rule, EPA states that it interprets empirical data to mean data that are collected by conducting observations and/or experiments that could be used to accurately calculate emissions at a facility, including direct emissions measurements, monitoring of methane emissions (e.g., leak surveys) or measurement of associated parameters (e.g., flow rate, pressure), and published data.

Although EPA's proposal allows for submission of empirical data for select source categories and components, it does not do so consistently across all source categories, in a deviation from Congress's mandate. For example, EPA should allow for data to be submitted to demonstrate that a flare is consistently achieving a greater destruction efficiency due to design and process operations, instead of limiting the destruction efficiency to a predetermined level. While previous studies exist that may indicate an appropriate destruction efficiency factor should be applied presently, technology continues to advance that could lead to even greater efficiency and emissions reductions, and EPA should not hinder that advancement. This paradigm is true for every source category. According to Devon's understanding of the proposal, several source categories are either flawed (e.g., liquids unloading, natural gas combustion, associated gas venting or flaring, flare stacks, etc.) or do not allow for a direct measurement or empirical data option as mandated by the IRA. EPA should ensure that the empirical data submission or direct measurement option exists for each source category, and where an option is proposed, it is not overly burdensome or prescriptive in a way that precludes advancements in technology and best practices that lead to actual emissions reductions.

Ideally, EPA should take an approach that allows for significant flexibility in the technologies used to collect data to inform reporting, while concurrently allowing for default emission factors for equipment to be updated as those technologies provide new information about typical emission sources and rates. This lends itself to a tiered approach, which Devon recommends, where operators are allowed to use default emission factors, engineering estimates, direct measurement, or other empirical data to determine their reported emissions. Devon believes this approach will incentivize operators to use the best available data to account for their emissions more accurately.

Commenter 0418: **The Associations support EPA's proposal to allow utilities to report emissions based on certain direct measurements; however, EPA should expand these options to include more measurement technologies and apply to additional source types, as this would increase reporting accuracy, provide greater flexibility to reporting facilities, and incentivize methane emission reductions.**

As a general matter, the Associations are pleased that EPA is proposing to allow entities in the natural gas value chain to use site-specific direct measurements and emission factors to calculate certain reported emissions. The Associations provide more detailed feedback on individual, source-specific aspects of these proposals throughout our comments, but at the outset we encourage EPA to allow broader flexibility for using an array of measurement technologies so that Subpart W reporters can select the empirical tool that is appropriate for each task.

…

In sum, EPA should allow companies sufficient flexibility to select technologies and calculation methodologies that will yield useful, more accurate empirical data.

Commenter 0240: Furthermore, by more directly incorporating measurement into the GHGRP, EPA will improve the quality of its inventory and fulfill Congress' mandate laid out in the Inflation Reduction Act of 2022, which stipulates:

"reporting under [Subpart W], and calculation of charges under subsections (e) and (f) of this section, are based on empirical data, including data collected pursuant to subsection (a)(4), **accurately reflect the total methane emissions and waste emissions** from the applicable facilities, and allow owners and operators of applicable facilities to submit empirical emissions data, in a manner to be prescribed by the Administrator"[9] (emphasis added.)

Footnote:

[9] Inflation Reduction Act of 2022 https://www.congress.gov/bill/117th-congress/house-bill/5376/text/rh

Commenter 0275: **Inflation Reduction Act Statutory Directive**

As a prelude to the comments which follow, the MSC refers to the statutory mandate enacted by the U.S. Congress which precipitated this proposed rulemaking, and strongly urges the U.S. Environmental Protection Agency (U.S. EPA) to ensure this rulemaking is consistent with the language found in the Inflation Reduction Act (Public Law 117-169). Specifically, Section 60113 of the Inflation Reduction Act requires the U.S. EPA, among other criteria, to "*allow owners and operators of applicable facilities to submit empirical emissions data*". As such, the U.S. EPA is encouraged to provide sufficient flexibility within its reporting requirements with respect to the receipt of emissions data so that owners and operators may have full confidence that the data submitted has been accurately tabulated and recorded to ensure that it is used appropriately and consistent with the intent authorized by the Inflation Reduction Act.

Commenter 0293: **Section 136 requires EPA to allow owners of applicable facilities to submit facility-specific, observed data for purposes of calculating their exposure to the Methane Waste Emissions Charge.**

As the Agency acknowledges, it has issued the Proposed Rule to meet mandates from Congress under section 136 of the Clean Air Act ("Methane Emissions and Waste Reduction Incentive for Petroleum and Natural Gas Systems"), which Congress added in section 60113 of the IRA.[2]

Section 136 consists of three elements:

(1) directives to EPA related to its proposed new rules under Section 111 of the Clean Air Act[3];

(2) the establishment of a Methane Waste Emissions Charge, to be calculated based on annual emissions reported pursuant to Subpart W; and

(3) the allocation of $1.5 billion to EPA to distribute for methane mitigation and monitoring, including $850 million to cover costs of reporting needed to implement the Methane Waste Emissions Charge.

In a letter to you, fourteen of the senators involved in drafting section 136, including the Chairman of the Environment & Public Works Committee, described these policies as comprising a "three-legged stool" in which "all three of these elements work together."[4]

A key element of this program is the Methane Waste Emissions Charge. The design of the charge relies substantially on Subpart W.

First, the Methane Waste Emissions Charge applies only to facilities reporting in certain industry segments defined in the Subpart W regulations. Section 136 refers to these facilities as "applicable facilities."[5]

Second, section 136 directs EPA to apply the Methane Waste Emissions Charge only to those applicable facilities that have annual Subpart W-reported emissions in excess of particular thresholds.[6] For applicable facilities with excess emissions, the Methane Waste Emissions Charge is calculated by multiplying a specified dollar amount by each ton of methane emissions in excess of the relevant threshold.[7] In other words, implementation of the Methane Waste Emissions Charge requires EPA to use the Subpart W framework to quantify annual emission levels for each of the applicable facilities and to calculate any charges on a per-ton basis.

Congress recognized that the current Subpart W framework is not up to this task. The existing Subpart W rules rely heavily on the use of presumptive, activity-based "emission factors" in lieu of facility- or site-specific measurement. Multiple studies have demonstrated the inaccuracy and flaws of the Subpart W emission factors.[8]

Had Congress been satisfied with the current Subpart W methodologies, it would have remained silent on these inadequacies and simply required the use of the existing Subpart W framework. However, Congress explicitly directed EPA to revise the Subpart W regulations. Section 136(i) provides:

Not later than 2 years after the date of enactment of this section, and as necessary thereafter, the Administrator shall revise the requirements of subpart W of part 98 of title 40, Code of Federal Regulations, to ensure the reporting under such subpart, and calculation of charges under subsections (e) and (f) of this section, **are based on empirical data**, including data collected pursuant to subsection (a)(4), **accurately reflect the total methane emissions and waste emissions from the applicable facilities**, and allow owners and operators of applicable facilities to **submit empirical emissions data**, in a manner to be prescribed by the Administrator, to demonstrate the extent to which a charge under subsection (c) is owed.[9]

Congress thus directed the Agency to revise the regulations to "ensure" that Subpart W reporting—which forms the basis of calculation of any Methane Waste Emissions Charges—is (1) "based on empirical data" and (2) "accurately reflect[s]" the emissions from applicable facilities.

And Congress went further. It specifically required the Agency to "allow owners and operators of applicable facilities to submit empirical emissions data in a manner to be prescribed by [the EPA] Administrator to demonstrate the extent" to which a charge is owed. In other words, it required EPA to make it possible for a facility owner to use empirical methods to show that its facility's actual emissions are lower than what the emission factors and other conventional Subpart W reporting methods would indicate.

Section 136 does not provide a definition of "empirical," so it is appropriate to assume that Congress intended the word to have its common dictionary definition, which is "originating in or based on observation or experience."[10] Emission factors do not fit this definition because they are, by definition, generalized and aggregated estimates that apply to all facilities and all activities in various categories.

When Subpart W applies an emission factor to a facility, it is not a measurement of the emissions actually observed at that facility.

Therefore, Congress' emphasis in section 136(i) on "empirical data" constitutes a mandate to EPA to introduce greater use of direct, facility-specific measurement into the Subpart W rules.

Further, as noted above, Congress allocated millions of dollars to subsidize this shift. Section 136(a) sets aside $850 million for EPA to provide grants, rebates, and loans to owners and operators of applicable facilities to prepare and submit Subpart W reports.[11] And innovative and advanced technologies are eligible for such funds.[12]

Section 136 establishes sensible mandates for the Agency regarding emissions reporting. With the enactment of the Methane Waste Emissions Charge, it will be critically important to allow each owner or operator of an applicable facility the opportunity to avail itself of technologies that can generate an accurate measurement of the facility's annual emissions—especially because such facilities will be subject to a charge that is measured on a per-ton basis. Congress clearly did not want EPA to levy Methane Waste Emission Charges exclusively on the basis of generalized emission factors. Congress directed EPA to allow owners or operators to rebut the presumptions inherent in emission factors using measured, facility-specific data.

The mandate to EPA to allow use of actually-observed data promotes two key objectives. One is fairness. An owner of an "applicable facility" should have the ability to use direct measurement methods to ensure that it has a fair and accurate tax burden—especially since the Methane Waste Emissions Charge is calculated on a highly granular, per-ton basis. The second is environmental progress. Congress intended the Methane Waste Emissions Charge to incentivize mitigation of methane emissions. However, a facility owner will not have any incentive to invest in mitigating its emissions below presumptive emission factors if it cannot use proven empirical methods to demonstrate that it has lowered its emissions.

As explained in greater detail below, the Proposed Rule is inconsistent with EPA's statutory mandate under Section 136(i) because it broadly prohibits owners and operators from using facility-specific measurements generated by a proven technology—continuous monitoring systems—in lieu of emission factors.

Footnotes:

[2] Section 60113, P. L. 117-169.

[3] U.S. EPA, Standards of Performance for New, Reconstructed, and Modified Sources and Emissions Guidelines for Existing Sources for Existing Sources; Oil and Natural Gas Sector Climate Review, 87 Fed. Reg. 74,702 (Dec. 6, 2023) (hereinafter "Section 111 Supplemental Proposal").

[4] Letter from Sen. Carper et al. to Administrator Regan

[5] CAA Section 136(d) (defining "applicable facility"). Section 136(c) further limits "applicable facilities" to those reporting more than 25,000 mtCO2e.

[6] CAA Section 136(f) (specifying waste emission thresholds).

[7] CAA Section 136(e) (specifying annual charge amounts).

[8] See, e.g., Alvarez, R. A. et al. Assessment of methane emissions from the US oil and gas supply chain. Science 361, 186–188 (2018); Lu X, et al. Observation-derived 2010-2019 trends in methane emissions and intensities from US oil and gas fields tied to activity metrics. Proc. Natl Acad. Sci. USA. 2023;120:e2217900120. Doi; Rutherford, J. S.; Sherwin, E. et al. Closing the methane gap in US oil and natural gas production emissions inventories. Nature Comm. 2021 12:4715. DOI: 10.1038 s41467-021-25017-4.: 10.1073/pnas.2217900120.

[9] CAA Section 136(i) (emphasis added).

[10] Merriam-Webster, On-Line Dictionary, definition of "Empirical," htps://www.merriam-webster.com/dictionary/empirical.

[11] CAA Section 136(a)(1).

[12] CAA Section 136(c).

Commenter 0293: c. Congressional emphasis, in Section 136(h) of the IRA, on "empirical data" constitutes a mandate to EPA to introduce greater use of direct, facility-specific measurement into the Subpart W rules. With the enactment of the Methane Waste Emissions Charge, it will be critically important to allow each owner or operator of an applicable facility the opportunity to avail itself of technologies that can generate an accurate measurement of the facility's annual emissions—especially because such facilities will be subject to a charge that is measured on a per-ton basis.

d. Congress clearly did not want EPA to levy Methane Waste Emission Charges exclusively on the basis of generalized emission factors. Congress directed EPA to allow owners or operators to rebut the presumptions inherent in emission factors using measured, facility-specific data.

Commenter 0298: Estimated vs. Actual Emissions

MOGA's constituents are concerned that current and proposed Subpart W emissions factors overestimate emissions from the emission source categories and do not accurately reflect the actual emissions. The proposed taxation of Methane Waste Emissions should be based on actual emissions rather than calculated emission factors. MOGA recommends the EPA develop and propose specific, cost-efficient methodologies that would allow all operators, including both very small and small businesses to calculate actual emissions.

Commenter 0338: The Inflation Reduction Act directs EPA to revise the requirements of 40 Code of Federal Regulations (C.F.R,) part 98, subpart W ("Subpart W") to "ensure the reporting under [the] subpart," is "based on empirical data, … accurately reflect[s] the total methane emissions and waste emissions from the applicable facilities, and allow[s] owners and operators of applicable facilities to submit empirical emissions data." 42 U.S.C. § 7436(h). That directive is a primary impetus for the Proposed Rule. 88 Fed. Reg. at 50,285.

Antero agrees with the direction in the Act to ensure greenhouse gas reporting under Subpart W is based on empirical data, and that it "allow owners and operators of applicable facilities to submit empirical emissions data." 42 U.S.C. § 7436(h). This directive is necessary to ensure EPA has the best and most reliable data on greenhouse gas emissions from the natural gas industry, and that operators are assessed and pay accurate fees under the Act's fee provisions.

Commenter 0346: IRA Requires EPA to Collect Empirical Data, but the Proposed Rule Does not Accomplish that Objective

In the opening lines of the preamble to the Proposed Rule, EPA states that the purpose is "to ensure that reporting is based on empirical data, accurately reflects total methane emissions and waste emissions from applicable facilities, and allows owners and operators of applicable facilities to submit empirical emissions data that appropriately demonstrate the extent to which a charge is owed." That purpose is consistent with the IRA, in which Congress requires the EPA to:

revise the requirements of subpart W to ensure the reporting under subpart W [and corresponding waste emissions charges under the Clean Air Act ("CAA") section 136] are based on empirical data… accurately reflect the total methane emissions and waste emissions from the applicable facilities, and allow owners and operators of applicable facilities to submit empirical emissions data, in a manner to be prescribed by the Administrator, to demonstrate the extent to which a charge…is owed. [2]

But the Proposed Rule does not ensure that reporting under Subpart W yields empirical data for all sources. Instead, it requires operators to rely on generic emission assumptions that inflate emissions reporting, in some instances up to three times the actual emission amounts. PBPA does not support changes that would lead to unnecessary or inaccurate reporting. Any revisions to the GHGRP should accomplish the intended ends of improved quality and consistency, without resulting in undue costs or inaccuracies in reporting.

As an example, one PBPA member calculated the emissions under the existing reporting rule and compared them to emissions that would be calculated using the Proposed Rule. Nothing changed about the facility's operations. The only change was the methodology for calculating emissions. Specifically, total company methane emissions increased 240% due to leak emissions. Associated gas/flare emissions increased total company methane emissions by 34% due to the Proposed Rule's destruction removal efficiency ("DRE") requirements. Combustion methane slip emissions increased total company methane emissions by 25%. Emissions associated with gas pneumatic controllers increased total company methane emissions by 20%. Emissions associated with reciprocating compressor rod packing increased total company emissions by 18%. But these increases are based on assumptions that do not reflect the empirical data of what actually occurs.

If an emissions tax or fee system as required under IRA is implemented utilizing GHGRP, additional flexibility will need to be provided to truly support quality and consistency in reporting. Studies have shown that similar equipment and production can result in different emission amounts— because of differences in facility design, operation, and maintenance. However, as further described below, the Proposed Rule does not account for these differences, and instead dictates that certain emission factors be used even when they do not accurately reflect actual emissions.

Footnote:

[2] Clean Air Act § 136(h).

Commenter 0348: **Section 136 requires EPA to allow owners of applicable facilities to submit facility-specific, observed data for purposes of calculating their exposure to the Methane Waste Emissions Charge.**

As the Agency acknowledges, it has issued the Proposed Rule to meet mandates from Congress under Section 136 of the CAA ("Methane Waste Emissions Charge"), which Congress added in Section 60113 of the IRA. [3]

Section 136 consists of three elements:

(1) directives to EPA related to its proposed new NSPS OOOOb and EG OOOOc rules;

(2) the establishment of a Methane Waste Emissions Charge, to be calculated based on annual emissions reported pursuant to Subpart W; and

(3) the allocation of $850 million to EPA to distribute for methane mitigation and monitoring by applicable facilities, including financial and technical assistance to owners and operators of such

facilities to prepare and submit Subpart W reports needed to implement the Methane Waste Emissions Charge.

In a letter to you of June 13, 2023, fourteen of the senators involved in drafting Section 136, including the Chairman of the Environment & Public Works Committee, described these policies as comprising a "three-legged stool" in which "all three of these elements work together."[4] The letter goes on to emphasize that the IRA, "requires EPA to update the existing Greenhouse Gas Reporting Program for oil and gas production—which provides the basis for assessing the emissions charge—to ensure more accurate quantification and reporting of methane emissions."[5]

A key element of this program is the Methane Waste Emissions Charge. The design of the charge relies substantially on Subpart W.

The Methane Waste Emissions Charge applies only to facilities reporting in certain industry segments defined in the Subpart W regulations. Section 136 refers to these facilities as "applicable facilities."[6] Section 136 directs EPA to apply the Methane Waste Emissions Charge only to those applicable facilities that have annual Subpart W-reported emissions in excess of particular thresholds.[7] For applicable facilities with excess emissions, the Methane Waste Emissions Charge is calculated by multiplying a specified dollar amount by each ton of methane emissions in excess of the relevant threshold.[8] In other words, implementation of the Methane Waste Emissions Charge requires EPA to use the Subpart W framework to quantify annual emission levels for each of the applicable facilities and to calculate any charges on a per-ton basis.

Congress recognized that the current Subpart W framework is not up to this task. The existing Subpart W rules rely heavily on the use of presumptive, activity-based "emission factors" in lieu of facility- or site-specific measurement. Multiple studies have demonstrated the inaccuracy and flaws of the Subpart W emission factors.[9]

Had Congress been satisfied with the current Subpart W methodologies, it would have remained silent on these inadequacies and simply required the use of the existing Subpart W framework. However, Congress explicitly directed EPA to revise the Subpart W regulations. Section 136(h) provides:

Not later than 2 years after the date of enactment of this section, the Administrator shall revise the requirements of subpart W of part 98 of title 40, Code of Federal Regulations, to ensure the reporting under such subpart, and calculation of charges under subsections (e) and (f) of this section, **are based on empirical data**, including data collected pursuant to subsection (a)(4), **accurately reflect the total methane emissions and waste emissions from the applicable facilities, and allow owners and operators of applicable facilities to submit empirical emissions data, in a manner to be prescribed by the Administrator, to demonstrate the extent to which a charge under subsection (c) is owed.**[10]

Congress thus directed the Agency to revise the regulations to "ensure" that Subpart W reporting—which forms the basis of calculation of any Methane Waste Emissions Charges—is

(1) “based on empirical data” and (2) “accurately reflect[s]” the emissions from applicable facilities.

And Congress went further. It specifically required the Agency to “allow owners and operators of applicable facilities to submit empirical emissions data in a manner to be prescribed by [the EPA] Administrator to demonstrate the extent” to which a charge is owed. In other words, it required EPA to make it possible for a facility owner to use empirical methods to show that its facility’s actual emissions are lower than what the emission factors and other conventional Subpart W reporting methods would indicate.

Section 136 does not provide a definition of “empirical,” so it is appropriate to assume that Congress intended the word to have its common dictionary definition, which is “originating in or based on observation or experience.”[11] Emission factors do not fit this definition because they are, by definition, generalized and aggregated estimates that apply to all facilities and all activities in various categories. When Subpart W applies an emission factor to a facility, it is not a measurement of the emissions actually observed at that facility. Therefore, Congress’ emphasis in Section 136(h) on “empirical data” constitutes a mandate to EPA to introduce greater use of direct, facility-specific measurement into the Subpart W rules.

Further, as noted above, Congress allocated millions of dollars to subsidize this shift. Section 136(a) sets aside $850 million for EPA for four purposes—one of which is to provide grants, rebates, and loans to owners and operators of applicable facilities to prepare and submit Subpart W reports. [12] And innovative and advanced technologies are eligible for such funds. [13]

Section 136 establishes sensible mandates for the Agency regarding emissions reporting. With the enactment of the Methane Waste Emissions Charge, it will be critically important to allow each owner or operator of an applicable facility the opportunity to avail itself of technologies that can generate an accurate measurement of the facility’s annual emissions—especially because such facilities will be subject to a charge that is measured on a per-ton basis. Congress clearly did not want EPA to levy Methane Waste Emission Charges exclusively on the basis of generalized emission factors. Congress directed EPA to allow owners or operators to rebut the presumptions inherent in emission factors using measured, facility-specific data.

The mandate to EPA to allow use of actually-observed data promotes two key objectives. One is fairness. An owner of an “applicable facility” should have the ability to use direct measurement methods to ensure that it has a fair and accurate tax burden—especially since the Methane Waste Emissions Charge is calculated on a highly granular, per-ton basis. The second is environmental progress. Congress intended the Methane Waste Emissions Charge to incentivize mitigation of methane emissions. However, a facility owner will not have any incentive to invest in mitigating its emissions below presumptive emission factors if it cannot use proven empirical methods to demonstrate that it has lowered its emissions.

As explained in greater detail below, the Proposed Rule is inconsistent with EPA’s statutory mandate under Section 136(h) because it broadly prohibits owners and operators from using facility-specific measurements generated by a proven technology—continuous monitoring systems—in lieu of emission factors.

Footnotes:

3 Section 60113, P. L. 117-169 (amending the CAA to add Section 136).

4 Letter from Sen. Carper et al. to EPA Administrator Regan (June 13, 2023), htps://www.epw.senate.gov/public/_cache/files/a/d/add69148-5551-44d1-a723-9712b2356aa6/7528A8ED3B05E497624AE68DABD20E6D.06-15-23-letter-to-regan-methane-final.pdf (last visited Sep. 19, 2023).

5 Id. (emphasis added)

6 CAA § 136(d) (defining "applicable facility"). Section 136(c) further limits "applicable facilities" to those reporting more than 25,000 mtCO2e.

7 Id. at § 136(f) (specifying waste emission thresholds).

8 Id. at § 136(e) (specifying annual charge amounts).

9 See, e.g., Alvarez, R. A. et al. Assessment of methane emissions from the US oil and gas supply chain. Science 361, 186–188 (2018); Lu X, et al. Observation-derived 2010-2019 trends in methane emissions and intensities from US oil and gas fields tied to activity metrics. Proc. Natl Acad. Sci. USA. 2023;120:e2217900120. Doi; Rutherford, J. S.; Sherwin, E. et al. Closing the methane gap in US oil and natural gas production emissions inventories. Nature Comm. 2021 12:4715. DOI: 10.1038 s41467- 021-25017-4.: 10.1073/pnas.2217900120.

10 AA § 136(h) (emphasis added).

11 Merriam-Webster, On-Line Dictionary, definition of "Empirical," htps://www.merriam-webster.com/dictionary/empirical.

12 CAA § 136(a)(1).

13 Id. at § 136(c).

<u>Commenter 0375</u>: Subpart W currently requires that operators of facilities containing petroleum and natural gas systems that emit 25,000 or more metric tons of GHGs per year report GHG emissions data to EPA annually. 40 C.F.R. § 98.231. Operators must conduct equipment leak surveys using specified leak detection methods for components in streams with gas content greater than ten percent CH4 plus CO2 by weight. 40 C.F.R. § 98.233(q). These methods include, but are not limited to, OGI instruments as per § 60.18 or OOOOa (40 C.F.R. § 60.5397a), infrared laser beam illuminated instruments, and acoustic leak detection devices. 40 C.F.R. § 98.234(a). When leaks are detected during surveys, operators must calculate GHG emissions using a formula (*Es,,i = GHGi * EFs,* * Σ *Tp, xp z*=1), which accounts for various leaker emission factors (EF) for specific component types, as well as a time component (T). 40 C.F.R. § 98.233(c)(1), (q)(2) & tbls.W-1A; see also id. tbls. W-1E, W2, W-3A, W-4A, W-5A, W-6A, and W-7 (listing emission factors by component type).

The Inflation Reduction Act (IRA) requires EPA to revise the requirements of GHGRP Subpart W to “ensure” that GHG reporting and calculations “are based on empirical data,” “accurately reflect the total methane emissions and waste emissions from the applicable facilities,” and permit operators to submit empirical emissions to demonstrate the amount owed under the methane emissions charge. Pub. L. 117-169, 136 Stat. 1817, 2076 (2022). Thus, Subpart W requirements must require more accurate reporting based on empirical data to increase the accuracy of the methane emissions inventory.

Commenter 0382: **Inflation Reduction Act (“IRA”) and Associated “Waste Emissions Charge”:**

EPA’s latest proposed Subpart W revisions still fail to accomplish the legislative mandate in Sec. 60113 of the IRA as it relates to ensuring reporting under 40 CFR Part 98 – Subpart W and the associated calculation of “Waste Emissions Charges”, better referred to as a methane tax, is based on “empirical data.” For certain emissions sources, such as natural gas driven pneumatic devices, EPA’s proposed revisions partially satisfy the legislative mandate to allow “empirical data,” but still require reporters to use one-size fits all emissions factors and/or assumptions for “in-service” or operating times. Therefore, resulting emissions will continue to be inaccurate and, in many cases, significantly overstated.

…

iii. As such, AIPRO strongly encourages the EPA to withdraw the proposed revisions in Docket ID No. EPA–HQ–OAR–2023–0234 and propose new updates to Subpart W that allow reporters to utilize empirical data representative of their actual emissions and accomplish the legislative mandate of the IRA. Further, AIPRO welcomes the opportunity to collaborate with the agency as it works to draft updated revisions to the GHGRP rules.

Commenter 0385: To the extent that the IRA mandate states that EPA shall revise Subpart W to "allow owners and operators… to submit empirical emissions data… to demonstrate the extent to which a charge" is owed, Pioneer has some concerns with certain aspects of the proposed changes which do not align with that directive.

…

With Subpart W playing an integral role in determining a company's waste methane emissions charge liabilities, it is imperative that the final rule be clearly written and aligned with best industry operating practices as well as EPA's intent to minimize and reduce methane emissions.

Commenter 0386: **Section 136 requires EPA to allow owners of applicable facilities to submit facility-specific, observed data for purposes of calculating their exposure to the Methane Waste Emissions Charge.**

EPA has issued the Proposed Rule to meet mandates from Congress under section 136 of the Clean Air Act (“Methane Emissions and Waste Reduction Incentive for Petroleum and Natural Gas Systems”), which Congress added in section 60113 of the IRA.[3]

A central element of this program is the Methane Waste Emissions Charge. The design of the charge relies on industry's compliance with Subpart W. The Methane Waste Emissions Charge applies only to facilities reporting in certain industry segments defined in the Subpart W regulations. Section 136 refers to these facilities as "applicable facilities."[4]

Implementation of the Methane Waste Emissions Charge requires EPA to use the Subpart W framework to quantify annual emission levels for each of the applicable facilities and to calculate any charges on a per-ton basis.

Congress recognized that the current Subpart W framework falls short of covering all emissions that it aims to regulate. Subpart W as currently written relies on the use of "emission factors" in the absence of facility or site-specific measurements. This is concerning to us since multiple studies have demonstrated inaccuracies in the Subpart W emission factors methodology.[5]

It is reasonable to conclude that if Congress had been satisfied with current Subpart W methodologies, it would have taken no further legislative action and simply continued enforcing the existing Subpart W framework. But Congress directed EPA to revise the regulations to ensure that Subpart W reporting, which forms the basis of calculation of any Methane Waste Emissions Charge, is based on empirical data and accurately reflects the emissions from applicable facilities.

Congress also required EPA to "allow owners and operators of applicable facilities to submit empirical emissions data in a manner to be prescribed by EPA to demonstrate the extent" to which a charge is owed. Said differently, it required EPA to make it possible for a facility owner to use empirical methods to show that its facility's actual emissions are lower than what the emission factors would indicate.

Problematically, Section 136 does not provide a definition of "empirical," nor prescribe a method for construing empirical figures. Thus, emission factors as currently calculated and understood do not comport with the common meaning of empirical because they are by definition generalized and aggregated estimates. Therefore, when Subpart W assigns an emission factor to a facility, it is not an actual measurement of the emissions at that facility, but a generic one.

Therefore, Congress' emphasis on the notion of "empirical data" is tantamount to a mandate that EPA permits greater use of direct, facility-specific measurements in the Subpart W rules. Since regulated facilities under Subpart W will be subject to a charge that is measured on a per-ton basis, it is essential for operators to have the ability to leverage all available means to produce an accurate measurement of the facility's annual emissions on which any potential charge would be calculated.

If Congress wanted EPA to levy Methane Waste Emission Charges on the basis of generalized emission factors, it would have explicitly said so. Instead, Congress directed EPA to allow operators to improve generically determined emission factors by using facility-specific data.

The mandate from Congress to EPA to allow the use of actual data over emissions factors will ultimately achieve better emissions reduction outcomes because operators will not have any incentive to reduce emissions below presumptive emission factors if measurement methods that might otherwise demonstrate actual reductions below those figures are not permitted.

We find that the Proposed Rule is inconsistent with EPA's statutory mandate under Section 136(i) because it broadly prohibits owners and operators from using facility-specific measurements generated by a proven technology—continuous monitoring systems—in lieu of emission factors.

Footnotes:

[3] Section 60113, P. L. 117-169.

[4] Section 136(d) (defining "applicable facility"). Section 136(c) further limits "applicable facilities" to those reporting more than 25,000 $mtCO_2e$.

[5] See, e.g., Alvarez, R. A. et al. Assessment of methane emissions from the US oil and gas supply chain. Science 361, 186–188 (2018); Lu X, et al. Observation-derived 2010-2019 trends in methane emissions and intensities from US oil and gas fields tied to activity metrics. Proc. Natl Acad. Sci. USA. 2023;120:e2217900120. Doi; Rutherford, J. S.; Sherwin, E. et al. Closing the methane gap in US oil and natural gas production emissions inventories. Nature Comm. 2021 12:4715. DOI: 10.1038 s41467-021-25017-4.: 10.1073/pnas.2217900120.

Commenter 0395: Based on Congress identifying that the current subpart W framework is inadequate for the purpose of assessing the Methane Waste Emissions Charge due the fact it heavily relies on the use of presumptive, activity-based "emission factors" vs. facility or site-specific measurements, and thus Congress directed the Agency to revise the regulations to "ensure" that Subpart W reporting—which forms the basis of calculation of any Methane Waste Emissions Charges—is (1) "based on empirical data" and (2) "accurately reflect[s]" the emissions from applicable facilities, it is of concern that there are still aspects to the proposed revisions to subpart W that are void of providing the operators the ability to utilize direct measurement or limit the ability to use direct measurement to a small subset. For example, from the TSD Table 2-1 Source Specific Monitoring Methods and Emissions Quantification for Subpart W Emission Sources, as Proposed to be Amended, thief hatches that are open or not properly seated are required to assume a zero-capture rate. Using an assumption is not empirical as is called for in the IRA. There are means of quantifying thief hatch leaks and operators should be allowed to use empirical data vs. an assumed zero-capture. For example, a newer OGI plus AI technology, CleanConnect.ai, can pinpoint source-level emissions measurement (with live OGI video to prove it) and reconcile the live mass-balance loss using ProMax 6 integrated with onsite IIoT direct measurement devices. Operators who are deploying this or other similar advanced monitoring technology should be allowed to use their empirical measurements vs. being pushed into a "zero-capture" assumption factor.

Similarly, under section (z) for combustion sources and the introduction of the methane slip factors, under the current proposal, the option to quantify emissions from combustion slip using a performance test is limited to combustion sources operating using fuel meeting the standards in 98.233(z)(1)(i) or 98.233(z)(2)(i). However, the fuel type for that same site where the combustion source is operating referred to as “expected to be highly variable composition over the course of the year”, is being used for other calculations and emissions quantification also being reported under this subpart. It would follow that having the composition of the fuel and the results of a stack test provide better direct measurement and are more empirical than just using estimation factors even if there is variability within gas composition. This would allow for the additional calculation option of method 2 as outlined in the list below of the proposed added calculation methods.

In the newly proposed section (ee) for crankcase venting there is only the single option of calculating emissions using the provided equation that relies on the old calculation method 5 of population count and population emission factors. As the IRA directed the EPA to provide the operators with a means of using empirical data, there needs to be an alternative method of calculation using one of the newly proposed four methods as outlined in the proposal, such as method 2 which would allow for a combination of measurement and engineering calculations.

1. Direct emission measurement;
2. Combination of measurement and engineering calculations;
3. Engineering calculations
4. Leak detection and use of a leaker emission factor; and
5. Population count and population emission factors.

Commenter 0399: *The Proposed Rule Conflicts with IRA’s Methane Fee Provision*

The proposed Subpart W revisions are not aligned with the clear language in IRA. Primarily, the IRA language requires EPA to revise Subpart W to ensure that reported emissions "are based on empirical data," "accurately reflect the total methane emissions and waste emissions," and allow the submission of "empirical emissions data" to support the calculation of emission charges.

…

IRA requires the use of empirical data and accurately reported emissions. In many cases, the use of new default factors will vastly increase emissions from activities and equipment for which empirical data is available from aircraft studies, the published literature, and even EPA’s own collected data within the methane rule information collection request. Even if emissions for a specific piece of equipment for which additional flare flow monitoring or gas composition requirements are implemented result in increased accuracy for that single equipment or activity, that does not necessarily provide additional accuracy to the overall inventory, especially if what must be used in lieu of that burdensome monitoring data is shown to be far too conservative to represent an accurate picture of emissions from that emissions category. Essentially, EPA is replacing more reasonable factors with far more conservative (overestimated) ones and allowing operators to essentially revert back to the more reasonable factors, but only if confirmed by expensive and time consuming measurement. Even with the option of developing a site-specific leak factor, this will be cost prohibitive for most operators and most facilities, causing the inventory for those facilities to revert to the overly conservative factors. So, while allowing for instrument-specific data that would be correct for a single piece of equipment, the impact of the rulemaking to the overall reporting program will be to make it less accurate. EPA should not claim that this rule as proposed increases the accuracy of the inventory based on purported accuracy improvements on single pieces of equipment.

In addition, various points in the rule require overly conservative assumptions on duration for open thief hatches, malfunctioning dump valves, and unlit flares that will likely result in overreporting emissions. Like the increasing leak emissions factors, this is contrary to the intent of IRA to make reporting more accurate and to assess an equitable methane fee. EPA should allow for more reasonable assumptions for source duration, especially for equipment that is visited and worked on with a much greater than annual frequency.

EPA instead seems to be forcing operators to make a false choice between installing overly burdensome, unnecessary, and expensive equipment that requires much more frequent monitoring and overreporting emissions using inaccurate default emissions factors, resulting in an artificially inflated methane fee. EPA would be in violation of IRA by imposing a methane fee on operators based on data EPA knows to be inaccurate and overestimated based on the available science. This is further exacerbated by the fact that there is a third option that EPA is not considering and that is the flexibility to employ the same type of advanced methane detection that EPA claims to be trying to incentivize within the OOOOb/c rulemaking proposals–namely, field-scale aircraft, drone, satellite, and fixed equipment monitoring. Such technologies have a better ability to identify unknown emissions sources or leaks. By allowing operators to use data from such surveys and monitors to better align their methane fee with their actual emissions in the field, EPA would encourage more frequent use of advanced technologies and field-wide surveys, consequently reducing emissions in the industry segment, which should be a goal that EPA and industry can align on.

<u>Commenter 0415</u>: **EPA Must Align with Congressional Intent**

The DGCC is concerned that EPA's proposed subpart W rule does not align with Congressional intent regarding the establishment of the Methane Waste Emissions Charge, as outlined in section 136 of the Clean Air Act, which was added via Section 60113 of the IRA.[7] In this section, Congress sought to leverage recent developments in direct measurement technologies to accurately and fairly quantify operators' tax burdens under the Charge and to ensure measurable, verifiable environmental progress. [8]

The EPA's existing Subpart W rules utilize presumptive, activity-based emission factors instead of direct emission measurements. Numerous scientific studies highlight the shortcomings and inaccuracies of this approach. [9] In light of these inadequacies, Congress has explicitly instructed the EPA to update the Subpart W regulations, as outlined in Section 136(h) of the Clean Air Act:

Not later than 2 years after the date of enactment of this section, and as necessary thereafter, the Administrator shall revise the requirements of subpart W of part 98 of title 40, Code of Federal Regulations, to ensure the reporting under such subpart, and calculation of charges under subsections (e) and (f) of this section, are based on empirical data, including data collected pursuant to subsection (a)(4), accurately reflect the total methane emissions and waste emissions from the applicable facilities, and allow owners and operators of applicable facilities to submit empirical emissions data, in a manner to be prescribed by the Administrator, to demonstrate the extent to which a charge under subsection (c) is owed.

This language clearly emphasizes the need for empirical data to accurately report and calculate charges, ensuring accurate reflection of total methane emissions from relevant facilities. Congress specifically required the Agency to "allow owners and operators of applicable facilities to submit empirical emissions data in a manner to be prescribed by [the EPA] Administrator to demonstrate the extent" to which a charge is owed. In other words, it required EPA to make it possible for a facility owner to use empirical methods to show that its facility's actual emissions are lower than what the emission factors and other conventional Subpart W reporting methods would indicate.

Section 136 does not provide a definition of "empirical," so it is appropriate to assume that Congress intended the word to have its common dictionary definition, which is "originating in or based on observation or experience."[10] Emission factors do not fit this definition because they are, by definition, generalized and aggregated estimates that apply to all facilities and all activities in various categories. When Subpart W applies an emission factor to a facility, it is not a measurement of the emissions observed at that facility.

Therefore, Congress' emphasis in section 136(h) on "empirical data" constitutes a mandate to EPA to introduce greater use of direct, facility-specific measurement into the Subpart W rules.

Despite these clear instructions, the proposed rule contradicts the EPA's statutory mandate under Section 136(h). In general, it denies facility owners or operators the opportunity to employ advanced measurement methodologies for methane emissions calculation, failing to analyze the potential accuracy of advanced measurement technologies comprehensively. The rule does not provide specific analysis for advanced emission monitoring systems or establish a framework for the approval of emerging technologies as they advance over time, reflecting a gap in addressing the Congressional emphasis on empirical data and facility-specific measurements. Not only will the adoption of such a framework better align with Congress's directives, but it will also ensure a more rapid adoption of technologies and processes to mitigate methane emissions.

Footnotes:

[7] See Section 60113, P. L. 117-169.

[8] See letter from Sen. Carper et al. to EPA Administrator Regan (June 13, 2023): "[Section 136] also requires EPA to update the existing Greenhouse Gas Reporting Rule for oil and gas production – which provides the basis for assessing the waste emissions charge – to ensure more accurate quantification and reporting of methane emissions."

[9] See, e.g., Alvarez, R. A. et al. Assessment of methane emissions from the US oil and gas supply chain. Science 361, 186–188 (2018); Lu X, et al. Observation-derived 2010-2019 trends in methane emissions and intensities from US oil and gas fields tied to activity metrics. Proc. Natl Acad. Sci. USA. 2023;120:e2217900120. Doi; Rutherford, J. S.; Sherwin, E. et al. Closing

the methane gap in US oil and natural gas production emissions inventories. Nature Comm. 2021 12:4715. DOI: 10.1038 s41467-021-25017- 4.: 10.1073/pnas.2217900120.

[10] See Merriam-Webster's definition of "Empirical."

Response 3: As noted in the preamble to the 2023 Subpart W proposal, the EPA reviewed available empirical data methods for accuracy and appropriateness for calculating annual unit or facility-level GHG emissions. The review included both the evaluation of technologies and methodologies already incorporated in subpart W for measuring and reporting annual source- and facility-level GHG emissions and the evaluation of the accuracy of potential alternative technologies and methodologies, with a focus on CH_4 emissions due to the directive in CAA section 136(h). For this final rule, the EPA considered currently available information, including comments on the proposed methods, and in some cases is finalizing methods that are different from proposed as appropriate, increasing availability of methods that utilize facility measurements. For example, the EPA proposed one calculation method for crankcase venting based on an emission factor, but we are finalizing an additional method based upon measurement (see Section III.C.5 of the preamble to the final rule for additional information). Responses to comments on specific empirical methods suggested by commenters are provided in the sections of preamble to the final rule and this document specific to the source type.

Regarding the comment that the EPA should provide significant flexibility within subpart W, we note that we have provided flexibility for many source types, but at this time, the EPA is not providing all types of calculation methods for every source type. In some cases, the EPA is not aware of an appropriate direct measurement method. Of the calculation methods available for a given source type, reporters have the flexibility to choose a method in some cases, but in other cases a specific method is required. For example, if reporters have collected measurement data, they must use that information, which is intended to avoid a situation in which reporters measure emissions but then use a default emission factor if that results in a calculation of less emissions than the measurement. This approach is most consistent with the directives in CAA section 136(h), that reported emissions be based on empirical data and accurately reflect total methane emissions from the facility.

As discussed in Section II.B of the preamble to the final rule, this final rule integrates advanced measurement approaches for specific sources in certain appropriate circumstances, including for other large release events. The EPA agrees that rapid detection of these large release events resulting in facilities taking immediate action to mitigate the event will substantially decrease the duration of these events and significantly lower methane emissions. However, the Agency recognizes that these technologies, and approaches for using these technologies for long-term quantification of emissions from oil and natural gas operations, have a wide level of uncertainty and are not ready for widespread use for quantification purposes at this time. The EPA acknowledges the rapid evolution of these technologies, and their potential utilization for long term emission quantification. Historically, the Greenhouse Gas Reporting Rule has been revised to incorporate the latest data, updated scientific knowledge or additional measurement methods and EPA intends to continue to evaluate the appropriateness of additional updates. In preparation for potential future rulemaking, the EPA is actively reviewing peer reviewed literature and pilot programs to explore the potential incorporation of diverse continuous monitoring solutions and methodologies in subpart W.

One commenter requested that the EPA include specific additional options to determine emissions. Our responses to these specific requests are provided or referenced below:

- The commenter requested that the EPA allow the duration of other large release events to be assessed by more than monitored process parameters or monitoring or measurement surveys, and include the use of, for example, operator inspection logs. As discussed in Section III.B.2 of the preamble to the final rule, we intentionally provided flexibility for using monitored process parameters for determining the start time of a release in the proposed rule without trying to limit the types of parameters that could be monitored to identify the start date of an event. In addition, in the final rule, we expanded the monitoring methods that can be used to identify the start date of other large release events to include audio, visual and olfactory (AVO) monitoring (in cases where the event was identified by AVO). However, we consider other methods of determining the start of other large release events, such as operator inspection logs, to be inconsistent with the directives specified in CAA section 136(h).
- See our response to comment 2 in Section 6.1 and comment 2 in Section 6.2 of this document regarding the use manufacturer specification data for natural gas driven pneumatic pumps and devices, respectively.
- See Section III.K.1.b of the preamble to the final rule for our response to the request to allow demonstration of capture efficiencies greater than zero percent for open or not properly seated thief hatches and the request to allow for the use of tank pressure sensors to determine if a thief hatch is open.
- See our response to comment 6 in Section 12.1 of this document on allowing demonstration of thief hatch repair to limit leak duration periods.
- See Section III.N.1.b of the preamble to the final rule for our response to the request to allow manufacturer guarantees or test data to be used to determine flare destruction efficiency.
- See Section III.P.2.b of the preamble to the final rule for our response to the request to eliminate the undetected leak factor for equipment leak emissions.
- With regard to allowing actual gas composition to be used when calculation transmission and underground storage equipment leak emissions, and as discussed in Section III.P.1.a of the preamble to the final rule, the EPA finalized updates to allow the Onshore Natural Gas Transmission Compression or Underground Natural Gas Storage industry segments to use the concentration of CH_4 or CO_2 in the feed natural gas in lieu of the default concentrations provided in equation W-30 when quantifying equipment leak emissions using Calculation Method 1.
- See our response to comment 1 in Section 17.7 of this document regarding the request to allow operators to account for equipment leak repairs.
- See Section III.C.5.b of the preamble to the final rule for our response to the request to allow direct measurement of engine crankcase emissions.
- See Section III.S.2.b of the preamble to the final rule for our response to the request to allow use of stack test data for engines combusting field gas.

Regarding one commenter's request that EPA allow data to be submitted to demonstrate that a flare is achieving greater destruction efficiency, see our discussion and response on this subject in Section N.1 of the preamble to the final rule.

We disagree with one commenter's assertion that emission factors do not represent empirical data because they are not "originating in or based on observation or experience". As discussed in Section II.B of the preamble to the final rule, certain calculation methodologies rely on the use of emission factors but these are derived from representative empirical data and are expected provide a reasonably accurate estimate of facility-level emissions.

See Section II.B of the preamble to the final rule for our response on the use of continuous monitoring systems.

With respect to one commenter's assertion that EPA requires "one-size fits all" emission factors and/or assumptions for "in-service" or operating times for pneumatic devices, we note that both the proposed and final Subpart W rules include direct measurement methodologies for these devices, including measurement of the natural gas supply to devices and measurement of vent emissions from the devices. Notwithstanding the fact that EPA considers the final rule emission factors for pneumatic devices to provide a reasonably accurate estimate of emissions, reporters are not required to use the emission factors.

One commenter asserted that emissions would increase without changes in a facility's operations simply due to changes in calculation methodology between the existing Subpart W and this final rule. Firstly, we note that, where emission factors were updated in the final Subpart W rule, the updates were based on EPA's review of recent, peer-reviewed studies. Therefore, to the extent that emissions will increase for a particular facility due to the use the final Subpart W emission factors, we contend that the increased emissions more accurately represent actual emissions relative to emissions based on the factors they are replacing. Secondly, with respect to specific examples raised by this commenter (equipment leaks, flaring, methane slip, and pneumatic devices), we note that the final rule includes provisions to incorporate direct measurement data and other empirical data that can be optionally used by reporters as an alternative to default emission factors and flare destruction efficiencies. For reciprocating compressors, we proposed and are finalizing requirements to measure rod packing emissions when compressors are in the standby-depressurized mode because recent studies indicate that rod packing emissions can occur while the compressor is in this mode. Therefore, and although these emissions were not required to be quantified and reported under the existing rule, their inclusion in this final rule is appropriate and consistent with the CAA section 136(h) directive that reporting under Subpart W accurately reflect total CH_4 emissions and waste emissions from applicable facility.

See Section III.K.1.b of the preamble to the final rule for EPA's response to comments regarding emissions from thief hatches. With regards to quantifying open thief hatch (and other) emissions using advanced technologies, see EPA's discussion in Section II.B of the preamble to the final rule.

One commenter asserted that EPA is "replacing more reasonable factors with far more conservative (overestimated) ones". Given the commenter's subsequent mention site-specific leak factors, we assume the comment regarding the reasonableness of the factors refers specifically to equipment leak emission factors. We disagree with the contention that EPA is replacing more reasonable factors with overestimated factors. As discussed in Sections III.P and Q of the preamble to the final rule, the EPA finalized updated emission factors based on recent peer reviewed studies, which are expected to result in more accurate estimates of emissions relative to the factors being replaced.

See our responses to comment 6 in Section 12.1, comment 2 in Section 12.2, and comment 7 in Section 15.2.5 of this document regarding the approach to determining the duration of open thief hatches, malfunctioning dump valves, and flares, respectively.

Commenter: Environmental Defense Fund, et al.
Comment Number: EPA-HQ-OAR-2023-0234-0413
Page(s): 10-11

Commenter: American Gas Association (AGA) and American Public Gas Association (APGA)
Comment Number: EPA-HQ-OAR-2023-0234-0418
Page(s): 5, 7

Comment 4: Commenter 0413: 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 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.

Commenter 0418: **The Associations support EPA's proposal to allow utilities to report emissions based on certain direct measurements; however, EPA should expand these options to include more measurement technologies and apply to additional source types, as this would increase reporting accuracy, provide greater flexibility to reporting facilities, and incentivize methane emission reductions.**

… Further, to improve data accuracy across the board, we request that EPA allow gas distribution reporters to develop company/utility-specific activity factors wherever possible.

…

EPA should allow for a broader use of site-specific, company/utility-specific, or collaboratively developed inter-company/utility emission factors based on direct measurements of emission sources.

Whether via newly approved or well-established measurement technologies, EPA should allow the use of direct data in the development of site-specific, company/utility-specific, or even inter-company/utility collaboratively developed emission factors for as many types of sources as possible. Activity factors based on each reporter's own facilities are more accurate than national average emission factors because they reflect each facility's real-life emissions—including emission reductions. Allowing companies/utilities to accurately demonstrate the emission reductions achieved via improved monitoring, leak detection, and repair methods is itself an incentive to achieve greater reductions and creates a more accurate emissions inventory. Conversely, default emission factors do not allow a company to demonstrate its actual emission reductions. Particularly with population-based default emission factors (i.e., those multiplied by miles of pipe or numbers of components), this problem is compounded when a utility expands its natural gas system to serve more customers or improve reliability. In that scenario, the additional miles of pipe or number of pressure-regulating stations will result in the calculation and reporting of what appears to be an increase in methane emissions—even if actual emissions declined due to the use of best practices and improved pipeline materials.

Further, enabling Subpart W reporters to use emission factors that are collaboratively developed by multiple companies can open up Section 136(a) funding for these projects, which fosters cooperative innovation to the benefit of the industry at large. Making it possible to use this funding for creative methods to improve emissions estimates and increase the use of empirical data for Subpart W reporting would align perfectly with the objectives of Section 136 of the Clean Air Act. Conversely, forcing Subpart W reporters to use generic emission factors instead of data derived from direct measurement can act as a disincentive—particularly for the distribution segment, which is currently required to use emission factors that often are based on data from other, higher-emitting segments,[24] thereby inflating the amount of GHG emissions attributable to distribution equipment.

Footnote:

[24] According to the 2023 GHG Inventory, only about 7 percent of total GHG emissions from the natural gas value chain were attributable to the distribution segment in 2021. See GHG Inventory at 3-95 (Table 3-65).

Response 4: To the extent commenters requested that the EPA develop basin-level population emission factors, the EPA did not propose and is not finalizing any provisions for development or use of basin-level population emission factors (see Section 24 of this document for more information). The EPA is finalizing methodologies for developing facility-specific emission factors where we expected such an approach to result in sufficiently representative emission factors, for natural gas pneumatic devices and equipment leaks sources that are subject to 40 CFR 98.233(q); see Sections III.E and III.P of the preamble to the final rule for more information about these final provisions. We also intend to continue to evaluate potential calculation methodologies, including as further information becomes available, and may provide additional methodologies in a future rulemaking.

With regard to one commenter's concern that population-based default emission factors will not allow for a demonstration of actual emission decreases from distribution pipelines and pressure-regulating stations, we note that the final rule provides an option for measurement or survyes for above-grade transmission-distribution stations. Furthermore, emission factors developed from measurement or surveys of above-grade transmission-distribution stations are also applied to quantifying emissions from other above-grade metering-regulating stations that are not transmission-distribution stations. Therefore, actual reductions in equipment leak emissions from these components will be captured through the final rule methodologies. With regard to equipment leak emissions from distribution pipelines and below-grade stations, see EPA's responses to Comments 3 and 4 in Section 18.2 of this document. This commenter also asserted that emission factors for the distribution segment are based on data from other segments. We disagree with this assertion and note that, as discussed in Section III.Q.2 of the preamble to the final rule and in the TSD to the final rule, the emission factors in the proposed and final Subpart W rule are derived from study data specific to the distribution segment.

Commenter: Chesapeake Energy Corporation
Comment Number: EPA-HQ-OAR-2023-0234-0400
Page(s): 4-5

Commenter: Bridger Photonics, Inc.
Comment Number: EPA-HQ-OAR-2023-0234-0407
Page(s): 6

Commenter: American Petroleum Institute et al. (Part 1 of 2)
Comment Number: EPA-HQ-OAR-2023-0234-0402
Page(s): 6

Comment 5: Commenter 0400: **EPA should ensure that its Final Rule incorporates additional empirical data in calculating emissions and provides sufficient opportunity for operators to demonstrate emissions reductions.**

CAA Section 136 centers around two key policy objectives: (1) improving reporting accuracy by increasing opportunities for operators to include empirical data in their emissions measurements;[9] and (2) encouraging operators to invest in innovative emissions reduction measures.[10] Chesapeake encourages EPA to finalize a rule that better accomplishes these objectives while still adequately accounting for cost considerations and providing needed flexibility for operators, consistent with our comments above.

First, EPA should revise its Proposed Rule to include additional methods to more accurately estimate emissions based on a broader range of empirical data. As discussed in our specific comments below,[11] there are source-specific metrics based on existing data that operators can use to report emissions more efficiently and accurately. Incorporating this data into the final reporting requirements would be more consistent with CAA Section 136(h).

Second, EPA should revise its Proposed Rule to ensure that operators have sufficient opportunities to demonstrate emissions reductions across all sources. As discussed in more detail in our comments below,[12] specific measures in the Proposed Rule may discourage innovative emissions reduction measures by disincentivizing voluntary monitoring measures and failing to credit reductions for specific emission reductions under existing calculation methods. This is inconsistent with Congress' explicit direction in CAA Section 136(a)(3)(C) for EPA to "support[] innovation in reducing methane and other greenhouse gas emissions."

FOOTNOTES

[9] See 42 U.S.C. § 7436(h).

[10] See id. § 7436(a).

[11] See infra Comment B and Comment F.

[12] See infra Comment C, Comment D, and Comment F.

Commenter 0402: **Accommodate Empirical Data, as a Demonstration of Emission Reductions:**

Provisions must be built into the Subpart W rule so that each operator can demonstrate actual reductions; this would promote consistency, transparency, and accuracy in emissions reporting. For example, reporters are precluded from using readily available empirical data (such as engine performance tests) and are instead required to use static emission factors that were based on limited data sets, which will not be reflect emissions reductions and will disincentivize emission reductions. The Industry Trades have noted throughout our comments where EPA must adjust the rule to accommodate empirical data.

Commenter 0407: Recommendation 3: Allow operators to demonstrate low emissions at their reporting facilities by developing facility-level measurement-based methane emissions inventories.

If an operator wishes to demonstrate that their subpart W reporting facility emits reduced methane, they should be able to do so using state-of-the-art scientific approaches. The methods for developing regional measurement-based emissions inventories can be extended to individual reporting facilities because the fundamental principles are the same for both size scales. The EPA should allow measurement-based inventory development methods to be approved for calculating emissions both at the regional scale and at the scale of individual reporting facilities. This recommendation is in line with the IRA's mandate that "[subpart W] allows owners and operators to submit empirical emissions data, in a manner prescribed by the Administrator, to demonstrate the extent to which a [waste emissions] charge is owed.[13]

We urge the EPA to allow operators to accurately demonstrate their methane emissions volumes using approved methods for developing measurement-based emissions inventories.

Footnote:

[13] 88 FR 50285

Response 5: In this final rule, we have finalized revisions to Subpart W that provide additional measurement-based methodologies where such methodologies were not available in the existing or proposed subpart W rules to give owners and operators additional options for submitting appropriate empirical data. Also, after consideration of comments, we have also finalized provisions for increased flexibility in methods available to reporters, including by allowing newly finalized calculation methodologies as optional methodologies for reporting year 2024. For more information, see our response to Comment 1 in Section 24.1 of this document and the discussion in Sections II.B and IV of the preamble to the final rule. For comments regarding source-specific emissions, see our response to Comment 3 in Section 1 of this document. For comments regarding the calculation of emissions at individual reporting facilities, see our response to Comment 4 in Section 1 of this document.

2 General and Applicability Amendments

2.1 Ownership Transfer

Commenter: Independent Petroleum Association of America (IPAA)
Comment Number: EPA-HQ-OAR-2023-0234-0265
Page(s): 4

Commenter: American Exploration and Production Council
Comment Number: EPA-HQ-OAR-2023-0234-0295
Page(s): 21

Commenter: Endeavor Energy Resources, L.P.
Comment Number: EPA-HQ-OAR-2023-0234-0381
Page(s): 19-21

Commenter: Arkansas Independent Producers and Royalty Owners (AIPRO)
Comment Number: EPA-HQ-OAR-2023-0234-0382
Page(s): 9-10

Comment 1: Commenter 0265: Property Transfer

When property transfers, the reporting of emissions takes on a different context because of the introduction of the methane tax. Previously, these issues have been largely related to assuring that there was a source responsible for assuring emissions were reported. The methane tax changes the process because substantial amounts of money are involved and there are equities that need addressed. Essentially, no new owner should be responsible for the methane taxes generated by the prior owner. This EPA proposal regarding the transfer of property fails to set forth clear delineations to create the equity that is essential.

Commenter 0295: **Ownership Changes**

AXPC recognizes that ownership changes during the reporting year are inherently complex, especially regarding emissions quantification. However, as the Proposal now includes financial implications for methane emitted during the reporting period, there is an increased concern about which parties will be responsible for payment of emissions produced. In its current form, the Proposal would require that new owners are responsible for reporting methane emissions covering the entire calendar year, but if this is not adequately accounted for in the implementation of the Waste Emissions Charge, it could result in a substantial monetary burden for new ownership even if they only controlled the asset for a small portion of the reporting period.

AXPC recommends that EPA allow companies to prorate reported methane emissions (and subsequent fees) relative to a facility's date of ownership change. This flexibility will allow for new owners to only be charged for emissions produced while the facility is under their control. To facilitate meaningful and productive communications between the EPA and facilities related to follow up items on submitted reports, AXPC also recommends that all correspondence be directed to the Designated Representative for the facility associated with the report in question.

<u>Commenter 0381</u>: **EPA Should Revise the Proposed Ownership Transfers Provisions so that Owners and Operators Are Responsible for Only Those Emissions that Occurred During Their Time of Ownership or Operation.**

For Subpart A, EPA proposes to revise the reporting requirements when there is a change in owner or operator of a Subpart W-covered facility.[64] As Endeavor understands it, EPA proposes that transactions will fall into one of four groups, dependent upon the number of purchasers, the allocation of assets among sellers and purchasers, and a purchaser's prior reporting status under Subpart W.[65] Endeavor understands and appreciates EPA's desire to provide clarity with respect to reporting obligations for assets transferred during a reporting year. Yet, the reality is that multiple emissions reports and reporters will be necessary to ensure *accurate* emissions reporting, as required by the IRA; those who generated the emissions at a moment in time are the ones with the most reliable operational knowledge and supporting data to provide an accurate accounting of the emissions. Any benefits on EPA's end by consolidating reporting in one entity cannot justify deviating from the IRA and increasing the likelihood of inaccurate reporting. Moreover, we believe that EPA's proposed four-group approach is unnecessarily complex and will not be workable in practice; the proposed approach will likely have the unintended effect of chilling transactions in the oil and gas sector due to risks of noncompliance. Our concerns and recommendations are provided below:

Reporting Start Date for New Owners or Operators

EPA proposes for all four groups of transactions that the new owner or operator be responsible for emissions reporting for the entire reporting year in which the transaction occurred, and for subsequent reporting years.[66] While Endeavor understands EPA's desire to have a single reporter each reporting year, this will be unworkable in practice. It often takes time for a new owner or operator to gather accurate reporting data for newly acquired facilities, and delays or difficulties in gathering that data create noncompliance and enforcement for a new owner or operator under EPA's proposed approach, particularly in light of EPA's newly announced emphasis on enforcement of the reporting program. Endeavor thus recommends that Section 98.4(n) be revised such that a new owner or operator is required to begin emissions reporting for the newly acquired facility starting with the first full reporting year after the reporting year within which it acquired the facility and do so only retroactively to the time that it acquired the covered assets. The prior owner should continue to be responsible for reporting during the time of their ownership.

Responsibility for Past Emissions Reports (Groups 1 and 2)

In proposed Section 98.4(n)(1) and (2), EPA contemplates that a purchasing owner or operator would be responsible for revisions to emissions reports for reporting years prior to the reporting year in which the acquisition occurred.[67] Endeavor believes that it is improper to place the legal risks of noncompliance for prior emissions reports on the new owner or operator, and the potential risk for noncompliance due to a prior owner's or operator's error may chill transactions within the oil and gas sector at large. Endeavor recommends that EPA instead adopt a rule that the owner or operator that generated the reportable emissions should be responsible for and continue to be responsible for those reportable emissions under the GHGRP and Subpart W, even if the facility is sold to a new owner or operator. Endeavor again recognizes that this approach could result in more than one reporter for the acquired facility during the reporting year in which it was acquired, but we nevertheless believe this approach is preferable to one requiring a new owner or operator to rely on the prior owner or operator in order for the former to fulfill its compliance obligations.

Exploration and production companies like Endeavor purchase and sell facilities (primarily wells) to other parties, and the transactions often include multiple purchasers. Based on its experience, Endeavor believes that requiring a new owner or operator to retroactively piece together or generate corrected reporting data on behalf of the previous owner or operator would be extremely difficult in practice and is unlikely to advance the IRA's mandate for accurate and empirical data. A new owner or operator would need more than simply copies of the prior reports and would likely need the underlying data, calculations, and documentation—much of which the previous owner or operator may claim as confidential, may not have retained years later, or may simply withhold from the new owner or operator. Without that information, a new owner or operator will be unable to truly evaluate the accuracy of past emissions reports. It will also be difficult during the due diligence period of an acquisition to access the accuracy of previous reporting. In sum, the Proposal creates unnecessary enforcement risks without any benefit to the accuracy of GHG reporting.

Footnotes:

[64] *Id.* at 50,292–94, 50,375.,

[65] *Id.* at 50,293–94.

[66] *Id.* at 50,375–76

[67] *Id*. at 50,375.

Commenter 0382: Transferred Assets:

EPA's proposed requirements for a new owner/operator of an asset to be responsible for historical GHGRP submittals/data, prior to the effective date of an acquisition, presents several challenges and concerns for owners/operators. …

AIPRO proposes that EPA amend the proposed rules to only require new owners/operators to be responsible for GHGRP reporting, re-submittals and responses post the effective date of an acquisition.

Response 1: See Section III.A.1 of the preamble to the final rule regarding ownership transfer revisions and the EPA's response for this final rule.

Commenter: GPA Midstream Association
Comment Number: EPA-HQ-OAR-2023-0234-0299
Page(s): 18

Commenter: Endeavor Energy Resources, L.P.
Comment Number: EPA-HQ-OAR-2023-0234-0381
Page(s): 20

Commenter: Arkansas Independent Producers and Royalty Owners (AIPRO)
Comment Number: EPA-HQ-OAR-2023-0234-0382
Page(s): 9

Commenter: Williams Companies, Inc.
Comment Number: EPA-HQ-OAR-2023-0234-0394
Page(s): 15

Commenter: American Petroleum Institute et al. (Part 1 of 2)
Comment Number: EPA-HQ-OAR-2023-0234-0402
Page(s): 16

Comment 2: Commenter 0299: **The "historic reporting representative" concept is unworkable, and EPA should instead implement a "data freeze."**

The requirements in the proposed rule regarding the selection of "a 'historic reporting representative' that would be responsible for revisions to annual GHG reports for previous reporting years within 90 days" of an ownership or operator change at a source are unworkable.[44] There are serious legal issues associated with an individual whose company no longer owns or operates a source amending reports for a facility with which they are no longer connected. This proposed approach also gives rise to issues with confidential business information and goes against the definition of a designated representative under the GHGRP.[45] The new owner should be responsible for updating any past reports—with the recognition that they would be responsible for doing so only to the best of their ability.

Rather than ask an individual to certify changes to a report (for which they are liable for criminal and civil penalties) for a source for which they are no longer associated, EPA should instead endeavor to limit requests to amend previous reports—especially if EPA did not alert the initial reporter to a potential error within six months of the initial report submittal. GPA respectfully suggests that EPA instead implement a data freeze wherein all data in a report would be "frozen" (and thus unable to be revised) once one year passes from the submittal of the report. Especially because obligations under the methane fee program are driven by these reports, continual changes to reports beyond the one-year mark would be add a layer of complexity that would quickly become unwieldy.

Footnotes:

[44] See id. At 50,294.

[45] 40 C.F.R. § 98.4.

Commenter 0381: **EPA Should Revise the Proposed Ownership Transfers Provisions so that Owners and Operators Are Responsible for Only Those Emissions that Occurred During Their Time of Ownership or Operation.**

…

D. Historic Reporting Representative (Groups 3 and 4)

At proposed Section 98.4(n)(3) and (4), for instances where there are multiple purchasers of a facility's emission sources, EPA proposes the use of a "historic reporting representative," chosen by binding agreement among the owners and operators involved in the transaction, to handle revisions to past emissions reports.[70] Endeavor reiterates its position that emissions reporting should remain the responsibility of the owner or operator who generated the reportable emissions, although we view the use of a "historic reporting representative" as a preferable alternative to placing the reporting obligations on the purchasing owners and operators.

Footnote:

[70] *Id*. At 50,376.

Commenter 0382: Transferred Assets:

…Even with the proposed requirement to assign a "Historical Reporting Representative" under a binding agreement, the ability of a new owner/operator to respond to inquiries/follow-ups on historical GHGRP submittals/data in an accurate and reliable manner is unlikely. Further, the new owner/operator is unnecessarily placed in an extremely difficult position when having to "certify" responses within eGGRT.

Commenter 0394: Ownership Transfer

Williams supports the proposed ownership transfer and the contractually determined e-GGRT reporting updates for prior years between the selling owner or operator and each purchasing owner or operator. Even so, however, some transactions may be too complicated to fit within the proposed categories. Additionally, because the EPA has not yet proposed the Waste Emissions Charge rule, it is unknown which owner, current or previous, will be responsible for fee changes resulting from revisions to annual GHG reports for prior reporting years.

Commenter 0402: Transferred Assets

A new owner/operator should not be responsible for correcting or resubmitting reports submitted and certified prior to the date of acquisition of a reporting facility.

The Industry Trades acknowledge that EPA has attempted to address concerns over the requirement for a new owner/operator of a reporting facility to be responsible for historical GHGRP reporting prior to the facility's acquisition date by proposing assignment of a "Historical Reporting Representative."

…

Proposing a "Historical Reporting Representative" does not guarantee the accuracy of historically reported information. First, there remains no guarantee that the selected representative would maintain access to the critical data systems used to generate the information used for historical GHG reports; once an acquisition is complete, those historical data systems are often no longer accessible by the purchaser (and in some cases, no longer maintained by the seller). While the "Historical Reporting Representative" could provide some anecdotal context around previously submitted reports, there is no guarantee that the "Historical Reporting Representative" would have had "primary responsibility for obtaining the historical information" which would not meet the threshold required for certification from a Designated Representative.[13] This is particularly true when assets are acquired from economically distressed companies which might no longer have any personnel who were involved in any of the historical GHG reports still on staff.

Footnote:

[13] 40 CFR 98.4(e)(1): Each such submission shall include the following certification statement signed by the designated representative or any alternate designated representative: "I am authorized to make this submission on behalf of the owners and operators of the facility or supplier, as applicable, for which the submission is made. I certify under penalty of law that I have personally examined, and am familiar with, the statements and information submitted in this document and all its attachments. Based on my inquiry of those individuals with primary responsibility for obtaining the information, I certify that the statements and information are to the best of my knowledge and belief true, accurate, and complete. I am aware that there are significant penalties for submitting false statements and information or omitting required statements and information, including the possibility of fine or imprisonment."

Response 2: See Section III.A.1 of the preamble to the final rule regarding ownership transfer revisions and the EPA's response for this final rule.

Commenter: The Petroleum Alliance of Oklahoma
Comment Number: EPA-HQ-OAR-2023-0234-0398
Page(s): 3, 5

Commenter: American Petroleum Institute et al. (Part 1 of 2)
Comment Number: EPA-HQ-OAR-2023-0234-0402
Page(s): 16-17

Comment 3: Commenter 0398: Ownership Transfer – EPA is proposing to add provisions to Subpart A that would define which owner or operator is responsible for current and future reports and clarify how to determine responsibility for revisions to annual reports for reporting years prior to owner or operator changes for specific industry segments in subpart W, beginning with RY2025 reports.

…

Finally, for the third and fourth categories, EPA is proposing to clarify responsibilities for reporting years prior to the reporting year in which the acquisition occurred. EPA is proposing provisions that (where ownership transactions occur on or after January 1, 2025) the purchaser would be responsible for reporting or responding to questions for the years prior to the transaction.

The purchaser may not have information on previous emissions reports or how they were derived. The purchaser may only have information based on their current surveys and assessments of the newly acquired facilities and can only speculate on how or what was reported prior to the acquisition. The prior owner would be in the best position to respond to EPA's annual report questions or data requests prior to the transaction.

Action Requested: EPA should revise its provision to direct questions or data requests on prior year reports to the previous owner and/or reporter, not the new purchaser.

Commenter 0402: Transferred Assets

A new owner/operator should not be responsible for correcting or resubmitting reports submitted and certified prior to the date of acquisition of a reporting facility.

…

The Industry Trades reiterate concerns highlighted in our October 6, 2022, letter[12] that a new owner/operator should not be responsible for correcting or resubmitting reports submitted and certified prior to the date of acquisition of any reporting facility. There are several complicated factors that EPA has not addressed as part of this rulemaking.

…

Furthermore, EPA has requested updates to previously submitted reports dating back 5 years and beyond; in many instances, the requested updates do not impact reported emissions and are often simply requests for clarification on certain reporting elements which are solely administrative in nature (e.g., a rolled up total of "Producing" wells in Table AA.1.ii does not match the count of wells labeled "Producing" in Table AA.1.iii). New owners or operators should not be required to update or submit reports for administrative issues which do not impact reported emissions, and EPA should limit the timeframe under which they request additional information or request re-submittals…

Currently within EPA's E-GGRT system, there is no way for a new company to access the reports that were previously submitted by the previous owner. Many times when files are transferred, files are missed or it is not clear what was actually submitted by the company. The new owner may not have access to the previous 5 years of submittals and will likely not have access to all the supporting historical records required to generate the report.

The Industry Trades are recommending that EPA require new owners to be responsible for resubmitting or correcting reports only after the point of acquisition…

Footnote:

[12] API Comments to EPA October 6, 2022. https://www.regulations.gov/comment/EPA-HQ-OAR-2019-0424-0322

Response 3: See Section III.A.1 of the preamble to the final rule regarding ownership transfer revisions and the EPA's response for this final rule.

Commenter: The Petroleum Alliance of Oklahoma
Comment Number: EPA-HQ-OAR-2023-0234-0398
Page(s): 3-4

Comment 4: Ownership Transfer – EPA is proposing to add provisions to Subpart A that would define which owner or operator is responsible for current and future reports and clarify how to determine responsibility for revisions to annual reports for reporting years prior to owner or operator changes for specific industry segments in subpart W, beginning with RY2025 reports.

Under the first category where the entire facility is sold to a single purchaser and the purchasing owner or operator does not already report under to the GHGRR in that industry segment, the purchasing owner or operator would be responsible for submitting the facility's annual report for the entire reporting year in which the acquisition occurred (i.e., the owner or operator as of December 31 would be responsible for the report for that entire reporting year) and each reporting year thereafter.

For a new reporter, it may take time for the purchasing operator or owner to fully understand all the requirements of the GHGRR, calculate emissions, establish processes and procedures to fully comply with annual reporting. In addition, the acquisition may be of significant size, cover a large geographic area and/or occur late in the year. This may prevent the purchasing owner or operator from assessing all the acquired facilities and providing the annual report by the March 31 reporting due date.

Action Requested: We request EPA include in the rule a provision that allows the purchasing owners or operators the ability to request an extension to the annual report deadline for such situations.

Under the second category, the entire facility is sold to a single purchaser and the purchasing owner or operator already reports under the GHGRR in that industry segment (and basin or state, as applicable). EPA is proposing that the purchasing owner or operator merge the acquired facility with its existing facility for purposes of reporting under the GHGRR. The purchaser would be responsible for submitting the merged facility's annual report for the entire reporting year in which the acquisition occurred (i.e., the owner or operator as of December 31 would be responsible for the report for that entire reporting year) and each reporting year thereafter.

Similar to the previous category, the acquisition may be of significant size, located over a large geographic area and/or occurs late in the year, that prevents the purchasing owner or operator to be able to fully assess all the acquired emission sources at each facility and provide the annual report by the March 31 reporting deadline.

Action Requested: We request EPA include in the rule a provision that allows the purchasing owners or operators the ability to request an extension to the annual report deadline for such situations.

Response 4: Regarding these requests, they are outside the scope of this rule as the EPA did not reopen the annual report deadline; thus, the EPA did not propose and is not taking final action on amendments that would provide purchasing owners or operators the ability to request an extension to the annual report deadline in situations where a full facility is acquired.

Commenter: Endeavor Energy Resources, L.P.
Comment Number: EPA-HQ-OAR-2023-0234-0381
Page(s): 21

Commenter: CrownQuest Operating
Comment Number: EPA-HQ-OAR-2023-0234-0393
Page(s): 46

Comment 5: Commenter 0381: Certificate of Representation (Groups 1 and 2)

In proposed Section 98.4(n)(1) and (2), it is not clear which party (i.e., the selling owner or operator, or the purchasing owner or operator) is responsible for filing the certificate of representation. Both paragraphs reference that "within 90 days after the change in the owner or operator, *the designated representative or any alternate designated representative* shall submit a certificate of representation."[68] EPA does not specify that this is the *new* designated representative (i.e., for the new owner or operator), despite doing so elsewhere in paragraphs (1) and (2).[69] Endeavor recommends that EPA clarify in Section 98.4(n)(1) and (2) that it is the designated representative of the *new* owner or operator who is responsible for filing the certificate of representation.

Footnotes:

[68] Id. At 50,375 (emphasis added).

[69] See, e.g., id. ("The new owner or operator and the new designated representative shall be responsible for submitting the annual report for the facility for the entire reporting year . . . ." (emphasis added)). }

Commenter 0393: It is unclear what certification of representation in e-GGRT.

Response 5: See Section III.A.1 of the preamble to the final rule regarding ownership transfer revisions and the EPA's response for this final rule.

Commenter: The Petroleum Alliance of Oklahoma
Comment Number: EPA-HQ-OAR-2023-0234-0398
Page(s): 3-5

Commenter: Environmental Defense Fund, et al.
Comment Number: EPA-HQ-OAR-2023-0234-0413
Page(s): 40-42

Comment 6: Commenter 0398: **Ownership Transfer** - EPA is proposing to add provisions to Subpart A that would define which owner or operator is responsible for current and future reports and clarify how to determine responsibility for revisions to annual reports for reporting years prior to owner or operator changes for specific industry segments in subpart W, beginning with RY2025 reports.

…

Under the third category, EPA proposes that if the selling owner or operator retains some of the emission sources and sells other emission sources to one or more purchasing owners or operators, the selling owner or operator would continue to report under subpart W for the retained emission sources unless and until that facility meets one of the criteria in 40 CFR 98.2(i) and complies with those provisions. Each purchasing owner or operator that does not already report to the GHGRR in that industry segment (and basin or state, as applicable) would begin reporting as a new facility for the entire reporting year beginning with the reporting year in which the acquisition occurred. The new facility would include the acquired applicable emission sources as well as any previously owned applicable emission sources. The purchasing owner or operator would follow the provisions of 40 CFR 98.2(i) and continue to report unless and until one of the criteria in 40 CFR 98.2(i)(1) through (6) are met, instead of comparing the facility's emissions to the reporting threshold in 40 CFR 98.231(a) to determine if they should begin reporting.

We do not support this proposal as it is unnecessarily onerous and costly for the seller or the purchaser to report if they are below the GHGRR reporting threshold. For example, in 40 CFR 98.2(i)(1), if a seller's or a purchaser's emissions are below 25,000 metric tons CO2e per year (MtCO2e/year) but greater than 15,000 MtCO2e/year, sellers or purchasers would be required to continue to submit reports for 5 consecutive years while maintaining records for three years following the year the reporting was discontinued. In addition, see our comments above in II.a.i.

Action Requested: We request EPA provide a provision that allows sellers and/or operators to submit facility emissions information that shows they are below the GHGRR threshold and are not subject to any reporting requirements. [II.a.i: Action Requested: We request EPA include in the rule a provision that allows the purchasing owners or operators the ability to request an extension to the annual report deadline for such situations.]

Under the fourth category, the selling owner or operator does not retain any of the emission sources and sells all of the facility's emission sources to more than one purchasing owner or operator. EPA is proposing that the selling owner or operator of the existing facility would notify the EPA within 90 days of the transaction that all of the facility's emission sources were acquired by multiple purchasers. The purchasing owners or operators would begin submitting annual reports for the acquired emission sources for the reporting year in which the acquisition occurred following the same provisions as in the third scenario.

Action Requested: See our requests in II.a.i-iii above. [II.a.i and ii: **Action Requested**: We request EPA include in the rule a provision that allows the purchasing owners or operators the ability to request an extension to the annual report deadline for such situations. II.a.iii: **Action Requested**: We request EPA provide a provision that allows sellers and/or operators to submit facility emissions information that shows they are below the GHGRR threshold and are not subject to any reporting requirements.]

<u>Commenter 0413</u>: 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 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 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.

Footnotes:

[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.

[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."

Response 6: See Section III.A.1 of the preamble to the final rule regarding ownership transfer revisions and the EPA's response for this final rule.

Commenter: Endeavor Energy Resources, L.P.
Comment Number: EPA-HQ-OAR-2023-0234-0381
Page(s): 22

Comment 7: Notification of Purchase (Group 4)

In proposed Section 98.4(n)(4), EPA proposes that if all emission sources at a facility are sold to multiple purchasers within the same reporting year, "then the *current* owner or operator of the existing facility shall notify EPA within 90 days of the last transaction that all of the facility's emission sources were acquired by multiple purchasers, including the identity of the purchasers." [71] It is not readily apparent what EPA means by "*current* owner or operator," especially within the context of a transfer of ownership or operation. Endeavor recommends that EPA clarify that only the *new* owners or operators are responsible for notifying EPA as to the emission sources they acquired for the reasons discussed in the previous sections.

Footnote:

[71] *Id*. At 50,376 (emphasis added).

Response 7: See Section III.A.1 of the preamble to the final rule regarding ownership transfer revisions and the EPA's response for this final rule.

Commenter: GPA Midstream Association
Comment Number: EPA-HQ-OAR-2023-0234-0299
Page(s): 18

Comment 8: Appendix A

Table of changes GPA supports as proposed.

Subpart	Citation	Change
…		
A	98.4(n)(1)-(4)	Clarify reporter for acquisitions/divestitures in oil and gas during the year of sale and onward
…		
A	98.1(c)	Clarify definitions of owner and operator for G&B

Response 8: The EPA acknowledges the commenter's support for the proposed revisions. The EPA is finalizing the amendments to 40 CFR 98.1(c) as proposed. See Section III.A.1 of the preamble to the final rule for discussion of the final amendments to 40 CFR 98.4(n)(1) through (4).

Commenter: Williams Companies, Inc.
Comment Number: EPA-HQ-OAR-2023-0234-0394
Page(s): 15

Comment 9: Ownership Transfer

… An e-GGRT archive feature would be beneficial for allowing the industry and the Agency to track reported emissions to aid in compliance with Subpart W and any forthcoming rulemakings reliant upon Subpart W data.

Response 9: The EPA is not certain of the specific functionality being sought by the commenter's suggestion of an archive feature. For response to comments regarding reporting and notifications related to partial facility sales (including the ability to track sales of emission sources) see Section III.A.1 of the preamble to the final rule. The EPA notes that facility-level data reported to subpart W is available through EPA's Facility Level Information on GreenHouse gases Tool (FLIGHT)[3] as well as the Envirofacts database.[4]

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[3] Accessible at https://ghgdata.epa.gov/ghgp/main.do
[4] Accessible at https://enviro.epa.gov/

2.2 Onshore Natural Gas Processing Industry Segment Definition

Commenter: GPA Midstream Association
Comment Number: EPA-HQ-OAR-2023-0234-0299
Page(s): 17, 18, 78

Commenter: Williams Companies, Inc.
Comment Number: EPA-HQ-OAR-2023-0234-0394
Page(s): 16

Comment 1: Commenter 0299: The following is a list of substantive proposed changes that GPA expressly supports.

…

- Alignment of the onshore natural gas processing definition with NSPS OOOOa through targeted consistency changes [98.230(a)];
- Removal of the 25 million standard cubic feet ("MMscf") per day threshold in the definition of natural gas processing [98.230(a)];

…

GPA supports the proposed changes to the definition of the Onshore Natural Gas Processing industry segment.

GPA supports the proposed changes to the definition of the Onshore Natural Gas Processing segment [98.230(a)(3)] because these revisions will better categorize facilities to align with industry terminology, which will also better align reported emissions with the appropriate industry segments. For the reasons EPA articulated in the preamble,[43] these changes also add certainty for reporters and reduce burden. This proposed change will result in some facilities reporting under a different segment, but GPA members do not anticipate the proposed changes to the definition will impact reported emissions significantly.

…

Request For Comment ("RFC"): EPA proposes to revise the definition of the Onshore Natural Gas Processing segment to largely align with OOOOa and to remove the 25 MMscf per day threshold for facilities that do not fractionate NGLs. EPA requests comment on the impact the proposed definition and throughput threshold changes would have on the number of reporting facilities and emissions from both the Onshore Natural Gas Processing and Onshore Petroleum and Natural Gas Gathering and Boosting industry segments. EPA also requests comment on any other advantages or disadvantages to finalizing the proposed change.

> **Comment**: GPA does not anticipate the proposed changes will impact reported emissions significantly. The proposed changes better categorize facilities to align with industry terminology, which will also better align reported emissions with the appropriate industry

segments. For the reasons EPA articulated in the preamble, these changes also add certainty for reporters and reduce burden.

Footnote:

[43] 88 Fed. Reg. at 50,294-96.

Commenter 0394: **Natural Gas Processing Segment Definition**

Williams supports the proposed change to refine the processing segment definition. Removing the amine source and 25 MMscfd processing facility requirement promotes clarity in reporting and encourages streamlining of routine reporting and record keeping. The proposed change also allows for improved overall reporting by including more facilities in gathering basins that operate amine units and fall below the 25,000 CO2e reporting threshold.

Response 1: The EPA acknowledges the commenters' support for proposed revisions. The EPA is finalizing these amendments as proposed.

Commenter: The Petroleum Alliance of Oklahoma
Comment Number: EPA-HQ-OAR-2023-0234-0398
Page(s): 5-6

Comment 2: Onshore Natural Gas Processing Industry Segment Definition

EPA proposes to remove the 25 MMscf per day threshold on gas processing plants.

These are small gas plants that may not be currently reporting emissions under the GHGRR. These plants may not have the requirements in place to easily comply in a timely manner. For example, they may have to install equipment, develop processes and procedures to collect and manage data, and train employees. To require the reporting of small emissions from these plants will be onerous and burdensome.

Action Requested: We request EPA maintain the 25 MMscf per day threshold for these plants. If EPA maintains its proposed requirement in the final rule, at a minimum, it should consider extending the compliance period.

Response 2: The proposed removal of the 25 MMscf per day threshold is not expected to increase the number of small gas plants that would be required to report under the GHGRP. Gas plants that do not exceed 25 MMscf per day are already reporting under the GHGRP as part of a facility that reports under the Onshore Petroleum and Natural Gas Gathering and Boosting industry segment if the emissions from the facility (i.e., all gathering pipelines and other equipment located along those pipelines that are under common ownership or common control by a gathering and boosting system owner or operator and that are located in a single hydrocarbon basin) exceed the reporting threshold of 25,000 mt CO_2e. With the removal of the 25 MMscf per day threshold from the 40 CFR 98.230(a)(3), the emissions from the gas plant alone must exceed the reporting threshold of 25,000 mt CO_2e for that facility to be required to report under the GHGRP. The EPA is finalizing the removal of the 25 MMscf per day threshold from the definition of "Onshore natural gas processing" in 40 CFR 98.230(a)(3), as proposed.

Commenter: American Petroleum Institute et al. (Part 1 of 2)
Comment Number: EPA-HQ-OAR-2023-0234-0402
Page(s): 55

Comment 3: Leak Detection at Onshore Gas Processing

Industry Trades generally support the updated definition of onshore natural gas processing that align with New Source Performance Standards as proposed in 98.230(a)(3). This update provides the regulated community with much needed alignment between regulatory programs and removed the confusion for reporting emissions under subpart W based on the previous definition included in the GHGRP.

However, the Industry Trades request that **CO2 plants be included within the Onshore Gas Processing segment definition**, and not under the Gathering and Boosting definition.

Response 3: The EPA did not propose and is not finalizing a definition of natural gas processing in 40 CFR 98.230(a)(3) that includes CO_2 plants that do not engage in either forced extraction of natural gas liquids (NGLs) from field gas or fractionation of mixed NGLs to natural gas products. These plants are not considered natural gas processing plants under NSPS OOOOa (or NSPS OOOOb), so including them in the definition of natural gas processing under subpart W would not be consistent with the NSPS. The commenter did not provide rationale for their request to define natural gas processing differently than the NSPS. Therefore, the EPA is finalizing the provisions of 40 CFR 98.230(a)(3) as proposed.

Commenter: GPA Midstream Association
Comment Number: EPA-HQ-OAR-2023-0234-0299
Page(s): 78

Comment 4: RFC: EPA requests comment on whether to remove the existing requirement to include residue gas compression equipment owned or operated by the natural gas processing facility from 40 C.F.R. § 98.230(a)(3) and 40 C.F.R. § 98.231(b). If these changes were finalized, EPA anticipates that residue gas compression equipment would then be part of the Onshore Natural Gas Transmission Compression industry segment.

> **Comment**: EPA should absolutely retain the existing language in 40 CFR § 98.230(a)(3) and 40 CFR § 98.231(b). Residue gas compression equipment owned or operated by the natural gas processing facility is permitted under the natural gas processing facility in state and federal permits and is considered part of the natural gas processing facility under OOOOa (*see* TSD, Proposed 40 C.F.R. 60 subpart OOOOa, page 73, link), where

EPA, when describing Natural Gas transmission and storage stations says, "Residue (sales) gas compression operated by natural gas processing facilities are included in the onshore natural gas processing segment and are excluded from this segment." *See also* 40 C.F.R. § 60.5365a which clarifies that OOOOa applies to an affected facility located with the Crude Oil and Natural Gas Production source category, as defined in 40 C.F.R. § 60.5430a, which defines the Crude Oil and Natural Gas Production source category to mean "Natural gas production and processing, which includes the well and *extends to*, but does not include, *the point of custody transfer to the natural gas transmission* and storage segment."[23] Residue compressors at a gas plant are clearly upstream of the point of custody transfer to the natural gas transmission and storage segment.

Further, there is no reason for EPA to create unnecessary confusion by redrawing the commonly understood boundaries of these industry segments. Doing so would be a mistake and could have considerable unforeseen consequences. Additionally, removing this language, as contemplated by EPA's proposal, would likely decrease reported emissions, as emissions reported at processing plants would decrease, and a handful of plant residue compressors which would be considered "transmission compression" may not trigger the 25,000 mtCO_2e reporting threshold for Onshore Natural Gas Transmission Compression.

[23] 40 C.F.R. § 60.5430a (emphasis added).

Response 4: The EPA acknowledges the commenter's comment on the 2022 Proposed Rule. In the 2023 Subpart W Proposal the EPA did not propose and in this final rule is not finalizing the removal of a definition of natural gas processing in 40 CFR 98.230(a)(3) that does not include residue gas compression equipment owned or operated by the natural gas processing facility.

2.3 Applicability of Proposed Subpart B to Subpart W Facilities

Commenter: GPA Midstream Association
Comment Number: EPA-HQ-OAR-2023-0234-0299
Page(s): 61, 101

Commenter: Downstream Natural Gas Initiative
Comment Number: EPA-HQ-OAR-2023-0234-0396
Page(s): 7-8

Commenter: The Petroleum Alliance of Oklahoma
Comment Number: EPA-HQ-OAR-2023-0234-0398
Page(s): 6-7

Commenter: American Gas Association (AGA) and American Public Gas Association (APGA)
Comment Number: EPA-HQ-OAR-2023-0234-0418
Page(s): 20

Comment 1: Commenter 0299: **EPA unnecessarily mandates reporting under Subpart B in 98.232(n) because Subpart B reporting applicability is already specified in that Subpart.**

The following proposed language is unnecessary and should not be added unless all other GHGRP subparts are also modified to include analogous language. As noted below, GPA recommends striking this language entirely in the final regulatory text:

~~98.232(n) For all facilities meeting the applicability provisions under § 98.2 and, if applicable, §98.231, report the information required under subpart B of this part (Metered, Non-fuel, Purchased Energy Consumption by Stationary Sources).~~

…

Purchased Energy Products

RFC: EPA is seeking comment on requiring GHGRP reporting facilities to submit summary data elements quantifying their consumption of purchased energy products and characterizing associated markets and products (e.g., regulated, or de-regulated electricity markets and renewable attributes of purchased products). Under this approach, facilities would not be required to quantify indirect emissions, and indirect emissions would not count towards GHGRP applicability.

> **Comment**: The primary purposes of this proposed rule are to streamline implementation, make minor changes, clarify confusing provisions, and to improve the overall quality and consistency of the data reported under the GHGRP. This aspect of the proposed rule would not achieve any of those goals. It would represent an extraordinary broadening of the GHGRP. It could also result in significant double-counting of emissions. Undoubtedly, the vast majority of GHG emissions associated with power generation are already accounted for under EPA rules. That information is supplied directly by power producer, who have access to the best information available to characterize GHG emissions associated with such power. Asking power consumers to report that same information will result in unnecessary duplication of efforts and poorer quality information overall.
>
> Further, the purpose of any information collection under section 114 of the CAA is for the development or implementation of regulatory requirements. EPA does not have authority to regulate energy consumption, so there is no appropriate purpose for collecting the information addressed in this element of the proposed rule.
>
> This information is also very hard to track down. In most cases, facilities receive an electricity bill, similar to what you receive for your home. It does not include information on regulated or de-regulated electricity markets and renewable attributes of purchased products. For this request to work, electricity suppliers would need to provide this information in a clear manner to their customers. Right now, that is not the case, and there is presently no obligation upon those providers to do so. Operators simply do not have access to this information. EPA suggests that this information could be used to

support the development of voluntary programs. Under those circumstances, EPA could consider providing for a voluntary purchased power reporting program. Such a program would require significant additional consideration and would not appropriately be included in the GHGRP

Commenter 0396: Subpart B

EPA is proposing to add Subpart B to Part 98 (Metered, Non-fuel, Purchased Energy Consumption by Stationary Sources) for reporting the quantity of metered electricity and thermal energy purchased. These requirements for natural gas LDCs would be extensive and impose significant administrative burdens, especially compared to the minimal usage that would be reported that would be of little benefit to EPA or the public.

DSI does not support the proposed Subpart B changes and recommends that EPA remove those elements that would be applicable to Subpart W facilities. Additionally, since EPA has stated that they do not plan to collect emissions data, DSI requests EPA to clarify if they intend to use the data collected under Subpart B to calculate Scope 2 emissions in the future or if the data would be used to cross reference data under another program.

Commenter 0398: Applicability of Proposed Subpart B to Subpart W Facilities

EPA is proposing to add Subpart B to Subpart W facilities. The Alliance submitted comments to EPA on this issue on July 21, 2023. First, EPA fails to provide information on how Subpart B emissions are not already being collected under the existing GHGRR requirements (e.g., Subpart C and D) from the direct emissions from energy providers/producers or how it will avoid duplication or double-counting emissions if both the provider/producer and the energy consumer are reporting this information. Additionally, EPA fails to discuss if this type of data is already collected by other government agencies (e.g., Energy Information Administration) and how EPA could use that data to avoid expanding the collection of data under the GHGRR.

EPA's Subpart B requirements provide significant concerns and burdens on Subpart W reporters to supply energy consumption information that includes substantial amounts of data to be collected, retained and reported. In API's comments on the Supplemental GHGRR, the burdens generally include:

- The quantity of purchased electricity and thermal energy products for every purchased energy product meter at a facility;
- The development of a Metered Energy Monitoring Plan (MEMP), which includes identifiers for each meter (including photographs), accuracy specifications, manufacturer's certifications, and other details;
- Documentation of quality assurance for purchased electricity monitoring including documentation that meters are conforming with appropriate ANSI standards;
- Documentation of quality assurance for purchased thermal energy including copies of the most recent audit of the accuracy of each meter in the purchasing agreement, and if the audit is more than 5 years old, documentation of a request for a new audit to the energy provider (and auditing the meter every 5 years); and

- The collection and reporting of detailed information for every single bill for every purchased energy product meter.

Our members that currently report under Subpart W may have thousands of wells across large geographical areas (including many remote areas), may utilize thousands of energy meters and may have hundreds of energy providers associated with those meters. The collection of specific meter-by-meter information and accuracy, data collection process, recordkeeping and reporting along with other additional requirements under Subpart B is excessive and unnecessary. We do not think EPA has adequately addressed the cost impacts and we think that EPA lacks authority to collect Scope 2 emissions for energy consumption as proposed.

In EPA's Supplemental GHGRR, EPA states that it is proposing to require reporting of metered energy consumption from direct emitter facilities that currently report under part 98 in order to gain an improved understanding of the **energy intensity** (i.e., the amount of energy required to produce a given level of product or activity) of specific facilities or sectors, **and** to better inform our understanding of the potential **indirect GHG emissions** associated with certain sectors (emphasis added, 88 Fed. Reg. 32914).

For Supplemental GHGRR, EPA states its authority under Clean Air Act (CAA) section 114. "As stated in the preamble to the *Mandatory Reporting of Greenhouse Gases* final rule (74 FR 56260, October 30, 2009) (hereinafter referred to as ''2009 Final Rule''), CAA section 114(a)(1) provides the EPA broad authority to require the information proposed to be gathered by this rule because such data would inform and are relevant to the EPA's carrying out of a variety of CAA provisions." (88 Fed. Reg. 32857).

We disagree. The reporting of energy consumption (indirect emissions) exceeds CAA section 114 which authorizes (in general) reporting for the purpose of developing standards of performance, any emission standard, or solid waste combustion for emission sources. EPA states that this information will improve their understanding of the energy intensity of specific facilities or sectors, and to better inform their understanding of the potential indirect GHG emissions associated with certain sectors. However, energy consumption (indirect emissions) is not the type of information authorized under CAA section 114. If EPA proceeds ahead with Subpart B as currently written, it must provide its specific Congressional authority to collect indirect energy consumption emissions.

Action Requested: We request EPA remove this requirement for Subpart W reporters.

<u>Commenter 0418</u>: **The Associations oppose the proposed inclusion of the natural gas distribution segment in new Subpart B for energy consumption reporting because it exceeds EPA's Clean Air Act authority while providing little informational benefit.**

The 2023 Supplemental Proposal would create a new Subpart B for reporting the quantity of metered electricity and thermal energy purchased by a facility, which would apply to all facilities that report their direct emissions under other GHGRP subparts.[66] The Proposed Rule would add language "to clarify the intent for subpart W reporters to also report under subpart B."[67] The

Associations reiterate our opposition to EPA's proposal to require natural gas distribution facilities to report their energy consumption under the GHGRP. [68]

EPA does not have authority under the GHGRP to collect broad energy consumption data and, in any event, has not shown how such data would be relevant to establishing emission standards and limitations. Congress has not authorized EPA to collect data for unspecified purposes untethered from its regulatory authority and, even if the Agency had authority to collect such energy consumption data, it is not clear what regulatory benefit EPA would obtain in exchange for imposing this broad reporting burden on facilities. If, in spite of the lack of authority to do so, EPA finalizes proposed new Subpart B, it should exempt natural gas distribution facilities from this reporting requirement. Imposing electricity reporting on the distribution segment would entail undue complexity, as it requires gathering the relevant portions of multiple small bills from multiple providers, yet it would yield minimal useful information because of the minor amount of electricity consumed by the distribution segment. There is little indication that this energy consumption information would provide any benefit to EPA or the public.

Footnotes:

[66] *See* 2023 Supplemental Proposal, 88 Fed. Reg. 32,852 (May 22, 2023).

[67] Proposed Rule, 88 Fed. Reg. at 50,296.

[68] More extensive discussion on these points is available in the Associations' comments on the 2023 Supplemental Proposal. *See* AGA and APGA Comments on 2023 Supplemental Proposal (July 21, 2023), https://www.regulations .gov/comment/EPA-HQ-OAR-2019-0424-0318.

Response 1: For the reasons explained in section III.B of the preamble to the GHGRP amendments that were signed by the EPA Administrator on April 3, 2024,[5] the EPA did not take final action on the proposed addition of subpart B of part 98 (Energy Consumption). Therefore, in this final rule the EPA is not taking final action on the proposal to add 40 CFR 98.232(n) to subpart W.

[5] A copy of the final preamble and rule is available at https://www.epa.gov/ghgreporting/rulemaking-notices-ghg-reporting.

3 Other Large Release Events

3.1 General Comments

Commenter: Public Hearing Transcript
Comment Number: EPA-HQ-OAR-2023-0234-0224
Page(s): 12 (Morgan King), 20 (Antoinette Reyes), 26 (Bill Midcap), 28 (Rebecca Edwards), 30 (Marlene Perrotte), 42 (Glenn Wikle), 53 (Pattrice Tomcik)

Commenter: Carbon Mapper and RMI
Comment Number: EPA-HQ-OAR-2023-0234-0301
Page(s): 3

Commenter: Environmental Defense Fund et al.
Comment Number: EPA-HQ-OAR-2023-0234-0401
Page(s): 1

Commenter: Environmental Defense Fund, et al.
Comment Number: EPA-HQ-OAR-2023-0234-0413
Page(s): 16

Comment 1: Commenter 0224: We support the proposal to require reporting of other large release events because these emission events are not currently reflected in Subpart W reporting and some are extremely large.

…

The proposal to report large release events and the efforts to improve the accuracy of emissions data will make a difference in ensuring that reported emissions more closely reflect real world pollution levels. Reporting of large emission events and equipment malfunctions is an incredibly important change since in the past, emissions have been grossly underestimated based on studies.

…

We support changes to account for super emitting events. EPA proposes to require reporting of other large release events and Rocky supports this important addition because these emission events are not currently reflected in Subpart W reporting and some of those events are extremely large.

…

The EPA should require operators to report large release events, defined as emissions of more than 100 kilograms per hour or those that release 250 mega ton CO_2 equivalent per event, which are not currently reflected in Subpart W reporting despite their important contributions to climate pollution.

…

I support EPA's proposal requirement to account for super emitting events.

…

Require reporting of large release events …

…

Families like mine who live with oil and gas operations in their communities support the addition of reporting large emission events. Front-line community members are often the first to detect leaks through sight, smell, and sound. I urge you to provide clear guidance for reporting these super emitter events and a clear pathway for community members to participate by ensuring that approved monitoring technologies and data are accessible to all. Addressing large pollution leaks from the oil and gas operations in a timely manner can really help to protect our children's health and the climate.

Commenter 0301: **We support EPA's efforts to fill critical inventory gaps**

We support EPA's inclusion of the "other large release events" category. Numerous studies have shown that a small number of strong methane point sources or "super-emitters" can account for a disproportionately high fraction of emissions within a basin. For example, Cusworth et al. (2022) conducted a three-year study consisting of eleven aerial surveys over five basins in the United States.[1] Results found that methane emissions large enough to be observed by remote sensing technologies (over 10 kg/hr) consisted of 40% of the total methane flux in a basin, regardless of the basin. Currently, Subpart W fails to fully capture these high-emission, episodic events, as methodologies assume normal operational conditions. The "other large release events" category is fundamentally additive and will fill a critical gap, particularly since this category includes both unplanned and planned releases.

Footnotes:

[1] Cusworth, D. H., et al. (2022). Strong methane point sources contribute a disproportionate fraction of total emissions across multiple basins in the United States. Proceedings of the National Academy of Sciences, 119(38), e2202338119. https://doi.org/10.1073/pnas.2202338119

Commenter 0401: **Finalize the reporting requirements for large release events.** Ensure that the large release events category encompasses all large emission events that are not otherwise captured in the reporting methodologies and encourages finding and reporting these events.

Commenter 0413: **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.

Footnotes:

[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.

Response 1: We acknowledge the comments expressing support for the proposed provision for other large release events. We are finalizing requirements for facilities to report emissions from other large release events with some revisions from what was proposed as discussed in Section III.B.1 of the preamble to the final rule.

Commenter: Environmental Defense Fund, et al.
Comment Number: EPA-HQ-OAR-2023-0234-0413
Page(s): 18-19, 47

Comment 2: 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 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]

…

<u>Gathering lines should report large release events</u>

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]

Footnotes:

[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.

[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.

[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).

Response 2: We agree that these and all other industry segments should be subject to reporting emissions from other large release events. We are finalizing the requirement to report emissions from other large release events for all 10 Subpart W industry segments as proposed.

Commenter: GPA Midstream Association
Comment Number: EPA-HQ-OAR-2023-0234-0299
Page(s): 18

Commenter: ConocoPhillips
Comment Number: EPA-HQ-OAR-2023-0234-0374
Page(s): 2

Commenter: American Petroleum Institute et al. (Part 1 of 2)
Comment Number: EPA-HQ-OAR-2023-0234-0402
Page(s): 57

Comment 3: Commenter 0299: GPA supports EPA's overall objective to account for large, episodic releases because the GHGRP can underestimate emissions totals in the absence of these emissions when compared to estimates by other methodologies. If done properly, GPA believes that this change will go a long way to addressing concerns regarding underestimation from the GHGRP and reduce the need to keep multiple "sets of books" on GHG emissions. GPA has identified several issues with the proposed requirements, however, and offers solutions to these issues below.

Commenter 0374: **Other Large Release Events**

In general ConocoPhillips supports inclusion of a category of other large release events in Subpart W reporting requirements because these sources have been observed across many basins and literature has demonstrated that they can have an outsized impact on total emissions; however, both the threshold and triggers for inclusion of an event based on credible information are problematic.

Commenter 0402: Other Large Release Events

The Industry Trades support inclusion of a category of other large release events in Subpart W reporting requirements because these sources have been observed across many basins, and literature has demonstrated that they can have an outsized impact on total emissions. However, both the threshold and triggers for inclusion of an event based on credible information are problematic. Furthermore, in many cases it will double count emissions reported elsewhere in the regulation.

Response 3: We acknowledge the commenters' support for the inclusion of the other large release events source category. Responses to the issues referenced by the commenters are provided in other comments' responses throughout Section 3 of this document.

Commenter: Independent Petroleum Association of America (IPAA)
Comment Number: EPA-HQ-OAR-2023-0234-0265
Page(s): 16

Commenter: Texas Commission on Environmental Quality (TCEQ)
Comment Number: EPA-HQ-OAR-2023-0234-0349
Page(s): 4

Commenter: Endeavor Energy Resources, L.P.
Comment Number: EPA-HQ-OAR-2023-0234-0381
Page(s): 4-5

Comment 4: Commenter 0265: Large emissions events

The comments filed by API extensively address the complexity and flaws in the EPA Subpart W proposal on large emissions events. IPAA commends these comments, which it joined in submitting, as a detailed assessment of the issues that need to be resolved.

Commenter 0349: **EPA should reconsider the inclusion of "other large release events" in the GHGRP requirements.**

As stated in the previously referenced TCEQ comments regarding EPA's Methane Rule Proposal, TCEQ supports use of the annual emissions inventory data reported by affected facilities as part of the GHGRP to fulfill the EG OOOOc state plan emissions inventory requirement for these sources; however, TCEQ does not support the proposed GHGRP reporting requirements for these "other large release events" including, but 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, explosion, or other event that is sudden, unavoidable and outside the control of the operator. EPA should reconsider the overall effectiveness and necessity of the super-emitter response program included in proposed NSPS OOOOb and referenced in the current rule proposal given the significant resource burden the program will have on states. As previously mentioned in the Methane Rule Proposal comments, EPA should provide clear guidance on acceptable methods to be used for the detection and quantification of super-emitter leaks. The high-profile nature of such events, and the resources required to respond to them in a timely manner, require well-established methods to ensure accurate identification and quantification of super-emitters.

Commenter 0381: **EPA Should Remove "Other Large Release Events" from Reporting Requirements in the Final Rule.**

Endeavor has serious concerns about EPA's proposed inclusion of "other large release events" as a new emission source across Subpart W. EPA asserts that this new catch-all emission source is intended to capture both planned and unplanned uncontrolled "emission events that are not fully accounted for using existing methods in subpart W."[8] EPA proposes to define "other large release events" to include a variety of emission events: well blowouts;[9] well releases;[10] pressure relief valve releases from process equipment other than hydrocarbon liquids storage tanks; storage tank cleaning and other maintenance activities; releases that occur as a result of an accident, equipment rupture, fire, or explosion; and failures 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.[11] Under the Subpart W Proposal, the emissions threshold for "other large release events" is subject to two, independent triggers: (1) a per-event reporting threshold of 250 metric tons of carbon dioxide equivalent ("mtCO_2e") and (2) an instantaneous methane-specific threshold of 100 kilograms per hour ("kg/hour").[12] As explained by EPA, this second trigger is meant to align the emission source with the Methane Proposal's "super-emitter response program"[13]

While Endeavor understands EPA's desire to ensure that the GHGRP covers those infrequent yet large emission events that could result in environmentally significant quantities of emissions, we nevertheless urge EPA to withdraw its proposed emission source for "other large release events." Simply put, despite nods to the IRA, EPA's proposal for "other large release events" does little to meaningfully advance accurate, empirical emissions reporting that the law requires. The covered events are often either already captured and reported through, for example, flaring and venting reporting or are simply far too infrequent or difficult to measure accurately to justify an entirely new source and attendant reporting requirements across the industry. Endeavor therefore recommends removing this category of events from the final rule.

To the extent EPA chooses to include these "events" going forward, we urge EPA to reconsider key aspects of the "other large release events" proposal because the proposal, as currently drafted, lacks sufficient clarity. For example, while EPA defines well blowouts and well releases according to duration ("long duration" and "short duration"), [14] the Agency has not made clear what "long duration" or "short duration" means for purposes of defining the types of reportable events. More broadly, EPA should eliminate planned maintenance events from the scope of "other large release events," provide greater flexibility in calculating emissions from "other large release events," and remove the reporting requirements directly linked to the Methane Proposal's super-emitter response program. These major concerns are described below.

Footnotes:

[8] 88 Fed. Reg. at 50,296–301,

[9] Defined as "a complete loss of well control for a long duration of time resulting in an emissions release." *Id.* at 50,437.

[10] Defined as "a short duration of uncontrolled emissions release from a well followed by a period of controlled emissions release in which control techniques were successfully implemented." *Id.*

[11] *Id.*

[12] *Id.* at 50,296.

[13] *Id.* at 50,298–99; *see* Methane Proposal, 87 Fed. Reg. at 74,746–55.

[14] *See* 88 Fed. Reg. at 50,300, 50,437.

Response 4: We disagree with commenters that recommend that we should not finalize reporting requirements for other large release events. As discussed in Sections III.B.1 and III.B.2 of the preamble to the final rule, we are not finalizing the 250 $mtCO_2e$ threshold, but we are retaining reporting requirements for other large release events above a 100 kg/hr methane emission rate threshold. Reporting of other large release event emissions is an important step to developing more accurate emission inventories from the oil and gas sector and reconciling top-down and bottom-up emission estimates. Not finalizing these provisions would exclude from subpart W reporting these other large release events, which can significantly contribute to a facility's emissions, and lead to inaccurate reported methane emissions. Section 136(h) of the CAA requires the EPA to revise subpart W to "…accurately reflect total methane emissions and waste emissions from the applicable facilities…". We disagree with the commenter suggesting that the inclusion of other large release event source reporting does little to meaningfully advance accurate, empirical emissions reporting. One need only consider the Aliso Canyon event to recognize that, without reporting requirements for other large release events, subpart W reports can significantly underestimate actual methane emissions.

Commenter: CrownQuest Operating
Comment Number: EPA-HQ-OAR-2023-0234-0393
Page(s): 37

Comment 5: This study is used by the EPA to support the claim that super emitter events are caused by malfunctioning equipment and abnormal operating conditions. It states that this regulation would decrease the frequency of these events. The study does not show any evidence that a regulatory change would aid in equipment malfunction, abnormal operating conditions, or human error. The EPA states in the rule that many high-rate events that aren't causes by equipment failure or malfunction are instead the result of human error. The operators certainly be motivated to prevent these types of events happening, after all, it is product we are losing to the atmosphere instead of sales. It appears the study does not realize that operators carry a vast incentive to prevent the events from happening.

Response 5: This rulemaking effort is aimed at improving the emission estimates within subpart W. For the amendments proposed regarding other large release events under subpart W, the cited studies are used to demonstrate that other large release events are significant contributors to oil and gas emissions and should, therefore, be accounted for in the subpart W reporting requirements.

3.2 Definition of Other Large Release Event

Commenter: Pipeline Safety Trust
Comment Number: EPA-HQ-OAR-2023-0234-0411
Page(s): 2

Commenter: Environmental Defense Fund, et al.
Comment Number: EPA-HQ-OAR-2023-0234-0413
Page(s): 18

Comment 1: Commenter 0411: PST is also supportive of EPA's proposal to require reporting of large release events on a "per event" basis. We believe that this will provide a more inclusive and accurate representation of large release events. However, we believe that the list suggested by EPA for "other large release events" should be modified to include the term "leak" as well.[11] While we recognize that this is not meant to be an exhaustive list, we believe including this as an example will be helpful to EPA in ensuring that all releases of natural gas are accounted for and to meet the rule's purpose.

Footnote:

[11] 88 Fed. Reg. at 50,299.

Commenter 0413: 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.

Footnotes:

[44] Proposed 40 C.F.R. § 98.238.

[45] *Id*.

Response 1: We acknowledge the support for the proposed definition of other large release event. We disagree with the commenter suggesting we need to use the term "other large release event or leak" because we consider a leak as a subset of the types of releases under an "event." In the definition of other large release event, we provide an example of "… a single equipment leak or release…" with emissions exceeding the applicable emissions threshold as an other large release event. We also included "large leak" as one of the reporting categories for describing an other large release event at 40 CFR 98.236(y)(5)(ii). We are finalizing the definition of other large release event as proposed except that we are removing blowdown venting from the definition as described in Sections III.B.1 and III.B.2 of the preamble to the final rule.

Commenter: American Exploration and Production Council
Comment Number: EPA-HQ-OAR-2023-0234-0295
Page(s): 13

Commenter: Ascent Resources, LLC
Comment Number: EPA-HQ-OAR-2023-0234-0339
Page(s): 2

Commenter: Enerplus Resources (USA) Corporation
Comment Number: EPA-HQ-OAR-2023-0234-0342
Page(s): 3

Commenter: Ovintiv Inc.
Comment Number: EPA-HQ-OAR-2023-0234-0350
Page(s): 2

Commenter: Marathon Oil Company
Comment Number: EPA-HQ-OAR-2023-0234-0378
Page(s): 3

Commenter: North Dakota Petroleum Council (NDPC)
Comment Number: EPA-HQ-OAR-2023-0234-0417
Page(s): 8

Comment 2: Commenter 0295: **Large Release Events**

AXPC supports EPA's attempt to account for significant emissions events that are not currently covered under other source categories in Subpart W. However, there are some ambiguities and inconsistencies in the proposed rule language that raise concern, which are discussed in greater detail in the following points.

Consistency and Overlap with NSPS OOOOb Super-Emitter Requirements:

The Proposal states that its intent is to quantify and report "other large release events" as defined in Subpart W with reference to NSPS OOOOb. Under Subpart W, this category is termed "other large release events", whereas NSPS OOOOb uses the term "super-emitters." AXPC recommends that EPA use the same terminology in both rulemakings for clarity and consistency if the intent is for these to be considered the same source type/category under both rules.

Further, under NSPS OOOOb, super-emitters are defined as "any source of emissions located at an individual well site, centralized production facility, or compressor station with emissions detected, using remote detection methods, with a quantified emission rate of 100 kg/hr of methane or greater."

Under this Proposal, large release events are defined as "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 in § 98.233 other than under § 98.233(y) to appropriately estimate these emissions. Other large release events include, but are 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. Other large release events also include 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 in § 98.233(a) through (s), (w), (x), (dd), or (ee) by the threshold in § 98.233(y)(1)(ii)."

While this Proposal directly references the NSPS OOOOb rulemaking with the apparent intent toward alignment of this source type under both regulatory programs, a plain read of the proposed language reveals inherent disparities with "other large release events" as defined under Subpart W being a subset of super-emitters as defined under NSPS OOOOb. The most obvious disparity is that super-emitters proposed under NSPS OOOOb would cover any release from any source emitting greater than 100 kg/hr of methane, whereas large release events under Subpart W would only cover releases of that same rate if not covered under another source category under Subpart W. For example, unlit flares are mentioned in the Subpart OOOOb proposal as a type of super-emitter. However, under this Proposal, these sources would be covered under the flares category.

Commenter 0339: **Large Release Events**

The proposed rule states that the intent is to quantify and report "other large release events" as defined in Subpart W with reference to NSPS OOOOb. Under Subpart W, this category is termed "other large release events", whereas NSPS OOOOb uses the term "super-emitters". We recommend that EPA use the same terminology and thresholds in both rulemakings for clarity and consistency if the intent is for these to be considered the same source type/category under both rules.

Commenter 0342: **Large Release Events**

The proposed rule states that the intent is to quantify and report "other large release events" as defined in Subpart W with reference to NSPS OOOOb. Under Subpart W, this category is termed "other large release events", whereas NSPS OOOOb uses the term "super-emitters". We recommend that EPA use the same terminology and thresholds in both rulemakings for clarity and consistency if the intent is for these to be considered the same source type/category under both rules.

Commenter 0350: **Large Release Events**

The proposed rule states that the intent is to quantify and report "other large release events" as defined in Subpart W with reference to NSPS OOOOb. Under Subpart W, this category is termed "other large release events", whereas NSPS OOOOb uses the term "super-emitters". We recommend that EPA use the same terminology and thresholds in both rulemakings for clarity and consistency if the intent is for these to be considered the same source type/category under both rules.

Commenter 0378: **Provisions relating to large release events should be harmonized with related programs.**

The proposed Subpart W revisions state that the intent of the rule is to quantify and report "other large release events" as defined in Subpart W with reference to NSPS 0000b. Under Subpart W, this category is termed "other large release events", whereas NSPS 0000b uses the term "super-emitters". We recommend that EPA use the same terminology, definitions, and thresholds in both rulemakings for clarity and consistency if the intent is for these to be considered the same source type/category under both rules. However, it is also critical that EPA avoid the potential of double counting emissions in this category that may be reported elsewhere.

Commenter 0417: Large Release Events

The proposed rule states that the intent is to quantify and report “other large release events” as defined in Subpart W with reference to NSPS OOOOb. Under Subpart W, this category is termed “other large release events,” whereas NSPS OOOOb uses the term “super-emitters.”

NDPC requests that EPA use the same terminology and thresholds in both rulemakings for clarity and consistency if the intent is for these to be considered the same source type/category under both rules.

Response 2: We disagree that we should use the same terminology or definitions in the GHGRP and the NSPS OOOOb rules. We intentionally used different terminology because the scope of the two programs are different. For example, subpart W already captures some of these emissions, such as blowdowns, separately and source-specific reporting continues to be useful. We specifically proposed to include a 100 kg/hr threshold within the reporting requirements to align other large release event reporting requirements with the NSPS SEP. As discussed in Section III.B of the preamble, we are finalizing only the 100 kg/hr threshold, as we agree that this will both provide a consistent and streamlined threshold to reporters and is also consistent with the types of events not otherwise covered by other subpart W sources. However, we find that the use of “other large release events” rather than the term “super-emitter” helps to clarify that the GHGRP other large release event reporting requirements are not identical to those in the NSPS Super Emitter Program (SEP). Although we are making some revisions to the final thresholds, as detailed in Section 3.2 of this document, we disagree that the reporting of emissions from other large release events should be limited to only those events for which notifications are received under the NSPS SEP. Exclusion of other large release events that are identified by the facility’s own monitoring surveys but that are not identified via the final NSPS SEP would result in underreporting of emissions. CAA section 136(h) requires the EPA to revise subpart W to “…accurately reflect total methane emissions and waste emissions from the applicable facilities…” We agree that double counting of emissions should be avoided and as discussed in the response to Comment 1 in Section 3.4 of this document, consistent with the proposal, the final language (with clarifications from proposal) in 40 CFR 98.233(y)(1)(ii) instruct the reporter to exclude emissions that would have been calculated for that source during the timespan of the other large release event from source-specific emissions calculated under paragraphs 40 CFR 98.233(a) through (h), (j) through (s), (w), (x), (dd), or (ee), as applicable, to avoid double counting.

Commenter: Endeavor Energy Resources, L.P.
Comment Number: EPA-HQ-OAR-2023-0234-0381
Page(s): 6-7

Commenter: The Petroleum Alliance of Oklahoma
Comment Number: EPA-HQ-OAR-2023-0234-0398
Page(s): 8

Comment 3: Commenter 0381: EPA should exclude planned maintenance events from the scope of "other large release events."

In a departure from its 2022 GHGRP proposal,[15] EPA proposes for "other large release events" to encompass both unplanned *and planned* uncontrolled release events (meeting the requisite emissions thresholds), and specifically planned maintenance events, like storage tank emptying, degassing, and cleaning.*16* Within our industry, planned maintenance is simply a reality of the business, and necessary to ensure the safety and reliability of systems and the safety of employees and the communities within which companies operate. Most maintenance events would likely not come close to the emission thresholds EPA proposes (i.e., 250 mtCO2e per event, 100 kg/hr of methane), but operators would nonetheless be required to attempt to measure those events so that they could confirm that they do not meet the reporting thresholds. As a result, there is a significant burden associated with this requirement without any meaningful benefit to the accuracy of the data reported to EPA. Given the infrequency in which a planned maintenance event would rise to the level of "other large emissions event" in terms of quantity or rate of emissions, Endeavor does not believe it is necessary to include such events as an express category of large release events. Put differently, the reportable emissions for planned maintenance events (i.e., those in excess of the thresholds) for most owners and operators are likely to be zero, making the need to include these events questionable at best. Their inclusion thus does little if anything to advance the IRA's mandate for more accurate reporting. And because these planned maintenance events are not typically subject to ongoing emissions measurement or monitoring, meaning that the additional burdens in measuring or calculating any resultant emissions (whether during or after the fact) would far outweigh any hypothetical benefits from more accurate and comprehensive emissions reporting. Endeavor thus recommends that planned maintenance events be excluded from the scope of "other large release events."

EPA should remove requirements to report unplanned "other large release events" where measurement or estimations are infeasible and unreliable.

EPA proposes that to calculate the emissions from "other large release events," reporters should use "measurement data, if available, or a combination of engineering estimates, process knowledge, and best available data." [17] But many of EPA's examples of unplanned "other large release events" (e.g., emptying, degassing, tank cleanings, well blowouts, equipment failures) are either already captured within Subpart W, undercutting the need for a new and additional emission source category, or too infrequent and random to have in place a reliable measurement system or method. In some instances, such as blowdown events (i.e., removing gas from a pipeline to depressurize it) for safe maintenance of a pipeline, the gas is released or flared in a such a way that makes it easier to directly measure. For such events, there is little need to *additionally* measure and report such emissions according to new "other large release event" criteria; comparing flared or vented emissions to EPA's proposed thresholds adds additional burdens with little if any added value in accuracy of reporting, as required by the IRA. For others, like well blowouts, they are infrequent and unexpected, meaning that emission calculations would likely need to be based on engineering estimations and design, rather than measured data; there is not presently a direct measurement device or technique that could feasibly provide measured data, as blowout events can vary widely in scale and volume. This would make it difficult to even determine if a particular event met EPA's proposed reporting threshold, much less obtain an accurate emissions calculation. Endeavor thus recommends that EPA remove unplanned events from the reporting requirements in any final rule to avoid introducing inaccuracies into the reporting scheme in violation of the IRA's mandate for accurate emissions reporting.

Footnotes:

[15] *See* Revisions and Confidentiality Determinations for Data Elements Under the Greenhouse Gas Reporting Rule, 87 Fed. Reg. 36,920, 37,099 (June 21, 2022) ("Other large release event means an unplanned, unexpected, and uncontrolled release to the atmosphere . . . .").

[16] 88 Fed. Reg. at 50,296 ("We are also proposing to expand the definition of other large release events to include planned releases, such as those associated with maintenance activities for which there are not emission calculation procedures in subpart W. Emptying, degassing, and cleaning a tank is an example of a maintenance activity for which emissions would need to be reported under this proposal (if the emissions exceed the thresholds for an other large release event) that would not have been required to report under the 2022 Proposed Rule's definition of other large release event."); *id.* At 50,437 (definition of "other large release events").

17 *Id.* at 50,297.

Commenter 0398: Under this section (88 Fed. Reg. 50299-300), EPA states that if a single leak or event has emissions that exceed the emissions estimated by an applicable methodology included in subpart W by 250 mtCO2e or more on a per event basis or 100 kg/hr of methane or more as an instantaneous rate at any time during an event, EPA proposes that such releases would be included in the definition of ''other large release events'' and that reporters would be required to calculate and report the GHG emissions from these events using the proposed requirements for other large release. EPA states that reporters would identify the type of event (e.g., normal operations, a planned maintenance event, leaking equipment, malfunctioning equipment or device).

EPA does not provide any information on how it will avoid double-counting emissions for such things as normal activities or maintenance activities, e.g., blowdowns.

Action Requested: We request EPA remove normal routine maintenance activities and operations as part of "other large events."

Response 3: We disagree with commenters that planned maintenance events or unplanned events that are difficult to monitor should be excluded from the definition of other large release events. CAA section 136(h) requires the EPA to revise subpart W to "…accurately reflect total methane emissions and waste emissions from the applicable facilities…" We disagree with the commenters that suggest that because there are uncertainties in the calculated emissions from planned and unplanned maintenance events, it would somehow be more accurate to report zero emissions for those events that exceed the emissions threshold for an other large release event than to develop an emission estimate for that event. In order to include all potentially large release events for which there is no calculation method within subpart W, we determined that both planned and unplanned events must be included in the definition of other large release events. We disagree with commenters suggesting that planned and unplanned maintenance events are too infrequent to need to include emissions reporting requirements or that the requirement places undue burden on the reporter. First, we are only finalizing the 100 kg/hr methane emissions threshold and not the 250 $mtCO_2e$ threshold, so there is now only one calculation needed (rather than having to assess both thresholds). Second, we also considered that the 100 kg/hr methane emission threshold is large enough that the emissions would only need to be estimated for a limited number of larger maintenance activities, limiting reporter burden to individually track each maintenance activity. Third, we agree that methodologies already exist for blowdown events and that the blowdown calculation method would be used for all blowdown events, including those in preparation of maintenance activities. Therefore, we have removed the proposed cross-reference to 40 CFR 98.233(i) for blowdowns in the definition of other large release events in the final provisions so that no additional calculations are necessary for the emissions from blowdown activities. With these revisions, we disagree with the commenters that the other large release event requirements for planned (or unplanned) activities is unnecessary or overly burdensome. Finally, with respect to double-counting emissions, we agree that double counting of emissions should be avoided and is discussed in the response to Comment 1 in Section 3.4 of this document. For maintenance activities, we do not expect significant overlap with other emission sources with the exclusion of blowdowns from other large release events in the final rule.

Commenter: Offshore Operators Committee (OOC)
Comment Number: EPA-HQ-OAR-2023-0234-0409
Page(s): 11-13

Comment 4: Section/Paragraph Reference: §98.236(y)

Proposed Text: (1) You must report emissions for other large release events that emit GHG at or above any applicable threshold listed in paragraphs (y)(1)(i) or (ii) of this section considering the entire event duration. The thresholds listed in paragraphs (y)(1)(i) or (ii) of this section are not limited to the emissions that occur within a given reporting year. (i) For sources not subject to reporting under paragraphs (a) through (s), (w), (x), (dd), or (ee) of this section (such as but not limited to a fire, explosion, well blowout, or pressure relief), a release that either: (A) Emits methane at any point in time at a rate of 100 kg/hr or greater; or (B) Emits combined GHG across the entire event duration of 250 metric tons of CO_2e or more. (ii) For sources subject to reporting under paragraphs (a) through (s), (w), (x), (dd), or (ee) of this section, a release that emits GHG at or above at least one of the thresholds listed in paragraphs (y)(1)(ii)(A) or (B) of this section. For a release meeting the criteria in either paragraph (y)(1)(ii)(A) or (B) of this section, you must report the emissions as an other large release event and exclude the emissions from this release in the source-specific emissions calculated under paragraphs (a) through (s), (w), (x), (dd), or (ee) of this section, as applicable. (A) Emits methane at any point in time at a rate of 100 kg/hr or greater in excess of the emissions calculated from the source using the applicable methods under paragraphs (a) through (s), (w), (x), (dd), or (ee) of this section; or (B) Emits combined GHG across the entire event duration of 250 metric tons of CO_2e or more in excess of the emissions calculated from the source using the applicable methods under paragraphs (a) through (s), (w), (x), (dd), or (ee) of this section.

Comment: OOC recommends the proposed regulatory text be modified as follows:

(1) You must report emissions for other large release events that emit GHG at or above any applicable threshold listed in paragraphs (y)(1)(i), (ii), or (iii) of this section considering the entire event duration. The thresholds listed in paragraphs (y)(1)(i), (ii), or (iii) of this section are not limited to the emissions that occur within a given reporting year.

(i) For sources not subject to reporting under paragraphs (a) through (r)~~(s)~~, (w), (x), (dd), or (ee) of this section (such as but not limited to a fire, explosion, well blowout, or pressure relief)…

(ii) For sources subject to reporting under paragraphs (a) through (r)~~(s)~~, (w), (x), (dd), or (ee) of this section….

(iii) For sources subject to reporting under paragraph (s) of this section, a release that emits GHG at or above the thresholds listed in paragraphs (y)(1)(iii)(A) and (B) of this section not otherwise accounted for within the calculation methodologies in paragraph (s). For a release meeting the criteria in paragraph (y)(1)(iii)(A) and (B) of this section not otherwise accounted for within the calculation methodologies in paragraph (s), you must report the emissions as an other large release event. (A) Emits methane at any point in time at a rate of 100 kg/hr or greater; and (B) Emits combined GHG across the entire event duration of 250 metric tons of CO_2e or more.

Rationale: As acknowledged in 98.232(b) and 98.233(s), for offshore facilities there is a regulatory program that already exists to capture the majority of other large release events. Therefore, we are providing this recommendation to clarify reporting of other large release events for offshore facilities such that only events that are not captured by BOEM's methods are reported as a large release. Additionally, excluding emissions from these releases from source-specific emissions could potentially dilute the data associated with source-specific emissions. For example, turnaround venting would be accounted for in cold vent emissions either reported to BOEM or calculated in accordance with those methods.

Section/Paragraph Reference: §98.238

Proposed Text: Other large release event 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 in §98.233 other than under §98.233(y) to appropriately estimate these emissions. Other large release events include, but are 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. Other large release events also include 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 in §98.233(a) through (s), (w), (x), (dd), or (ee) by the threshold in §98.233(y)(1)(ii).

Comment: OOC recommends the proposed regulatory text be modified as follows:

Other large release event 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 in Bureau of Ocean Energy Management (BOEM) 30 CFR 550.302 through 304 for offshore operators, or §98.233 other than under §98.233(y) to appropriately estimate these emissions. Other large release events include, but are 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. Other large release events also include 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 in §98.233(a) through (s), (w), (x), (dd), or (ee) by the threshold in §98.233(y)(1)(ii) or (iii).

Rationale: We are providing this recommendation to clarify the definition of other large release events for offshore facilities to specifically exclude events that are captured by BOEM's methods 30 CFR 550.302 through 304.

Response 4: We disagree that special provisions are needed in the definition of OLRE for offshore production facilities. The BOEM methods are referenced in 40 CFR 98.233(s), so the suggested edit is duplicative of the reference already provided. We agree that double counting of emissions should be avoided and as discussed in the response to Comment 1 in Section 3.4 of this document. If the emissions from the event are accurately estimated and reported using BOEM methods, than no other reporting is required. If the emissions from the event are not accurately estimated using BOEM methods, the final language at 40 CFR 98.233(y)(1)(ii) instruct the reporter to exclude emissions that would have been calculated for that source during the timespan of the other large release event from source-specific emissions calculated under paragraph 40 CFR 98.233(s) to avoid double counting.

Commenter: GPA Midstream Association
Comment Number: EPA-HQ-OAR-2023-0234-0299
Page(s): 98-99

Comment 5: Proposed Change: If a single leak or event has emissions that exceed the emissions estimated by an applicable methodology included in Subpart W by 250 mtCO_2e or more, EPA is proposing that such releases would be included in the definition of "other large release events" and that reporters would be required to calculate and report the GHG emissions from these events using the proposed requirements for other large release events.

> **Comment**: EPA must clearly define the emission sources to be reported as (or excluded from) the "other large release events" emission source category. It would be unworkable

and confusing for reporters if EPA were to "mix" reporting requirements for certain sources where sometimes emissions are characterized as "other large release events" and sometimes not. The articulated categories suggested below should capture the majority of large release events in a manner that would accurately reflect such emissions.

98.238 Definitions. Other large release event means an unplanned, unexpected, and 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 in § 98.233 to appropriately estimate these emissions. Other large release events include, but are not limited to,~~ well blowouts, well releases, pressure relief valve releases from process equipment other than onshore production and onshore petroleum and natural gas gathering and boosting storage tanks, and releases that occur as a result of an accident, equipment rupture, fire, or explosion. ~~Other large release events also include 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 in § 98.233 by the threshold in § 98.233(y).~~

Response 5: As noted in the responses to Comments 2 and 3 in this section of this document, we disagree that other large release events should only apply to accidental releases and should not include reference to other sources covered under subpart W, but for which the calculation method significantly understates the actual emissions. We note that, for sources that have methodologies under subpart W, reporting these events as other large release events is only required when the emissions as calculated using the subpart W method underestimates emissions by 100 kg/hr of methane or more. Furthermore, as discussed in Sections III.B.1 and III.B.2 of the preamble to the final rule, we are excluding blowdown venting from the definition of other large release events because that method accurately estimates total volume of gas released but does not estimate the release rate, which is much higher at the start of the blowdown than at the end. However, for all other sources, we are finalizing requirements to assess the estimated emission rate compared to actual emission rate and include releases that exceed the estimated emission rate by 100 kg/hr or more. We find that limiting other large release events to exclude sources for which the existing methodology greatly underestimates the methane emission rate would be contrary to CAA section 136(h), which requires the EPA to revise subpart W to "…accurately reflect total methane emissions and waste emissions from the applicable facilities…"

3.3 Thresholds That Define an Other Large Release Event

Commenter: Kairos Aerospace
Comment Number: EPA-HQ-OAR-2023-0234-0240
Page(s): 16

Commenter: Carbon Mapper and RMI
Comment Number: EPA-HQ-OAR-2023-0234-0301
Page(s): 3

Commenter: Taxpayers for Common Sense (TCS)
Comment Number: EPA-HQ-OAR-2023-0234-0351
Page(s): 5

Commenter: Environmental Defense Fund, et al.
Comment Number: EPA-HQ-OAR-2023-0234-0413
Page(s): 19-20

Comment 1: Commenter 0240: The addition of the Other Large Release Events reporting category will likely increase the accuracy of the Inventory, because the scientific literature has clearly demonstrated these large, anomalous events are likely to be a major driver in total greenhouse gas emissions. We agree with EPA's decision to align the Other Large Release Event category threshold of 100 kg/hr with the OOOOb/OOOOc SERP.

Commenter 0301: We support the proposed instantaneous CH_4 emission rate threshold of 100 kg/hr, in addition to the 250 mt CO2e per event threshold previously proposed. A 100 kg/hr detection threshold is currently attainable by most remote sensing techniques, including satellite, aircraft, and drone technologies, which are well suited to identify large emissions events safely.

Commenter 0351: *Gas Emitted During Super-Emitter Events*

As EPA has previously reported, the top 5 percent of emission sources are responsible for roughly half of all methane emissions.12 These large-scale emissions are usually caused by accidents or similarly nonroutine failures that result in large release events known as "super-emitters." Super-emitters contribute substantially to total GHG emissions from the oil and gas industry, but, as EPA notes, are "not well represented" under the existing rule. One example cited in the proposed rule describes a storage wellhead leak at Aliso Canyon, which released approximately 100,000 metric tons of methane between October 2015 and February 2016.

The proposed rule seeks to ameliorate this by creating a new emissions source, referred to as "other large release events," to capture abnormal emission events. The rule would set two emissions thresholds for reporting: events that release at least 250 metric tons of CO2 equivalent (CO2e) per event—equivalent to approximately 500,000 cubic feet of natural gas—or events that have a methane emission rate of 100 kg/hr or greater at any moment. The rule would also expand the definition of large release events and include planned releases such as degassing and cleaning a tank, which would not have been required under current and previously proposed rules. TCS supports including multiple emissions thresholds to more accurately capture "super-emitter" events and believes the cumulative mass emissions per event threshold should not be increased beyond the proposed amount. TCS also supports the expansion of the definition of large release events to capture emissions data more comprehensively and accurately.

Commenter 0413: 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 CO2e 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 CO2e 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 which a small leak that is more appropriately reported through other provisions may need to be reported as a large release event.

Footnote

[48] For example, EPA could rely on the average duration of the events EPA cites as constituting large releases, like blowdowns and completions.

Response 1: See Section III.B.2 of the preamble to the final rule for our response to these comments.

Commenter: Occidental (Oxy)
Comment Number: EPA-HQ-OAR-2023-0234-0276
Page(s): 3-4

Commenter: Downstream Natural Gas Initiative
Comment Number: EPA-HQ-OAR-2023-0234-0396
Page(s): 3

Commenter: Western Energy Alliance
Comment Number: EPA-HQ-OAR-2023-0234-0399
Page(s): 10

Commenter: American Petroleum Institute et al. (Part 1 of 2)
Comment Number: EPA-HQ-OAR-2023-0234-0402
Page(s): 59

Commenter: Atmos Energy Corporation
Comment Number: EPA-HQ-OAR-2023-0234-0406
Page(s): 8-9

Commenter: Offshore Operators Committee (OOC)
Comment Number: EPA-HQ-OAR-2023-0234-0409
Page(s): 11-12

Comment 2: Commenter 0276: Oxy is committed to identifying and repairing fugitive emissions from our operations and encourages EPA to eliminate the potential double counting of emissions within Subpart W.

Where possible, Oxy designs our operations to eliminate or minimize emissions sources. For example, at a number of our oil and gas production facilities we have eliminated our oil and condensate tanks and natural gas driven pneumatics. Where we cannot eliminate a source, we are committed to quickly identifying and repairing fugitive emissions. Oxy generally supports the framework of EPA's proposed "other large release event" source category; however, Oxy encourages EPA to refine the applicable threshold of the source category to be both an instantaneous rate of 100 kg/hr of CH4 AND greater than 250 mtCO2e per event. This change will ensure the source category operates as intended, "to capture maintenance or abnormal emission events that are not fully accounted for using existing methods in subpart W." Without this change, the thresholds will capture events that are already accounted for in the rule (e.g., maintenance blowdowns, etc.).

Commenter 0396: Lastly, DSI requests that EPA clarify in the regulatory text whether an event must meet both or either of the two proposed thresholds for reporting release events (i.e., 100 kg/hr **and** 250 metric ton CO_2e vs. 100 kg/hr **or** 250 metric ton CO_2e).

Commenter 0399: *Other Large Releases*

Under the proposed rule, EPA aims to categorize a reporting scheme for "Other Large Release Events," using a defined threshold as either 100 kg/hour or 250 metric tons CO_2e. The Alliance believes that this unintentionally would include a much larger subset of emissions than EPA intends and would also potentially lead to a large amount of double reporting. While an "Other Large Release Events" threshold could be set at a total mass, such as 250 MT CO_2e, and that event could be further constrained by having a minimum mass flow rate threshold as well, to include the flow rate threshold essentially renders the total mass threshold meaningless. Very short duration events can at times have very high mass flow rates, but overall very low total mass. For example, a 100 kg/hr flow from a pipeline leak or other piece of equipment that lasts only 3 minutes would result in a total emission event of 5 kg. Surely EPA does not intend to define 5 kg releases as large events that trigger "Other Large Release Event" reporting and notification. Not only does such an event not fit the plain language meaning of a large release event, but reporting of such low emissions events would be severely misleading to the public consuming the reported information, who could misinterpret a fairly small event of short duration as releasing a much larger amount of emissions than actually released. For this reason, EPA should amend the definition to either clarify that both criteria must be met or remove the mass flow rate threshold of 100 kg/hr.

> **Recommendation:** EPA should remove the mass flow rate threshold or at least require that the large release event meet both criteria, not either.

Commenter 0402: Other Large Release Threshold Needs to be Modified

If Other Large Releases Remain in the Rule, Modify the Threshold

At a minimum, the Industry Trades recommend that EPA modify the threshold for this category in 98.233(y)(1)(i) as follows (and modifying 98.233(y)(1)(ii) as applicable):

> (i) For sources not subject to reporting under paragraphs (a) through (s), (w), (x), (dd), or (ee) of this section (such as but not limited to a fire, explosion, well blowout, or pressure relief), a release that~~either~~:
>
> (A) Emits methane at any point in time at a rate of 100 kg/hr or greater; ~~or~~ **and**
>
> (B) Emits combined GHG across the entire event duration of 250 metric tons of CO2e or more.

Requiring both thresholds be met would catch large releases discussed in the proposed rule's TSD, such as well blowouts, while also easing the burden on reporters to assess relatively smaller emission events, such as PSV releases that occur over a few seconds to minutes.

If EPA does not change the threshold as recommended below, the Industry Trades recommend that a duration of 100 hours be paired with the instantaneous rate of 100 kg/hr, which is commensurate with a duration at that emission rate that would result in 250 mtCO2e of

Commenter 0406 Third, EPA should also reconsider any "instantaneous" threshold for other large release events. Many release events have the potential to exceed the proposed instantaneous emission rate threshold but would not be considered a "large release." For example, a 30-second release with an instantaneous emission rate equivalent to 100 kg/hr would only result in 0.83 kg of CH4 emissions for the entire event. The Proposed Rule would require these emissions to be reported as a "large release event," even though the overall emissions are minimal. Imposing this additional reporting obligation on operators would significantly increase compliance burdens with no significant benefit in reporting accuracy and would capture emissions well beyond the intended scope of this new category. To avoid this pitfall, Atmos Energy strongly encourages EPA to revise the Proposed Rule to require emissions of at least 100 kg in any one hour—specifically, section 98.233(y)(1)(i)(A) should read "emits at least 100 kg of methane in any hour, and." EPA should also revise section 98.233(y)(1)(i) to require ***both*** (A) ***and*** (B) (i.e., not (A) ***or*** (B)) to confirm that both the per event and hourly thresholds must be met to qualify as a large release event.

Commenter 0409: **Section/Paragraph Reference:** §98.236(y)

Proposed Text: (1) You must report emissions for other large release events that emit GHG at or above any applicable threshold listed in paragraphs (y)(1)(i) or (ii) of this section considering the entire event duration. The thresholds listed in paragraphs (y)(1)(i) or (ii) of this section are not limited to the emissions that occur within a given reporting year. (i) For sources not subject to reporting under paragraphs (a) through (s), (w), (x), (dd), or (ee) of this section (such as but not limited to a fire, explosion, well blowout, or pressure relief), a release that either: (A) Emits methane at any point in time at a rate of 100 kg/hr or greater; or (B) Emits combined GHG across the entire event duration of 250 metric tons of CO_2e or more. (ii) For sources subject to reporting under paragraphs (a) through (s), (w), (x), (dd), or (ee) of this section, a release that emits GHG at or above at least one of the thresholds listed in paragraphs (y)(1)(ii)(A) or (B) of this section. For a release meeting the criteria in either paragraph (y)(1)(ii)(A) or (B) of this section, you must report the emissions as an other large release event and exclude the emissions from this release in the source-specific emissions calculated under paragraphs (a) through (s), (w), (x), (dd), or (ee) of this section, as applicable. (A) Emits methane at any point in time at a rate of 100 kg/hr or greater in excess of the emissions calculated from the source using the applicable methods under paragraphs (a) through (s), (w), (x), (dd), or (ee) of this section; or (B) Emits combined GHG across the entire event duration of 250 metric tons of CO_2e or more in excess of the emissions calculated from the source using the applicable methods under paragraphs (a) through (s), (w), (x), (dd), or (ee) of this section.

Comment: OOC recommends the proposed regulatory text be modified as follows:

(1) You must report emissions for other large release events that emit GHG at or above any applicable threshold listed in paragraphs (y)(1)(i), (ii), or (iii) of this section considering the entire event duration. The thresholds listed in paragraphs (y)(1)(i), (ii), or (iii) of this section are not limited to the emissions that occur within a given reporting year.

(i) For sources not subject to reporting under paragraphs (a) through (r)~~(s)~~, (w), (x), (dd), or (ee) of this section (such as but not limited to a fire, explosion, well blowout, or pressure relief), a release that ~~either~~: (A) Emits methane at any point in time at a rate of 100 kg/hr or greater; ~~or~~ and (B) Emits combined GHG across the entire event duration of 250 metric tons of CO_2e or more.

(ii) For sources subject to reporting under paragraphs (a) through (r)~~(s)~~, (w), (x), (dd), or (ee) of this section, a release that emits GHG at or above at least one of the thresholds listed in paragraphs (y)(1)(ii)(A) ~~or~~ and (B) of this section. For a release meeting the criteria in either paragraph (y)(1)(ii)(A) and (B) of this section, you must report the emissions as an other large release event and exclude the emissions from this release in the source-specific emissions calculated under paragraphs (a) through (r)~~(s)~~, (w), (x), (dd), or (ee) of this section, as applicable. (A) Emits methane at any point in time at a rate of 100 kg/hr ~~or~~ and greater in excess of the emissions calculated from the source using the applicable methods under paragraphs (a) through (r)~~(s)~~, (w), (x), (dd), or (ee) of this section; ~~or~~ and (B) Emits combined GHG across the entire event duration of 250 metric tons of CO_2e or more in excess of the emissions calculated from the source using the applicable methods under paragraphs (a) through (r)~~(s)~~, (w), (x), (dd), or (ee) of this section.

(iii) For sources subject to reporting under paragraph (s) of this section, a release that emits GHG at or above the thresholds listed in paragraphs (y)(1)(iii)(A) and (B) of this section not otherwise accounted for within the calculation methodologies in paragraph (s). For a release meeting the criteria in paragraph (y)(1)(iii)(A) and (B) of this section not otherwise accounted for within the calculation methodologies in paragraph (s), you must report the emissions as an other large release event. (A) Emits methane at any point in time at a rate of 100 kg/hr or greater; and (B) Emits combined GHG across the entire event duration of 250 metric tons of CO2e or more.

Response 2: See Section III.B.2 of the preamble to the final rule for our response to these comments.

Commenter: American Exploration and Production Council
Comment Number: EPA-HQ-OAR-2023-0234-0295
Page(s): 15

Commenter: GPA Midstream Association
Comment Number: EPA-HQ-OAR-2023-0234-0299
Page(s): 19-20

Commenter: ConocoPhillips
Comment Number: EPA-HQ-OAR-2023-0234-0374
Page(s): 2

Commenter: Interstate Natural Gas Association of America (INGAA)
Comment Number: EPA-HQ-OAR-2023-0234-0387
Page(s): 14-15, 25, 37

Commenter: CrownQuest Operating
Comment Number: EPA-HQ-OAR-2023-0234-0393
Page(s): 61

Commenter: Williams Companies, Inc.
Comment Number: EPA-HQ-OAR-2023-0234-0394
Page(s): 4-5

Commenter: Chesapeake Energy Corporation
Comment Number: EPA-HQ-OAR-2023-0234-0400
Page(s): 11-12

Commenter: Encino Energy (EAP Ohio, LLC)
Comment Number: EPA-HQ-OAR-2023-0234-0408
Page(s): 1-2

Commenter: American Petroleum Institute et al. (Part 1 of 2)
Comment Number: EPA-HQ-OAR-2023-0234-0402
Page(s): 58-59

Comment 3: Commenter 0295: ***Emission Rate Thresholds***

The Proposal establishes two thresholds for determining a large release event: an instantaneous CH_4 emission rate of 100 kg CH_4/hr and a total 250 mt CO_2e per event threshold. AXPC agrees that EPA should establish a threshold to define large release events, however, AXPC does not believe the thresholds should be based on mass emission rates due to the large discrepancies that can occur with mass conversion based on variations in composition (and thus molecular weight) of the gas and other site-specific conditions such as temperature and pressure. The instantaneous mass-based emission threshold of 100 kg CH_4/hr would not only catch "large release events," but also many other emission events which are reported elsewhere in the proposed rule. For example, blowdowns are routine practice that may exceed the instantaneous mass-based emission threshold. However, these events may only occur for a very brief period and therefore only emit a small amount overall and blowdowns are reported elsewhere in the proposed rule. An instantaneous mass-based emission rate threshold that is as low as 100 kg/hr and decoupled with a duration will potentially require hundreds, if not thousands, of events to be reported, even if cumulatively these events are not responsible for a significant amount of emissions. For example, if an operator has a blowdown that lasted for 5 minutes at the 100 kg CH_4/hr emission rate, it would take 1,200 of those events in a year to equal to the per event total threshold of 250 MT CO_2e[4].

Footnote:

[4] An example of how many events at the 100 kg CH4/hr threshold would be cumulatively add to the one "large release event" at the proposed reporting threshold of 250 MT CO2e if the events lasted for 5 minutes each:

> 100 kg CH4/hr * 1 hr/60 min * 5 min/event * N events/yr * 1 MT/1000 kg * 25 MT CO2e/1 MT CH4= 250 MT CO2e
> Solve for number of events/year required to exceed 250 MT CO2e/year:
> 0.2083 MT CO2e/event * N events/yr = 250 MT CO2e
> N = **1,200 events**

Commenter 0299: **The 100 kilograms per hour ("kg/hr") instantaneous emission rate that is proposed in NSPS OOOOb and EG OOOOc as part of the proposed SERP is not appropriate for the GHGRP and has significant detrimental consequences.**

In the proposed rule, EPA proposes to apply the 100 kg/hr CH4 threshold in the proposed SERP under proposed NSPS OOOOb and EG OOOOc to Subpart W. This proposal is fundamentally flawed, however, as the proposed SERP is intended to serve as a compliance program to drive rapid corrective response to potential emission events. In contrast, the GHGRP is intended to serve as a reporting program to inform EPA of annual GHG emissions. On its own, the instantaneous 100 kg/hr CH4 threshold is an unjustified metric to quantify total GHG emissions for inventory purposes. It is entirely possible emissions from a 100 kg/hr CH4 emission event may only last for a very short period of time and result in immaterial GHG emissions. GPA believes that setting a single large event threshold (e.g., 250 metric tons of carbon dioxide equivalent ("CO2e")[46]) is reflective of EPA's intent to include previously unreported GHG emission events into annual inventories and is the most appropriate course of action for this rulemaking.

…Further, the 100 kg/hr proposed SERP program does not apply to pipelines.[50,51] As a result, aligning SERP thresholds with Subpart W for pipelines is arbitrary, capricious, and unnecessary. It also has the unfortunate effect of adding complexity and circumventing the applicability of the proposed standards under NSPS OOOOb and EG OOOOc. EPA should remove this requirement from any final rule.

Lastly, proposing to incorporate the SERP into Subpart W might cause an inequitable reporting program. Under EG OOOOc, states have the authority to adopt more stringent standards and could establish a response threshold lower than 100 kg/hr CH4. This could result in additional emissions being reported and additional waste emission charges being imposed on some reporters. If EPA maintains a need to tie Subpart W to the SERP, reporting under Subpart W should be limited to verified super-emitter events under the SERP and include an "and" designation between the two reporting thresholds to distinguish between the significance of total GHG tonnage.

For these reasons, EPA should eliminate the 100 kg/hr threshold from this source category. Alternatively, at a minimum, EPA should apply both thresholds to indicate the emission event is truly a large release event (i.e., both 100 kg/hr and 250 metric tons ("MT") CO2e).

…

Proposed Change: Calculate and report GHG emissions from other large release events that release at least 250 mtCO_2e <u>per event</u>.

> **Comment**: A quantifiable time element must be added to the emissions threshold of "other large release events." We propose that 250 mt of CO_2e released in any 24-hour period be used as the threshold for the definition of "other large release events." This will align with other common state and federal reporting thresholds, which include quantification of emissions over a 24-hour period. This will reduce burden by allowing reporters to align GHG emissions quantifications with other requirements when determining whether release event thresholds are met. A 24-hour quantifiable time element will also ensure that events that are quantified and reported are truly "large" release events, rather than low-level leaks over longer periods of time that would be addressed via the fugitive leak quantification requirements of Subpart W.

Suggested text: *98.233(y) Other large release events. Calculate CO_2 and CH_4 emissions from other release events for each release that emits GHG in excess of 250 metric tons of CO_2e in a 24-hour period as specified in paragraphs (y)(1) through (4) of this section.*

Footnotes:

[46] See Comment 16 below for discussion on an appropriate per-event threshold.

[50] Proposed 40 C.F.R. § 60.5365b(j) ("Each super-emitter affected facility, which is any source of emissions located at an individual well site, centralized production facility, or compressor station with emissions detected, using remote detection methods, with a quantified emission rate of 100 kg/hr of methane or greater.").

[51] Proposed 40 C.F.R. § 60.5386c(i) ("Each super-emitter designated facility, which is any source of emissions located at an individual well site, centralized production facility, or compressor station with emissions detected, using remote detection methods, with a quantified emission rate of 100 kg/hr of methane or greater.").

Commenter 0374: Instead of two thresholds of 100 kg/hr or 250 mtCO2e per event, either of which could imply a large release event, we support a threshold of 100 kg/hr that persists for a duration of 100 hours which is commensurate with an emissions of 250 mtCO2e. Our experience with monitoring/measurement indicates that excursions above the 100 kg/hr threshold can often be very short-lived, often of the order of a few minutes or seconds. These are not persistent emissions and are not indicative of any anomalous operating conditions that may lead to emissions that exceed these thresholds for any length of time. Also, such instantaneous emissions do not contribute to significant methane emissions from a reporting perspective. Therefore, we are proposing a 100-hour persistence threshold for these events which translates to 250 mtCO2e and is indicative of the large events that need to be captured as discussed by EPA in its proposal.

Commenter 0387: **The proposed thresholds for the new "other large release events" category establish emission thresholds not consistent with a "super emitter" event and does not adequately consider event duration for instantaneous measurements. Subpart W should not include flawed program requirements from the third-party program proposed for the NSPS (Subparts OOOOb and OOOOc guidelines). In addition, tons emitted rather than rate should be the basis for defining such an event, and operators should be allowed to use available data to define the event duration.**

INGAA commented extensively on this topic in October 2022 and also commented on the new 100 kilogram per hour (kg/hr) threshold in February 2023 comments ("February 2023 NSPS Comments")[23] on the proposed NSPS rulemaking. Those comments are not repeated here, but the cited documents should be reviewed by EPA. For example, previous comments discuss relative emission levels, noting that the proposed emission thresholds are not consistent with a "super emitter" event.

The apparent intent is to capture blowouts and other failures related to well releases, catastrophic equipment failure, fire, and explosion. For T&S sources, the related venting events (i.e., blowdowns associated with maintenance, emergency events, etc.) are reported per §98.233(i). For example, the preamble highlights maintenance related venting[24] as an important source that would be addressed by the "other large release events" category, but those emissions are already addressed for T&S sources because blowdown reporting is already required (e.g., for compressor stations and transmission pipelines) or is added by the Proposed Rule (e.g., for underground storage facilities). The added burden for tracking these events is not adequately considered by EPA. A higher threshold as discussed in previous INGAA comments should be adopted to ensure that Subpart W focuses on "large release" / "super emitter" events that occur within the T&S segment. for example, the preamble also discusses emissions associated with production wells, which is consistent with a lower threshold than the other event types discussed (i.e., events that have occurred with emissions several orders of magnitude higher than the proposed thresholds). Analogous events from the T&S segments are not identified, and the rule could define segment- and source-specific methods or thresholds to address emissions sources such as well releases discussed in the preamble.

INGAA's concerns are exacerbated by the new threshold of 100 kg/hr based on proposed Subpart OOOOb criteria, including events identified by third parties. As discussed in INGAA's February 2023 NSPS Comments, the proposed thresholds and third-party program are fraught with issues. Rather than copying the related flawed regulatory criteria into Subpart W, EPA should cite the relevant NSPS sections because the proposed NSPS program may change in the final rule or in response to potential challenges to final NSPS provisions. This is imperative in order to avoid additional, unnecessary changes or program inconsistencies in the future.

For example, the February 2023 NSPS Comments discuss the 100 kg/hr threshold and the need to consider event duration rather than an "instantaneous" measurement, as described by EPA in the preamble.25 An instantaneous measurement at a rate of 100 kg/hr that lasts for one minute emits less than 0.05 metric tons CO_2e. Clearly, such a release that could potentially be identified by a third party is not indicative of a "large release event" and should not trigger operator requirements. INGAA recommends a tonnage (i.e., total mass of emissions) based threshold rather than an emission rate. If an emission rate basis is included in the final rule, an associated duration should be defined to ensure the occurrence of a large release *event*.

…

EPA should reconsider the thresholds for large release events and consider a higher mass-based threshold than proposed, commensurate with a "super emitter" event. In addition, if an emission rate threshold is retained, EPA should define a reasonable duration for a rate (i.e., kg/hr) based threshold. EPA should also: (1) clarify §93.233(y)(2)(ii) to ensure that engineering estimates and available data can be used to estimate event duration; (2) cite NSPS criteria rather than copying flawed NSPS propositions in the Proposed Rule; and (3) preclude duplicative reporting and recordkeeping requirements in Subpart W associated with the NSPS third party large release program.

…

INGAA recommends that EPA increase the threshold for reportable large leaks to 5.5% of the 40 CFR Part 98 threshold of 25,000 metric tons CO2e per year, bringing the quantity in line with the Pipeline Hazardous Materials and Safety Administration (PHMSA) threshold of 3,000,000 standard cubic feet (49 CFR 191.3(1)(ii)).

…

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

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

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

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

Footnotes:

[23] INGAA Comments, Docket Document Number EPA-HQ-OAR-2021-0317-2483, February 13, 2023.

[24] 88 Fed. Reg. 50,296 – 50,300.

[25] 88 Fed. Reg. 50,296

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

Commenter 0393: Other large release events threshold:

EPA is proposing that a release event that emits at least 100 kg/hr or 250 MT CO2E or more be reported under "other large release events". We believe this is a low hourly threshold that can result in the inclusion of very short events and could also inadvertently be counted on the "blowdowns" category.

The definition of "other large release events" is excessive. In the proposal EPA defines "other large release events" as any emissions event not otherwise covered by Subpart W that results in cumulative total emissions of more than 250 MtCO2E or a release event of any duration that exceeds an emissions rate of 100 kg/hr CO2e. Both reporting thresholds seem very low, especially with the 25,000 MT/yr CO2e applicability threshold for the methane fee program. The 100 kg/hr threshold is extremely unreasonable due to the short duration event exceeding that emissions rate of 100 kg/hr is only about 10 kg of GHG emissions. We ask the EPA to please provide a decent explanation of why these thresholds make sense in the context of the methane fee program.

Commenter 0394: Turning to what is provided by the EPA in the Proposed Rule, as currently written, Williams also opposes the addition of instantaneous super–emitter (> 100 kg/hr CH4) events created under EPA's proposed OOOOb/c Rule to this Proposed Subpart W Rule because it is not compatible with the original June 2022 Subpart W Proposed Rule.[12] In the 2022 proposal, the EPA identified an "other large release event" to be an abnormal event resulting from a fire, explosion, or other equipment malfunction that released 250 mt or more CO2e. Yet in the current Proposed Rule, the EPA alters course and proposes to additionally include abnormal instantaneous alleged super-emitter events that have no reference to the overall mass of the release, only a *rate* of the release.

While Williams is not opposed to a methodology to capture abnormal emissions events, inclusion of abnormal emissions events solely based on the rate of release is entirely inappropriate for an inventory program like Subpart W. The mass of GHG (CO2e) emissions from a point source is reported in Subpart W, not the rate. If the EPA retains the super-emitter concept in Subpart W, the EPA must revise the proposed language to affirm that "Other Large Release Events" are only those that result in a release of CO2e based on a mass of = 250 mt CO2e being released, regardless of the emissions rate (above or below 100 kg / hr CH_4). The reporter can recognize a purported "super-emitter event" and appropriately respond in accordance with the yet-to-be-finalized OOOOb/c regulations. However, for an event that is short in duration despite a high release rate it should not be considered an "Other Large Release Event" for reporting purposes. Reporters would use best available event release rate information and duration information to calculate and report GHG (CO2e) emissions in Subpart W that equal or exceed 250 mt CO2e.

Footnote:

[12] See Revisions and Confidentiality Determinations for Data Elements Under the Greenhouse Gas Reporting Rule, supra n. 3.

Commenter 0400: **EPA should limit "other large release events" to a volume-based emissions threshold.**

Chesapeake strongly encourages EPA to limit the applicability threshold for this emissions category to a volume-based emissions metric, based on the total quantity of emissions generated during an event, for the following reasons:

First, EPA's instantaneous rate-based standard will require operators to report emissions beyond those within the scope of maintenance or other abnormal emission events. In the Proposed Rule, EPA emphasized that this new category is intended to capture two major types of emissions events: (1) "super-emitters" that significantly contribute to the emissions from oil and gas facilities but are frequently underestimated using existing reporting requirements, and (2) major planned releases associated with maintenance activities (such as emptying, degassing, and tank cleaning) that are not currently covered by existing emission calculation procedures.[34] However, by including a rate-based threshold for defining covered release events, EPA will capture emissions well beyond the intended scope of this new emissions category.

Many routine practices—such as blowdowns—have the potential to exceed the proposed instantaneous emission rate threshold. The Proposed Rule would require operators to repeatedly address purported "releases," even though resulting exceedances would occur over very brief periods and have minimal impacts. For example, a compressor blowdown may reach an instantaneous emission rate greater than 100 kg/hr, but the blowdown would last approximately 5 minutes, so the overall emissions would be limited to around 10 kg, which is less than one percent of the volume-based threshold. As a different framing, nearly 1,200 compressor blowdowns per year would need to occur at a facility to be equivalent to 250 $mtCO_2e$. Operators would have to incur substantial compliance costs for *each of these events*, with very few associated emissions benefits.

Second, an instantaneous rate-based standard will create a disincentive for operators to add voluntary emissions detection equipment to their facilities. The proposed rate-based standard would create an outsized risk that operators would be subject to excessive compliance costs based on measured emissions rates, even if these rates persisted for a de minimis duration. EPA estimates that average labor costs to comply with monitoring requirements for "other large release events" range from $49,560 for Onshore Petroleum and Natural Gas Gathering and Boosting operators to $76,920 for Onshore Petroleum and Natural Gas Production operators.[35] Installing additional detection equipment would worsen this risk and increase these already-high compliance costs— operators would therefore be less likely to undertake additional voluntary measures on top of existing requirements. This sacrifices vital emissions reductions and reporting accuracy without any measurable benefits. It is also inconsistent with the goals of EPA's proposed revisions to NSPS Subpart OOOOb and EG Subpart OOOOc, where EPA is seeking to encourage use of emerging technologies that enhance detection of potential emissions from the natural gas sector by providing "additional flexibility" to operators.[36]

Footnotes:

[34] Id.

[35] Stephanie Bogle, Assessment of Burden Impacts for Proposed Greenhouse Gas Reporting Rule: Revisions and Confidentiality Determinations for Petroleum and Natural Gas Systems, EPA-HQ-OAR-2023-0234-0165 (Jul. 27, 2023), https://www.regulations.gov/document/EPA-HQ-OAR-2023-0234-0165 ("2023 Regulatory Impact Analysis").

[36] 87 Fed. Reg. 74,702, 74,742 (Dec. 6, 2022).

Commenter 0402: Other Large Release Events Threshold

Instantaneous Rate of 100 kg/hr is Not a Meaningful Threshold

A threshold of an instantaneous rate of 100 kg/hr should be paired with a duration in order to ensure that the observation is, indeed, associated with a large release event. A measurement report of an instantaneous rate of 100 kg/hr should lead an operator to confirm whether or not such an observation was an indication of an ongoing large and otherwise unaccounted for event.

EPA explains that it "is proposing revisions to include reporting of additional emissions or emissions sources to address potential gaps in the total CH_4 emissions reported by facilities to subpart W."[48] "These revisions include proposing to add a new emissions source, referred to as ''other large release events,'' to capture large emission events that are not accurately accounted for using existing methods in subpart W."[49] An "other large release event" would be defined to include any event that exceeds an instantaneous methane emissions rate of 100 kg/hr or exceeds 250 mt CO_2e for the entire event.[50]

EPA further explains that the 250 mt CO_2e event-based threshold is based on a comparison to the Aliso Canyon event and other release scenarios that EPA considers to be objectively large. EPA asserts that the 100 kg/hr instantaneous emissions rate threshold is appropriate because it would "align with the super-emitter response program proposed in the NSPS OOOOb" and would "provide a means to get information for these large, shorter duration releases."[51]

The proposed reporting thresholds for "other large release events" are flawed for two reasons. First, EPA fails to provide any explanation of whether the reporting thresholds are appropriate or necessary for purposes of implementing the WEC. As explained above, the key purpose of the Proposed Rule is to provide information necessary for implementing the WEC. There are obvious questions that should be asked and answered by EPA as to how the type and scope of "other large release events" that would be required to be reported under the Proposed Rule squares with implementation of the WEC. EPA's views on the relationship between the proposed reporting thresholds and implementation of the WEC are necessary for EPA to fully assess the impact of the Proposed Rule and to allow for commenters to assess EPA's reasoning and provide informed input.

Since oil and gas emissions are highly variable in rate and duration, an instantaneous observation, even if extrapolated to provide results in units of an hourly emission rate as is typical, merely provides information regarding potential observations of far less than the represented hour in most cases. This is because an emission source with duration greater than 1 hour may have a variable rate over that hour or an emission source may resolve in far less than the hour. An instantaneous threshold of 100 kg/hr methane could result in numerous objectively small emission events (especially compared to an objectively large event release of at least 250 $mtCO_2e$). An emission duration, assuming perfect observation and consistent emission rate of 1, 100, or even 1,000 times the <1 minute observation period for many technologies (assume 1 minute here), would result in emission event quantities of 0.05, 4, or 42 $mtCO_2e$ or 0.02%, 2%, or 17% of the corresponding 250 $mtCO_2e$ threshold. In fact, it would take nearly 5 days of a constant emission rate of 100 kg/hr to accumulate emissions of 250 $mtCO_2e$, of which there is no reasonable extrapolation of an instantaneous remote sensing emissions event.

Therefore, an instantaneous rate of 100 kg/hr is not a meaningful threshold to indicate that an emission source is large or even otherwise unaccounted, since multiple intended and accounted for emissions have transient large emission rates (blow downs, drilling completions, liquid unloadings, etc.). Such data should lead an operator to confirm whether or not such an observation was an indication of an ongoing large and otherwise unaccounted for event. emissions.

Commenter 0408: The 100kg/hr threshold for Large Emission Events, also known as Super-Emitters in NSPS OOOOb/c, should be changed in both the Subpart W proposal and NSPS OOOOb/c.

Several normal facility emission sources can exceed 100kg/hr, but an instantaneous event at 100kg/hr is vastly different than a sustained 100kg/hr release. For example, a 100kg/hr rate for 1 minute is only 1.66kg or 3.66lb. 3.66lbs of emissions is a low quantity of gas, and a decimal fraction of the emissions allowed under issued facility permits. As written now, just under four pounds of emissions could kick off a windfall of regulatory events that would follow under NSPS OOOOb/c and revisions to the Greenhouse Gas Reporting Rule. EAP Ohio, LLC urges EPA to make changes such as:

- Clarify a time duration for the 100kg/rate to exclude short duration nonintermittent release events.
- If EPA is against including a time duration with the 100kg/hr rate, EAP Ohio, LLC offers a 6,000kg/hr threshold to replace the 100kg/hr for both Super-Emitters and Large Emission Events. A 6,000kg/hr rate of 1 minute is 100kg or 220lb, an amount EAP Ohio, LLC agrees is significant and worthy of emergency corrective action, reporting and, if necessary, taxation.
- The proposed 250$mtCO_2e$ per event threshold, or volumetric flow rate of 500,000scf of methane, should be maintained with the 100kg/hr threshold stricken from both rules.

Response 3: See Section III.B.2 of the preamble to the final rule for our response to these comments. Regarding the applicability of the Super-Emitter Program to pipeline facilities, the final Super-Emitter Program includes notifications to all facilities within the oil and natural gas source category, which includes pipelines. The NSPS Super-Emitter Program does not necessarily require corrective actions by pipeline facilities under the NSPS, but consistent with the final NSPS Super-Emitter Program, we are retaining the applicability of other large release event requirements for pipeline facilities.

Commenter: Public Hearing Transcript
Comment Number: EPA-HQ-OAR-2023-0234-0224
Page(s): 14 (Lisa Beal)

Commenter: Marcellus Shale Coalition (MSC)
Comment Number: EPA-HQ-OAR-2023-0234-0275
Page(s): 12

Commenter: GPA Midstream Association
Comment Number: EPA-HQ-OAR-2023-0234-0299
Page(s): 20-21, 23, 98

Commenter: Duke Energy
Comment Number: EPA-HQ-OAR-2023-0234-0376
Page(s): 6-7

Commenter: Arkansas Independent Producers and Royalty Owners (AIPRO)
Comment Number: EPA-HQ-OAR-2023-0234-0382
Page(s): 10

Commenter: Downstream Natural Gas Initiative
Comment Number: EPA-HQ-OAR-2023-0234-0396
Page(s): 2-3

Commenter: The Petroleum Alliance of Oklahoma
Comment Number: EPA-HQ-OAR-2023-0234-0398
Page(s): 7-8

Commenter: American Petroleum Institute et al. (Part 1 of 2)
Comment Number: EPA-HQ-OAR-2023-0234-0402
Page(s): 6

Commenter: American Gas Association (AGA) and American Public Gas Association (APGA)
Comment Number: EPA-HQ-OAR-2023-0234-0418
Page(s): 19

Comment 4: Commenter 0224: The proposed threshold for large release events, we believe, is too low. Since the 250 metric tons of CO2e emissions don't really constitute what has been called a super emitter. The proposal refers to large release events as super emitters, but really the two are not the same. A super emitter is a term of art that's been used to describe releases such as the Aliso Canyon event which was magnitudes higher than the proposed threshold for large release event.

Commenter 0275: Other Large Releases

- The U.S. EPA requested comment on the cumulative mass emissions per event threshold … MSC supports the use of 1500 mtCO2e per event threshold (approximately 3 million standard cubic feet) for consistency with the Pipeline and Hazardous Materials Safety Administration (PHMSA) definition of incident.

Commenter 0299: **EPA should apply a more reasonable threshold to describe "Large Events" and distinguish between "Large Events," "Pipeline Events," and "Other Events."**

GPA understands that EPA ultimately intends for the Large Event source category to serve as a "catch-all bucket" to report emissions from sources that are not otherwise categorized under Subpart W. As such, GPA is not advocating against the 250 MT CO_2e threshold, but we want to be clear that this quantity is not "large" when considering the total amount of emissions reported by most Subpart W reporters.

Additionally, GPA takes exception with the idea of reporting maintenance events, such as tank cleaning, as "Other Large Release Events." The preamble describes the "Other Large Release Events" category to capture significant emissions events like well blowouts and catastrophic fires.[52] It is misleading to characterize known, planned maintenance emissions as "large events" when other source categories can have emissions totals greater than 250 MT CO_2e (such as running an engine) that are categorized as normal emissions. It is also not appropriate to characterize lower rate leaks as Other Large Release Events. For example, it would take approximately 90 days for a 4.7 kg/hr CH_4 leak to exceed the proposed 250 MT CO_2e threshold. The rule language should be plain. A "large release event" should be just that, not a small release over a long period of time.

GPA does not understand why EPA would intend to characterize maintenance events or low-rate leaks as "Other Large Release Events" and believes this to be a by-product of introducing reporting thresholds into the proposed rule without time limitations. GPA reiterates its previously provided comment to EPA on this issue that a 24-hour period be used to determine applicability to the 250 MT CO2e threshold. This time period limitation would align with other common state and federal reporting thresholds (including Subpart Y, which EPA cites as justification for this threshold[53]) and reduce the burden on reporters by allowing them to align GHG emissions quantifications with other requirements when determining whether release event thresholds are met. If EPA does not incorporate a time boundary to the 250 MT CO_2e threshold and does not combine the instantaneous threshold with the total event threshold, then GPA suggests that the total event threshold be reevaluated. In this instance, a higher threshold of 1,000 MT CO_2e would more appropriately characterize an emission event as "large" and reduce the burden associated with reporting such events.

GPA suggests that EPA retitle this source category as "Other Events" and divide reporting categories as follows: (1) Large Events, (2) Pipeline Events, and (3) Other Events. This would more appropriately characterize emissions from maintenance events and low-rate leaks, while maintaining the reporting of large events associated with a large instantaneous CH_4 emission rate. Additionally, EPA requested comment regarding aligning the Other Large Release Event thresholds with PHMSA requirements,[54] and GPA supports aligning with the PHMSA definition of ''incident'' at 49 C.F.R. § 191.3. Given the unique nature of pipeline emissions and existing federal rules to report pipeline releases, aligning Subpart W with PHMSA requirements is justified. This will significantly reduce the burden on operators by maintaining consistency between the programs. To address the issues described in this and the previous comment (Comment 15), GPA suggests the following:

Source Category (y) Other Events	Applicability	Threshold
(1) Large Events	Unplanned episodic or intermittent emission events not subject to reporting under other paragraphs (e.g., fires, explosions, blowouts, etc.).	Verified "Super Emitter" Under NSPS OOOOb or EG OOOOc (Note: GPA suggests removing instantaneous 100 kg/hr CH_4 threshold altogether) **AND** 250 MT CO_2e released within 24-hours
(2) Pipeline Events	Pipelines regulated under Title 49, Chapter 1	3 MMscf
(3) Other Events	Planned periodic emission events not subject to reporting under other paragraphs (e.g., maintenance events, tank cleaning, etc.) For sources subject to reporting under other paragraphs, report emissions in excess of emissions calculated under Subpart W.	250 MT CO_2e

…

… in the event EPA retains the instantaneous threshold (which GPA urges EPA not to do), implement a phased-in step-down of the instantaneous threshold to allow technology to be further developed and deployed (e.g., 200 kg/hr initially, then stepping down to 150 kg/hr, and eventually reach 100 kg/hr in the future).[55]

…

Proposed Change: Calculate and report GHG emissions from other large release events that release at least 250 mtCO_2e <u>per event</u>.

Comment: A quantifiable time element must be added to the emissions threshold of "other large release events." We propose that 250 mt of CO_2e released in any 24-hour period be used as the threshold for the definition of "other large release events." This will align with other common state and federal reporting thresholds, which include quantification of emissions over a 24-hour period. This will reduce burden by allowing reporters to align GHG emissions quantifications with other requirements when determining whether release event thresholds are met. A 24-hour quantifiable time element will also ensure that events that are quantified and reported are truly "large" release events, rather than low-level leaks over longer periods of time that would be addressed via the fugitive leak quantification requirements of Subpart W.

Suggested text: *98.233(y) Other large release events. Calculate CO_2 and CH_4 emissions from other release events for each release that emits GHG in excess of 250 metric tons of CO_2e in a 24-hour period as specified in paragraphs (y)(1) through (4) of this section.*

Proposed Change: Calculate and report GHG emissions from other large release events that release at least 250 $mtCO_2e$ per event.

Comment: To reduce reporter burden, EPA should strive to align this requirement with other federal reporting thresholds. We suggest the large release event threshold should be 3 MMscf to align with Pipeline and Hazardous Materials Safety Administration reporting requirements. Doing so would help reporters align within their company on reporting and data collection procedures.

Footnotes:

[52] 88 Fed. Reg. at 50,296 (*"On the other hand, there have been several large, atypical release events at oil and gas facilities over the last few years where it was difficult to sufficiently include these emissions in annual GHGRP reports."*).

[53] *Id*. At 50,298.

[54] *Id*. At 50,299.

[55] Satellites can survey more frequently, but many current satellite options are limited to greater than 100 kg/hr detection threshold. E.D. Sherwin, et al., "Single-blind test of nine methane-sensing satellite systems from three continents," EarthArXiv, https://eartharxiv.org/repository/view/5605/ (pre-print, version 3) (noting that *"Orbio Earth, Maxar, and GHGSat all detected a 1.19 [1.15, 1.23] t/h emission using Sentinel-2, with errors ranging from – 8% to +170%. Orbio Earth detected a 1.05 [0.99, 1.10] t/h emission to within ±47%…The smallest detected emissions for the remaining satellites are 1.10 [1.06, 1.13] t/h for EnMAP, 1.26 [0.26, 2.26] t/h for GF5, 1.39 [1.34, 1.43] t/h for LandSat 8/9, 0.414 [0.410, 0.417] t/h for PRISMA, and 1.03 [0.98, 1.09] t/h for ZY1. GHGSat correctly detected and quantified the only nonzero release for which GHGSat-C collected data and passed quality control, which was 0.401 [0.399, 0.404] t/h…"*).

Commenter 0376: **The addition of a reporting requirement for “Other Large Release Events” threshold is too low.**

EPA is proposing an additional calculation and reporting requirement to Subpart W to capture “Other Large Release Events.”[7]

Duke Energy understands EPA’s desire to capture previously unrecorded “large release events.” However, EPA’s proposed new reporting category thresholds are too low and the category is not sufficiently defined and does not provide enough details on applicability and methodologies. Consequently, the rule as proposed is likely to require substantial work by facilities to capture information on infrequent events that result in relatively minor releases to assure compliance with the regulation. Measures that would be required to identify and quantify such infrequent and relatively small events are not practical. EPA may have intended to exclude consideration of relatively small releases from normal operations, for example, by stating that the reporting applies to “unplanned, unexpected, and uncontrolled” releases; however, those terms are subject to interpretation. Accordingly, EPA should provide additional clarification in any final rule requiring the reporting of “other large release events.”

It seems that the intent of this proposed reporting requirement is to address very significant methane releases, with EPA citing the examples of the Aliso Canyon event in 2015-2016 releasing approximately 100,000 MT CO2e over a five-month period and a well blowout in Ohio in 2018 releasing 40,000 to 60,000 MT CO2e over a 20-day period. Each of the events was large enough to exceed the general 25,000 MT per year CO2e threshold for reporting under Part 98 by itself. However, the proposed definition of “other large release events” specifies that releases greater than just 250 MT CO2e over the duration of an event (equivalent to 500,000 scf) or 100 kg/hr must be identified. Without further definition or clarification, that definition could subject facilities to extensive new monitoring and recordkeeping requirements for operations where a release event would be highly unlikely, infrequent, and for a short duration but might still be considered “unplanned, unexpected, and uncontrolled.”

Duke Energy recommends that EPA (i) reconsider applicability of “other large release events” and clarify that the provision will apply only to emission sources that have the potential to release large amounts of natural gas and (ii) increase the proposed reporting threshold from 500,000 scf to 3,000,000 scf (or 1,500 MT CO2e) per event. This represents the reporting threshold consistent with incident reporting in the Department of Transportation PHMSA regulations.[8]

Footnotes:

[7] 88 Fed. Reg. at 50,296-301

[8] 49 C.F.R. § 191.3(1)(ii).

Commenter 0382: Second, AIPRO is concerned that the proposed thresholds triggering “large release event” reporting, 100kg/hr or 250 mt CO2e, are too small, overly burdensome and not aligned with EPA’s intent for this new source category… Further, AIPRO proposes that EPA change the “large release event” thresholds to align with PHMSA’s definition of an “incident” (a release of 3 million scf of natural gas or more) and to match the intent of this new source category. If a rate-based threshold must be included, AIPRO proposes that EPA amend the proposal from 100 kg/hr to 1000 kg/hr.

Commenter 0396: **Other Large Release Events**

EPA proposes to add a new emissions source, “other large release events” to capture abnormal emissions events that are not accurately accounted for using existing methods in Subpart W.

In the Technical Support Document (TSD) for this proposed rulemaking, EPA notes that it “evaluated both an instantaneous emission rate threshold and a cumulative emissions quantity threshold.” EPA is proposing a 100 kilograms per hour (kg/hr) (86.7 standard cubic feet per minute (scfm)) methane emissions threshold or a cumulative emissions quantity of 250 metric ton CO_2e to require reporting. The 100 kg/hr instantaneous threshold aligns with the threshold in the proposed super-emitter response program in NSPS OOOOb and OOOOc. EPA notes that an instantaneous emission threshold is advantageous because releases can vary widely in duration, and that the 100 kg/hr methane emission threshold is large enough to allow a wide variety of advanced monitoring technologies, including aerial and satellite remote sensing technologies.

DSI appreciates the attempt at consistency between the various regulations but disagrees with the total event threshold and proposes a higher threshold to require reporting for the distribution segment. DSI requests that EPA increases the total event threshold of 250 metric ton CO_2e to 1,500 metric ton CO2e total. The 1,500 metric ton CO_2e is approximately equivalent to PHMSA’s definition of “incident” or an “unintentional estimated loss of three million cubic feet or more.” DSI believes this is a more appropriate threshold.

Commenter 0398: ***Other Large Events***

EPA proposes to include an instantaneous methane emission rate threshold of 100 kg per hour of methane emissions, in addition to the 250 mtCO2e per event (approximately equivalent to 500,000 standard cubic feet of pipeline quality natural gas) threshold that it previously proposed. Either of these thresholds would trigger reporting.

First, EPA’s proposed thresholds (100 kg per hour of methane or the 250 mtCO2e per event) are inconsistent with the Pipeline and Hazardous Materials Safety Administration’s (PHMSA’s) current reporting threshold of 3 million cubic feet (MMCF) of gas nor with PHMSA’s proposed 1 MMCF reporting threshold (88 Fed. Reg., 42284).[4] EPA proposes a unit of measure for both thresholds that operators are not familiar with, especially new reporters or smaller operators.

…

Action Requested: To reduce confusion and align company reporting requirements, we request EPA align its threshold with PHMSA’s existing reporting threshold of 3 MMCF. We request EPA provide a reporting threshold in units of measure similar to PHMSA (i.e., MMCF). This will provide significant clarity for operators, especially smaller operators…

Footnote:

[4] The Pipeline and Hazardous Materials Safety Administration's current reporting threshold is 3 million cubic feet (MMCF) but has proposed a 1 MMCF threshold in its proposed rule (88 Fed. Reg., 42284); however, it does not have data on the current number of leaks between 1 and 3 MMCF.

<u>Commenter 0402</u>: We urge EPA to seek true alignment and harmonization with other federal regulatory requirements, particularly the NSPS OOOOb and EG OOOOc "Methane Rules" and the GHGRP itself. Below are a few examples that are articulated in our comments:

…

- The "Other large release event" threshold for pipelines should align with the PHMSA incident threshold.

<u>Commenter 0418</u>: **The proposed threshold for reporting "other large release events" is too low and the presumptive release duration is too long for the stated purpose of capturing super-emitter event emissions.**

EPA is proposing to add "other large release events" as a new emissions source subject to reporting under Subpart W for all segments of the oil and natural gas industry.[61] The Agency intends for "other large release events" to cover emissions from abnormal emission events or "super-emitters," such as well blowouts, well releases, releases from equipment rupture, fire, or explosions. As proposed, "other large release events" would include planned releases, such as those associated with maintenance activities, for which there are not already emission calculation procedures in Subpart W, or releases from equipment for which the existing Subpart W calculation methodologies would significantly underestimate the episodic nature of those emissions. Under the Proposed Rule, the threshold for an "other large release event" is either a release of at least 250 mtCO2e per event or a CH4 emission rate of at least 100 kg/hour at any point during the event. These thresholds are much lower than what is typically considered a "super-emitter" event, including the Aliso Canyon (100,000 mt CH4) and Ohio well blowout (40,000 to 60,000 mt CH4) examples that EPA provides in the preamble to the Proposed Rule.[62] EPA should revise the thresholds to more closely align with the underlying purpose of adding "other large release events" as an emissions source under Subpart W.

The Associations believe that the PHMSA definition of "incident" as an "[u]nintentional estimated gas loss of three million cubic feet or more" [63] is a more reasonable threshold; however, we note that this is still orders of magnitude lower than EPA's super-emitter examples.

Footnotes:

[61] Proposed Rule, 88 Fed. Reg. at 50,296–301

[62] *Id.* At 50,296.

[63] 49 C.F.R. § 191.3.

Response 4: See Section III.B.2 of the preamble to the final rule for our response to these comments.

Commenter: Clean Air Council
Comment Number: EPA-HQ-OAR-2023-0234-0203
Page(s): 1

Commenter: Public Hearing Transcript
Comment Number: EPA-HQ-OAR-2023-0234-0224
Page(s): 13 (Alice Lu), 20 (Antoinette Reyes), 44 (Shanna Edberg)

Commenter: National Tribal Air Association (NTAA)
Comment Number: EPA-HQ-OAR-2023-0234-0239
Page(s): 3, 4

Commenter: Pipeline Safety Trust
Comment Number: EPA-HQ-OAR-2023-0234-0411
Page(s): 2

Comment 5: Commenter 0203: I urge EPA to strengthen its proposed rule in the following ways:

…

- Lower the super-emitter threshold for a leak's methane emission rate at any given time – known as the instantaneous emission size – from 100 kg/hr to 14 kg/hr. This will aim to provide more time to monitor, identify, and address leaks before they exceed the 250 metric tons of CO2e super-emitter threshold.

Commenter 0224: The EPA should also lower the super emitter event reporting thresholds. There are two proposed limits currently, a total of 250 metric tons of CO2 equivalent or an instantaneous methane emission size of 100 kilograms an hour. However, a methane leak of 100 kilograms an hour would exceed the total threshold within a week without regular checks in place. The instantaneous methane emission size must, therefore, be reduced to 14 kilograms an hour. A leak of this size instead would take about a month for it to exceed the total emissions limit, allowing for more time to find and fix leaks.

…

I also ask that you please reduce the threshold to define a super emitter event …

…

… reduce the proposed threshold for a super emitter event to 14 kilograms per hour …

Commenter 0239: The EPA should build on its already strong proposal by:

…

- Lowering the reporting threshold for "other large release events" to encompass leaks with an instantaneous detected emission rate greater than 10 kg/hr of methane rather than the 100 kg/hr limit proposed in the rule, to ensure that emissions from more leaks are reported.

Commenter 0411: EPA should also assess its 100 kg/hr emissions rate threshold to ensure that this standard and the leak detection technology standard adopted by PHMSA in its Advanced Leak Detection and Repair rulemaking are cohesive, consistent, and as protective as possible so as to protect communities from the risks of pipeline leaks and impacts of climate change. PST recognizes that a 100 kg/hr emissions rate would capture short-term events with large emissions, such as blowdowns, but it is our position that cumulatively, even smaller release events contribute in a significant way to environmental, health, and climate risks. Further, given the social cost of greenhouse gases,10 even small leaks that were traditionally considered "non-hazardous" by PHMSA have a major societal cost in terms of net harm to society, and could be addressed by EPA in this rulemaking.

Footnote:

[10] Interagency Working Group on Social Cost of Greenhouse Gases, United States Government, Technical Support Document: Social Cost of Carbon, Methane, and Nitrous Oxide Interim Estimates under Executive Order 13990, (Feb. 2021) https://www.whitehouse.gov/wp-content/uploads/2021/02/TechnicalSupportDocument_SocialCostof CarbonMethaneNitrousOxide.pdf.

Response 5: See Section III.B.2 of the preamble to the final rule for our response to these comments.

Commenter: American Exploration and Production Council
Comment Number: EPA-HQ-OAR-2023-0234-0295
Page(s): 15

Commenter: Downstream Natural Gas Initiative
Comment Number: EPA-HQ-OAR-2023-0234-0396
Page(s): 3

Commenter: Pipeline Safety Trust
Comment Number: EPA-HQ-OAR-2023-0234-0411
Page(s): 1-2

Comment 6: Commenter 0295: **Large Release Events**

Emission Rate Thresholds

… Additionally, that 250 MT CO2e threshold presents challenges as the variations in operating conditions make the conversion to mass unreliable. Instead, AXPC recommends that the threshold be based on an equivalent volumetric flowrate of methane (i.e., 500,000 scf, as cited in the preamble to the June 2022 proposed rule changes).

Commenter 0396: In addition, DSI requests that EPA also represent any CH_4 or CO_2e release threshold with an equivalent estimated volumetric rate to improve clarity in the regulation text. This would help understanding for field and operations teams. By including a volumetric rate, operations teams can have increased understanding of the threshold which would result in a better understanding of the requirements and data capture and reporting. DSI requests that EPA describe the thresholds for the "other large release events" source in volumetric units to ease regulatory understanding. This would also cause the two thresholds to be expressed in consistent units, thus improving the ease of implementation of reporting requirements by LDCs.

For example, the 100 kg/hr CH_4 threshold could be written as 5.5 MCF/hr of natural gas (calculated using 0.0192 metric ton CH_4/MCF CH_4 and 95% CH_4 content in gas). Similarly, the 1,500 metric ton CO_2e threshold could be written as 2.9 MMCF/event (calculated using 0.0192 metric ton CH_4/MCF CH_4, 0.0526 metric ton CO2/MCF CO2, 95% CH_4 content, 1% CO_2 content and the recently proposed [under Subpart A] GWP of 28 for CH_4).

Commenter 0411: PST is very supportive of the proposal's reporting threshold of 0.5 MMCF of natural gas per event.[1] As the EPA is aware, the Department of Transportation's Pipeline and Hazardous Materials Safety Administration (PHMSA) incident reporting threshold for natural gas pipelines stands at a staggering three million cubic feet.[2] In a recent rulemaking, PHMSA suggests amending this threshold to one million cubic feet.[3] While this is surely a major improvement over the previous standard, we believe it is still too high given the serious health, safety, and climate risks methane emissions pose, especially to environmental justice communities.[4] In comment, we suggested that PHMSA's final rule lower the threshold to match that found in this NPRM.[5] Clear and consistent reporting requirements are critical to public transparency, successful implementation of policy, and achieving our climate goals, so we suggested that PHMSA's standard mirror that of the EPA. In our comment to PHMSA we suggested that it maintain authority over leak detection and repair and adopt EPA's quarterly inspection schedule. However, it is our position that regardless of what agency asserts authority in this context, we believe that there should be quarterly leak detection surveys with equipment that is sensitive enough to detect leaks down to 5 ppm.

The threshold for this reporting standard should be expressed as a loss of 0.5 MMCF of natural gas, whether directly emitted or partially burned via fire. Although fire can reduce the amount of methane emitted into the atmosphere, it is unknowable how much methane is burned in ignition events, as EPA recognizes in the NPRM. Even in situations with perfect flaring, carbon dioxide and water are still released into the atmosphere. Water and carbon dioxide are greenhouse gases themselves and depending on the source, other contaminants such as hydrogen sulfide can also be released into the atmosphere during flaring.[6]

PST has some concerns about EPA's referral to "pipeline quality natural gas" in this rulemaking with respect to this reporting requirement. Because EPA's definition of "pipeline quality natural gas" is 95– 98% methane, emission events from certain pipelines such as gathering lines, which may have slightly lower percentages of natural gas, may require larger events to meet the emissions threshold. This is very concerning to the Pipeline Safety Trust because gathering lines have an outsized role in the overall pipeline methane emissions and are leaking at a rate that exceeds estimates. In fact, one study by the Environmental Defense Fund demonstrated that the emissions from gathering lines in the Permian Basin were 14x higher than EPA's estimate.[7] Gathering lines also transmit unprocessed natural gas that contains volatile organic compounds (VOCs) and hazardous air pollutants which can be flammable, toxic, and/or corrosive.[8] The constituents can increase the health and safety risks in the event of a release, and make these lines more susceptible to failure.[9] EPA should thus ensure that the language it uses to refer to the emissions standard is broad enough so as to include any event of 0.5 MMCF natural gas, even if it is unprocessed and may contain lower amounts of methane.

Footnotes:

1 88 Fed. Reg. 50,282, 50,298 (Aug. 1, 2023).

2 49 C.F.R. § 191.3(1)(iii).

3 88 Fed. Reg. 31,890, 31,945 (May 18, 2023).

4 Exhibit 1 at 12–13.

5 Id. At 8.

6 Duren, Riley and Deborah Gordon. ''Tackling unlit and inefficient gas flaring,'' Science. Vol. 337 Issue 6614. (2022): 1486–1487 https://www.science.org/doi/full/10.1126/science.ade2315.

7 Jevan Yu et al., Methane Emissions from Natural Gas Gathering Pipelines in the Permian Basin, ENVIRON. SCI. TECHNOL. LETT. (2022) https://pubs.acs.org/doi/10.1021/acs.estlett.2c00380.

8 Pipeline Safety: Gas Pipeline Leak Detection and Repair, 88 Fed. Reg. at 31,925 (May 18, 2023).

9 Id.

Response 6: For the reasons outlined in Section III.B.2 of the preamble to the final rule, the EPA is finalizing only the 100 kg/hr of CH_4 threshold. For the same reasons that the 250 mt CO_2e threshold is not being finalized, we are not finalizing a 0.5 MMCF natural gas threshold. We also note that reference in the preamble to pipeline quality natural gas was only illustrative of the size of a release that would be 250 mt CO_2e and in no way limited the applicability of the other large release event reporting requirements to only releases of pipeline quality natural gas.

Commenter: American Exploration and Production Council
Comment Number: EPA-HQ-OAR-2023-0234-0295
Page(s): 33

Comment 7: **<u>Aspects of the Proposal are arbitrary and capricious</u>**

EPA has not sufficiently justified its proposed treatment of "other large release events." As a threshold matter, because this aspect of EPA's Proposal is linked to the proposal in its pending CAA § 111 methane standards rulemaking of third-party reporting in the proposed "super emitter" program, we incorporate by reference here our discussion of that aspect of the Section 111 proposal in our comments on the December 2022 supplemental methane proposal, *docket at* EPA-HQ-OAR-2021-0317-2326 (Feb. 13, 2023) at 28-33; *.see esp id.* At 32 ("EPA should not encourage or require public reporting of the notifications provided by third parties.").

Furthermore, EPA has not justified this aspect of the Proposal as a policy matter. The Agency asserts generally that these events can "significantly contribute to total sector emissions," 88 Fed. Reg. at 50,297/1—after citing a few "large, atypical release events," id. At 50,296/2, without demonstrating that these events are likely to occur outside of the specific types of equipment at issue featured in those events, or any demonstration of their proportionate significance. And EPA offers no support, anecdotal or otherwise, for its presumption that a release started on the date of the most recent survey (or six months, whichever is shorter) demonstrating emissions below the "other large release event" threshold, *see id.* At 50,297/2. This is entirely out of keeping with Congress's direction that revisions to Subpart W be based on empirical data.

Oddly, EPA justifies its proposed mass threshold by asserting that it aligns with provisions in the New Mexico Administrative Code, *id.* At 50,298/3. A federal agency cannot rationally disregard federal statutory text directing it to focus on empirically based revisions for specific purposes in favor of state regulatory text that the Agency may prefer for other policy reasons beyond the remit of Congress's express direction. EPA's attempt to justify the rate threshold fares no better: "We are also proposing a 100 kg/hr CH4 emission threshold to align with the super-emitter response program proposed in the NSPS OOOOb." *Id.* But, as observed above, CAA § 136(h), which authorizes EPA to propose revisions to Subpart W, makes no mention of this pending proposed CAA § 111 rulemaking. Only the "exemption for regulatory compliance" in CAA § 136(f)(6) does. EPA cannot have it both ways. Either the MERP charge program and its cross-reference to the pending methane standards rulemaking is within the scope of the current Proposal, or it is not. If it is, EPA cannot treat these as two separate rulemakings and deem all MERP implementation issues out of scope of the current rulemaking. And if it is not, EPA cannot justify aspects of this Proposal by a desire to harmonize them with the pending standards rulemaking.

Response 7: We disagree with the commenter that the proposed inclusion of other large release events is not justified as a policy matter. Section 136(h) of the CAA requires the EPA to revise subpart W to "…accurately reflect total methane emissions and waste emissions from the applicable facilities…" We clearly identified in our rationale for the proposed standards and in the technical support document that large methane releases occur and that many of these large releases are not sources covered under the existing subpart W reporting requirements. There is a growing body of evidence that these large emission events are more prevalent than initially anticipated. For example, the Zavala-Ariaza, et al., 2017 study showed that 1 percent of the sites surveyed were responsible for 44 percent of site emissions.[6] Thus, while these events may be "rare" (only occurring at 1 percent of sites), this does not warrant their exclusion from the subpart W reporting requirements. Available literature studies confirm that these "super-emitter" events contribute significantly to oil and gas facility emissions. Therefore, consistent with requirements in section 136(h) of the CAA, we are finalizing reporting requirements for other large release events. We also disagree with commenter's suggestion that we cannot align the other large release event requirements with the oil and gas NSPS simply because CAA section 136 only references the NSPS in its exclusion provisions. One reason we elected to finalize the 100 kg/hr threshold was as a practical matter to be able to directly utilize information being collected under the NSPS Super Emitter Program, as discussed in Section III.B.1 of the preamble to the final rule. With respect to comments on conducting separate rulemakings for MERP and subpart W, see response to Comment 2 in Section 27.1 of this document. Finally, with respect to the cross-referenced comments on the NSPS OOOOb/c rulemaking, we consider those comments to be out of scope for this rulemaking. Notwithstanding this, the EPA will play a significant role it verifying NSPS Super-Emitter Program identified releases and all notifications will be submitted by the EPA to relevant facilities. For more discussion on the final NSPS Super-Emitter Program and how it relates to other large release event requirements, see Sections III.B.1 and III.B.2 of the preamble to the final rule.

3.4 Calculation Methodologies

Commenter: Alaska Oil and Gas Association (AOGA)
Comment Number: EPA-HQ-OAR-2023-0234-0241
Page(s): 6-7

Commenter: GPA Midstream Association
Comment Number: EPA-HQ-OAR-2023-0234-0299
Page(s): 23

Commenter: Independent Petroleum Association of New Mexico (IPANM)
Comment Number: EPA-HQ-OAR-2023-0234-0337
Page(s): 10-11

Commenter: Permian Basin Petroleum Association (PBPA)
Comment Number: EPA-HQ-OAR-2023-0234-0346
Page(s): 5

[6] Zavala-Ariaza, D., et al., 2017. "Super-emitters in natural gas infrastructure are caused by abnormal process conditions," *Nature Communications* **8**, 1401. 16 January. https://doi.org/10.1038/ncomms14012.

Commenter: Arkansas Independent Producers and Royalty Owners (AIPRO)
Comment Number: EPA-HQ-OAR-2023-0234-0382
Page(s): 8-9

Commenter: American Petroleum Institute et al. (Part 1 of 2)
Comment Number: EPA-HQ-OAR-2023-0234-0402
Page(s): 28, 63

Comment 1: Commenter 0241: **Source-specific reports should not exclude emissions from "Other release events."**

According to the proposed language in 40 C.F.R. 98.233(y)(1)(ii), "For a release meeting the criteria in either paragraph (y)(1)(ii)(A) or (B) of this section, you must report the emissions as an other large release event and exclude the emissions from this release in the source-specific emissions calculated under paragraphs (a) through (s), (w), (x), (dd), or (ee) of this section, as applicable." Reporting emissions under other large release events and excluding the emissions from the source-specific emissions is not only burdensome to reporters, but could potentially dilute the data associated with those source types. The language in 98.233(y) should be revised to read:

> *(y) Other large release events. Calculate CO_2 and CH_4 emissions from other large release events as specified in paragraphs (y)(2) through (5) of this section for each release that meets or exceeds the applicable criteria in paragraph (y)(1) of this section. You are not required to measure every release from your facility, but if you have credible information that demonstrates the release meets or exceeds one of the thresholds or credible information that the release may reasonably be anticipated to meet or exceed (or to have met or exceeded) one of the thresholds in paragraph (y)(1) of this section, then you must calculate the event emissions and, if the thresholds are confirmed to be exceeded, report the emissions as an other large release event.*
>
> *(1) You must report emissions for other large release events that emit GHG at or above any applicable threshold listed in paragraph (y)(1)(i) ~~or (ii)~~ of this section considering the entire event duration, except as applicable in paragraph (y)(1)(ii). The thresholds listed in paragraph (y)(1)(i) ~~or (ii)~~ of this section are not limited to the emissions that occur within a given reporting year.*
>
> *(i) For sources not subject to reporting under paragraphs (a) through (s), (w), (x), (dd), or (ee) of this section (such as but not limited to a fire, explosion, well blowout, or pressure relief), a release that either:*
>
> *(A) Emits methane at any point in time at a rate of 100 kg/hr or greater; or*
>
> *(B) Emits combined GHG across the entire event duration of 250 metric tons of CO2e or more.*
>
> *(ii) For sources subject to reporting under paragraphs (a) through (s), (w), (x), (dd), or (ee) of this section, for a release that emits GHG at or above at least one of the*

thresholds listed in paragraphs (y)(1)~~(ii)~~(i)(A) or (B) of this section in excess of the emissions calculated from the source using the applicable methods under paragraphs (a) through (s), (w), (x), (dd), or (ee) of this section ~~For a release meeting the criteria in either paragraph (y)(1)(ii)(A) or (B) of this section~~, you must report the emissions ~~as an other large release event and exclude the emissions~~ from this release in the source-specific emissions calculated under paragraphs (a) through (s), (w), (x), (dd), or (ee) of this section, as applicable.

~~(A) Emits methane at any point in time at a rate of 100 kg/hr or greater in excess of the emissions calculated from the source using the applicable methods under paragraphs (a) through (s), (w), (x), (dd), or (ee) of this section; or~~

~~(B) Emits combined GHG across the entire event duration of 250 metric tons of CO2e or more in excess of the emissions calculated from the source using the applicable methods under paragraphs (a) through (s), (w), (x), (dd), or (ee) of this section.~~

Commenter 0299: **EPA must explain how to parse data between the source category and "other large release events" to avoid double-counting emissions.**

EPA proposes that if a source is subject to reporting under Subpart W and its emissions exceed the "Other Large Release Events" thresholds, then a reporter "must report the emissions as an other large release event and exclude the emissions from this release in the source-specific emissions" [98.233(y)(1)(ii)]. EPA does not address, however, how this math would work, especially for sources with population emission factors such as pipeline leaks. EPA must address this critical calculation methodology, at a minimum through comprehensive guidance or preferably by incorporating it directly into the rule itself.

Commenter 0337: **40 CFR § 98.233(y) Large Release Events**

According to the proposed language in § 98.233(y)(1)(ii), "For a release meeting the criteria in either paragraph (y)(1)(ii)(A) or (B) of this section, you must report the emissions as an other large release event and exclude the emissions from this release in the source-specific emissions calculated under paragraphs (a) through (s), (w), (x), (dd), or (ee) of this section, as applicable." Reporting emissions under other large release events and excluding the emissions from the source-specific emissions is not only burdensome to reporters but could potentially dilute the data associated with those source types. This would defeat the goal of basing data collection using empirical data.

We recommend the language in § 98.233(y) should be revised to read:

"(y) Other large release events.
Calculate CO2 and CH4 emissions from other large release events as specified in paragraphs (y)(2) through (5) of this section for each release that meets or exceeds the applicable criteria in paragraph (y)(1) of this section. You are not required to measure every release from your facility, but if you have credible information that demonstrates the release meets or exceeds one of the thresholds or credible information that the release may reasonably be anticipated to meet or

exceed (or to have met or exceeded) one of the thresholds in paragraph (y)(1) of this section, then you must calculate the event emissions and, if the thresholds are confirmed to be exceeded, report the emissions as an other large release event.

(1) You must report emissions for other large release events that emit GHG at or above any applicable threshold listed in paragraph (y)(1)(i) or (ii) of this section considering the entire event duration, except as applicable in paragraph (y)(1)(ii). The thresholds listed in paragraph (y)(1)(i) or (ii) of this section are not limited to the emissions that occur within a given reporting year.

(i) For sources not subject to reporting under paragraphs (a) through (s), (w), (x), (dd), or (ee) of this section (such as but not limited to a fire, explosion, well blowout, or pressure relief), a release that either:

(A) Emits methane at any point in time at a rate of 100 kg/hr or greater; or

(B) Emits combined GHG across the entire event duration of 250 metric tons of CO2e or more.

(ii) For sources subject to reporting under paragraphs (a) through (s), (w), (x), (dd), or (ee) of this section, a release that emits GHG at or above at least one of the thresholds listed in paragraphs (y)(1)(i)(A) or (B) of this section in excess of the emissions calculated from the source using the applicable methods under paragraphs (a) through (s), (w), (x), (dd), or (ee) of this section, you must report the emissions from this release in the source-specific emissions calculated under paragraphs (a) through (s), (w), (x), (dd), or (ee) of this section, as applicable.

(A) Emits methane at any point in time at a rate of 100 kg/hr or greater in excess of the emissions calculated from the source using the applicable methods under paragraphs (a) through (s), (w), (x), (dd), or (ee) of this section; or

(B) Emits combined GHG across the entire event duration of 250 metric tons of CO2e or more in excess of the emissions calculated from the source using the applicable methods under paragraphs (a) through (s), (w), (x), (dd), or (ee) of this section."

Commenter 0346: Large Release Events

EPA states that "large GHG emission releases may also occur from equipment for which there is a calculation methodology and reporting requirement in Subpart W but for which the existing calculation methodologies in Subpart W would significantly underestimate the magnitude of the emissions."[5] To address the concern that certain equipment may result in large GHG releases, EPA is proposing to require the reporting of large emission events by revising the calculation methodology to increase the emission factor for this equipment, resulting in double counting. Such double counting does not result in the empirical data upon which the EPA should rely and upon which a waste emission charge should be assessed.

EPA appears to recognize that there is inherent variability in emissions from sources that may appear to be very similar. In the Proposed Rule, EPA states, "In cases where there is significant variability in source-level emissions and the default emission factors are thus not appropriately representative of facility-level emissions, and other calculation methodologies are available that are representative of facility-level emissions, we are proposing to remove default emission factors."[6] PBPA members affirm that variability exists in source-level emissions based on differences in operations, basins, and industry sectors that are not accounted for in the emission factors EPA has proposed.

Footnotes:

[5] 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, at 25.

[6] Proposed Rule at 50289.

<u>Commenter 0382</u>: <u>Potential for "double-counting" of emissions from certain sources due to certain requirements:</u>

Under current GHGRP rules as well as proposed GHGRP revisions, there are multiple scenarios where emissions may be "double-counted", some of these include the following:

…

- Proposed requirements for reporting emissions from blowdown vent stacks that may also be identified as a "large release event."

…

AIPRO encourages EPA to identify and eliminate all potential double-counting scenarios.

<u>Commenter 0402</u>: *Blowdowns*

As discussed in the 'Other Large Release Events' comments, there is a significant probability of double counting between blowdowns and 'Other Large Release Events' due to the low emission rate threshold proposed for the 'other large release events' source.

The Industry Trades are also concerned that, due to the low hourly emission rate threshold specified by EPA for the "Other Large Release Events" category, these events could be inadvertently counted in both this blowdown category as well as "Other Large Release Events" – resulting in significant double counting. EPA should clarify that any emission event that triggers the "Other Large Release Events" threshold but belongs under a reportable emissions source category (e.g., blowdowns) should be reported within its associated source category, not under "Other Large Release Events." The Industry Trades have elaborated on this point in the "Other Large Release Events" section of this letter.

…

Furthermore, remote sensing technologies generally do not distinguish between emissions sources that are transient, included sources (blow downs, liquid unloadings, crankcase venting, etc.), or unintended sources that may or may not already be identified (unlit flares, over pressurized tanks, etc.) and thus there is a risk for double counting of certain emissions. Owner/operators should exclude sources that are already otherwise accounted for under another category, and EPA should explicitly allow exclusion of observations that could be classified as large emissions events but are otherwise already accounted for in another category.

Response 1: The proposed rule was clear that, for sources that have source-specific emission calculations, the emission would be reported according to the provisions for that source, unless the source-specific method understates emissions by more than the threshold defining an other large release event. In that exception, the proposed rule stated that the emissions would be reported on a per event basis as an other large release event and that the emissions from that event would be excluded from the source-specific calculations and this has been further clarified in the final rule. We agree that double counting those emissions should be avoided and the proposed language achieved that end. The other alternative, as suggested by some commenters, is that part of that release would be reported under the source-specific reporting requirements and the remainder of the release reported under other large release events. However, we do not see that this approach would reduce the burden of the reporting requirement. Also, facilities are required to report the equipment from which the other large release event occurred, so the other large release event can still provide source-specific information. Since some of the other methodologies are not event-specific reporting requirements, we find it more straight-forward to report the full event emissions as an other large release event. For further clarity as discussed in Section III.B.1 of the preamble to the final rule, we are finalizing the reporting requirements at 40 CFR 98.233(y)(1)(ii) with clarifications regarding excluding reporting of emissions associated with the timespan of an other large release event from source specific reporting to avoid double counting.

Commenter: MiQ
Comment Number: EPA-HQ-OAR-2023-0234-0392
Page(s): 9-10

Comment 2: 98.233(y) opening paragraph: You are not required to measure every release from your facility, but if you have credible information that demonstrates the release meets or exceeds one of the thresholds or credible information that the release may reasonably be anticipated to meet or exceed (or to have met or exceeded) one of the thresholds in paragraph (y)(1) of this section, then you must calculate the event emissions and, if the thresholds are confirmed to be exceeded, report the emissions as an other large release event.

MiQ Comments: MiQ requests clarification for how EPA plans to interpret “confirmed” and “reasonably anticipated to meet or exceed.” Does EPA plan to publish additional guidance for how operators must account for quantification uncertainties in measurement technologies? For example, if an operator is using a “snapshot” measurement technology with a MDL of 20 kg/hr at a 90% PoD and single measurement quantification error of +/- 50%, and detects two emission events at 95 kg CH_4/hr ± 50% and 105 kg CH_4/hr ± 50% that both fall below the 250 MT CO_2e

threshold, what will the expectations be for including these events as other large release events? Will a heavier burden of proof be placed on the event that calculates an average emission rate of 105 kg/hr even though the error bands overlap?

MiQ is supportive of solutions that do not pass undue burden on individual operators to justify the data they are reporting and are supportive of solutions which provide clarity on the intent of any reporting requirements placed on operators. As an example, MiQ requires operators to evaluate all results of emission event inspections with the goal of verifying what MiQ grade band the operator falls under. EPA could consider taking a similar approach and tie both the reporting threshold and the level of confirmation necessary on an operator's risk of surpassing the threshold stated in the waste emissions charge.

Response 2: We recognize that there is uncertainty in the measurements and that a measured rate of 98 kg/hr could have an actual rate above 100 kg/hr just as a measured rate of 102 kg/hr could have an actual rate below 100 kg/hr. While we acknowledge this, we consider this approach of a numeric threshold to be appropriate, including for clarity for reporters and the EPA in implementation. First we note that, regardless of where and how we design the threshold, there will always be a few measurements with emissions just over or just under the threshold. For example, if we said the threshold had to have 90% certainty that the measured emissions were over 100 kg/hr, there would be cases where one measurement has 88% certainty that the emissions are greater than 100 kg/hr and another measurement has 92% certainty that the emissions were above 100 kg/hr. These two measurements would have considerable overlap considering the uncertainty in the measurements, but one measurement would trigger reporting while the other one would not. Thus, regardless of how the threshold is structured, there will be measurements that are just above and just below the threshold. Second, while there will be measurements close to the threshold, these are not expected to be a majority of the measured events. For example, Cusworth, et al., (2021) quantified 3,067 emission plumes. Of these 3,067 emission plumes: 2,864 exceeded 100 kg/hr, 2,295 exceeded 200 kg/hr, and 457 kg/hr exceeded 1,000 kg/hr.[7] Based on this data, we expect that only 20 percent of the measurements above 100 kg/hr will be within a factor of 2 of the 100 kg/hr threshold and potentially impacted by the uncertainty of the measurement. While we understand there are measurement uncertainties, we maintain that it is appropriate to establish a distinct threshold and that the average emission rate is the most appropriate means by which to assess the threshold because it is the central tendency of the measured emission rate.

Under the SEP, certified third-party notifiers must report the quantified emission rate of the super-emitter event in kg/hr and the associated uncertainty bounds (e.g., 1-σ) of the measurement. The EPA will consider this information when deciding to notify the facility. We note that if a facility is notified of a super-emitter event under the NSPS Super-Emitter Program (even when the uncertainty bound may drop below 100 kg/hr) the facility is required under NSPS OOOOb or EG OOOOc to investigate and attempt to identify the source of the emissions. Under subpart W, the facility is required to report that the SEP notification was received from the EPA and information on the assessment of the super-emitter event, which may include the

[7] Cusworth, D.H., et al., 2021. "Intermittency of Large Methane Emitters in the Permian Basin." *Environmental Science & Technology Letters.* **8** (7), 567-573. DOI: 10.1021/acs.estlett.1c00173.

emissions from the event as estimated using the methods specified for other large release events in subpart W.

Commenter: Encino Environmental Services
Comment Number: EPA-HQ-OAR-2023-0234-0364
Page(s): 4-5

Commenter: Endeavor Energy Resources, L.P.
Comment Number: EPA-HQ-OAR-2023-0234-0381
Page(s): 7

Commenter: CrownQuest Operating
Comment Number: EPA-HQ-OAR-2023-0234-0393
Page(s): 62

Comment 3: Commenter 0364: ***Other large release events***

Large release events threshold

The EPA proposes an instantaneous threshold for reporting large emissions events to be 250 metric tons of CO2e total (approximately 500 mscf of pipeline quality natural gas) or an emission rate of 100 kilograms of methane per hour. Based on this, Encino understands that an emission with a rate of 10 kg/hr will take about 42 days to reach 250 metric tons of CO2e and about 17 days when the emission rate is 25 kilograms of methane per hour. This trend indicates that, in order to minimize a large release event, an operator should focus on leveraging tiered approaches in order to have periodic monitoring. For example, Encino's solutions could provide continuous emissions monitoring (CEMS) coupled with weekly satellite revisitations to promptly identify, source allocate, and quantify leaks, and use optical gas imaging (OGI) cameras to identify and verify successful repairs. Encino also acknowledges that the probability of occurrence plays an important role. Each facility type tends to show a certain behavior over time in a given area or basin, so it is important to consider this stochasticity when selecting the monitoring technology.

Commenter 0381: **EPA Should Remove "Other Large Release Events" from Reporting Requirements in the Final Rule.**

For any "other large emissions events" that EPA retains in the final rule, EPA should provide greater flexibility in measuring and calculating emissions from "other large release events."

While Endeavor recommends that EPA remove all reporting requirements for "other large emissions events" from its final rule, if it does retain any of these categories of events, it should provide flexibility in recognition that direct measurement is impractical or impossible. This flexibility is critical to ensure that the permitted calculation methods will produce the most consistent and accurate emissions data possible, in keeping with the directive in the IRA. Endeavor supports EPA's proposed use of monitored process parameters (e.g., pressure or temperature changes) as the primary mechanism to determine the start date of a large emissions event, in combination with a wide array of monitoring and survey methods (e.g., vehicle-mounted monitoring systems, drones, helicopters, airplanes, satellites). [18] Endeavor strongly supports EPA's integration of alternative monitoring and survey technologies—here and throughout the Subpart W Proposal—especially given the unique location and nature of each well site and facility. Many operators in our industry use a combination of monthly flyovers and SOOFIE (Systematic Observations of Facility Intermittent Emissions) continuous monitoring and leak detection devices to monitor their operations—systems that we find to be invaluable and cost-effective tools for emissions identification and quantification. We believe that flexibility will both ensure accurate, consistent, and useful emissions reporting, as well as help spur continued innovation within the oil and gas sector. Endeavor recommends, though, that EPA be careful not to codify only a limited set of alternative methods and systems, as technology in this area is likely to outpace any future revisions to EPA's regulations. Any finalized requirements *must* recognize that direct measurement is not currently feasible for many sources subject to, or that EPA proposes making subject to, reporting under Subpart W. This recommendation extends beyond "other large release events" to all parts of the Subpart W Proposal. As Endeavor has noted in previous rulemakings, direct measurement can be infeasible or impractical under certain circumstances, especially when accounting for the increased demand for such technologies and technicians trained to operate those technologies in response to regulatory requirements for direct measurement or monitoring.

Commenter 0393: These examples [of other large release events] are the extreme. They are not indicative of every day normal operations. These events, when they do happen, they are well reported and known.

The agency is advocating for greater emission detection technology to classify these events because they are not allowing us to use them for the emission factors, specifically for fugitives and pneumatic controllers. In the same vein, advanced technology could be a way to quantify other large release events but not being able to use them for developing actual emission factors in the field.

Response 3: We provided significant flexibility and a wide range of measurement methods for determining other large release event emissions. Specifically, a wide range of advanced measurement technologies, including satellite and aerial measurements, can be used to identify and help quantify an emission event or estimate the duration. Frequent or continuous monitoring systems can be used to help identify the start of an event. Additionally, we specifically allow the use of a wide range of process data, which include SCADA data, that can be used with sound engineering principles for determining the start date of the event. We also allow the use of process data in conjunction with engineering calculations to assess the emissions rate or volume of gas released (for example, using pressure measurement with valve opening diameter to assess emissions during a release from a pressure relief valve. We note that, unless the emissions are released via a stack vent that has a continuous flow meter with appropriate range installed, none of the measurement methods specified in 40 CFR 98.234 are applicable to quantify releases at or above 100 kg/hr methane. Therefore, considering the size of emission events under other large release events, we allow a full range of advanced measurement methods as well as engineering calculations for assessing the emissions from other large release events.

Commenter: Clean Air Council
Comment Number: EPA-HQ-OAR-2023-0234-0203
Page(s): 1

Commenter: Public Hearing Transcript
Comment Number: EPA-HQ-OAR-2023-0234-0224
Page(s): 13 (Alice Lu), 33 (Margeret Bell), 50 (Christina Digiulio)

Commenter: American Exploration and Production Council
Comment Number: EPA-HQ-OAR-2023-0234-0295
Page(s): 13

Commenter: American Lung Association
Comment Number: EPA-HQ-OAR-2023-0234-0335
Page(s): 1

Commenter: MiQ
Comment Number: EPA-HQ-OAR-2023-0234-0392
Page(s): 7-9

Commenter: Environmental Defense Fund et al.
Comment Number: EPA-HQ-OAR-2023-0234-0401
Page(s): 1

Commenter: American Petroleum Institute et al. (Part 1 of 2)
Comment Number: EPA-HQ-OAR-2023-0234-0402
Page(s): 63

Comment 4: <u>Commenter 0203</u>: I urge EPA to strengthen its proposed rule in the following ways:

…

- Utilize top-down approaches, such as aerial monitoring, to detect and quantify super-emitter events from oil and gas sources.

<u>Commenter 0224</u>: The EPA must also utilize top-down approaches such as aerial monitoring to detect and quantify super emitter events. These events generally lack empirical emissions factors so they're difficult to calculate and aerial monitoring can instead measure emissions when they do occur.

…

And include top-down approaches such as continuous aerial monitoring to detect and quantify especially large emissions from oil and gas sources. These emission events generally do not have empirical emissions factors and calculating their magnitude would likely not be accurate.

…

And EPA should definitely use top-down approaches such as continuous aerial monitoring to detect and quantify especially large emissions particularly super emitters from oil and gas sources and these emission events generally do not have empirical emission factors and calculating their magnitude would likely not be accurate.

Commenter 0295: EPA invited comment on how best to combine top-down data with bottom-up methods, sometimes referred to as reconciliation. AXPC recommends that both methods be used separately due to process emissions being indistinguishable from fugitive emissions in satellite, or other asset quantification surveys. It is important to note that thus far, experts in the field of methane measurement do not see a scientifically defensible methodology to reconcile "point in time" flux measurements with other bottom up methodologies. The accuracy challenges behind flux measurements will always result in a difference between the two methodologies. The methodologies should be complementary to show directional decreases and inform on blind spots and emission events rather than to try to create a balance sheet that scientifically will not add up. For a recent study of this phenomenon, please reference the study titled "Informing Methane Emissions Inventories Using Facility Aerial Measurements at Midstream Natural Gas Facilities."[3]

Footnote:

[3] Jenna A. Brown, Matthew R. Harrison, Tecle Rufael, Selina A. Roman-White, Gregory B. Ross, Fiji C. George, and Daniel Zimmerle, Informing Methane Emissions Inventories Using Facility Aerial Measurements at Midstream Natural Gas Facilities. Published by American Chemical Society. September 2023.

Commenter 0335: The EPA should use basin-level measurement data and top-down approaches, such as continuous aerial monitoring, to detect and quantify especially-large emissions, particularly super-emitters, from oil and gas sources. Large emission events, or "super-emitters," can be a significant source of GHGs and will be required to be reported. Continuous optical gas imaging (OGI) is a simple, non-invasive, qualitative process that consists of surveying the facility with a specialized infrared camera that makes gas leaks readily apparent on a screen. This technology would result in more frequent and accurate data, and it would help catch emissions data for potential super emitter incidents.

Commenter 0392: **Other Large Release Events**

Preamble II.B: *"... different types of top-down data have a wide range of detection limits and spatial resolution, which makes it difficult to reliably convert point estimates to an annual emissions estimate as required by the GHGRP. Therefore, this proposal does not propose using top-down approaches for sources other than besides other large release events due to the* *limitations described earlier in this section. However, we invite comment on whether there are top-down approaches that could be used to estimate annual emissions for any source categories under subpart W or for facility-level emissions, what level of accuracy should be required for such use, and whether the development of standards (either by the EPA or third-party organizations) could help inform this determination. We also invite comment on how frequently measurements would need to be conducted to be considered reliable or representative of annual emissions for reporting purposes…In addition to the proposed use of top-down data to help identify and quantify super-emitter and other large emissions events, we invite comment on whether there are other appropriate uses of top-down data for the purposes of reporting under subpart W of the GHGRP, including what types of emission sources and emission events, what specific top-down methods may be appropriate, especially in terms of spatial scale and minimum detection limits."*

MiQ Comments: The MiQ Standard requires operators to utilize data from Facility Scale surveys to reconcile their calculated emissions. Facility Scale surveys must be conducted using a technology that has conducted single blind testing demonstrating a minimum detection limit (MDL) of at least 25 kg/hr at a probability of detection (PoD) of 90%. Operators may use other means of emissions monitoring through the usage of equivalency modeling using models such as the Fugitive Emissions Abatement Simulation Tool (FEAST) or LDAR-Sim. The data gathered from Facility Scale surveys, or any third-party data must be evaluated by the operator to determine whether a detected emission is already included in an operator's baseline emissions calculations. Examples of emissions that may already be included are periods of normal tank flashing emissions or properly performed and reported pipeline blowdowns. Operators are required to evaluate the impact of all their additional emissions to their overall MiQ grade.

Reconciliation of the results of Facility Scale inspections are used as assurance of an operator's MiQ grade band. For example, an operator must have an intensity of 0.05% or less to claim a MiQ A-grade. Along with the detection and quantification data gathered from monitoring and measurement surveys, other available data such as operating conditions, parametric monitoring or other inspection data can be used to help provide context to detected emission events, which also leads to more accurate quantification of emissions. As EPA has observed, many Facility Scale inspection results have indicated emissions from highly episodic events. More frequent surveys such as quarterly or monthly inspections give operators more data ultimately to help understand both the magnitude and periodicity of individual emission events. Most MiQ-certified operators reconcile the results of their advanced monitoring and measurement inspections in an event-based format, assessing the additionality of emissions to the operator's current inventory, the average emission rate and event duration, similar to EPA's guidance under "Other Large Release Events," but without the reporting thresholds that EPA has set. Other results have indicated systemic underreporting or lack of reporting from methane emissions from certain sources. In these situations, some operators have decided to use survey results to indicate a gap in their bottom-up inventory and utilize engineering calculations to account for emissions on an annual basis.

Since the vast majority of MiQ Operators in the MiQ program use Facility Scale inspection methods, our program does not provide a disincentive for operators to use certain technologies. All Operators are on a level playing field regarding the requirement to use Facility Scale inspections and the technology requirements for the methods utilized. However, proposed OOOOb and OOOOc rules will not require operators to conduct inspections other than traditional equipment leak inspection methods. As many others are surely also commenting, this may create disincentives for operators to use top-down inspection methods for fear of discovering emissions that they otherwise may not be required to inspect for and report.

MiQ believes that the proposed updates to improve emission source calculation methodologies and require more complete reporting of all potential emission sources will lead to more accurate methane emission inventories. However, to provide additional assurance MiQ encourages EPA to adopt a mechanism to require all operators to utilize some type of advanced monitoring and measurement method annually. Results from these inspections could either be used by operators to quantitatively reconcile the emissions they are reporting to EPA or simply be required to be reported to EPA in annual GHGRP reporting. EPA should consider the following technological requirements, which are present in the MiQ Standard.

- Independent, single-blind testing of each monitoring or measurement method using controlled releases or field tests is required
- Testing must produce a probability of detection curve at certain wind conditions, or a probability of detection curve must be able to be deciphered
- Probability of detection and frequency should be considered when developing performance requirements.
    - For example, EPA could present a matrix that could, among other options, require periodic screening methods with a MDL of 10 kg/hr or less at 90% PoD be used at least once per year, screening methods with a MDL of 25 kg/hr or less at 90% PoD be used at least twice per year, and screening methods with a MDL of 100 kg/hr or less be used at least bi-monthly
- The spatial coverage of the method across an operator's Facility must be transparent. For reference, MiQ requires 100% of an operator's Facility to be monitored via Facility Scale inspection methods. Spatial coverage requirements may also be refined based on the performance characteristics of the method.
- Continuous monitoring systems (CMS) must also be given a path to comply with this requirement, and should have, at minimum, the following requirements
    - Identical independent, single-blind testing requirements as other methods
    - Probability of detection curves
    - In lieu of a high spatial coverage requirement, a floor (i.e. 25%) should be set for deployment percentage coupled with requirements that deployment must occur on a representative swath of an operator's Facility

Commenter 0401: **Use funds from the Methane Emissions Reduction Program for monitoring for large release events**, focusing on sites that are not otherwise monitored, and gathering and incorporating additional types of observational monitoring data.

Commenter 0402: To address one of EPA's requests for comments in the preamble, the Industry Trades believe that reconciling top-down data with bottom-up data should not force reporters to revise bottom-up estimates. The values recorded by these top-down sensors require significant data processing and analytics to provide the required measurement values, including concentration or flux. Moreover, even if the concentration (or concentration-pathlength) were perfectly accurate, error is introduced in post processing to produce estimates of emission rates, and these errors vary greatly depending on both the technology deployed, but even proprietary data treatment techniques between vendors of similar technologies. Beyond these uncertainties, however, is an inherent uncertainty introduced due to the temporal misalignment between the observational data and the bottom-up reporting methods. Not only do "matching" style reconciliation exercises require high spatial resolution of bottom-up emissions estimates (disaggregation to sites or even to the equipment level), but such exercises demand high temporal resolution. Otherwise, reliable extrapolation techniques must be applied to the often short duration observations to produce longer term emissions estimates. The aggregation of these uncertainties implies that the "top-down" measurements cannot be deemed more accurate, but simply useful in that they provide a different view of emissions.

Response 4: We recognize the difficulties in reconciling short-term, top-down measurement data with bottom-up emission inventories. We consider that the inclusion of other large release event reporting, as proposed, strikes an appropriate balance between a top-down monitoring approach and bottom-up measurement and inventory approach. Final requirements for other large release events will help to close this gap, but it does not require facilities to adjust their bottom-up emission estimates to match top-down measurements because of the generally short time scale of top-down emission measurements and the episodic nature of many other large release events. While facilities can use a broad range of advanced measurement methodologies to identify other large release events or to help determine start date of an event, including the use of continuous OGI, we are not mandating that facilities conduct some type of advanced measurement technologies for all sites within their facility for several reasons. First, we did not propose this requirement and we recognize that including this requirement would increase the cost of the rule. Second, we determined that it was not necessary to require facilities to conduct their own advanced monitoring for the purposes of this rulemaking because most aerial monitoring has an uncertainty range of about plus or minus 30 to 50 percent of the measured value[8] and engineering calculations can often estimate the emissions with similar or less uncertainty. Therefore, we are not finalizing provisions to require facilities to conduct site level aerial surveys or other advanced measurement methods of their sites. We also note that, with publicly available data from Carbon Mapper and the potential to receive Super-Emitter Program notifications, many facilities may nevertheless conduct their own monitoring to better characterize their facility's emissions and more accurately determine event start dates. When these data are available, we allow their use under subpart W to help quantify the emissions from the event. For more detail on our consideration of alternate technologies, refer to Section 23 of this document.

[8] Measured rates reported by Johnson, et al. (2021) were generally within ±30 to 50% for controlled releases that were detected (Johnson, M.R, D.R. Tyner, and A.J. Scekeres. "Blinded evaluation of airborne methane source detection using Bridger Photonics LiDAR." *Remote Sensing of Environment* 259 (2021) 112418. https://doi.org/10.1016/j.rse.2021.112418); When evaluating Kairos's technology, Chen et al., (2022) reported basin-wide emissions of 153 Mg/hr (+71/−70, 95% CI; or ±50% of the average) but sensitivity test cases were reported with 95% CI of ±35% of the average (Chen, Y., et al. "Quantifying Regional Methane Emissions in the New Mexico Permian Basin with a Comprehensive Aerial Survey." *Environ. Sci. Technol.* 2022, 56, 4317−4323. https://doi.org/10.1021/acs.est.1c06458).

Comments on potential uses of funds collected by the Methane Emissions Reduction Program are outside of the scope of this rulemaking.

Commenter: Public Hearing Transcript
Comment Number: EPA-HQ-OAR-2023-0234-0224
Page(s): 8-9 (Asa Carre-Burritt)

Commenter: Kairos Aerospace
Comment Number: EPA-HQ-OAR-2023-0234-0240
Page(s): 8-11, 17

Commenter: Colorado Department of Public Health and Environment (CDPHE)
Comment Number: EPA-HQ-OAR-2023-0234-0373
Page(s): 2-3

Commenter: Chesapeake Energy Corporation
Comment Number: EPA-HQ-OAR-2023-0234-0400
Page(s): 11

Comment 5: Commenter 0224: The subject rulemaking has the potential to significantly impact the oil and gas industry's approach to methane emissions management. Therefore, we urge the EPA to make sure that the final rule incentivizes operators to find emission and does not penalize operators for detecting and reporting emissions.

…

In this statement, we would like to draw the EPA's attention to our specific concerns with reporting for the proposed other large release events source category. Reporting for this category is based on the best available information, notably this includes information from OGI surveys or advanced methane sensing technology that may be deployed to achieve regulatory compliance under OOOOb. Relying on operator funded LDAR programs as a key element for reporting under this source category gives rise to several issues. For example, reporting could be inconsistent depending on the technology that is deployed because in practical application, methane sensing technologies can have significantly different coverage of emissions. Because Subpart W reporting will be tied to the waste methane emissions charge, if provisions are finalized in their current form, there's now clear disincentive for comprehensively characterizing emissions using the best available technology. The improved detection of emissions would be penalized with the potential for additional charges. This is a major issue considering the potential importance of this source category. In addition, we are not aware of a clear methodology to make sure operators have collected enough information to ensure accurate reporting of large release events. Instead of relying on operator-funded LDAR programs and the Super Emitter Response Program to determine the presence of many of the emissions subject to the other large release event reporting, we encourage the EPA to finalize rules that leverage an optimally systematic approach to assessing total emissions. This can be achieved by considering basin wide measurement. Empirical measurement across production basins can be used to develop basin specific emission factors for equipment. This approach provides a reliable back stop for emissions reporting and a level playing field for operators. The technology is already available to characterize basin emissions at the equipment scale with defined uncertainty. In addition to implementing a more systematic approach to evaluating total emissions, we also urge the EPA to provide operators with a pathway to demonstrate improved performance relative to basin norms. This can be accomplished through measurement protocols executed at the operator scale such as those that may be developed based on the Veritas protocol.

<u>Commenter 0240</u>: Improving consistency in data collection will minimize perverse incentives

As EPA outlines in the Proposed Rule, measurement data show that large but relatively rare sources of emissions may contribute an outsized amount of methane emissions. By gathering more robust data, EPA's Inventory will better reflect the prevalence and cause of large emissions. There are many technologies capable of detecting these kinds of events, ranging from ground-based sensors, to drones, and manned aircraft. Several technologies can both detect and quantify these events. We also note that these large emission events often make up the bulk of cumulative emissions. That trend was noted in a variety of production regions in the Cusworth, Chen, and Sherwin studies referenced earlier in this letter. Capturing better data on these events will undoubtedly improve the overall quality of EPA's Inventory.

However, we are concerned that the collection of Other Large Release Event data may inadvertently disadvantage the companies that have invested the most into methane detection programs. That is because EPA appears poised to create a requirement to report Other Large Release Events that companies identify, but not to have a mechanism to ensure data is being gathered and reported consistently across industry.

For example, Kairos clients conduct aerial methane detection surveys as frequently as once per month, gathering data on emissions as small as 10 kg/hr. A number of clients are also collecting data from continuous monitors, satellite surveys, and ground-based optical gas imaging camera inspection teams in addition to their aerial survey programs with Kairos. These companies are often investing heavily to reduce emissions far beyond any regulatory requirement because of their deep commitment to operate responsibly. Kairos believes companies taking such strides to reduce methane should be applauded, not punished.

Conversely, there may be operators who utilize no leak detection technology, particularly at sites that will be subject to the OOOOc rules and thus have no regulatory drivers to conduct regular surveys today. In our experience, even the most diligent operators can have occasional large emissions, and companies that do not invest in emission reduction strategies will almost certainly have large emissions on occasion.

EPA's reporting structure would require companies surveying monthly to report far more emissions simply because they're finding emissions. Conversely, a company that doesn't look for leaks may be able to not report any emissions from Other Large Release Events, even if such events are present but undiscovered. **We're deeply concerned this will create a perverse incentive where the companies working the hardest to eliminate methane will wind up reporting (and through the Inflation Reduction Act, paying fees) on more emissions than**

companies that do not make similar strides to reduce emissions. In reality, both operators who are working to reduce emissions and the EPA itself will benefit from more consistent measurement–operators through a more level playing field on Methane Fees, and EPA through a more accurate, more complete Inventory.

We encourage EPA to think of strategies to avoid inadvertently penalizing operators that are working diligently to identify and eliminate emissions. We offer several examples for EPA to consider that attempt to address this possible risk to operators.

One possible approach would be to provide incentive for operators that survey more frequently than required by regulations and disclose emissions. The New Mexico Oil Conservation Division took such an approach in its Waste Prevention rules with the creation of the ALARM Program. The ALARM program provides operators with a direct financial incentive to go above and beyond the required annual survey frequency within New Mexico's Waste Prevention rules and avoid a perverse incentive structure.

Under New Mexico's ALARM program, operators can elect to use a division-approved remote or automated monitoring technology to survey for leaks. If electing to use an ALARM-approved technology at a cadence more frequent than that required under the Waste Prevention rules, operators can obtain credit against the volume of gas lost reported for the year. For example, if a pipeline operator uses an ALARM-approved technology like Kairos to survey their gathering lines at least twice per year, they can claim a credit for 40% of the volume of gas from leaks repaired within 15 days of discovery. If the operator uses the technology at least once per calendar quarter as part of routine waste-reduction practices, an additional 20% can be claimed.

The ability to claim credit to offset emissions through the ALARM program provides clear incentive to utilize approved advanced technology and survey for leaks more frequently. A similar approach could be considered by EPA as a way to avoid penalizing operators with robust voluntary methane detection programs while promoting the use of advanced technologies and finding and rapidly repairing leaks.

Another possible framework to consider is the State of Colorado's approach in the Greenhouse Gas Intensity Verification Rule. The State of Colorado has determined that its state greenhouse gas inventory undercounts total methane emissions, and has developed through rulemaking a strategy to incorporate emissions measurement into its inventory. The State's rule allows companies to measure and calculate their own emission intensity, through a process akin to what's being proposed within the Proposed Rule.

However, to ensure that companies that do not conduct robust, voluntary measurement still end up with a more accurate emission intensity, the State of Colorado is developing a "default" measurement enhancement factor that would be applied across the board to all companies that do not elect to measure emissions themselves. To develop this "default" enhancement factor, Colorado plans to use widespread methane measurement to understand the discrepancy between so-called top-down vs. bottom-up measurement.

For example, the State may conduct basin-scale measurement of methane emissions, and determine that actual observed emissions are 20% higher than reported via the inventory. In this instance, companies would be required to increase their reported emission intensity by 20% if they do not elect to measure their methane intensity themselves, or conduct measurement to determine what their true greenhouse gas intensity is.

The Oil and Gas Methane Partnership 2.0 (OGMP) Level 5 Framework offers another possible avenue for EPA to consider in how to incorporate empirical data into its greenhouse gas inventory approach. The level 5 requirement specifically reports emissions at the facility level, which aligns with the approach contained within the Proposed Rule. However, OGMP 2.0 Level 5 also requires facility-specific, site-level measurement. Adopting the principles of the OGMP 2.0 Level 5 Framework would clearly incorporate empirical data into the Proposed Rule, and may ultimately help EPA gather data more consistently from facilities, rather than relying on a patchwork of voluntary and regulatory measurement programs.

Ultimately, EPA's inventory will best fulfill Congressional intent by using more empirical data. We are concerned that if the Proposed Rule creates a situation where some operators use robust empirical data, and others use none at all, EPA will fall short of Congress' intent while also penalizing operators that are striving to eliminate methane emissions. There are many possible strategies to avoid this situation, and we encourage EPA to consider its available options to avoid undue harm to industry entities that have embraced methane mitigation.

…

We are concerned, however, that the reporting requirements created within the Proposed Rule will be felt unevenly across industry. This would both disadvantage large swaths of the industry that have embraced methane mitigation and cause the Proposed Rule to fall short of Congressional intent to create an accurate, complete, measurement-based Greenhouse Gas Inventory. We encourage EPA to consider ways to more equitably gather data on Other Large Release Events and avoid punishing companies with the most robust methane mitigation programs.

Commenter 0373: CDPHE suggests EPA consider how best to incentivize operators to conduct methane and parametric monitoring, such as what Colorado has done for GHG emissions intensity from the upstream (Onshore Petroleum & Natural Gas Production) segment.

Under Colorado's GHG emissions intensity program, operator-specific programs[1] are critical to the success of our GHG reduction efforts. This option is technology-agnostic, promotes early adoption of measurement techniques, encourages use of multi-scale measurements, and provides facility and source specific emissions data. CDPHE is proud of our efforts to develop a first of its kind regulatory protocol for operators to utilize a measurement-strategy that will reliably allow operators to create a measurement-informed inventory with opportunities for learning and improvement over time, which may become a useful model for EPA and other jurisdictions. CDPHE has led the nation in such flexible programs in the past, with alternative instrument monitoring methods for use in leak detection and repair. In this case, Colorado determined that early adoption (by operators) of new and improving monitoring technologies is the fastest way for operators to find and reduce methane emissions, while also providing additional insight into developing a measurement-informed inventory. Essentially, Colorado has asked operators to start measuring NOW, even while these technologies are still developing and evolving.

The Greenhouse Gas Intensity Verification Protocol is currently being developed with the participation of many academic, technical, and policy experts[2] in this field. CDPHE has committed to diligently reviewing and iterating this document over many years to achieve the end goal of a comprehensive understanding of how differing technologies can be used independently and in conjunction to inform emission reporting.

CDPHE fears that certain provisions, such as in the proposed language for other large release events (98.233(y)), may instead create a disincentive for operators to utilize newly developing and improving emission monitoring technology, especially those that have high frequency or sensitivity for finding emissions. For example, if an owner or operator conducts an equipment leak monitoring survey and finds credible information that demonstrates that a release meets or exceeds 250 mt CO_2e or 100 kg/hr methane, the proposed rule would require the release to be quantified and reported as an "other large release event". This approach could perversely benefit the reporter to NOT use effective or quality detection technologies in their leak surveys, because those better technologies may lead to an increase in detected emissions affecting methane fees associated with those detected emissions. This would reduce the accuracy of reported GHG emissions and result in improper avoidance of fees from the Methane Emissions Reduction Program. But most importantly, this will prevent operators from looking for and reducing emissions from their operations.

Instead, EPA might propose a framework that rewards companies that use technology to detect emissions and credible information. EPA could incentivize companies to develop and implement their own programs to detect their actual emissions. In Colorado, CDPHE is doing this by conducting its own methane monitoring and developing a basin-wide default factor to create a measurement-informed inventory which is required to be used in an operator's intensity calculation, unless the operator has developed an operator-specific program. Under EPA's current proposed structure, such a basin-wide factor might be used to adjust what methane emissions are subject to fees, while an operator's robust monitoring might actually relieve some of those fees if they can demonstrate that those emissions were either not from "other large release events" or that the duration was limited.

Footnotes:

[1] Colorado's operator-specific programs require an operator to develop a comprehensive measurement strategy using direct measurement and, optionally, parametric measurement to identify emissions and inform the operator's annual emission inventory. This program further requires operators to have a third-party audit conducted of emission calculations and records on key years through 2030.

[2] CDPHE is especially thankful to all of the academic and technical experts that are lending their expertise to the development of this protocol.

Commenter 0400: **EPA should revise its "other large release events" emission category to better account for operational realities and to encourage broader voluntary emissions monitoring.**

EPA is proposing to expand reporting requirements to include "other large release events" (also known as "super-emitters") that generate either an instantaneous methane emission rate of 100 kg/hour or volume-based emissions of 250 mtCO2e per event.[32] EPA stated in the Proposed Rule that it intends for this source to capture maintenance or other abnormal emission events that are not fully accounted for in Subpart W.[33] Chesapeake supports and appreciates the flexible approach proposed for calculating emissions from large release events (i.e., measurement data or a combination of engineering estimates, process knowledge, and best available data), as well as EPA's clarification that large release events do not include emissions that are not already reported to existing source categories under Subpart W. But as proposed the rule risks requiring reporting even though no large-scale emissions event has occurred. Accordingly, Chesapeake encourages EPA to revise the proposal to ensure accurate and verifiable accounting of event-level emissions, better account for on-the-ground operating practices, and to incentivize voluntary emissions monitoring measures.

Footnotes:

[32] Id.

[33] 88 Fed. Reg. at 50,296.

Response 5: While it is understandable to think that facilities conducting more frequent monitoring will have more emissions to report, our experience with leak detection and repair programs suggests that, after initial application, the number of emissions sources identified actually goes down. Also, because more frequent monitoring is conducted, the maximum duration of any source identified would be less if repairs or other mitigation activities are conducted, again reducing the reportable emissions. Facilities electing not to conduct routine monitoring would still be subject to reporting emissions associated with Super Emitter Response notifications. The default start date period (in the absence of monitored data to identify the start of the leak) would likely be higher than the start date allowed for those doing more frequent monitoring, by virtue of earlier identification. This applies to other sources as well. For example, the duration of emissions from stuck dump valves or open thief hatches will be reduced when more frequent monitoring is conducted, even though these sources are generally not other large release events. Therefore, we consider the reporting requirements in subpart W, including those for other large release events, provide an incentive for routine monitoring rather than a disincentive, to use commenters' terminology. We considered using the scaling approach suggested by one commenter, but given the limited time scale of the basin level measurements, we considered that approach to be overly conservative at the facility level and that separately accounting for the other large release events would provide a more accurate approach that could be consistently applied to all reporters. The EPA considers this approach consistent with the directives Congress specified in CAA section 136(h), as it ensures that reporting is based on empirical data and accurately reflects total methane emissions while also allowing reporters to submit appropriate empirical emissions data. The EPA recognizes that the option for reporters to submit additional empirical data for a given facility may lead to reporters taking additional voluntary actions for subpart W reporting, including for the purpose of demonstrating the extent to which a charge under CAA section 136(c) is owed. To the extent this approach "incentivizes" additional actions by the reporter, the EPA considers this to be inherent in the directives Congress gave the EPA in CAA section 136(h). With respect to commenters suggesting that the EPA provide a direct financial incentive to conduct more frequent monitoring similar to New Mexico's ALARM program, we consider that a direct financial incentive outside of the scope of this subpart W rulemaking, which aims to ensure that reporting is based on empirical data and accurately reflects total methane emissions while also allowing reporters to submit appropriate empirical emissions data. Nonetheless, we note that other provision of the Methane Emission Reduction Program in CAA section 136 provide significant financial incentives for methane mitigation and monitoring.

Commenter: GPA Midstream Association
Comment Number: EPA-HQ-OAR-2023-0234-0299
Page(s): 22, 99-100

Commenter: American Petroleum Institute et al. (Part 1 of 2)
Comment Number: EPA-HQ-OAR-2023-0234-0402
Page(s): 62

Commenter: Pipeline Safety Trust
Comment Number: EPA-HQ-OAR-2023-0234-0411
Page(s): 2-3

Commenter: Environmental Defense Fund, et al.
Comment Number: EPA-HQ-OAR-2023-0234-0413
Page(s): 16-18

Comment 6: Commenter 0299: **Reporting requirements duplicative of NSPS OOOOb and EG OOOOc must be deleted.**

In proposed section 98.236(y)(11), EPA proposes reporting requirements that are nearly identical to the proposed SERP reporting requirements in NSPS OOOOb and EG OOOOc. It is unclear how this information informs the reporting of emissions that is relevant to the GHGRP. Data reporting elements such as the unique notification identification number under the SERP, latitude/longitude of release, a description of the technology or method used to identify the release, and the total number of super-emitter release notifications received from a third-party for the facility have no bearing or impact on the reporting of GHG emissions. If this information is somehow pertinent to EPA, then GHGRP reporters should not have to bear the burden of retransmitting that information through a separate reporting program as it is already being provided to EPA through the NSPS program.

…

Proposed Change: For "other large release events," EPA proposes to collect data elements that are extraneous to the information EPA needs to assess and compile GHG emissions. This information includes proposed reporting of the start and duration of an event, a description of the event, and volume fractions of emissions, among other things.

Comment: Such reporting is not likely to provide information of regulatory value or to inform the development or implementation of any EPA regulatory program. The significant additional burden that these requirements will impose are, therefore, not justified, and they should be removed from the rule.

Additionally, it is important to emphasize that these types of emissions are likely complicated to assess, and providing EPA with additional "raw" data is unlikely to allow the Agency to effectively validate reporting of emissions from these sorts of abnormal emission events. Regarding EPA's proposal to request reporting on "whether the release was identified under the provisions of part 60, subpart OOOOb of this chapter or an applicable approved state plan or applicable Federal plan in part 62 of this chapter," the rule should expressly recognize that "NA" must be an option because some events will be caused by sources not subject to those rules.

Suggested Text:

98.236(y) Other large release events. You must indicate whether there were any other large release events from your facility during the reporting year. If there were any other large release events, you must report the total number of other large release events from your facility that occurred during the reporting year and, for each other large release event, report the information specified in paragraphs (y)(1) through ~~(8)~~(4) of this section.

(1) Unique release event identification number (e.g., Event 1, Event 2).

~~(2) The approximate start date, start time, and duration (in hours) of the release event.~~

~~(3) A general description of the event. Include:~~

~~(A) Identification of the equipment involved in the release.~~

~~(B)~~(2) ~~A description of how the release occurred, from one of the following categories~~ The category: fire/explosion, gas well blowout, oil well blowout, gas well release, oil well release, pressure relief, large leak, and other (specify).

~~(C) A description of the technology or method used to identify the release.~~

(D) An indication of whether the release was identified under the provisions of part 60, subpart OOOOb of this chapter or an applicable approved state plan or applicable Federal plan in part 62 of this chapter.

~~*(E) An indication of whether a portion of the natural gas released was combusted during the release, and if so, the fraction of the natural gas released that was estimated to be combusted.*~~

~~*(4) The total volume of gas released during the event in standard cubic feet.*~~

~~*(5) The volume fraction of CO_2 in the gas released during the event.*~~

~~*(6) The volume fraction of CH_4 in the gas released during the event.*~~

~~*(7)*~~*(3) Annual CO_2 emissions, in metric tons CO_2, from the release event.*

~~*(8)*~~*(4) Annual CH_4 emissions, in metric tons CH_4, from the release event.*

Commenter 0402: Other Concerns Regarding Other Large Release Events

The Industry Trades request that EPA remove the latitude/longitude reporting requirement proposed in 98.236(y)(11)(iii), and instead allow county-level reporting for pipeline release events (consistent with PHMSA requirements). If EPA maintains the requirement to report latitude and longitude of the release event, the Industry Trades request that EPA clarify that these events at sites other than pipeline locations may consist of a single latitude/longitude for a site (and should not include the granular latitude and longitude of the individual component).

Commenter 0411: PST also recommends that as part of its reporting requirements for "other large release events"[12] that an operator be required to provide information about whether or not it attempted to mitigate said emissions and submit a report of what method an operator used in each event including information about what an unmitigated release would have been vs the actual emissions with the use of the selected mitigation method. EPA should require operators to use average operating pressure to estimate unmitigated release volumes and the information should be made available to the public. This type of reporting would give EPA a better idea of what kinds of mitigation methods are effective for reducing methane emissions and give more transparency to the public about emissions. PST made a similar request to PHMSA in its Advanced Leak Detection and Repair rulemaking, and we encourage EPA to coordinate to avoid duplicative efforts.[13]

Footnotes:

[12] 88 Fed. Reg. at 50,300.

[13] Exhibit 1 at 11.

Commenter 0413: 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.

Response 6: See Section III.B.2 of the preamble to the final rule for our response to these comments.

3.5 Determination of Release Event Duration

Commenter: Kairos Aerospace
Comment Number: EPA-HQ-OAR-2023-0234-0240
Page(s): 8, 11

Commenter: Carbon Mapper and RMI
Comment Number: EPA-HQ-OAR-2023-0234-0301
Page(s): 3

Commenter: Taxpayers for Common Sense (TCS)
Comment Number: EPA-HQ-OAR-2023-0234-0351
Page(s): 5-6

Commenter: Colorado Department of Public Health and Environment (CDPHE)
Comment Number: EPA-HQ-OAR-2023-0234-0373
Page(s): 4

Commenter: Environmental Defense Fund, et al.
Comment Number: EPA-HQ-OAR-2023-0234-0413
Page(s): 20

Comment 1: Commenter 0240: EPA's default of 182 days for Other Large Release Event duration

We also offer the following perspective on EPA's decision to use a 182-day duration as a default assumption for Other Large Release Events in absence of measurement or parametric data that establishes duration. In our experience, many companies will have access to either measurement or parametric data through SCADA systems that allow them to more accurately establish duration and ultimately avoid using the default duration of 182 days. We do not envision many companies needing to routinely rely on the default factor.

The intermittent nature of super emitters is also something that is often discussed, and in our experience can certainly be accurate. However, Kairos has also noted instances where emissions that would qualify as "Other Large Release Events" do appear to be highly persistent in nature. Kairos analyzed our emission detections during 2022 across the Anadarko, Barnett, DJ, Eagle Ford, Haynesville, Permian, San Joaquin, San Juan, and Uinta Basins and observed 714 upstream sites that had emissions that persisted for at least 182 days. This does not represent a majority of Kairos detections–Kairos observes thousands of emissions per year, the majority of which persist for less than 182 days–but it does appear that long duration events can happen.

Ultimately, EPA would be best served by encouraging measurement and monitoring to adequately establish duration, since events can have an extremely wide variability in their durations. More frequent measurement surveys, increased use of SCADA, and improving operational practices will all make long-duration events unlikely, but the rate at which that change occurs will be difficult to determine with anything other than measurement.

Commenter 0301: We also support the 182-day default duration assumption in the other large release events category. This default, coupled with EPA's proposed updates to the New Source Performance Standards (NSPS) and Emission Guidelines (EG) for the oil and natural gas sector, will incentivize more frequent and comprehensive leak detection and repair efforts among Subpart W reporters.

Commenter 0351: Due to the unpredictable and accidental nature of super-emitter events, efforts to identify and address them are frequently delayed. The proposed rule would encourage more routine monitoring for leaks by establishing an assumed super-emitter event start date 182 days before the event is identified, in the absence of more recent data showing normal levels. TCS supports the proposed requirements. Super-emitter events represent a significant portion of annual GHG emissions and must be identified and addressed as quickly as possible. By compelling reporters to default to an assumed 182-day window in the absence of more current data, the rule encourages more frequent monitoring, leading to quicker identification of super-emitter events and, likely, reduced overall emissions. TCS does not believe a 91- day default duration, or any duration less than the proposed level, would be reasonable.

Commenter 0373: For **other large release events (98.233(y))**, we support EPA's proposal to require the estimation of the volume of gas released by using measurement data, engineering estimates, process knowledge, and best available data. When the start date cannot be determined, we believe the proposed 182-day assumption is preferable over a shorter period such as a 91-day assumption. We also believe that the EPA's proposed approach for the "other large release event" threshold to span more than one calendar year (rather than per-event within a calendar year) will more fully and properly quantify the event, as well as incentivize operators to utilize parametric and direct measurement to better characterize emission release events.

Commenter 0413: 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.

Response 1: See Section III.B.2 of the preamble to the final rule for our response to these comments.

Commenter: American Exploration and Production Council
Comment Number: EPA-HQ-OAR-2023-0234-0295
Page(s): 15

Commenter: GPA Midstream Association
Comment Number: EPA-HQ-OAR-2023-0234-0299
Page(s): 22-23

Commenter: Encino Environmental Services
Comment Number: EPA-HQ-OAR-2023-0234-0364
Page(s): 4

Commenter: Duke Energy
Comment Number: EPA-HQ-OAR-2023-0234-0376
Page(s): 7

Commenter: Endeavor Energy Resources, L.P.
Comment Number: EPA-HQ-OAR-2023-0234-0381
Page(s): 7

Commenter: CrownQuest Operating
Comment Number: EPA-HQ-OAR-2023-0234-0393
Page(s): 64, 66, 76

Commenter: Williams Companies, Inc.
Comment Number: EPA-HQ-OAR-2023-0234-0394
Page(s): 5

Commenter: The Petroleum Alliance of Oklahoma
Comment Number: EPA-HQ-OAR-2023-0234-0398
Page(s): 8

Commenter: American Petroleum Institute et al. (Part 1 of 2)
Comment Number: EPA-HQ-OAR-2023-0234-0402
Page(s): 59-60

Commenter: American Gas Association (AGA) and American Public Gas Association (APGA)
Comment Number: EPA-HQ-OAR-2023-0234-0418
Page(s): 19

Comment 2: Commenter 0295: **Default Event Duration**

AXPC supports EPA's proposed language in § 98.233(y)(2)(ii) that specifies the start time of a large release event can be determined based on monitored process parameters. Similarly, EPA should consider that various methods (e.g., AVO, OGI surveys, flyovers, process parameters, etc.) may also be used to determine the end time of such events, rather than defaulting to a specified duration as in the Proposal. Further, if the rule requires operators to consider all "credible information" when determining whether a large release event has occurred, it is reasonable to use similar criteria to evaluate the duration of such events. If EPA retains a default duration in the final rule, AXPC supports a shorter duration (e.g., 30-day default) rather than the current proposed timeframe of 182 days. Facilities subject to closed vent certifications will be inspected monthly. The audio, visual and olfactory inspection should be acknowledged as valid and the emissions window should be limited to 30 days. It is very unlikely that large release events would go unnoticed/unaddressed for 182 days, especially given that the vast majority of operators are or will be conducting quarterly leak detection surveys in addition to monthly inspections to comply with NSPS or state requirements.

Commenter 0299: **The proposed 182 day "backstop" and 100 kg/hr threshold are problematic because many of the advanced technologies mentioned in the rule are not deployed by all operators, especially small operators, and because these requirements could drive exceptional costs.**

EPA proposes that emissions detected above the proposed thresholds must be assumed to start on either (1) the date of the most recent monitoring or measurement survey that confirms the source was not emitting at or above the proposed thresholds, or (2) must be assumed to have a duration of 182 days (six months) [98.233(y)(2)(ii)]. EPA also proposes that the definition of "monitoring or measurement survey" include any monitoring or measurement method in 98.234(a) through (d), as well as advanced screening methods such as monitoring systems mounted on vehicles, drones, helicopters, airplanes, or satellites capable of identifying emissions at 100 kg/hr [98.233(y)(2)(iv)].

For gathering system pipeline leaks, these proposed provisions may lead to an untenable environment where operators would be forced to monitor pipelines frequently to create temporal "backstops" on emission events. For example, to avoid the possibility of an emission being assumed to have taken place over a six-month period of time, reporters will need to monitor far more frequently than the proposed rule contemplates to avoid this result. Monitoring is a very expensive endeavor with costs being in the hundreds of thousands or millions of dollars depending on how many sources/miles need to be monitored. The cost for this more frequent, additional monitoring was not assessed by EPA.

In addition to the enormous cost that this additional monitoring will require, with the current state of advanced screening methods, it is unclear if there are enough technology service providers to meet the increased demand, which could unfairly disadvantage some reporters to report larger than actual emissions (because the emissions will be attributed to an arbitrarily assumed duration of six months regardless of whether the emissions actually took place over that period of time), which will lead to increased methane fees. This concern about the availability of technology service providers is already occurring. Some GPA members have already been contacted by their technology service providers with warnings that they will lack capacity to service all of their customers' needs if the monitoring frequency increases, with the providers urging members to sign contracts now to ensure that they will be able to utilize their services.

To alleviate these problems, EPA should consider some or all of the following changes: (1) adjust the thresholds as described above in Comments 15 and 16; (2) minimize the "backstop" as much as possible (30 days at most—182 days is arbitrary and capricious); (3) allow event duration to be assessed by more than "monitored process parameters" or "monitoring or measurement survey"(e.g., operators' inspection logs should be an accepted credible limit on event duration);…

Commenter 0364: ***Other large release events***

Comment on the proposed default duration of 182 days in the absence of information on the start time.

The rule proposes changes to 40 CFR 98.233(y) by introducing new calculation methods for estimating the greenhouse gas emissions from other large release events, as well as reporting requirements for other large release events (40 CFR 98.236(y)). Encino agrees with the EPA that the new calculation requirement must rely on measurement data when available. If not available, a combination of engineering calculations, process knowledge and best available data should be pursued.

The proposed calculation considers the gas composition along with an estimate amount of the released gas. For this, EPA is proposing that the start time of the duration must be determined based on monitored process parameters (e.g., pressure, temperature) for which sudden changes could signal the start of the emissions event; whereas the end time of the release must be the date of the confirmed repair or confirmed cessation of emissions. The EPA proposes that if the start time cannot be determined through operational parameters, then it should default to the most recent monitoring or measurement survey event or assume a duration of 182 days, whichever duration is shorter. Encino believes that 182 days is overly conservative. Encino understands the rationale leading to that number but still believes that a 91-day duration is moderately conservative and would minimize overestimation of the emissions.

Commenter 0376: Additionally, EPA proposes a presumptive release duration of 182 days prior to the documented end of the release when measurement data is unavailable and there is not definitive information on the start of the release. This is not representative of most large leak events as they are intermittent and typically would be reported or detected and remediated quickly. We ask EPA to reconsider the presumptive duration based on other known data that is more representative of actual events such as documented trips to sites by qualified personnel, or documented reports of potential gas leaks in the same vicinity.

Commenter 0381: With respect to EPA's proposed default duration for "other large release events" (in the absence of a known start date for the event), not all operators will be subject to the default duration because of the frequency of their monitoring efforts and use of a combination of monitoring and detection systems, as noted above. But Endeavor asks that EPA explicitly clarify in its final rule that monitoring utilizing methods such as flyovers and SOOFIE continuous monitoring are sufficient to avoid the default detection duration.

Endeavor is also concerned about EPA's proposed default event duration in the absence of an identified start date for a large emissions event. EPA proposes that if the start date cannot be identified using monitored process parameters, then an owner or operator should 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. [19]

Endeavor suspects that, in many instances, a default of 182 days will far exceed the duration of a reportable large release event, and a shorter time period is generally more appropriate. This is consistent with EPA's own statement that "[s]tudies on large releases from oil and gas facilities commonly report that these emissions are intermittent, with typical durations of several hours to several days," even if others may last for weeks or months.[20] Endeavor therefore recommends a shorter default duration period supported by the data. The use of an excessively long default duration that is not sufficiently tethered to on-the-ground experience or empirical study would not advance the IRA's mandate for accurate and reliable data. Endeavor thus supports the shortening of the default duration to 91 days, as EPA suggests, but also recommends an even shorter duration that reflects both (1) the frequency with which those in the oil and gas industry inspect their facilities (often weekly or at least monthly) and (2) the IRA's mandate for accurate, empirical reporting that does not rely on loose estimates or assumptions. Endeavor recommends a default duration of no more than 30 days to reflect the industry standard of monthly inspections.

Footnote:

[20] *Id.; see id.* ("For many releases, such as maintenance events, fires, explosions, and well blowouts, the reporter would be able to identify the start and end time of an event. Other releases may be identified via monitoring surveys or site inspections. For these the start date can often be identified from process operating records or previous monitoring results. For identifying the start date, we are specifically proposing to allow monitoring or measurement surveys to include methods specified in 40 CFR 98.234(a) through (d) 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 an other large release event.").

<u>Commenter 0393</u>: Aside from "monitored process parameters" we have actual field personnel on site that identify these releases well before a 6-month timeline. The ask from the agency to assume 182 days is very extreme. With current LDAR programs, continuous monitoring technology, field personnel site visits, flyovers, etc a more reasonable ask is to let the operator calculate the timeline of the release instead of requiring them to calculate based off a 6-month time frame.

…

instead of the 91-day duration, a more reasonable time frame is 31 days. For all the reasons stated above. The operator could utilize different types of technology to address these "events" well before the 91-day time frame

…

Super emitters: "other large release event" the default assumption that the release started 182 days prior to the documented end of the release. This implies that the operator would have to monitor constantly, of course, if the operator does not have monitored data associated with the release. Our "super emitter" events are few and far between. With the combination of the following: regular site visits, LDAR programs (both required and voluntary), and quarterly/bi-annual voluntary flyovers of assets, the 182-day duration of super emitter events w/o constant monitoring seems excessive. With the above listed measures taken, any large release events are caught and repaired within a matter of hours/days. As an industry, we do a good job of monitoring this, and gets looked at very often, see the data of the Environmental Partnership. In the Aliso Canyon example, it wouldn't have changed the number of emissions that have occurred.

Furthermore, we believe that more clarification and flexibility is needed for "monitored process parameters". This is integral in very short emission events where telemetry may not be completely reliable. We are concerned with any ambiguity involved with this requirement may result in an extreme over-reporting of emissions by assuming the 182-day duration, even if there are additional parameters confirming the event to be much shorter time.

<u>Commenter 0394</u>: In further response to the EPA's solicitation for comment, Williams believes that the alternate 91-day default event duration for other large release events is more appropriate than the 182-day duration. In our experience for the vast majority of cases, the duration of the release event can be readily identified from a review of operations data (e.g., operating pressures) and use of a default duration will not be required. Based on our experience with non-routine emissions events involving known durations, even a 91-day duration would be extremely conservative. Natural gas pipeline operators monitor system pressure very closely, not just for emissions purposes but also to detect whether a safety event may be occurring. It would be very unlikely for an "other large emissions event" to go undetected for more than 91-days.

<u>Commenter 0398</u>: …Finally, EPA proposes that if the monitored process parameters cannot identify the start of the event, 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 <u>or</u> assume the duration of the event was 182 days (six months), whichever duration is shorter.

The purpose of the Proposed Rule is to obtain accurate data. By establishing 182-day default duration or the most recent monitoring or measurement survey, EPA is introducing unnecessary and possibly significant inaccuracies into the emission reporting process which is counter to the Inflation Reduction Act (IRA).

Action Requested: … Also, EPA should use the date of discovery for determining when a leak started and not force reporters to go back any further than the beginning of the calendar year in which the leak began. This would be in alignment with leak reporting requirements, and it would not require reporters to make unnecessary revisions (possibly minor in nature) to previous annual reports.

<u>Commenter 0402</u>: Other Large Release Events Duration

EPA is proposing that reporters must assume a leak duration of 182 days if the start time of an event cannot be determined based on "monitored process parameters." EPA has no basis for using 182 days.

As noted in the proposed rule's TSD, typical durations for large releases are several hours to several days. The Industry Trades believe this 182-day assumption is derived using average leak duration data including a significant statistical outlier event[52] that should be excluded from calculated averages, most notably because the time it took to resolve the leak was not due to lack of awareness of the leak, but rather the complexity of resolving the leak. Accordingly, the Industry Trades disagree with EPA's statement in the TSD that the duration should not be shorter than the Aliso Canyon event. Besides it being a known event, EPA is proposing a default leak duration even longer than that statistical outlier event (111 days vs. 180 days).

The Industry Trades recommend a duration of half the time since the last optical gas imaging inspection, or the time since operator inspection of the source in question (e.g., operator rounds that proactively include flare, thief hatch or other inspections), site level measurement campaign, continuous monitoring system, or other monitoring data, or a maximum of 30 days if no other data is available. The maximum duration of 30 days is a conservative estimate consistent with (a) EPA's acknowledgement in the TSD that "Studies on large releases from oil and gas facilities commonly report that these emissions are intermittent, with typical durations of several hours to several days (Chen *et al*., 2022; Wang *et al*., 2022)", and (b) that most well sites are expected to have operator rounds occurring more frequently than every 30 days and, further, the odds of a significant event going unnoticed by both and operator and 3rd parties (satellite, etc.) are unlikely.

Furthermore, the Industry Trades believe that additional clarification and flexibility needs to be provided for "monitored process parameters." This is particularly critical for very short emission events for which telemetry may not be available or reliable. The Industry Trades are concerned that any ambiguity around this requirement could result in vast over-reporting of emissions by assuming a duration of 182 days. Monitored process parameters are not defined in the rule, but in 98.236(y)(4) EPA says that this includes "pressure monitor, temperature monitor, other monitored process parameter (specify)." The Industry Trades recommend clarifying this by allowing reporters to use additional process parameters, such as site inspections, cameras on location, etc. that confirm the event duration.

Footnote:

[52] Underground storage station well blowout near Los Angeles, CA (i.e., Aliso Canyon) in 2015, event duration was 112 days as opposed to other events which were significantly shorter.

Commenter 0418: The Associations support the flexibility that EPA proposes for the manner of calculating emissions of "other large release events," which is to use measurement data if it is available, or a combination of engineering estimates, process knowledge, and best available data to estimate both the amount and composition of released gas.[64] It is reasonable and sound to allow the estimates to be tailored to the type of release at issue and rely on the expertise of the facility staff, particularly given how broad the "other large release events" category is. However, the Associations believe that the proposed presumptive release duration of 182 days (*i.e.*, six months) prior to the documented end of a release—a duration that would be used in the absence of more definitive information on the start time—is excessive. Given that most large releases are intermittent and typically only several hours or several days in duration,[65] EPA should consider a presumptive duration that is closer to the typical event length, as that would result in a more representative emissions calculation to be used in charging the Section 136(c) methane fee.

Footnotes:

[64] Proposed Rule, 88 Fed. Reg. at 50,297.

[65] *See id.; see also* 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 at 27.

Response 2: See Section III.B.2 of the preamble to the final rule for our response to these comments.

Commenter: Chevron
Comment Number: EPA-HQ-OAR-2023-0234-0232
Page(s): 4

Commenter: Carbon Mapper and RMI
Comment Number: EPA-HQ-OAR-2023-0234-0301
Page(s): 6

Commenter: Interstate Natural Gas Association of America (INGAA)
Comment Number: EPA-HQ-OAR-2023-0234-0387
Page(s): 15

Commenter: MiQ
Comment Number: EPA-HQ-OAR-2023-0234-0392
Page(s): 10

Commenter: Range Resources Corporation
Comment Number: EPA-HQ-OAR-2023-0234-0397
Page(s): 12

Comment 3: Commenter 0232: Other Large Release Events - Event Duration Estimation

EPA is seeking feedback on the proposed estimation of duration for Other Large Release Events. Different types of information, such as previous monitoring data, can be used to bound the estimated duration of the event. An innovative approach to estimating the duration of such emissions involves the integration of details from operational data and parametric monitoring information collected at the facility. These sources of data can provide invaluable insights into methane emission duration by offering a more continuous and comprehensive data source.

Higgins et al. 2023[5] presents an advanced approach to estimating the duration of an emission event detected from aircraft-based sensors that relies on parametric data, through systems like Supervisory Control and Data Acquisition (SCADA), and other types of operational records. The study provides a framework for the use of parametric data for event duration estimation and offers examples of parametric or other operational information that may be available at some oil and gas operations to showcase the potential for utilizing such information. Additionally, a discussion of the estimated duration of emissions where monitoring and parametric data are not available is included in the paper. Specifically, the development of empirical estimates based on the average duration per type of emission source is proposed and discussed. Consequently, we encourage EPA to include the use of parametric data and other operational records in the list of tools used to estimate the duration of emissions from Other Large Release Events.

Footnotes:

[5] https://chemrxiv.org/engage/chemrxiv/article-details/6511c17db927619fe7cd60ee

Commenter 0301: We recommend EPA provide clear guidelines for the following elements, at a minimum:

- **Data supporting an alternative duration for a large release event:** EPA should develop guidelines for using operational data for determining the start date of an "other large release event," if recent survey data is unavailable. For example, data on pressure drops should be as local and isolated as possible from the leaking infrastructure; system-wide monitors or monitors covering branching lines may not be directly indicative of the beginning of an event. Audio, visual, and olfactory (AVO) detection should not be used as a basis for identifying the start time of an event.

Commenter 0387: INGAA also recommends clarifying the basis for defining event duration. §93.233(y)(2) indicates that measurement "or a combination of process knowledge, engineering estimates, and best available data" can be used to estimate event volume. However, §93.233(y)(2)(ii) states, "The start time of the event must be determined based on monitored process parameters," which could be interpreted stringently. As implied in the introductory text, it may be possible to estimate event start by inference from available process or other facility or system data. Engineering judgment should be allowed to define event start, which would preclude the use of default event times that may significantly over-estimate emissions. For clarity, INGAA recommends revising the proposed text in §93.233(y)(2)(ii) to restate the introductory text on "process knowledge, engineering estimates," etc. rather than solely referring to "monitored process parameters."

Commenter 0392: 98.233(y)(2)(iv): For the purposes of paragraph (y)(2)(ii) of this section, ''monitoring or measurement survey'' includes any monitoring or measurement method in§ 98.234(a) through (d) 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 in paragraph (y)(1).

MiQ Comments: MiQ supports EPA's proposed methodology to allow operators to determine the start time of certain emission events based on the results of monitoring and measurement surveys. To drive consistency, MiQ requests that EPA consider publishing guidance or interpretation material describing what general types of emission events can be time-bounded by types of monitoring and measurement surveys.

MiQ also requests that EPA clarify and provide guidance on how audio, visual and olfactory (AVO inspections) can be used by operators to assist in determining the start time of emission events, and what the requirements of AVO surveys need to be to use them as permissible data. MiQ believes that certain emission events should be able to be discovered by thorough AVO inspections and currently are not systematically employed in this way by the oil and gas industry because there are no regulatory drivers to improve systematic tracking of AVO survey results.

Commenter 0397: **EPA should clarify the "monitored process parameters" it expects operators to use in reporting large release events.**

Proposed 40 C.F.R. § 98.233(y) provides that operators must report carbon dioxide and methane emissions from "other large release vents" that meet certain thresholds identified in the Proposed Rule. 88. Fed. Reg. at 50409-10. Specifically, 40 C.F.R. § 98.233(y)(2)(ii) provides that the "[t]he start time of the event must be determined based on monitored process parameters." 88. Fed. Reg. at 50410. But it is unclear what "monitored process parameters" are considered. The proposed rule would benefit from additional clarification that operators may use appropriate process parameters that will allow them to determine when a large release event occurs. Operators certainly have process data to make this determination, so this would be a reasonable clarification in the final rule. This same clarification should be made as it relates to 98.236(y)(4).

Response 3: See Section III.B.2 of the preamble to the final rule for our response to these comments.

Commenter: Marcellus Shale Coalition (MSC)
Comment Number: EPA-HQ-OAR-2023-0234-0275
Page(s): 12

Commenter: Encino Energy (EAP Ohio, LLC)
Comment Number: EPA-HQ-OAR-2023-0234-0408
Page(s): 2

Comment 4: Commenter 0275: Other Large Releases

The U.S. EPA requested comment on … whether the thresholds for other large releases should be assessed per event within the calendar year, rather than per event. MSC recommends events be assessed on a calendar year basis, rather than per event to avoid resubmission of subpart W reports when the start date is determined to be in the previous year.

Commenter 0408: EPA requested comment on when to begin the start time for releases which bridge from one reporting year to another. EAP Ohio, LLC offers the below comments to assist EPA in resolving their concerns with this topic:

If a release start date was determined to have occurred before the reporting period, the start date should be included in the emissions reporting for the current reporting year.

If a leak cannot be closed before or at the time of the report, emissions after the end date of the calculation should be included in the following reporting year.

Flexibility on start and end dates of leaks which may fall outside of the reporting year will reduce repetitive revisions, agency time, and will not change the amount agency will receive over a potential tax.

Response 4: Because of the potential impact that emissions from other large release events has on overall facility emissions and potential charges based on the WEC, we maintain that accurate calendar year reporting is necessary. If an event spans two calendar years (like the Aliso Canyon leak did), then the reporter must estimate and separately report the emissions from that leak that occurred in each calendar year. We also note that with the reduction of the default start date to 91 days, there is much less risk that an event detected near the due date of a calendar year report will affect the emissions that should be included in that report.

Commenter: Encino Energy (EAP Ohio, LLC)
Comment Number: EPA-HQ-OAR-2023-0234-0408
Page(s): 2

Comment 5: EPA requested comment on when to begin the start time for releases which bridge from one reporting year to another. EAP Ohio, LLC offers the below comments to assist EPA in resolving their concerns with this topic:

…

Additional time should be provided for companies to submit the GHG report due to the extra data being requested in the revision and the heightened consequences of the report for a company. Additional time would allow a larger number of Super-Emitter/Large Emission Event releases and other leaks identified in the prior year to be repaired before submittal.

EAP Ohio, LLC requests that the EPA extend the GHG reporting deadline to the end of April to allow for leak closure and accurate reporting.

Response 5: We expect that most GHGRP reports can be accurately completed within the current reporting deadlines. If leaks span two calendar years, the repair date would impact the emissions to be reported in the next calendar year's report. We recognize that a small number of events may not be identified until January or February that may impact the previous year's report, but by decreasing the maximum default other large release event duration to 91 days, it is very unlikely that an event identified near the report date would alter the emissions required to be reported in the previous year. Also, it is not uncommon that facilities revise their submitted reports either because of new information or verification queries, and revisions of submitted reports GHGRP provisions will continue to apply for subpart W facilities, including those with OLRE source reporting.

3.6 Combustion of Release Events

Commenter: Environmental Defense Fund, et al.
Comment Number: EPA-HQ-OAR-2023-0234-0413
Page(s): 20-21

Comment 1: 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.

Response 1: We proposed and are finalizing that facilities must determine the fraction of gas released that is combusted. If half of the gas released is not combusted based on how the emissions are released, other available information and engineering judgement, then the facility would assess the emissions assuming 50% of the release is directly emitted to the atmosphere (no combustion) and that 50% of the release is combusted. Facilities may elect to use lower combustion efficiencies for the fraction of gas that is combusted, but they cannot use a combustion efficiency of greater than 92%. As noted in section III.B.1 of the preamble, because these releases are not through engineered nozzles that can be designed to promote mixing and combustion efficiency, the combustion efficiency of these releases can be highly variable and are expected to be less efficient than a flare designed to destroy methane. We elected a maximum combustion efficiency of 92% consistent with our assumed flare combustion efficiency when limited monitoring data are available. We consider this approach to provide an accurate and flexible approach to account for combustion from different types of explosion or fire release events.

3.7 NSPS OOOOb Super-Emitter Response Program and Other Third-Party Notifications

Commenter: Kairos Aerospace
Comment Number: EPA-HQ-OAR-2023-0234-0240
Page(s): 13-14

Commenter: GPA Midstream Association
Comment Number: EPA-HQ-OAR-2023-0234-0299
Page(s): 22

Commenter: ConocoPhillips
Comment Number: EPA-HQ-OAR-2023-0234-0374
Page(s): 3

Commenter: Arkansas Independent Producers and Royalty Owners (AIPRO)
Comment Number: EPA-HQ-OAR-2023-0234-0382
Page(s): 10

Commenter: CrownQuest Operating
Comment Number: EPA-HQ-OAR-2023-0234-0393
Page(s): 76

Commenter: Downstream Natural Gas Initiative
Comment Number: EPA-HQ-OAR-2023-0234-0396
Page(s): 3

Commenter: American Petroleum Institute et al. (Part 1 of 2)
Comment Number: EPA-HQ-OAR-2023-0234-0402
Page(s): 6, 60-62

Comment 1: Commenter 0240: For example, we agree with the decision to align the reporting threshold of the Other Large Release Event program with the proposed Super Emitter Response Program (SERP). The clear and consistent 100 kg/hr standard across rules will make this easier to implement and from the perspective of a technology developer, gives us clarity on how to develop our technology and products around these standards. For example, both the SERP and Other Large Release Events reporting category may drive oil and gas industry operators to need highly expedited reporting timelines around methane emissions. By maintaining a consistent standard across these rules, it becomes easier for companies like Kairos to develop products that clearly fulfill market needs. With multiple overlapping and perhaps conflicting standards, this becomes a much greater challenge. Therefore we support alignment between the Other Large Release Event and SERP requirements.

We do ask EPA to further clarify how the SERP and Other Large Release Event requirements will align for facilities that are subject to OOOOc but not OOOOb in the period of time before OOOOc is fully implemented. As a hypothetical example, in 2025 a facility constructed in 2014 (prior to the adoption of the OOOOa rule) would be required to report emissions on Other Large Release Events in the Proposed Rule but would not be subject to the SERP or even OOOOa LDAR requirements until the OOOOc rule is finalized.

In this example, suppose that during a large-scale SERP survey in 2025 by an approved third party, surveyors detect a release of 100 kg/hr from that facility and report their findings to the operator. Would that operator be subject to Other Large Release Event reporting requirements, and would that third party SERP detection constitute "credible data" even for facilities not yet subject to SERP requirements?

In other words, does the link between SERP detections and Other Large Release Events depend on the effective dates of OOOOc, or would a detection based on "credible data" trigger reporting thresholds irrespective of whether a given facility is currently subject to SERP requirements? We request that EPA offer clarification on this point.

We also suggest that if EPA develops a technology approval/demonstration requirement to qualify what measurement systems provide "credible data" that it aligns that approval process with the OOOOb/OOOOc alternative technology review process. What we envision is that if a system is approved for regulatory leak detection compliance, it would also qualify as "credible data" for the purposes of the Proposed Rule. Such a decision would improve consistency for technology developers, limit duplicative technology reviews for EPA staff, and increase advanced technology uptake.

Commenter 0299: **EPA must add definitions for "super-emitter" and "third-party" if it decides to retain them in the final rule.**

EPA does not define the term "super-emitter" in the proposed rule, nor does it cross-reference NSPS OOOOb and EG OOOOc to define the term. Proposed 98.236(y)(11)(iv) states that reporters must "[r]eport the total number of super-emitter release notifications received from a third-party," including:

An indication of whether the super-emitter release notification was received under the provisions of 40 C.F.R. § 60.5371b of this chapter, an applicable approved state plan, or applicable Federal plan in part 62 of this chapter, or from another third-party. If the notification was received from another third-party, report the following information about the notifier and data received, if known.

The term "super-emitter" either needs to be replaced with "other large release event" or defined.

EPA should also clarify that "third-party" is not intended to include third parties that are hired by the reporter to identify potential emissions (i.e., through a compliance program or voluntarily). To do otherwise would discourage operators from proactively surveying for possible emissions. Operators would still be required to report such detected emissions as applicable under Subpart W but should be exempt from reporting information under proposed 98.236(y)(11)(iv).

Commenter 0374: Our other concern is around the use of "credible information" to determine other large release events. EPA is proposing that operators must report emissions from other large release events if they have "credible information" that a large release event has occurred. EPA is proposing that credible information would include but is not limited to, data from monitoring or measurement data completed by the facility, information from notifications as a potential super-emitter emissions event as defined by NSPS OOOOb or data of similar quality. ConocoPhillips has been piloting various emerging technologies for methane detection over the past few years. These emerging technologies can often have a large range of uncertainty with potentially unreliable quantitative emission estimates over very short time durations. These technologies can indicate spurious, erratic short-lived excursions some of which may even be artifacts and anomalies of the emerging technologies. It would not be efficient for the operator to have to evaluate each of these short-lived excursions to determine whether it qualifies for a large release event. This is another reason why we believe that a duration threshold, as discussed earlier, be considered in conjunction with the emission threshold of 100 kg/hr. We are concerned that a very broad definition of credible emissions requiring reporters to use any and all such information, may disincentivize voluntary monitoring with emerging technologies.

Commenter 0382: **Other Large Release Events:**

AIPRO has significant concerns surrounding this new proposed emissions source. First, there are major concerns regarding third-party reporting and the lack of requirements for being qualified to submit reports of a "large release event," as well as the lack of requirements surrounding what "credible information" must be provided by a third-party reporter. Second, AIPRO is concerned that the proposed thresholds triggering "large release event" reporting, 100kg/hr or 250 mt CO2e, are too small, overly burdensome and not aligned with EPA's intent for this new source category.

AIPRO encourages EPA to amend the proposed rules to either: 1) eliminate the option for third party reporters to be able to report and instigate an investigation of an alleged "large release event," or 2) to include specific requirements for third-party reporter qualifications, equipment specifications, calibration & maintenance records and to include penalties/consequences for third-party reporters that submit erroneous reports of "large release events."

Commenter 0393: Credible Evidence:

EPA is proposing that operators must report emissions from other large release events if they have "credible evidence". We have huge issue here as "credible evidence" is not defined in the rule. We recommend that EPA define "credible evidence" to allow operators to account for telemetry malfunctions. Also, to allow for other parameter monitoring or engineering judgments to determine if a release has occurred. We are concerned that the consequence, unintended as it is, of this term could result in operators declining to install direct monitoring measurement if this is not adequately addressed.

Commenter 0396: To allow for more flexibility DSI requests that the regulation provides explicit text to calculate emission events using data from third party notifications (e.g., date and time of public leak notification per NSPS OOOOb). This will allow for better alignment between Subpart W calculated emissions and NSPS OOOOb reportable events.

Commenter 0402: We urge EPA to seek true alignment and harmonization with other federal regulatory requirements, particularly the NSPS OOOOb and EG OOOOc "Methane Rules" and the GHGRP itself. Below are a few examples that are articulated in our comments:

- “Other large release events” should be governed by the Methane Rules Super Emitter Response Program (“SERP”), not by an additional and separate Subpart W notification process.

…

Credible Information

EPA is proposing that operators must report emissions from other large release events if they have “credible information” that a large release event has occurred. The Industry Trades are concerned that requiring reporters to use all credible information, especially where credible information in this context is ill defined, may disincentivize voluntary monitoring with emergent technologies where leaks could be discovered, but may have a large range of uncertainty (generally associated quantitative emissions estimates and short observational periods of less than 1 minute). Paradoxically, the shorter duration measurements tend to have higher accuracy in quantification for the short duration and the longer duration measurements tend to have emission estimating uncertainties that can span orders of magnitude. The Industry Trades recommend that EPA define “credible information” in a way to allows operators to use regulatory-driven inspections, allow for additional parameter monitoring while accounting for telemetry malfunctions, site inspections or camera monitoring, and engineering estimates to determine if a release has occurred and is subject to reporting.

3rd Party Event Reporting

In 98.236(y), EPA is proposing that reporters must report any events identified through a potential super-emitter release. The Industry Trades urge EPA to implement guardrails around what and how a third party could report, which is particularly impactful for those subject to SERP. Industry experience with third-party notification of suspected emissions events has demonstrated substantial variability in the quality and accuracy of those reports (including, but not limited to, data integrity, completeness, free from atmospheric interference, timing or greatly delayed notification, etc.). While the industry strives for excellence in reducing large release events, resources which would otherwise be utilized to minimize emissions could be diverted to respond to large volumes of unfounded third-party notifications which may have no basis in reality.

The proposed requirement to consider third-party release reports is beyond EPA’s authority.

Additionally, the **Industry Trades request EPA to clearly define the scope of credible information that would trigger additional investigative and reporting burdens**. The Industry Trades are concerned that unqualified third-party reports developed by unqualified operators could unnecessarily increase the reporting burden while not leading to more accurate GHG reporting. The Industry Trades are requesting EPA to provide clear guidelines on who would be qualified to provide third-party reports and the associated duration of an observation necessary to trigger investigation and reporting obligations under Subpart W.

EPA proposes that third-party reports of "other large release events" submitted under NSPS Subparts OOOOb or OOOOc must be documented and addressed under Subpart W.[53] **API explained in its comments on the Subpart OOOOb and OOOOc proposed rules that EPA does not have authority to allow third parties to generate information that triggers regulatory requirements for affected/designated facilities**.[54] We incorporate by reference those comments here. Because the proposed third-party reporting requirements under Subparts OOOOb and OOOOc are beyond EPA's authority, those requirements should not be finalized and, by extension, should not be referenced or incorporated into the Subpart W provisions addressing "other large release events."

To begin, it is not possible to discern without further explanation from EPA who might constitute "another third party." That ambiguity makes it impossible to devise and submit informed comments on this aspect of the proposed reporting requirement.

Having said that, it is possible that EPA intends "another third party" to mean an entity submitting information to an affected facility outside of the third-party reporting provisions established under NSPS Subparts OOOOb or OOOOc. If that is the case, this aspect of the Proposed Rule is inadequate because EPA fails to explain the legal basis for imposing such requirements, including why such a requirement might be a reasonable under CAA § 114. Such a requirement would, in any event, be outside of EPA's CAA § 114 authority because CAA § 114 authorizes only EPA to collect information. It does not authorize EPA to impose a mandatory reporting obligation that would be triggered by third-party observations or assertions. If EPA believes that information about "other large release events" not reported pursuant to NSPS Subparts OOOOb or OOOOc should be reported by affected facilities, EPA must initiate the information request and may not rely on reports submitted by third parties.

Industry experience with third-party notification of suspected emissions events has demonstrated substantial variability in the quality (including data integrity, completeness, free from atmospheric interference, timing of or significant delay in notification, etc.) and accuracy of third-party reports. The Industry Trades may submit supplemental comments after the Oct. 2 deadline.

At this time, the term "credible" is not defined in this rule. The Industry Trades recommend that EPA adopt the Industry Trades recommendations for SERP, and 98.236(y) is modified to only include events which EPA deemed credible under the SERP, and modify the citation below as follows:

> *(y) Other large release events. You must indicate whether there were any ~~other~~credible large release events from your facility during the reporting year and indicate whether your facility was notified of a ~~potential~~credible super-emitter release under the provisions of § 60.5371b of this chapter or an applicable approved state plan or applicable Federal plan in part 62 of this chapter. If there were any ~~other~~credible large release events, you must report the total number of ~~other~~ large release events from your facility that occurred during the reporting year and, for each ~~other~~credible large release event, report the information specified in paragraphs (y)(1) through (10) of this section. If you received a notification of a potential super-emitter release from a third-party for*

this facility or a super-emitter release notification under the provisions of § 60.5371b of this chapter or an applicable approved state plan or applicable Federal plan in part 62 of this chapter, you must also report the information specified in paragraph (y)(11) of this section.

The Industry Trades are re-iterating our previously submitted comments regarding the credibility of those 3rd-parties reporting[55] as proposed in NSPS OOOOb. In short, the Industry Trades reiterate the importance that any third-party conducting these monitoring events should be certified by EPA to be included in the SERP.

In general, the Industry Trades are concerned that events reported under other source categories, such as "blowdowns," thief hatches or equipment leaks could inadvertently be double counted under other large release events. The Industry Trades requests that EPA codify clear guidance on how to ensure that information reported by a 3rd party can be appropriately subtracted from events that could reasonably be reported under another category.

Footnotes:

[53] 88 Fed. Reg. at 50433.

[54] API Comments on EPA's Proposed "Standards of Performance for New, Reconstructed, and Modified Sources and Emissions Guidelines for Existing Sources: Oil and Natural Gas Sector Climate Review," EPA-HQ-OAR-2021-0317- 2428 at 97-99.

[55] API Comments on NSPS OOOOb and EG OOOOc Supplemental Proposal letter, dated February 13, 2023. Section 1.1.

Response 1: See Section III.B.2 of the preamble to the final rule for our response to these comments.

Commenter: Chevron
Comment Number: EPA-HQ-OAR-2023-0234-0232
Page(s): 4-5

Commenter: Carbon Mapper and RMI
Comment Number: EPA-HQ-OAR-2023-0234-0301
Page(s): 6-7

Commenter: CrownQuest Operating
Comment Number: EPA-HQ-OAR-2023-0234-0393
Page(s): 78

Commenter: American Petroleum Institute et al. (Part 1 of 2)
Comment Number: EPA-HQ-OAR-2023-0234-0402
Page(s): 59

Comment 2: Commenter 0232: Other Large Release Events - Third-party Monitoring

For the inclusion of third-party monitoring data as part of the "Other Large Release Events", when credible information of emissions of that magnitude from our assets is available, Chevron would like to be notified as soon as possible. We have gained experience with notification programs through voluntary technology trials with multiple operators, such as a project with the Oil and Gas Climate Initiative for satellite-based monitoring in Iraq[6], The Environmental Partnership[7], and Project Astra[8], as well as receiving third-party data through the Permian Methane Analysis Project (PermianMAP)[9].

The proposed Super-Emitted Response Program (SERP) in EPA's proposed OOOOb/c, included the use of third-party monitoring results. As with Chevron's comments on the proposed OOOOb/c rule, we are sharing some specific elements that we believe should be included in the development of a third-party monitoring reporting framework to increase the effectiveness and accuracy of the detected events:

- Qualifications of third-party reporter – The proposed SERP program included language on EPA-approval of third parties who use EPA-approved remote methane detection technologies10. Similarly, detection data for Other Large Release Events should be from qualified third parties who are able to include the details of the detection (e.g., uncertainty with emission rate and localization) as part of their report.
- Time from detection to reporting – The utility of the screening data for an operator decreases as more time passes after the detection. In our experience with past third party monitoring, data received a month or more after the detection occurred is harder for operators to understand and assess. Timely receipt of detection data from third parties is also important in the availability of the operational data that can be used to estimate the duration of the emission.
- Emission source attribution – Technologies that can localize emissions to specific pieces of equipment will be more useful for direct follow-up activities than approaches that provide only site-level or regional information. Detection data that cover multiple operators and/or multiple sites cannot be attributed easily or accurately, which would present challenges with reporting. While remote sensing technologies provide information on methane emissions, identification of the operator and emission source often requires additional sources of data and information. In our experience with multi-operator campaigns, the operator of a detected emission event can be initially misidentified due to asset transfer, plume drift from a nearby site, or other factors. Additionally, unlike well locations, national, widely available databases of other components, such as tank batteries or compressor stations, do not exist. This could lead to a situation where operators are routinely in a position to prove a negative.
- Uncertainty associated with emission detection sensors – There is some uncertainty associated with the quantification of emissions from all remote sensing data that will depend on the type of equipment used and the environmental conditions at the time. The magnitude of the uncertainty value varies widely across technologies, so notifications should include the uncertainty associated with the measurement and quantification.

Footnotes:

[6] https://www.ogci.com/wp-content/uploads/2023/01/OGCI_Iraq_Whitepaper_jan23.pdf

[7] https://theenvironmentalpartnership.org/

[8] https://www.projectastra.energy/

[9] https://www.permianmap.org/

[10] https://www.epa.gov/system/files/documents/2022-11 /OIl%20and%20Gas%20Supplemental.%20Overview%20Fact%20Sheet.pdf

Commenter 0301: We recommend EPA provide clear guidelines for the following elements, at a minimum:

…

- **Data collection and validation standards:** EPA has an important role to play, working across the federal government, to inform and set transparent standards and frameworks for data collection and validation, for both operators and third parties. Specifically, for detecting and quantifying large release events, EPA should lead in the development of baseline standards for probabilistic detection limits, false alarm rates and uncertainty quantification for objectively evaluating observing systems, analytic frameworks, and supply chain certifications. Setting standards and defining how measurements will be validated, is a key step to developing effective methods to accurately measure, report, and verify methane emissions data.
- **Reconciliation of multiple observations for the same "other large release event":** EPA should specifically address what should be done when two measurements of the same event produce different emission rates. We suggest EPA consider data quality and measurement temporal and spatial representativeness, as discussed in OGMP 2.0 and Veritas.

Commenter 0393: We would like to emphasize the importance of credibility in these 3rd party reporters as proposed in NSPS OOOOb. We would like to convey the importance that any 3rd party conducting these monitoring events should be certified by the EPA to be included in the Super Emitter Response Program (SERP).

Commenter 0402: Detection Technology Must be Approved by the Super-Emitter Response Program

Furthermore, the Industry Trades are requesting that EPA clarify that the rate of 100 kg/hr is determined with only advanced detection technology and third parties approved by EPA through the SERP in NSPS OOOOb and not based on presumptive calculations, models, or ground sensors which have varying levels of uncertainty. Furthermore, if industry is not approved to use the technology for compliance with OOOOa, OOOOb, or OOOOc, the technology should not be required to be used for reporting purposes under Subpart W and used to determine fees under the WEC. Requiring this will discourage voluntary monitoring by companies, discourage new technology development, and include potentially highly inaccurate data to be the basis of the WEC.

Response 2: See Section III.B.2 of the preamble to the final rule for our response to these comments. With respect to multiple observations, some measurement methods use multiple passes to more accurately assess the average emissions and for those measurements, we expect that average of those measurements would be used. If two different methods are used, we expect that these would generally be done near the same time frame rather than perfectly at the same time. Reporters collecting this data should assume each are accurate for the time period associated with each measurement.

Commenter: GPA Midstream Association
Comment Number: EPA-HQ-OAR-2023-0234-0299
Page(s): 19-20

Commenter: Endeavor Energy Resources, L.P.
Comment Number: EPA-HQ-OAR-2023-0234-0381
Page(s): 8

Commenter: Interstate Natural Gas Association of America (INGAA)
Comment Number: EPA-HQ-OAR-2023-0234-0387
Page(s): 15

Commenter: Williams Companies, Inc.
Comment Number: EPA-HQ-OAR-2023-0234-0394
Page(s): 3-4

Commenter: Chesapeake Energy Corporation
Comment Number: EPA-HQ-OAR-2023-0234-0400
Page(s): 12-13

Comment 3: Commenter 0299: As GPA thoroughly explained in our comments on the proposed SERP, there are serious issues with deputizing third parties to act in a compliance enforcement capacity.[47] GPA continues to be very concerned that the NSPS OOOOb and EG OOOOc proposal completely lacks any substantive detail on how such a third-party authorization process would work (which is arbitrary and capricious and does not comport with the CAA). This Subpart W proposal has incorporated all those problems and then made them even worse. The Subpart W proposed requirements provide a back door to circumvent the third party authorization "proposed"[48] in the SERP. This Subpart W proposal does not attempt to propose such a process or any requirements for third-party notifiers, [49] which only furthers the arbitrary and capricious nature of the SERP program. For example, third parties could overwhelm GHGRP reporters at any time. It is not reasonable for EPA to require GHGRP reporters to address information coming from every third-party without robust structure as to how and when that information is provided to reporters and guardrails around when a third-party report requires a response. Reporters simply cannot be expected to submit complete and accurate reports when it is possible for any third-party to data dump on a reporter on March 30th when annual reports are due on March 31st.

Footnotes:

[47] GPA Comments on "Supplemental Notice of Proposed Rulemaking for Standards of Performance for New, Reconstructed, and Modified Sources and Emissions Guidelines for Existing Sources: Oil and Natural Gas Sector" (Dec. 6, 2022) ("GPA Comments on NSPS OOOOb and EG OOOOc"), Docket EPA-HQ-OAR-2021-0317 (attached hereto as Attachment C and incorporated by reference).

[48] EPA proposed a general framework of authorizing third parties completely lacking any substantive detail on how such an authorization process would work, including what criteria for authorization would be based on. See id. at 14-21.

[49] EPA seeks comment only "on the need to establish additional requirements for third-party notifiers and the verification of third-party notifications." 88 Fed. Reg. at 50,300. The Agency then seeks comment on whether the e-GGRT Help Desk is adequate for supporting this process. Id. This is difficult to comment on because EPA does not propose anything, and GPA is unclear what EPA is asking here. As GPA commented on the proposed SERP program, any third-party notifications need to be vetted through a robust process centrally managed by the EPA. Clearly a help desk is not adequate for establishing such processes and procedures.

[50] Proposed 40 C.F.R. § 60.5365b(j) ("Each super-emitter affected facility, which is any source of emissions located at an individual well site, centralized production facility, or compressor station with emissions detected, using remote detection methods, with a quantified emission rate of 100 kg/hr of methane or greater.").

[51] Proposed 40 C.F.R. § 60.5386c(i) ("Each super-emitter designated facility, which is any source of emissions located at an individual well site, centralized production facility, or compressor station with emissions detected, using remote detection methods, with a quantified emission rate of 100 kg/hr of methane or greater.").

<u>Commenter 0381</u>: EPA should remove the requirement to report unverified "super-emitter response program" notifications or similar notifications.

EPA proposes additional GHGRP reporting requirements related to the Methane Proposal's "super-emitter response program." Specifically, EPA proposes that owners and operators would need to report whether a reported "other large release event" was also identified as a potential super-emitter event under NSPS OOOOb or an applicable approved state plan or applicable federal plan.[21] Further, if a reporter receives a super-emitter notification, EPA proposes that the reporter would need to report information pursuant to Subpart W related to the super-emitter notification received (e.g., latitude and longitude of the release); whether the notification was received pursuant to NSPS OOOOb, an applicable approved state or applicable federal plan, or from "another notifier"; [22] the type of event resulting in emissions (e.g., normal operations, planned maintenance, leaking equipment); and whether or not (and if not, why not) a notified super-emitter event was included in the reporter's Subpart W reporting, either as an other large release event or as part of another emission source.[23]

Endeavor has previously raised its objections to the Methane Proposal's super-emitter response program, and we reiterate those concerns given their relevancy here. [24] The proposed super-emitter response program would allow EPA-certified third parties—i.e., those demonstrating "technical expertise" in any of three remote detection technologies—to issue notifications that would require an owner or operator to take corrective action following the notifier's detection and reporting of a "super-emitting emissions event," meaning an event with emissions of 100 kg/hour or greater of methane.[25] In short, EPA would authorize a third-party notifier (rather than EPA or a state regulatory authority) to require an owner or operator to quickly conduct a full root-cause analysis any time a notifier sends a notification, without any meaningful gatekeeping or verification role for EPA.[26] Aside from the legal concerns with the proposed program,[27] Endeavor believes that the super-emitter program lacks sufficient safeguards to ensure that information received from super-emitter notifiers is actually accurate, reliable, and actionable; this is a key concern given that many legal and necessary release events may appear as "leaks" to outside observers. The program also relies on vague certification standards for notifiers and provides no mechanisms for EPA to verify the veracity of a notification or to remove from the program a notifier who repeatedly makes erroneous, even if well-intended, notifications.[28]

As EPA appears to want to integrate the proposed super-emitter response program into Subpart W, Endeavor echoes our previously filed concerns with the program, particularly given the IRA's directive to make sure Subpart W is revised to ensure more empirical and accurate reporting. Owners and operators should not be required to report information regarding unverified super-emitter notifications, particularly in light of EPA's recent announcement that it will focus additional enforcement resources on Greenhouse Gas reporting. As noted, there are insufficient safeguards to ensure that super-emitter notifiers are sufficiently trained in remote detection, nor are there any mechanisms to ensure accountability, whether through independent EPA verification or removal of less-reliable super-emitter notifiers. Many legal and necessary operational events may appear to be "leaks" to the unwary observer, and many "notifications" may be sent to the wrong owner or operator or not be traceable to a specific facility. As proposed, the Subpart W Proposal would nonetheless require reporters to expend time and resources to attempt to verify whether an emissions event is an "other large release event" and spend additional time to either report that event or explain why it is not reportable—this is true even if a super-emitter notification is unverified or erroneous, or from a party who has repeatedly issued erroneous notifications. Otherwise, the owner or operator risks noncompliance under Subpart W. The potential benefits, which EPA does not identify, are far outweighed by the burdens in reporting or the risks of noncompliance with Subpart W and the potential to introduce inaccurate information into the reporting system in violation of the IRA.

Endeavor is also concerned with EPA's decision to explicitly integrate the super-emitter response program into its proposed Subpart W regulations. The Methane Proposal is still pending before the Agency and will likely be subject to judicial challenge once finalized. Integrating the super-emitter response program into the Subpart W Proposal only heightens the risk of judicial challenge to those provisions, and will create more confusion for the industry if one or both rules are challenged in court. The fact that the IRA's methane charges will soon take effect amplifies the need for accurate, reliable, and empirical reporting procedures sooner rather than later. EPA should not risk subjecting the Subpart W Proposal to needless litigation by introducing this unproven and legally questionable program into the reporting scheme.

Footnotes:

[22] If "another notifier," EPA proposes that the owner or operator would need 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." *Id.*

[23] *Id*.

[24] *See* Endeavor Methane Comments, *supra* n.7, at 12–17, which Endeavor incorporates by reference here.

[25] *See* Methane Proposal, 87 Fed. Reg. at 74,747–48, 74,749–50.

[26] *Id.* at 74,751.

[27] *See* Endeavor Methane Comments, *supra* n.7, at 12–13.

[28] *Id.* at 13–17.

Commenter 0387: Examples of additional implementation issues discussed in INGAA's February 2023 NSPS Comments include the need for standardized methods and other criteria for measurement and third party qualifications, and verification that an "event" actually occurred because it is likely that faulty or erroneous third-party notices will occur. Significant additional discussion is available in INGAA's NSPS comments.

Commenter 0394: **Incorporation of the proposed 'Super Emitter Response Program' into Subpart W is legally and technically inappropriate.**

The EPA introduced the first-of-its-kind concept of a "super emitter" in the Agency's proposed Subpart OOOOb/c rule.[4] As part of that proposed rulemaking, Williams, along with numerous other commenters, expressed several significant concerns in creating and sponsoring such a program. It is surprising to see this fundamentally and legally flawed program incorporated into the Proposed Rule for the Subpart W GHG Reporting program.[5] The EPA posits the inclusion of super-emitter emissions in Subpart W reporting may "capture emissions that would not have otherwise been included under prior GHG [reporting] regulations" and "help ensure the completeness and accuracy of emissions reporting data." The Proposed Rule goes on to state this data "may also help to flag areas where there is a large gap between the bottom-up CH4 emissions estimates and top-down measurement data." Such statements reveal the experimental nature of this concept and why it is inappropriate to establish legally binding requirements upon it. Williams opposed the creation of a third-party based, super-emitter reporting program in the

OOOOb/c proposed rule and opposes any usage of this program or concept in the Subpart W Proposed Rule.

Consistent with our comments to the EPA's February 2023 OOOOb/c proposed regulation[6], Williams maintains that a super-emitter or other large release events should not be based upon the detection, monitoring, or reporting by private entities (including media companies and environmental non-government organizations) to potential emitters. Neither the Clean Air Act (CAA), nor any other federal legislation, provides the EPA with a legal foundation for establishing this type of program. The proposed super-emitter program is an improper, unilateral delegation of pseudo-enforcement authority to third parties with minimal to no oversight by any regulatory agency. Further, the program circumvents the well-understood citizen enforcement mechanism that exists in Section 304 of the CAA. Instead of experimenting with a new program via a regulation, the EPA should assemble a working group consisting of community organizations, environmental non-government organizations, industry groups, and regulators to design and test a program that can best capture these large emissions events using remote technology, effectively aid in the ultimate objective of emissions reduction, and be legally sound under the CAA.

An additional legal concern with incorporating the super-emitter concept in the Proposed Rule, is that only the EPA knows whether it will move forward with the proposed super-emitter program and, if so, what material and substantive changes the Agency is making in response to the significant concerns raised during the prior comment period and partially revisited above.[7] More importantly for the Proposed Rule, only the EPA knows the details of how the two proposed rules (OOOOb/c and Subpart W GHG reporting) interact.[8] As such, the Agency is inappropriately forcing Williams and all other interested parties to guess at how the EPA will finalize the OOOOb/c proposed rule and guess at how the assumed final OOOOb/c rule will interact with the assumed Subpart W final rule. EPA fails to provide adequate notice as to how the final "super-emitter" program in the OOOOb/c rule will interact with the Proposed Rule for Subpart W thereby improperly limiting the ability to adequately comment on the Proposed Rule.[9] The regulated community cannot be expected to wait until these two rules are both final to learn these dynamics.[10] The EPA will need to allow opportunity for further comments once the OOOOb/c rule is finalized.[11]

Footnotes:

[4] Standards of Performance for New, Reconstructed, and Modified Sources and Emissions Guidelines for Existing Sources: Oil and Natural Gas Sector Climate Review." Docket ID No. EPA-HQ-OAR-2021-0317, 87 Fed. Reg. 74,702 (proposed December 6, 2022).

[5] Proposed Rule, 88 Fed. Reg. at 50,290.

[6] Williams incorporates its prior comments on the super-emitter program submitted in the OOOOb/c rulemaking docket into these comments for the Proposed Rule.

[7] For example, one significant concern raised by Williams was whether the Clean Air Act even provides EPA the authority to design a program whereby an owner or operator has a legal

obligation to engage in an immediate investigation into the cause of the “super emissions event” upon receipt of a notification from a third party, and must report its findings to the EPA in a prescribed period of time. EPA improperly delegates pseudo enforcement authority to a non-governmental third party.

[8] See Shell Oil Co. v. EPA, 950 F.2d 741, 751 (D.C. Cir. 1991) (“Interested parties cannot be expected to divine the EPA's unspoken thoughts.”).

[9] Shell Oil Co., 950 F.2d at 747 (“The relationship between the proposed regulation and the final rule determines the adequacy of notice. . . . If the deviation from the proposal is too sharp, the affected parties will not have had adequate notice and opportunity for comment.”)

[10] See Air Transport Association of America, Inc. v. United States, 37 F.4th 667, 677 (D.C. Cir. 2022) (“[A]n agency cannot rest a rule on data that, in critical degree, is known only to the agency.” (quoting Time Warner Entm't Co. v. FCC, 240 F.3d 1126, 1140 (D.C. Cir. 2001))).

[11] Further opportunity for public comment on this Proposed Rule may also be necessary after the Agency releases the forthcoming rulemaking for the Waste Emission Charge – one that is intricately linked to this Proposed Rule, setting up a domino effect of sorts. According to EPA’s Unified Agenda, the Waste Emissions Charge rule will be proposed and open for comment while the OOOOb/c and this Subpart W proposed rule remain pending. Because the EPA intends for these rules to interact with each other, the regulated community must be afforded an opportunity to provide additional comment on these three rule-makings once the Agency makes known its intent for how they will interact.

Commenter 0400: **EPA should limit instances where operators must take third-party data into account in reporting emissions from “other large release events.”**

The Proposed Rule would require operators to consider all “credible information” in reporting large release events.[37] “Credible information” would include not only “data from monitoring or measurement data completed by the facility,” but also “information from notifications as a potential super-emitter emissions event… or data of similar quality… that is received by the facility,” in accordance with the third party notification system outlined in EPA’s NSPS Subpart OOOOb proposal.[38]

As proposed, this requirement does not provide sufficient guidance to operators as to how to resolve potential conflicts between different datasets. For instance, facilities may measure a large release event at one volume, but third parties may measure the same release event at a different volume, or different third parties may measure the same release events differently. These potential conflicts are significant—under CAA Section 136(c), operators will be subject to a waste emissions charge if their annual methane emissions exceed a certain threshold.[39] Resolving these conflicts may meaningfully impact reported emissions.

Chesapeake strongly encourages EPA to adopt provisions in its Final Rule that mitigate any potential for conflict:

- First, operators should be permitted to exclude redundant third-party data where data measured at the facility is sufficiently accurate to measure emissions from a release event. Chesapeake recommends that EPA establish specific criteria to show that facility-measured data is sufficiently accurate. For example, EPA should permit facilities to rely on continuous monitors—this would encourage facilities to invest in these monitors and would increase overall emissions reporting accuracy.
- Second, EPA should define specific metrics for third-party data to ensure that such data is accurate before requiring operators to take this data into account in reporting emissions.
- Third, EPA should require third-party notifiers to determine the volume of emissions using specific data, rather than only an emissions rate. For example, third parties should be required to determine the persistence of an observed emissions event by performing a series of measurements, rather than simply relying on a single observation and measurement. Such a requirement will increase the accuracy and verifiability of third-party data.

Footnotes:

[37] 88 Fed. Reg. at 50,300.

[38] Id.

[39] 42 U.S.C. § 7436(c).

Response 3: See Section III.B.2 of the preamble to the final rule and Section 28.4 of this document for our response to these comments.

Commenter: Wyoming Department of Environmental Quality (WDEQ)
Comment Number: EPA-HQ-OAR-2023-0234-0388
Page(s): 7-8

Commenter: Ute Indian Tribe of the Uintah and Ouray Reservation
Comment Number: EPA-HQ-OAR-2023-0234-0421
Page(s): 2

Comment 4: Commenter 0388: **WDEQ raises concerns regarding the reporting pertaining to "other large release events" and how it functions in relation to EPA's proposed Super Emitter Response program.**

In the proposed rule, EPA promulgates reporting requirements for "Other Large Release Events" that would reference NSPS OOOOb and approved state plans under the proposed methane rule. While it is unclear specifically how these provisions tie to EPA' s proposed Super Emitter Response program, WDEQ raises concerns that the proposed rule could interface with this program and here restates some of the concerns it raised in its February 13, 2023 comments on the supplemental proposal to the methane rule.

WDEQ is deeply concerned that the regulatory authority granted in the Clean Air Act for states to implement air quality monitoring programs is improperly being ceded by EPA to "EPA-certified" third-party entities (87 FR 74747). The opportunity to monitor methane should lie first with the states, not with third parties. EPA's supplemental proposal diminishes Wyoming's primacy to implement a state-level program and contradicts the principles of cooperative federalism; air quality monitoring has always fallen under the regulatory purview of federal, state, local, and tribal governments. EPA's proposed expansion falls well beyond the bounds of the Clean Air Act and unnecessarily complicates the implementation and day-to-day function of a state's monitoring program and its maintenance of quality-assured regulatory data.

Commenter 0421: Regarding the EPA's creation of "Other Large Release Events" which is designed to align with the Super-Emitter Response Program proposed in New Source Performance Standards OOOOb, we reiterate our concerns around the Super-Emitter Response Program. The Tribe has determined that the Super-Emitter Response Program presents a tangible threat to our jurisdictional sovereignty by private interest groups that do not align with the Tribe's economic energy development goals.

Response 4: These comments are primarily focused on the requirements of the proposed SEP, so to that extent they are out of scope of this final rule. We note that the final NSPS subpart OOOOb and EG OOOOc rule no longer includes a third party acting as an "authorized representative" under CAA section 114(a)(2) and instead has the EPA in a centralized role for the SEP. See also the final NSPS rule regarding our authority for the final SEP. As we similarly explained in the preamble to the final NSPS subpart OOOOb and EG OOOOc rule, the EPA has the authority to require submission of information under CAA section 114 from "any person who owns or operates any emission source," whether or not the emission source is regulated under the CAA, for purposes of carrying out a provision of the Clean Air Act. As such, the collection of information on other large release events, including information related to a SEP notification from the EPA, within subpart W from reporters is consistent with the EPA's authority under CAA section 114 and is also consistent with the directives in CAA section 136(h) as explained elsewhere in this RTC section 3.

Commenter: Offshore Operators Committee (OOC)
Comment Number: EPA-HQ-OAR-2023-0234-0409
Page(s): 10-11

Comment 5: Section/Paragraph Reference: §98.236

OOC recommends the proposed regulatory text be modified as follows:

y. *Other large release events*. You must indicate whether there were any other large release events from your facility during the reporting year and indicate whether your facility was notified of a potential super-emitter release under the provisions of §60.5371b of this chapter or an applicable approved state plan or applicable Federal plan in part 62 of this chapter, for those facilities who are subject to these provisions. If there were any other large release events calculated in accordance with 98.233(y), you must report the total number of other large release events from your facility that occurred during the reporting year and, for each other large release event, report the information specified in paragraphs (y)(1) through (10) of this section. If you received a notification of a potential super-emitter release from a third-party for this facility or a super-emitter release notification under the provisions of §60.5371b of this chapter or an applicable approved state plan or applicable Federal plan in part 62 of this chapter, you must also report the information specified in paragraph (y)(11) of this section.

Rationale: OOC recommends amending this requirement to clarify 3rd party notification of events under the currently-proposed Super-Emitter Response Program is not applicable to offshore facilities on the U.S. OCS since these events would only apply to facilities potentially subject to NSPS OOOOb or the applicable approved State plan or applicable Federal plan in 40 CFR 62.

Response 5: For offshore operators, as we similarly explained in the preamble to the final NSPS subpart OOOOb rule, the EPA has the authority to require reporting under CAA section 114 for "any person who owns or operates any emission source," whether or not the emission source is regulated under the CAA, for purposes of carrying out a provision of the Clean Air Act. As such, the collection of information on other large release events, including information related to a SEP notification from the EPA, within subpart W from reporters is consistent with the EPA's authority under CAA section 114 and is also consistent with the directives in CAA section 136(h) as explained elsewhere in Section 3 of this document. Applicability of the NSPS, such as to an off-shore facility, does not impact or restrict the EPA's authority to notify and require reporting of large emission events under the other large release event requirements within subpart W. See Section III.B.2 of the preamble to the final rule for our response to the other points addressed in these comments.

Commenter: CrownQuest Operating
Comment Number: EPA-HQ-OAR-2023-0234-0393
Page(s): 72

Commenter: Encino Energy (EAP Ohio, LLC)
Comment Number: EPA-HQ-OAR-2023-0234-0408
Page(s): 3

Commenter: Environmental Defense Fund, et al.
Comment Number: EPA-HQ-OAR-2023-0234-0413
Page(s): 20-21

Comment 6: Commenter 0393: This seems to be duplicate reporting on "super emitter" events. Super emitter program vs OOOOb/c. The EPA needs to make it distinguishable for operators and not be hung up on the overlapping years of an "other large release event". The burden for operators to track down these dates is completely unnecessary.

Commenter 0408: EAP Ohio, LLC askes EPA to treat the proposed rule more like an accounting framework than an NSPS OOOOb/c enforcement document.

Instances of the rule which require duplicate reporting of enforcement items required under NSPS OOOOb/c should be removed. Exempt items should not be required in the report such as Super-Emitter/Large Emission Event allegations which did not result in confirmed actual emissions. Submitting false events in the Subpart W report would be unnecessary duplicate reporting since agency will already have the data regarding these events in the NSPS OOOOb/c reporting framework.

Commenter 0413: 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 CO2 and methane in the gas released, and CO2 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.

Response 6: See Section III.B.2 of the preamble to the final rule for our response to these comments.

Commenter: Clean Air Council
Comment Number: EPA-HQ-OAR-2023-0234-0203
Page(s): 1

Commenter: Public Hearing Transcript
Comment Number: EPA-HQ-OAR-2023-0234-0224
Page(s): 13 (Alice Lu), 17 (Luke Metzger), 20 (Antoinette Reyes), 22 (Cyrus Reed), 34 (Dr. Dakota Raynes), 44 (Shanna Edberg)

Commenter: National Tribal Air Association (NTAA)
Comment Number: EPA-HQ-OAR-2023-0234-0239
Page(s): 3-4

Commenter: American Lung Association
Comment Number: EPA-HQ-OAR-2023-0234-0335
Page(s): 1

Commenter: Wyoming Department of Environmental Quality (WDEQ)
Comment Number: EPA-HQ-OAR-2023-0234-0388
Page(s): 8-10

Comment 7: Commenter 0203: I urge EPA to strengthen its proposed rule in the following ways:

…

- Require operators that experience a super-emitter event to repair the leak as quickly as possible, but within 5 days, report greenhouse gas emissions monthly going forward, submit a compliance plan to demonstrate how additional incidents will be avoided, and follow-up to ensure the incident has been addressed.

Commenter 0224: When these super emitter events do occur the EPA should require operators to repair the leak as quickly as possible, within five days, report monthly emissions going forward, submit a compliance plan to prevent future incidents and test after the leak to show it's been addressed.

…

I also ask that you please … require more frequent reports temporarily after a super emitter event as well as set a requirement for how soon a leak must be fixed that led to a super emitter event.

…

Still as others have already mentioned, there are some ways to strengthen this rule … also requiring folks to actually fix the leaks in these super emitter events…

…

We also urge the EPA to strengthen the final rule, including by … requiring operators that have a super emitter event to repair the leak as soon as possible.

…

The EPA should also require operators that have a super emitter event to stop that emission as quickly as is possible, and report their greenhouse gas emissions monthly going forward, and submit a compliance plan to demonstrate how they will prevent additional such incidents from occurring.

…

… after a super emitter event has occurred, operators should be required to repair the leak as quickly as possible, report greenhouse gas emissions monthly going forward, and submit a compliance plan to demonstrate how they will prevent additional incidents from occurring. Operators should be required to follow up and test after a leak takes place to ensure that the incident has been addressed.

Commenter 0239: The EPA should build on its already strong proposal by:

Requiring third-party monitors participating in the Super Emitter Response Program to notify directly, communities and Tribes potentially affected by super emitter events. Likewise, the EPA should require owners and operators that are notified of possible Super Emitter events to provide timely emissions estimates from those events to relevant Tribal entities, including Tribal air programs, rather than requiring Tribes to learn about events later through publicly accessible tools. This would allow Tribal staff to verify the reported emissions data along with the EPA.

Commenter 0335: Once detected, these significant leaks should be repaired within 5 days and the emitter required to submit a plan to prevent future emissions incidents from occurring.

Commenter 0388: **WDEQ raises concerns regarding the reporting pertaining to "other large release events" and how it functions in relation to EPA's proposed Super Emitter Response program.**

WDEQ is also concerned with the impracticality of implementing a Super Emitter Response program for state-level agencies and operators, as well with data accuracy, as described below:

- EPA's proposed Super Emitter Response program convolutes the compliance process and communications between WDEQ and operators. WDEQ's compliance program actively performs outreach to operators and ensures compliance issues are timely addressed. For example, WDEQ's compliance staff currently complete approximately 1,000 Full Compliance Evaluations (FCEs) on oil and gas sites annually, with an additional 1,500 site visits or Partial Compliance Evaluations (PCEs) each year. Similarly, operators are already conducting their own compliance activities. Requiring compliance operators to respond to compliance observations from third-party entities (as described in 87 FR 74747-74748) only complicates the compliance process. Furthermore, it could leave

WDEQ's Compliance program in the dark about ongoing compliance issues that have been reported by a third party.

- WDEQ is concerned that requiring approved third-party entities to process data that has been gathered from remote detection methods would result in significant delays between a perceived "super emitter" event and companies being notified. WDEQ understands that it can take weeks for data from remote detection methods to be processed. As a result, it is possible that data could indicate an event that occurred in the past. Based on the proposed Super Emitter Response program, operators would have to expend significant time and resources undertaking root-cause analyses for one-time-events that may have already been addressed.
- WDEQ is concerned certain necessary operational processes (such as scheduled blowdowns or other maintenance events and safety measures) at a facility could appear as "super emitter" events through remote detection even though they may be necessary measures already permitted by WDEQ. In these instances, operators would again have to undertake unnecessary root-cause analyses in spite of the fact that the events reported are not compliance issues.
- WDEQ is deeply concerned with the supplemental methane proposal's specification in 87 FR 74750 that "Third parties may also make such reports available to the public on other public websites. The EPA would generally not verify or authenticate the information in third party reports prior to posting." This is problematic and allows for the public dissemination of data that is not properly quality assured and would likely result in redirection of limited resources away from other critical agency priorities. The potential for spreading misinformation to the public is extremely concerning.
- EPA claims that the supplemental proposal to the methane rule allows EPA to retain oversight, provide safeguards, and limit third-party discretion. (87 FR 74750). However, not only will EPA not authenticate the information prior to posting but retains the discretion whether to remove a third-party from the pre-approved list even after multiple demonstrated errors. (Id.) ("The EPA in its discretion, may remove that third party from the pre-approved list of third-party notifiers upon demonstration by the owner or operator and/or a finding by the EPA that more than three notifications to that same owner or operator were made in error."). If EPA proceeds with the Super Emitter Response Program, states, operators, owners, and the public should not have to depend on EPA to exercise its discretion to remove a third-party notifier that persistently provides wrong information to the EPA and the public. Especially since EPA will have labeled this third-party as pre-approved, the public will incorrectly perceive that party as more credible.
- WDEQ requests that EPA require similarly stringent requirements for third-party equipment operators as those in the proposed Appendix K regulatory text. Compliance staff at agencies like WDEQ and operators must conduct OGI surveys for a minimum of 1,400 hours over the entirety of his/her career under the proposed regulations. It is inappropriate to allow "qualified" third parties to operate remote detection equipment under requirements that are less stringent than those that apply to states and operators.
- WDEQ maintains that third party data collection requirements for what is allowed in third party collection of data could be moved in the future. While EPA has acknowledged third-party safety concerns in the preamble as its rationale for limiting data collection only to remote-sensing technologies (74749), WDEQ has concerns that these rule revisions could open the door for other methods of third-party monitoring data collection.

Put simply, there are abundant public safety concerns and private property issues that would arise.

- WDEQ strongly disagrees with EPA's assertion in the preamble that "the proposed super-emitter response program would provide a cost-effective backstop to the rest of the regulatory program" (74748). EPA's proposed super-emitter program will consume state-level resources in WDEQ's Compliance and Monitoring programs, as state agencies will nevertheless have to spend additional time responding to and investigating root cause analyses, corrective actions, and monitored data. Ultimately, this process will unnecessarily burden WDEQ's already-effective programs with no additional financial support from EPA.

In sum, WDEQ does not support the proposed Super Emitter Response program. EPA has not addressed the significant questions regarding the accuracy of the data collected by remote-sensing technologies. If EPA decides to move forward with the Super Emitter Response program, EPA must set specific guidelines for credible and actionable data. EPA must perform extensive work to identify instruments or methods with quantifiable accuracy, precision, and reliability. Credible and actionable data must be collected by instruments that meet performance testing similar to 40 CFR Part 53 and a documented quality system. Further, EPA must include data handling provisions in these specifications, as well as data collection plans, to minimize interferences from other sources of methane.
WDEQ is aware of other states that share a number of concerns pertaining to the proposed Super Emitter Response program. Instead of moving forward with the Super Emitter Response program as proposed, WDEQ encourages EPA to engage with its state co-regulators to examine existing state frameworks for addressing citizen concerns. State, Local, and Tribal air agencies are more accessible to, familiar with, and responsive to their citizens' concerns because they are located in and accountable to those communities.

Response 7: These comments are out of scope of the GHGRP rulemaking as the GHGRP is a reporting program. These comments appear to be directed to the NSPS OOOOb/c rulemaking.

4 New and Additional Emission Sources

4.1 Current Subpart W Emission Sources Proposed for Additional Industry Segments

4.1.1 Natural Gas Pneumatic Device Venting

Commenter: Downstream Natural Gas Initiative
Comment Number: EPA-HQ-OAR-2023-0234-0396
Page(s): 6-7

Commenter: Atmos Energy Corporation
Comment Number: EPA-HQ-OAR-2023-0234-0406
Page(s): 3-4

Commenter: American Gas Association (AGA) and American Public Gas Association (APGA)
Comment Number: EPA-HQ-OAR-2023-0234-0418
Page(s): 18

Comment 1: Commenter 0396: **Pneumatic Devices**

As part of the proposed updates to pneumatics, EPA is adding pneumatics as an emission source to the distribution segment. Additionally, for segments where pneumatics are currently reported such as transmission or underground storage stations, EPA is proposing revised population emission factors for high bleed and low bleed pneumatic devices, requiring measurement data under one of three proposed methods. Finally, EPA is proposing to remove population emission factors for intermittent bleed pneumatic devices.

DSI has two separate comments on the proposed updates to pneumatics. First, it is unclear what the basis is for high and low bleed emission factors for Distribution. In the TSD, EPA cites that there are similarities between Processing, Transmission, and Storage facilities, which is why the factors are the same. Stations along a distribution system (T-D, M&R) have different functionality than the aforementioned segments, including typically operating at lower pressures. EPA should consider using data applicable to a distribution system to determine these factors.

Second, the removal of population factors for intermittent bleed devices coupled with the addition of this category to distribution could cause significant burden. EPA should re-consider the allowance of a population factor for intermittent bleed devices. Alternatively, EPA could allow companies to calculate a company-specific emission factor under Calculation Method 3 of the proposed rule by using the percentages of normal functioning and malfunctioning intermittent bleed devices and the associated emission factors with those two categories of intermittent bleed devices. This factor could be developed initially in the first reporting year (2025) and updated over time with data from subsequent surveys. Like compressor surveys for transmission & storage under the current rule, actual results could be used for pneumatics surveyed, while a company average could be used for pneumatics not surveyed. EPA could require companies to survey all their intermittent bleed pneumatics on a multi-year cycle (e.g., 3-5 years) to reduce the burden.

Commenter 0406: **EPA should reconsider reporting requirements for pneumatic device venting for the distribution segment or, at minimum, revise proposed calculation methods.**

EPA's Proposed Rule would add the natural gas distribution industry segment to the list of industries required to report GHG emissions vented from pneumatic devices[1] and would revise the calculation methods for all reporting industry segments.[2] Doing so would impose inordinate costs on operators in the natural gas distribution segment without providing meaningful benefits—operators would be required to record and report for thousands of devices that make up a very small portion of the industry segment's total emissions.

The existing Subpart W regulations use default population emission factors for reporting GHG emissions from natural gas pneumatic device venting[3] for certain industry segments. Operators multiply the default factors by the number of devices and the average time the devices are "in-service" (i.e., supplied with natural gas) to calculate total emissions.[4]

The Proposed Rule would require natural gas distribution operators to report emissions from pneumatic device venting and calculate the emissions using one of three new calculation methodologies, based on direct measurement and leak screening.[5] In sum:

- For pneumatic devices with a flow monitoring device installed on their natural gas supply line, EPA would require reporters to calculate emissions using the measured flow (referred to as "Method 1").[6] If there is no flow meter on the natural gas supply line, reporters would instead be required to measure emissions at regular intervals from each pneumatic device vented directly to the atmosphere, using one of the methods outlined in the existing Subpart W regulations ("Method 2").[7]
- As an alternative to Method 2, EPA would permit reporters to continue to use population counts and updated default emission factors listed in proposed Table W-1[8] ("Method 3") for continuous high bleed and continuous low bleed devices.[9] For intermittent bleed pneumatic devices, Method 3 provides reporters with the option to monitor each device to determine whether it is functioning properly and to use a "leaker factor" approach that applies a different emissions factor based on whether each monitored device is found to be "properly functioning" or "malfunctioning."[10] A device would be considered "malfunctioning" if "any leak is observed when the device is not actuating or if a leak is observed for more than five seconds during device actuation."[11]

EPA has grossly underestimated the impact these changes would have on operators if finalized.

Atmos Energy strongly encourages EPA to consider the cost-effectiveness of these proposed updated methodologies more carefully for the natural gas distribution industry segment. EPA's Final Rule should strike the appropriate balance between increasing the amount and accuracy of reported emissions while ensuring that compliance costs are not unduly burdensome for operators. EPA's Proposed Rule fails to strike this balance, in part because EPA is severely underestimating the compliance burden imposed by these proposed updates.

Footnotes:

[1] 88 Fed. Reg. 50,282, 50,310-6 (Aug. 1, 2023).

[2] Id.

[3] 40 C.F.R. § 98.233(a).

[4] 88 Fed. Reg. at 50,310.

[5] *Id.* 50,310.

[6] *Id.* 50,310-1.

[7] *Id.* 50,311.

[8] *Id.* 50,383.

[9] *Id.* 50,314.

[10] *Id.*

[11] *Id.*

Commenter 0418: **If EPA adds pneumatic device venting as a reportable source for the distribution segment, the Agency should provide more flexibility for the manner of determining emissions from LDCs' pneumatic devices.**

EPA is proposing to add distribution to those industry segments required to report their GHG emissions vented from pneumatic devices, and also proposes to revise the calculation methods for all segments that are subject to this requirement.[59] Subpart W currently requires the calculation of GHG emissions from pneumatic device venting using default population emission factors multiplied by the number of devices and the average time those devices are in gas service. Under the Proposed Rule, emissions from pneumatic devices would be calculated based on direct measurements and leak screening. The existing default population emission factors for intermittent bleed natural gas pneumatic devices would no longer be applicable and the default population emission factors for continuous bleed natural gas pneumatic devices would only be applicable for the leak screening method. EPA is proposing three new calculation methods: Calculation Method 1 for pneumatic devices that use a flow monitoring device; Calculation Method 2 for pneumatic devices that do not use a flow meter, which includes a proposed facility-specific emission factor for facilities that conduct vent measurements over several years; and Calculation Method 3 for facilities that monitor for malfunctioning intermittent bleed pneumatic devices (analogous to a "leaker factor").

Pneumatic device venting is a notable source of GHG emissions in the upstream segments of the natural gas value chain but is a much lesser contributor further downstream—particularly in the distribution segment. EPA should consider whether requiring pneumatic device reporting is worthwhile for the distribution segment and, if it is, the Agency should provide a less burdensome manner of estimating those emissions. LDCs should not be required to spend significant time and resources to conduct direct measurements of such low-emitting devices.

If pneumatic device reporting is finalized for the distribution segment, then the Associations request that EPA offer additional methods of meeting Subpart W reporting obligations. Some options to consider are: (1) BAMM reporting, (2) a more streamlined manner of developing facility-specific emission factors, and/or (3) a “sunsetting” of reporting obligations after a set period of time. As to sunsetting, the Associations believe that if LDCs can demonstrate that their pneumatic device emissions are relatively trivial (e.g., not exceeding a specified percentage of overall segment or sector emissions), then facilities should not be required to conduct measurements each year for Subpart W purposes. EPA should consider sunsetting pneumatic device reporting obligations for LDCs after a specified number of years or a large enough data set is accumulated such that a durable facility-specific emission factor can be established. Alternatively, for segments that have relatively low pneumatic device emissions—such as the natural gas distribution, transmission, and storage segments[60]—EPA could maintain the current default emission factors for calculating reportable pneumatic device emissions.

Footnotes:

[59] Proposed Rule, 88 Fed. Reg. at 50,310–16.

[60] INGAA’s comments on the Proposed Rule contain further detail on pneumatic device emissions in the natural gas transmission and storage segments

Response 1: As discussed in Sections III.E.1 and 2 of the preamble to the final rule, we recognize natural gas distribution facilities may be geographically large and may contain large numbers of pneumatic devices, so measuring all devices may require significant effort. After considering these and other comments, the EPA is finalizing a fourth calculation method that provides a default population emission factor for all devices. This eliminates the proposed requirement to measure or monitor any natural gas pneumatic device except for those devices for which the natural gas supply flow is already being measured using a meter capable of meeting the requirements of § 98.234(b). The default population emission factors for natural gas devices in the distribution segment are based on those determined for the transmission compression industry segment. While the pipeline pressure of natural gas may be lower in the distribution segment, the pressure used to run the natural gas pneumatic devices is very consistent across industry segments, with these devices typically operating at 15 to 25 psig. Also, the intermittent bleed device emission factor considers only isolation valve actuators. We understand that natural gas distribution intermittent bleed pneumatic devices are largely isolation valve actuators, so the transmission compression industry segment natural gas pneumatic device emission factors are expected to be representative of the emissions from these devices at natural gas distribution facilities. With regard to one commenter’s concern with underestimated compliance burden and as discussed above, the direct measurement and leak screening methods are now optional in the final rule for all pneumatic device types except for those devices for which the natural gas supply flow is already being measured. Reporters that may consider these direct measurement and screening methods to be overly burdensome for their operations will have the option of using default population emission factors instead.

4.1.2 Acid Gas Removal Units

Commenter: Interstate Natural Gas Association of America (INGAA)
Comment Number: EPA-HQ-OAR-2023-0234-0387
Page(s): 19, 40-41

Comment 1: [T]hree additional items from the October 2022 Comments are highlighted here:

…

- Based on the complexity of liquefied natural gas (LNG) systems, INGAA recommends that EPA allow site-specific engineering estimates based on best available data for LNG import/export facility acid gas removal (AGR) vents, as well as nitrogen removal unit vents. The latter is added in the Proposed Rule.

…

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

EPA requested comments on whether all four calculation methods currently provided in 40 CFR 98.233(d) are appropriate for facilities in the LNG Import/Export industry segment and if not, how specific calculation methods could be adjusted to be more applicable to this industry segment. 98.233(d)(1) through (4) documents four calculation methodologies for CO2 vented directly to the atmosphere: Calculation Method 1 (if there is a Continuous Emission Monitor System (CEMS)), Calculation Method 2 (vent meter is installed), Calculation Method 3 (estimation method using inlet or outlet gas flow rates), and Calculation Method 4 (estimation method using simulations from software packages). EPA further states that the estimations under Calculation Methods 3 and 4 (i.e., 98.233(d)(3) or (4)) may provide incorrect and impossible calculated volumetric emissions. Therefore, EPA correctly proposed new provisions for specific situations for AGR vents comingled with other sources and routed to a flare or thermal oxidizer. Some of these methods still utilize Calculation Methods 3 and 4. With the possible errors in these methods and the further complexity of liquefied natural gas (LNG) systems, INGAA suggests the estimation methods under 98.233(d)(3) and (4) should not be utilized for acid gas removal vents at LNG facilities under any circumstance. LNG facilities are very complex with a variety of technologies and processed integrated. Streams at an LNG facility are often comingled with emissions from other source types. Further, the volume and composition of the streams (directly or comingled) are not necessarily monitored continuously. In these stream situations at an LNG facility the four calculation methodologies do not fit with typical plant procedures. Under certain circumstances, data may be available to utilize Calculation Methods 1 and 2 appropriately. LNG facilities have found that site-specific engineering estimates based on best available data is the most accurate, and sometimes the only way, to calculate emissions.

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

Response 1: The EPA is finalizing provisions requiring that AGR vents in the LNG Storage and LNG Import and Export Equipment industry segments use the same calculation methods as AGRs in other industry segments. The four calculation methods provide a variety of ways for reporters to determine emissions, through measurement, engineering calculations, or simulations, and each method has a well-defined procedure and specific elements that must be reported. The commenter's suggestion of using "site-specific engineering estimates based on best available data" is very open-ended and would not provide the EPA with the information needed to ensure the calculation methodology is sound and that the data can be verified, to ensure accuracy of total emissions reported. See Section III.F of the preamble to the final rule for information regarding final revisions and clarifications to Calculation Methods 3 and 4.

4.1.3 Blowdown Vent Stacks

Commenter: Endeavor Energy Resources, L.P.
Comment Number: EPA-HQ-OAR-2023-0234-0381
Page(s): 12

Comment 1: EPA Should Remove or Revise Many of the Additional Emission Sources Proposed for the Onshore Petroleum and Natural Gas Production Reporting Segment.

Blowdown Stacks

EPA proposes to include blowdown vent stacks as a reportable emission source for the Onshore Petroleum and Natural Gas Production segment.[37] Many of the blowdown vent stack emissions events that EPA identifies in its proposed regulations as reportable (e.g., compressor blowdowns, pig launchers and receivers)[38] are unlikely to produce enough emissions to justify the time and resources needed for measuring and calculating those emissions. In contrast to midstream and transmission reporting segments—where compressors are much more common and thus blowdowns are more frequent, necessitating the need for more continuous monitoring—it would be more burdensome to track emissions from blowdown events in the Onshore Production segment, where compressors are less common and not always connected to continuing monitoring systems. Reporters would need to expend significant time and resources across a vast system of operations in order to ensure emissions from such a wide array of activities and potential blowdown events could be measured and reported accurately, as required by the IRA. Endeavor thus recommends elimination of blowdown vent stacks as an emission source for the Onshore Petroleum and Natural Gas Production segment in any final rule.

Footnotes:

[37] *Id.* at 50,301.

[38] *Id.* at 50,394.

Response 1: The EPA disagrees with the commenter's request to eliminate blowdown vent stacks as an emission source for the Onshore Petroleum and Natural Gas Production industry segment. We expect the majority of blowdown events in this industry segment to occur at manned or frequently visited sites where the data needed for GHG reporting can readily be logged, and for emergency events, engineering estimates are allowed, which should minimize the burden to reporters. Moreover, the U.S. GHG Inventory estimated 3,760 metric tons of CH_4 emitted from blowdown vent stacks from the onshore production industry segment in 2022, and, to ensure that reporting under subpart W accurately reflects the total methane emissions and waste emissions from applicable facilities per section 136(h) of the CAA, we are finalizing blowdown vent stacks as an emission source for the onshore petroleum and natural gas production industry segment.

Commenter: The Petroleum Alliance of Oklahoma
Comment Number: EPA-HQ-OAR-2023-0234-0398
Page(s): 13

Comment 2: Blowdowns Vent Stacks

EPA is proposing new requirements (e.g., actual temperatures and pressures in the unique physical volumes) to determine emissions from blowdowns at Onshore Petroleum and Natural Gas Production facilities.

This will require reporters to collect a significant amount of new data that is not currently collected. Some of this information may be a challenge to collect without installation of new equipment such as flow meters or obtaining unique physical volumes by equipment or event types. In addition, it will require reporters to develop a management process that includes, but is not limited to, training employees, data collection and recordkeeping procedures and other similar issues. For other industry segments (gathering and boosting and transmission), EPA is proposing to allow the use of engineering estimates to determine the temperature and pressure for an emergency blowdown for both the geographically dispersed industry segments that currently report blowdown vent stack emissions.

Action Requested: We request EPA allow Onshore Petroleum and Natural Gas Production reporters the option to use engineering estimates to determine the temperature and pressure of blowdown events.

Response 2: The EPA acknowledges the commenter’s feedback and notes that the proposed text states that facilities in the onshore petroleum and natural gas production will also be allowed to use engineering estimates to determine temperature and pressure for emergency blowdowns. The EPA is finalizing these amendments as proposed. See also Response 1 in this section of this document.

Commenter : American Exploration and Production Council
Comment Number: EPA-HQ-OAR-2023-0234-0295
Page(s): 21

Commenter: Western Energy Alliance
Comment Number: EPA-HQ-OAR-2023-0234-0399
Page(s): 10

Commenter: Encino Energy (EAP Ohio, LLC)
Comment Number: EPA-HQ-OAR-2023-0234-0408
Page(s): 4

Comment 3: Commenter 0295: Blowdowns

EPA is proposing to add blowdown vent stack reporting to the Onshore Petroleum and Natural Gas Production segment. AXPC agrees with the need for tracking certain blowdown events in emissions reporting and supports the option of engineering estimates. AXPC requests EPA maintain a deminimus volume in which reporting would not be required for all equipment types. All equipment with a physical volume less than or equal to 50 cubic feet should not require reporting when blown down.

Commenter 0399: *Blowdowns*

EPA is proposing to require site-level details regarding blowdown events. While this source is already applied to gathering and boosting, within that segment it includes a 50 cubic foot equipment volume de-minimis exemption, but there is no mention of applying the exemption to the Production Segment. EPA should apply the same 50 cubic foot de minimis threshold for equipment blowdowns to the Upstream & Production Oil and Gas reporting segment to minimize unnecessary reporting burden for small emission events. Blowdowns from equipment smaller than 50 cubic feet are burdensome to record keep and will make up an insignificant amount of upstream operator's emissions.

…

> **Recommendation:** EPA should confirm the 50 cubic foot exemption will apply to the production segment …

Commenter 0408:

EPA is proposing to add blowdown vent stack reporting to the Onshore Petroleum and Natural Gas Production segment and EAP Ohio, LLC agrees with the need for tracking certain blowdown events in emissions reporting and supports the option of engineering estimates. EAP Ohio, LLC requests EPA maintain a de minimus volume in which reporting would not be required for all equipment types. All equipment with a physical volume less than or equal to 50 cubic feet, should not require reporting when blown down.

Response 3: The EPA did not propose changes to the introductory paragraph of 40 CFR 98.233(i) in this rule. The current provision that equipment with a unique physical volume of less than 50 cubic feet are not subject to 40 CFR 98.233(i)(2) through (4) does not specify any particular industry segments. We are finalizing different unique physical volume applicability provisions for the Natural Gas Distribution industry segment, as explained in section III.C.1 of the preamble to the final rule, but we did not propose and are not finalizing any changes to the 50 cubic foot unique physical equipment volume threshold for other industry segments. Thus, equipment in the Onshore Petroleum and Natural Gas Production segment with a unique physical volume of less than 50 cubic feet as determined in 40 CFR 98.233(i)(1) are not subject to the requirements in 40 CFR 98.233(i)(2) through (4), as proposed.

Commenter: Downstream Natural Gas Initiative
Comment Number: EPA-HQ-OAR-2023-0234-0396
Page(s): 4

Commenter: American Gas Association (AGA) and American Public Gas Association (APGA)
Comment Number: EPA-HQ-OAR-2023-0234-0418
Page(s): 17

Comment 4: Commenter 0396: **Blowdown Vent Stacks**

EPA proposes to expand the blowdown vent stacks category to include segments such as storage stations (underground and LNG) and distribution. For storage stations, EPA plans to mirror transmission stations (reporting under seven distinct categories) while under distribution, EPA plans to mirror transmission pipelines (reporting under eight distinct categories).

DSI agrees with the approach to add blowdowns for storage stations (mirroring transmission stations) and distribution systems (mirroring transmission pipeline). DSI endorses the proposal to capture emissions from mishaps (dig-ins) in distribution systems under "blowdowns (emergency category). Further, DSI agrees with the approach of allowing engineering estimates for temperature and pressure from emergency blowdown events (including mishaps/dig-ins as previously mentioned).

Under the current and proposed rule, EPA states that "equipment with a unique physical volume of less than 50 cubic feet" is not subject to reporting. On average, distribution pipelines operate at pressures approximately ten times lower than transmission pipelines. As a result, the volume of gas blown down from a 50 cubic foot section of pipe would be approximately ten times lower for distribution pipe than transmission pipe.

DSI requests that for the distribution segment, the threshold for reporting a blowdown should apply to equipment with a unique physical volume of 500 cubic feet or more, and that blowdowns of equipment less than 500 cubic feet should be exempt from reporting.

Commenter 0418: **As proposed, EPA's requirements for reporting blowdown stack emissions from dig- ins are unworkable with respect to the distribution segment.**

EPA is proposing to add distribution to the industry segments that are required to report blowdown vent stack GHG emissions.[55] For other industry segments, Subpart W currently requires reporting of blowdowns using either flow meter measurements or unique physical volume calculations by equipment or event types. EPA is essentially proposing to drop the distribution segment into the existing blowdown requirements at 40 C.F.R. § 98.233(i), which is akin to trying to fit a square peg into a round hole. Both the applicability determination and manner of calculating blowdown emissions depend on calculating unique physical volume between isolation valves; however, isolation valves are uncommon in the distribution segment, so it is not possible to derive a unique physical volume. EPA must revise its proposed language for § 98.233(i) so that it includes applicability criteria and calculation methodology that is actually workable for estimating blowdown emissions due to dig-ins (*i.e.*, excavation damage) at distribution pipelines. [56]

The current blowdown emissions applicability language, which EPA does not propose to change, states that "[e]quipment with a unique physical volume of less than 50 cubic feet" is not subject to the blowdown emission reporting requirements and that facilities must "calculate each unique physical volume . . . between isolation valves, in cubic feet, by using engineering estimates based on best available data."[57] The lack of isolation valves means that LDCs have no way to calculate unique physical volume, so there is no way to determine which dig-ins have reportable blowdown emissions under Subpart W. It would be extremely burdensome for LDCs to have to report *all* blowdown vent stack emissions due to dig-ins—which are generally caused by third-party activities, not by LDCs themselves. EPA has previously recognized that including "tiny blowdown sources would be a substantial burden for little contribution to emissions," which was not the Agency's intent in establishing the original blowdown vent stack reporting requirements under Subpart W.[58] Distribution line dig-in emissions can typically be mitigated quickly by pinching off the pipeline until a full repair can be completed, and the lower pressure in distribution lines also reduces emissions, therefore most dig-ins would be the type of "tiny blowdown sources" that EPA did not intend to include in Subpart W. EPA should establish a separate threshold for distribution segment dig-ins that appropriately excludes these types of minor blowdown emissions.

Without a unique physical volume, blowdown emissions calculations W-14A and W-14B are each missing required inputs, so the calculations cannot work. To facilitate the estimation of blowdown emissions for distribution segment dig-ins that are reportable under Subpart W, EPA should provide an engineering calculation that relies on pipeline diameter, pressure, temperature, and event duration. Alternatively, EPA could establish dig-ins as a separate emission source under Subpart W; however, the Agency would have to do this via a supplemental rulemaking to give LDCs and other stakeholders sufficient notice and opportunity to comment. Yet another option would be to exclude distribution dig-in emissions altogether in light of how minimal they are. In any event, EPA's current proposal for addressing distribution dig-in emissions under Subpart W is not viable as written.

Footnotes:

[55] Proposed Rule, 88 Fed. Reg. at 50,324–25.

[56] The Associations' comment on applicability is specific to the "unique physical volume" threshold. We support EPA's proposal to retain the existing reporting exemptions for "blowdown vent stack emissions from depressurizing to a flare, over-pressure relief, operating pressure control venting, blowdown of non-GHG gases, and desiccant dehydrator blowdown venting before reloading." 40 C.F.R. § 98.233(i).

[57] *Id*.

[58] See EPA Memorandum: Equipment Threshold for Blowdowns (Nov. 1, 2010), https://www.regulations.gov/ document/EPA-HQ-OAR-2009-0923-3581.

Response 4: See Section III.C.1 of the preamble to the final rule for the EPA's response to this comment.

4.1.4 Equipment Leaks

Commenter: Atmos Energy Corporation
Comment Number: EPA-HQ-OAR-2023-0234-0406
Page(s): 7

Comment 1: [A]spects of the Proposed Rule rely on outdated study data or data derived from a limited class of reporters. For example, EPA is proposing to add new emissions reporting for transmission pipeline leaks based on a 1996 GRI/EPA study.[25] … These updates are not supported by the same current, representative data—instead, EPA is attempting to rely on a small subset of data to broadly expand reporting obligations, without concrete support. EPA should not finalize these requirements. Atmos Energy urges EPA to only propose new emissions reporting where those changes are supported by current, representative data. To do otherwise would impose an undue burden on operators without clear, persuasive justification for the changes.

Footnote:

[25] *Id.* 50, 301.

Response 1: Throughout this rulemaking process EPA has assessed available information and included default emission factors based on the best available data, which for the transmission pipelines, transmission company interconnect metering and regulating stations as well as the direct sale or farm taps is the 1996 GRI/EPA study. We also sought comment specifically on more recent study data which may characterize the emissions from these sources to inform default population or leaker emission factors but did not receive any. The commenter stated that the use of the 1996 GRI/EPA study is, "not supported by the same current, representative data…", but it is unclear what data are being referenced. Our assessment is that the best available data at this time (*i.e.*, the 1996 GRI/EPA study) meets the directives in CAA section 136(h) and is appropriate to utilize in the final rule. Based on the best data available at this time, we are finalizing the default population emission factors for transmission pipelines as proposed. As new data arises, we will continue to evaluate it for potential inclusion in future rulemakings.

Commenter: Permian Basin Petroleum Association (PBPA)
Comment Number: EPA-HQ-OAR-2023-0234-0346
Page(s): 9

Commenter: CrownQuest Operating
Comment Number: EPA-HQ-OAR-2023-0234-0393
Page(s): 88

Comment 2: Commenter 0346: Additionally, EPA is seeking comment on what quantification techniques would be best suited for measuring emissions from pipeline leaks and whether these techniques require digging down to the pipeline in order to quantify emissions and also verify pipeline characteristics. Digging down to buried pipelines to quantify emissions and verify pipeline characteristics goes far beyond the scope of "reporting" requirements. Such onerous and costly requirements are not justified, especially when such information can be acquired through data analysis, sensors, and leak surveys.

Commenter 0393: Regarding "digging down" on transmission pipelines, it is of our opinion that this tactic is not reasonable. With the vast number of lines in the ground strung across multiple basins, it is unrealistic to expect operators to dig these lines for potential leaks. A very large percentage of these leaks are detected through other methods namely the discrepancy in throughput. Metering and site visits can keep the operator's privy to leaks. All of this seems redundant to PHMSA's proposed LDAR rule.

Response 2: After considering the comments we received relative to our request for comments related to quantification techniques for pipelines, including the concerns raised by commenters, we are not finalizing an approach that would require reporters to dig down in order to quantify emissions or verify pipeline characteristics in this rulemaking. Further discussion of the final rule requirements for pipelines is provided in Sections III.C.1 and III.Q.3 of the preamble to the final rule for transmission pipelines and gathering pipelines, respectively.

Commenter: Interstate Natural Gas Association of America (INGAA)
Comment Number: EPA-HQ-OAR-2023-0234-0387
Page(s): 3

Commenter: Downstream Natural Gas Initiative
Comment Number: EPA-HQ-OAR-2023-0234-0396
Page(s): 5-6

Comment 3: Commenter 0387: Measurement should be included as an optional alternative to emissions estimation using prescribed EFs

The Proposed Rule preamble acknowledges EPA's objective to address the IRA directive to include improved Subpart W emission estimates by using empirical data. INGAA supports the use of measured data to improve emission estimates. However, in some cases the Proposed Rule includes an EF-based method without the option to use measured data as an alternative. For those emission sources, measurement should be included as an alternative option used at the operator's discretion. Thus, for T&S sources, measurement (and EF development, as discussed below) should be added as an option for the following emission sources:

…

- Transmission pipeline leak estimates required in §98.232(m)(3) for interconnect metering regulating (M&R) stations, (m)(4) for farm taps and direct sales M&R, …… where emissions are estimated using population EFs per §98.233(r).

Methods included in Subpart W (e.g., calibrated bag, high volume sampler, and direct measurement with a meter) can be used for these measurements. For the two emission sources described above, the EFs are based on older data and/or limited datasets, thus use of measured data is an important option.

Commenter-0396: **Interconnects/Farm Taps**

As proposed, companies would calculate emissions from interconnects and farm taps using counts of the emission source and population emission factors. DSI requests additional flexibility in allowing the option to estimate emissions for this source category using actual leak data. For example, companies could survey interconnects and farm taps to determine the number of leaking components by type and apply similar leaker emission factors as those in Table W-4 used for transmission and underground storage stations. The number of leaking components, by type, could be determined either through an annual survey of all interconnects and farm taps or a survey cycle (e.g., 2-5 years) to estimate the total number of leaks.

Response 3: See Section III.C.1 of the preamble to the final rule for the EPA's response to this comment.

Commenter: Taxpayers for Common Sense (TCS)
Comment Number: EPA-HQ-OAR-2023-0234-0351
Page(s): 5

Commenter: Interstate Natural Gas Association of America (INGAA)
Comment Number: EPA-HQ-OAR-2023-0234-0387
Page(s): 3

Commenter: Downstream Natural Gas Initiative
Comment Number: EPA-HQ-OAR-2023-0234-0396
Page(s): 5-6

Comment 4: Commenter 0351: *Gas Emitted Through Leakage*

Natural gas is also routinely lost through leaking. On federal lands, oil and gas operators are not required to check for leaks or detect fugitive emissions, even as leaks and fugitive losses are common throughout the oil and gas production process.[11] The proposed rule seeks to improve monitoring and reporting of methane leakage in the oil and gas industry. … TCS supports … regular leak detection surveys and measurements for transmission pipelines.

Footnote:

[11] Alvarez et al., "Assessment of methane emissions from the U.S. oil and gas supply chain," Science, July 13, 2018. https://www.science.org/doi/10.1126/science.aar7204

Commenter 0387: Measurement should be included as an optional alternative to emissions estimation using prescribed EFs

The Proposed Rule preamble acknowledges EPA's objective to address the IRA directive to include improved Subpart W emission estimates by using empirical data. INGAA supports the use of measured data to improve emission estimates. However, in some cases the Proposed Rule includes an EF-based method without the option to use measured data as an alternative. For those emission sources, measurement should be included as an alternative option used at the operator's discretion. Thus, for T&S sources, measurement (and EF development, as discussed below) should be added as an option for the following emission sources:

…

- …[§98.232](m)(5) for pipeline leaks, where emissions are estimated using population EFs per §98.233(r).

Methods included in Subpart W (e.g., calibrated bag, high volume sampler, and direct measurement with a meter) can be used for these measurements. For the two emission sources described above, the EFs are based on older data and/or limited datasets, thus use of measured data is an important option.

Commenter 0396: **Pipeline Leaks**

As proposed, companies would calculate emissions from transmission pipeline leaks using miles of pipeline and population emission factors. DSI requests additional flexibility in allowing the option to estimate emissions for this source category using actual leak data.

For example, companies should be allowed to use a number of leaks multiplied by a leaker emission factor. Number of leaks could be determined either through annual leak surveys of the entire pipeline or a multi-year survey (e.g., 2-5 years) used to estimate the total number of leaks along the pipeline. The leaker emission factor could be either a default factor, or average emission factor from company measurements. See the "Direct Measurement" section for more details.

Response 4: See Section III.C.1 of the preamble to the final rule for the EPA's response to this comment.

Commenter: Downstream Natural Gas Initiative
Comment Number: EPA-HQ-OAR-2023-0234-0396
Page(s): 5

Comment 5: DSI also requests further clarification for the following terms: Interconnect, Farm Tap, and Direct Sale. DSI would like EPA to provide, explicit and detailed definitions for each of these three terms, and examples either in the rule or in an FAQ document.

Response 5: See Section III.C.1 of the preamble to the final rule for the EPA's response to this comment.

Commenter: GPA Midstream Association
Comment Number: EPA-HQ-OAR-2023-0234-0299
Page(s): 54

Comment 6: For transmission pipeline leaks by population count, there is a mismatch between equation W-32A and the emission factors in Table W-5.

The existing equation W-32A[117] is proposed to be used to calculate emissions from the proposed new source category transmission pipeline leaks by population count. This equation includes GHGi, which "for onshore natural gas transmission compression, underground natural gas storage, and onshore natural gas transmission pipeline, GHGi equals 0.975 for CH_4 and 1.1×10^{-2} for CO_2."[118] This equation also includes EFs,e which is a "[p]opulation emission factor for the specific emission source type, as listed in tables W–1, W–3, and W–5 to this subpart." [119] Table W-5 is called "Default Methane Population Emission Factors," however, and only provides methane emission factors. It is not correct to multiply this emission factor by the methane mole percentage. EPA must revise the equation or the factors, and EPA must also describe if and how CO_2 emissions should be calculated for transmission pipeline leaks by population.

Footnotes:

[117] Es,e,i = Counte * EFs,e * GHGi * Te (Eq. W-32A).

[118] 88 Fed. Reg. at 50,408.

[119] Id.

Response 6: See Section III.C.1 of the preamble to the final rule for the EPA's response to this comment.

Commenter: Ute Indian Tribe of the Uintah and Ouray Reservation
Comment Number: EPA-HQ-OAR-2023-0234-0421
Page(s): 2

Comment 7: While we agree that the current regulations governing emission calculations and reporting methodologies are outdated and in need of revision, the EPA's addition of new emissions sources to Subpart W in the Proposed Rule warrant further discussion.

Response 7: We acknowledge this comment and have replied to specific topics related to the addition of new emission sources in the 2023 Subpart W Proposal in this RTC document and the preamble to the final rule.

4.2 Nitrogen Removal Units

Commenter: Environmental Defense Fund, et al.
Comment Number: EPA-HQ-OAR-2023-0234-0413
Page(s): 74

Comment 1: 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.

Footnotes:

[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).

Response 1: The EPA acknowledges the commenter's support of the proposed revisions. The EPA is finalizing these amendments as proposed.

Commenter: Environmental Defense Fund, et al.
Comment Number: EPA-HQ-OAR-2023-0234-0413
Page(s): 75

Comment 2: 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.

Footnote

[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.

Response 2: In the final rule, nitrogen removal unit vent emissions are defined as the nitrogen gas separated from the natural gas and released with methane and other gases to the atmosphere. As described in Section III.F of the preamble to the final rule, based on consideration of public comments on the AGR requirements, the EPA is finalizing provisions for AGR and NRU vents routed to vapor recovery that are similar to the provisions for dehydrators and atmospheric storage tanks routed to vapor recovery systems. The provisions are generally consistent with the commenter's suggestion of determining emissions from the vent prior to the vapor recovery system and then adjusting those emissions to account for the quantity of emissions recovered versus emissions released directly to the atmosphere. However, the provisions for dehydrators and atmospheric storage do not require reporters to track the use of the recovered gas through the facility or system and then report those emissions as dehydrator emissions or storage tanks emissions when they are eventually released to the atmosphere from a different process unit. Similarly, the final provisions for AGRs and NRUs require the reporting of the mass of the CH_4 and CO_2 recovered but do not require reporters to track the distribution of those gasses. We note that if the recovered gases are eventually released to the atmosphere from an applicable process unit, those releases must be reported as emissions from that process unit, as applicable.

4.3 Produced Water Tanks

Commenter: Endeavor Energy Resources, L.P.
Comment Number: EPA-HQ-OAR-2023-0234-0381
Page(s): 10

Commenter: Arkansas Independent Producers and Royalty Owners (AIPRO)
Comment Number: EPA-HQ-OAR-2023-0234-0382
Page(s): 14-15

Commenter: American Petroleum Institute et al. (Part 1 of 2)
Comment Number: EPA-HQ-OAR-2023-0234-0402
Page(s): 28-29

Comment 1: Commenter 0381: **EPA Should Remove or Revise Many of the Additional Emission Sources Proposed for the Onshore Petroleum and Natural Gas Production Reporting Segment.**

Produced Water Tanks

EPA proposes to require reporters in the Onshore Petroleum and Natural Gas Production segment to report methane emissions from produced water tanks, calculated using the three calculated methods presently found at 40 C.F.R. § 98.233(j)(1) to (3).[29] As proposed, reporters would also be subject to additional reporting requirements for produced water tanks related to the total annual produced water volumes for each pressure range, estimates of the fraction of produced water throughput that is controlled by flares and/or vapor recovery, counts of controlled and uncontrolled produced water tanks, and annual methane emissions vented directly to atmosphere from produced water tanks.[30]

EPA's proposal to include produced water tanks is likely infeasible, overly burdensome, and unlikely to result in accurate empirical data. While the Onshore Production reporting segment uses a large number of produced water tanks, the methane emissions associated those tanks, even if aggregated, are so negligible that the gas cannot feasibly be captured with a vapor recovery unit ("VRU") and therefore is rarely gathered or flared.

Produced water tanks are frequently used in the Onshore Production segment, and there are likely tens of thousands within the segment, many of which are not required under applicable regulations to install controls. Generally speaking, the percentage of hydrocarbons in stored produced water is negligible at best, meaning that the emissions per tank are similarly negligible. And for produced water tanks for many vertical wells (also known as conventional wells), there is not a reliable, accurate device for, or other means of, measuring the emissions from the tanks. Most tanks can only handle a limited psi, and metering these tanks would cause damage to the tanks. As such, compliance with EPA's proposed reporting requirements for many produced water tanks would require either (1) calculating methane emissions using measured throughput and analysis, which is unlikely to produce an accurate picture of the actual emissions and thus would likely unduly inflate reported emissions and any associated IRA methane charges, or (2) investing resources and time in costly measurement software that will likely only verify there are negligible emissions associated with these tanks. Endeavor expects this is the reality throughout much of industry.

In short, the negligible methane emissions from produced water tanks do not justify the time, energy, and expense necessary to attempt to quantify such emissions. And given the small amount of emissions at stake, there is the real risk that the calculated emissions will not be sufficiently accurate and empirical, as required under the IRA and as necessary to simply gain an accurate picture of our industry's emissions profile. We therefore urge EPA to remove produced water tanks as a reportable emission source in any final rule in order to comply with both the IRA and APA.

Footnotes:

[29] 88 Fed. Reg. at 50,304–05. EPA defines "produced water" as "water (brine) brought up from the hydrocarbon-bearing strata during the extraction of oil and gas, and can include formation water, injection water, and any chemicals added downhole or during the oil/water separation process." *Id.* at 50,304.

[30] *Id.* at 50,305.

Commenter 0382: Produced Water Tanks:

AIPRO opposes the addition of this source category in the proposed Subpart W revisions as it will be overly burdensome to reporters, is unnecessary and will yield very little value in terms of more accurate emissions reporting as a result of the expected low emissions associated with produced water tanks. Emissions from produced water tanks during normal operations are extremely low because produced water at a typical oil & gas facility will have undergone one or more phases of separation to flash off residual methane. Further, there are solubility limitations associated with methane in produced water which also causes emissions associated with produced water tanks to be very low. As such, AIPRO encourages EPA to amend the proposed Subpart W revisions removing this proposed new source category.

Commenter 0402: Storage Tanks

Produced Water Tanks

Requiring estimation of emissions from produced water tanks is burdensome and unnecessary due to the low expected emissions of methane based on solubility limits.

Methane emissions from produced water tanks are expected to be low due to solubility limitations of methane in water. A study conducted by Idaho State University[22] to quantify the solubility of methane in produced water found that the solubility of methane was in a range between 1 and 12 scf/barrel at pressures ranging from around 100 to 2,000 psi and temperatures ranging from 200 to 300°F. While the study did not publish results for lower temperature ranges, the authors state that the solubility decreases with decreasing temperature and/or pressure. The solubility of methane in produced water is also expected to be lower in the presence of other hydrocarbon gases, such as ethane, per the study authors. The Idaho State University methane solubility study results are aligned with the produced water emission factors published in the 2021 API Compendium (Table 6-26): the Idaho State University study value at around 1000 psi, 200°F and 13 % salinity (4.2 scf/bbl.) equates to around 0.08 tonne CH_4/1,000 bbl which compares to 0.0536 tonne CH_4/1,000 bbl (at 1000 psi, 10% salinity) from Table 6-26 of the API Compendium. Since the methane emissions from a produced water tank would be lower than the solubility limit (i.e., emissions are based on the partial pressure of methane in the tank headspace, which is lowered when other hydrocarbons are present), the Idaho State University study corroborates the API Compendium emission factors for produced water tanks.

Footnote:

[22] Blount, C. *et al, Solubility of Methane in Water Under Natural Conditions*, Idaho State University Department of Geology, June 1982, https://www.osti.gov/servlets/purl/5281520.

Response 1: Although the EPA acknowledges that, relative to hydrocarbon liquid tank emissions, methane emissions from produced water tanks will be lower, we still consider methane emissions from produced water tanks to be a potentially significant source of CH_4 emissions for facilities in the Onshore Petroleum and Natural Gas Production, Onshore Petroleum and Natural Gas Gathering and Boosting, and Onshore Natural Gas Processing industry segments. Several notable guidelines on oil and natural gas emission sources include produced water tank emissions as a source of GHG emissions and provide calculation methods for estimating produced water emissions. This includes the U.S. GHG Inventory and the 2021 API Compendium. The U.S. GHG Inventory estimated 89,000 MT CH_4 emitted from produced water tanks in the U.S. in 2021. Therefore, we believe that produced water tanks should be included as an emissions source in reporting for the applicable industry segments to best ensure accurate reporting of total methane emissions from the facilities. We are, therefore, finalizing that reporters are required to report CH_4 emissions from produced water tanks per 40 CFR 98.236(j). The EPA disagrees with one commenter's concern that calculated produced water tank emissions "will not be sufficiently accurate and empirical". We note that, in the final rule and in addition to the optional default population emission factor, reporters will have the option to estimate methane emissions from produced water tanks using process software simulation based on certain measured inputs or sampling the produced water and assuming all of the CH_4 in solution is emitted. In addition to relying on empirical data, these methodologies are consistent with existing requirements for hydrocarbon liquid tanks and industry standard practice for estimating emissions from produced water tanks, and we believe they will result in sufficiently accurate estimates of emissions from produced water tanks.

Commenter: EnerVest Operating, LLC
Comment Number: EPA-HQ-OAR-2023-0234-0229
Page(s): 2-3

Commenter: American Exploration and Production Council
Comment Number: EPA-HQ-OAR-2023-0234-0295
Page(s): 19

Commenter: Enerplus Resources (USA) Corporation
Comment Number: EPA-HQ-OAR-2023-0234-0342
Page(s): 4

Comment 2: Commenter 0229: Water Tank Emission Factors

- Water Tank Methane Emissions are included in the proposed rule.
- In addition to working and breathing losses, it is plainly seen that the emission characteristics (Compositions) for HC and PW tanks are drastically different. This will be proven in the screening for the limits set forth under OOOOb.

- Flash gas analysis (empirical) has been performed for years at the laboratory. The percent methane is in the low single digits, as to be expected. ProMax or other Peng Robinson polar thermodynamic models yield the same results.
- Water volumes differ based on formation; formation pressures differ across formation. For high producing water wells, newer wells produce more water and decline, for older shale wells, the formation pressure could be 20-30 pounds and in coal bed methane wells, the formation pressure could be 3-7 pounds.
- In addition to proposed emissions, we would like to take production decline over the years and run models on the tanks. Since the number of tanks for a single producing area could be in the thousands, we would like to propose that we run a subset of the wells which have similar formation pressures, gas compositions and ratios of hydrocarbons to water (if any) that are produced. This will reduce the burden of running models on every PW Tank.
- Capture of Water tank emissions for purposes of control:
    - One would argue based on the fact that capturing gas from water tanks would be composed of primarily CO2 and a small percentage of methane. This would not be available for use as fuel.
        - To capture with VRU and inject into sales line would potentially violate contractual specifications by exceeding CO2 limits, it would introduce acid gas into pipelines, potentially inducing corrosion and make the gas stream unsafe for the public.
        - Burning the gas is not an option as supplemental fuel would be needed to bring the BTU content high enough to ignite the flare. This would result in lost revenue and depending on the amount of gas captured and destroyed, could make a well uneconomic.

Commenter 0295: **Produced Water Tanks**

AXPC recognizes that produced water tanks can contribute to methane emissions in some circumstances. However, this can be highly variable depending on several factors, including the size of the tank, throughput, and composition of the contents. Requiring operators to calculate emissions from all produced water tanks is overly burdensome and misleading, given that some will have negligible emissions. Smaller tanks, those with low throughput, produced water from dry gas basins, and produced water tanks with control devices would all be expected to have very low and insignificant emissions. Therefore, AXPC recommends that EPA only require calculation and reporting of emissions from uncontrolled produced water tanks that also contain hydrocarbon liquids.

Commenter 0342: Produced Water Tanks

Enerplus recognizes that produced water tanks can contribute to methane emissions in some circumstances. However, this can be highly variable depending on several factors, including the size of the tank, throughput, and composition of the contents. Enerplus controls all our produced water tanks and would expect that these would have very low emissions. Therefore, Enerplus recommends that EPA only require calculation and reporting of emissions from uncontrolled tanks.

Response 2: The EPA disagrees that there is significant burden associated with reporting produced water tanks under subpart W. We have provided reporters the option of using any of the three calculation methodologies specified in 40 CFR 98.233(j)(1) through (3). While calculation method 1 per 40 CFR 98.233(j)(1) requires knowledge of specific input parameters for produced water tanks, calculation method 3 per 40 CFR 98.233(j)(3) simply requires the annual flow rate of produced water sent to tanks. Thus, we expect the burden associated with calculation method 3 to be low, while still providing the EPA with an accurate estimate of CH_4 emissions from produced water tanks. One commenter recommended that the EPA require only calculation and reporting of emissions from uncontrolled tanks as they would expect controlled tanks to have very low emissions. However, no information was provided by the commenter to support this claim and the EPA does not have sufficient data at this time to determine the relative contributions to overall estimated produced water tank emissions from controlled versus uncontrolled tanks. Therefore and consistent with the directive under CAA section 136(h) to ensure that reporting under subpart W accurately reflects total methane emissions, we are finalizing as proposed requirements for calculation and reporting of emissions from both controlled and uncontrolled produced water tanks.

Commenter: GPA Midstream Association
Comment Number: EPA-HQ-OAR-2023-0234-0299
Page(s): 39

Commenter: American Petroleum Institute et al. (Part 1 of 2)
Comment Number: EPA-HQ-OAR-2023-0234-0402
Page(s): 29

Comment 3: Commenter 0299: **Emission calculations for produced water tanks should be limited to emissions associated with stuck dump valves.**

EPA proposes the inclusion of flashing emissions from produced water tanks,[96] in addition to the existing requirement to report flashing emissions from hydrocarbon tanks. Produced water tanks (i.e., tanks that receive a produced water stream with no measurable hydrocarbons present) are not expected to have significant emissions during times of normal operation. Substantive emissions are the result of improperly operating tanks, and these emissions are addressed otherwise in the GHGRP via stuck dump valve requirements. GPA proposes limiting the required emission calculations to emissions associated with stuck dump valves. This is how emissions from hydrocarbon tanks in the transmission and (as proposed) underground storage segments are determined.

If EPA maintains requirements to report produced water tank flashing emissions, GPA supports the allowance of multiple calculation methods to determine these emissions.

Footnote:

[96] Id. at 50,304.

Commenter 0402: Produced Water Tanks

…

The Industry Trades note that EPA provides a stuck dump valve emission factor for water tanks if method 1 or 2 is used, but no factor is provided for tanks using method 3.

Response 3: See Section III.C.3 of the preamble to the final rule for the EPA's response to this comment.

Commenter: Arkansas Independent Producers and Royalty Owners (AIPRO)
Comment Number: EPA-HQ-OAR-2023-0234-0382
Page(s): 14-15

Commenter: Wyoming Department of Environmental Quality (WDEQ)
Comment Number: EPA-HQ-OAR-2023-0234-0388
Page(s): 6

Commenter: CrownQuest Operating
Comment Number: EPA-HQ-OAR-2023-0234-0393
Page(s): 96

Comment 4: Commenter 0382: Produced Water Tanks:

…

To the extent EPA insists on including this new emissions source in the Final Rule, AIPRO encourages them to amend the requirement for the collection of pressurized liquid samples from being an annual requirement to once every three years. The annual requirement is overly burdensome, costly and will not yield better data quality compared to a three year frequency.

Commenter 0388: **WDEQ respectfully requests that EPA allows for flexibility in its emissions calculation methodologies.**

…

WDEQ has similar concerns with produced water storage tanks. Obtaining a direct measurement from vented produced water tanks is extraordinarily difficult in practice and, as such, WDEQ requests that EPA allows for flexibility in its emissions calculation methodologies.

Commenter 0393: Inclusion of produced water tanks: the record-keeping and reporting burden of acquiring total annual volumes for each pressure range, estimating produced water throughput controlled by flares/vapor recovery, counts of controlled/uncontrolled water tanks and annual emissions vented to atmosphere is overly burdensome for the actual emissions benefit.

…

Also, like representative oil samples, being able to use representative produced water analyses for calculations could prove to be less of a burden for operators.

Response 4: See Section III.C.3 of the preamble to the final rule for the EPA's response to this comment.

Commenter: American Petroleum Institute et al. (Part 1 of 2)
Comment Number: EPA-HQ-OAR-2023-0234-0402
Page(s): 29

Comment 5: Produced Water Tanks

…

If EPA opts to keep produced water tanks in the GHGRP, the Industry Trades recommend allowing operators to assume that water tanks contain 1% of the oil content. Texas Commission on Environmental Quality (TCEQ) Emissions Representation for Produced Water guidance[23] describes that oil or condensate floats on top of the water phase and contributes to the partial pressure within the tank. The Industry Trades recommend that EPA allow operators to assume that 1% of the oil content is in the produced water tanks which is a conservative estimation given that the guidance is intended to capture VOC emissions, and it is unlikely (as described above) that significant methane remains in the produced water.

Footnote:

[23] produced-water.pdf (texas.gov).

Response 5: See Section III.C.3 of the preamble to the final rule for the EPA's response to this comment.

Commenter: Independent Petroleum Association of New Mexico (IPANM)
Comment Number: EPA-HQ-OAR-2023-0234-0337
Page(s): 4-5

Commenter: Colorado Department of Public Health and Environment (CDPHE)
Comment Number: EPA-HQ-OAR-2023-0234-0373
Page(s): 3

Comment 6: Commenter 0337: **40 CFR § 98.233(j) Tanks**

EPA has requested comment on whether the Peng-Robinson equation of state should be used for produced water tanks and whether there are other parameters that should be considered as requirements for modeling emissions from produced water tanks. First, EPA should recognize that several state agencies allow the use of API 4697 E&P Tanks to calculate emissions from produced water tanks. Emissions are calculated with this API model by assuming that 1% of the total water throughput is crude oil or condensate.

We recommend that EPA revise § 98.233(j)(1) as follows: "Calculation Method 1. For atmospheric pressure storage tanks receiving hydrocarbon liquids, calculate annual CH4 and CO2 emissions using operating conditions in the well, last gas-liquid separator, or last non-separator equipment before liquid transfer to storage tanks. For atmospheric pressure storage tanks receiving produced water, calculate annual CH4 emissions using operating conditions in the well, last gas-liquid separator, or last non-separator equipment before liquid transfer to storage tanks. Calculate flashing emissions with a software program, such as AspenTech HYSYS®, Bryan Research & Engineering ProMax®, or, for atmospheric pressure storage tanks receiving hydrocarbon liquids from gas liquid separator or non-separator equipment, API 4697 E&P Tank, that uses the Peng-Robinson equation of state, models flashing emissions, and speciates CH4 and CO2 emissions that will result when the hydrocarbon liquids or produced water from the well, separator, or non-separator equipment enter an atmospheric pressure storage tank. If using API 4697 E&P Tank for atmospheric pressure storage tanks receiving produced water, calculate annual CH4 emissions with this model by assuming that 1% of the total water throughput is crude oil or condensate…."

Commenter 0373: …Further, we support the EPA's proposal to exclude E&P Tank v3.0 from use for produced water storage tank emissions calculations.

Response 6: The EPA is finalizing revisions to 40 CFR 98.233(j) that do not allow modeling of produced water tanks using API E&P Tanks, as proposed. The EPA maintains that API's E&P Tanks v3.0 program is not appropriate for determining emissions from produced water tanks, as the program's methodology is based on properties specific to crude oil. Further, the EPA is aware that as of December 31, 2018, the E&P TANKS v3.0 software is no longer supported or distributed by API. Additionally, only 30 percent of reporters to subpart W reported the use of API E&P Tanks in Reporting Year 2021. Thus, we feel that the lack of continuing updates to the software, in addition to software's already limited use in subpart W, should preclude API E&P Tanks from expanded use for modeling produced water tank emissions.

Commenter: Williams Companies, Inc.
Comment Number: EPA-HQ-OAR-2023-0234-0394
Page(s): 9

Comment 7: In response to the request for comment on whether the Peng-Robinson Equation of State (EOS) is appropriate for modeling methane emissions for produced water tanks, the Peng-Robinson EOS is well understood and typically works well for natural gas. However, water is not a hydrocarbon and is very dissimilar to hydrocarbons. The process simulators (e.g., Schlumberger's Symmetry and BR&E's ProMax) make specific corrections for natural gas -

water systems that are not in the base PengRobinson EOS. Prior to finalizing this Subpart W Proposed Rule, the EPA should consult with the process simulation software companies on the proper use of their corrected Peng-Robinson-based equations of state for produced water systems.

Response 7: The EPA thanks the commenter for this information. We have consulted with representatives from Bryan Research & Engineering (BRE), and they have confirmed that a fitted version of the Peng-Robinson equation of state can be used to model produced water tank emissions. Thus, the EPA is finalizing the use the Peng Robinson equation of state for modeling produced water tanks, per the requirements in 40 CFR 98.233(j)(1), as proposed.

Commenter: CrownQuest Operating
Comment Number: EPA-HQ-OAR-2023-0234-0393
Page(s): 96

Comment 8: …Also, there is no recommendation or mention of an emission percentage reduction value for water tanks.

Response 8: The EPA disagrees with the commenter that, in the proposed (and final) rule, facilities cannot reduce emissions from produced water tanks when they are controlled. Facilities with produced water tank emissions that are controlled with a flare or vapor recovery system may account for reductions in CH_4 emissions using the procedures outlined in 40 CFR 98.233(j)(4). The EPA is finalizing revisions to 40 CFR 98.233(j)(4) as proposed.

Commenter: Williams Companies, Inc.
Comment Number: EPA-HQ-OAR-2023-0234-0394
Page(s): 9

Comment 9: Methane Emission Factors in Equation W-15B

The EPA explained in the preamble that methane emissions factors proposed in Equation W15B are from a 1996 GRI / EPA study.[23] The underlying emissions data was apparently derived from a process simulator (Aspen Plus) and not based on measured data. It is worth noting that all the best-known process simulation companies (Aspen, Schlumberger, BR&E, and SimSci) typically modify and improve correlations over time. Aspen Plus would likely give different results today compared to results from the 1990s. Thus, the emission factors proposed in Equation W-15B are likely outdated.

Footnote:

[23] "Methane Emissions from the Natural Gas Industry, Volume 6: Vented and Combustion Source Summary", Final Report GRI-940257.23 and EPA-600-R-96-080, June 1996.

Response 9: The EPA disagrees with the commenter that the emission factor provided for produced water tanks is outdated. We do not expect software updates that may have occurred to Aspen Plus to heavily influence the outcome of the emissions modeling for produced water tanks in the 1996 GRI / EPA study. We also note that the commenter did not provide an alternative source for an emission factor representative of produced water tanks. However, as more studies and data become available, the EPA intends to consider such information in future rulemaking efforts.

Commenter: Western Energy Alliance
Comment Number: EPA-HQ-OAR-2023-0234-0399
Page(s): 11-12

Comment 10: *Produced Water Tanks*

EPA proposes to apply tank emissions calculation methodologies for oil storage tanks to produced water tanks, ignoring that methane emissions from produced water tanks are a very small percentage of emissions from oil storage tanks. Estimation of produced water tank emissions using modeling software, while possibly accurate, is a much higher burden than is necessary for estimating such a small emission number. Instead, EPA should allow the use of the factor from the 2021 API Compendium of 0.0536 tons CH_4/1,000 bbl.[3] Given how little methane is even present in produced water, even if emissions from a tank were to increase by several standard deviations, the calculation methodology as proposed would change a miniscule amount, making the additional regulatory burden unjustifiable.

> **Recommendation:** EPA should not require reporting for produced water tanks, or at the very least allow for a small emission factor to be used in lieu of individual tank calculations.

Footnote:

[3] Compendium of Greenhouse Gas Emissions Methodologies for the Natural Gas and Oil Industry, American Petroleum Institute (API), November 2021.

Response 10: Consistent with the proposed rule, the EPA is not requiring modeling for determining produced water tanks emissions in the final rule but is instead allowing modeling as an optional methodology (as further described in the response to Comment 2 of this section). Therefore, if facilities feel that modeling is too burdensome for this source, they may elect to use the emission factor methodology in 40 CFR 98.233(j)(3) and equation W-15B. As stated in Response 9 of this section, the EPA has assessed that the emission factor provided in Equation W-15B of 40 CFR 98.233(j)(3) is accurate and representative of produced water tank emissions. Additionally, in the 2023 U.S. GHG Inventory emissions estimate for 2021, the EPA estimated approximately 89,000 metric tons of CH_4 emissions from produced water tanks. Therefore, the EPA disagrees with the commenter that emissions from this source are insignificant.

With regard to the commenter's request that EPA should allow the use of the emission factor from the 2021 API compendium, we note that, as discussed in Section III.C.3.a of the preamble to the final rule, the proposed and final rule emission factors were already sourced from the API Compendium (Table 6-26). The specific factor requested by the commenter (0.0536 tons CH_4/1,000 bbl) is the factor provided in the API Compendium for a specific separator pressure (1,000 psi) and produced water salt content (10%), whereas our rule relies on the average emission factors provided in the API Compendium for pressures of 50, 250, and 1,000 psi. The use of different emission factors for different separator pressure ranges in lieu of the single factor proposed by the commenter is expected to result in more accurate estimates of emissions.

Commenter: GPA Midstream Association
Comment Number: EPA-HQ-OAR-2023-0234-0299
Page(s): 40

Commenter: Williams Companies, Inc.
Comment Number: EPA-HQ-OAR-2023-0234-0394
Page(s): 8-9

Comment 11: Commenter 0299: **Calculation requirements must be adjusted to account for mixtures of produced water and hydrocarbon liquids.**

Many facilities produce both hydrocarbon liquids (condensate) and produced water. A mixture of these products will typically be separated from the gas and will flow into the associated tank battery. While some separation of water and hydrocarbon liquids occurs in the separator, many tanks contain a mixture of condensate and produced water. As such, Calculation Methods 1 and 3 must be adjusted.

In the cases where tanks/separators receive both condensate and produced water, when modeling is performed for Method 1, the calculation of flashing emissions generally provides the total amount of flash gas that is emitted from both products based on gas and/or liquid composition and throughputs. Therefore, when using Method 1, it is not generally feasible to calculate produced water and condensate flashing separately, because the two products are typically mixed when flashing occurs. GPA proposes that in cases where tanks receive a mixture of condensate and produced water that flashing emissions be reported as a whole for both products, as that is representative of the mechanism of the actual emissions source and the results that are provided by modeling.

For Calculation Method 3, the proposed rule is unclear on which equation (produced water or hydrocarbon) should be used for tanks that receive a mixture of the two products. GPA requests clarification on how to account for this common scenario, and we propose the following: in cases where a liquid stream contains any measurable hydrocarbons, W15-A should be used. If a stream contains no measurable hydrocarbons, W15-B should be used.

Commenter 0394: Combined Produced Water and Liquid Hydrocarbon Storage Tanks

Williams has numerous atmospheric storage tank batteries at our gathering compressor stations and processing plants that receive a combination of produced water and hydrocarbon liquids totaling less than 10 bbl/day. The new proposed methodology, which includes inventorying GHG emissions from produced water tanks for the first time, is written as though a tank battery exclusively stores one liquid (i.e. only hydrocarbon liquid or only produced water). That scenario is often not the case as many upstream separators utilizing storage tank batteries are two-phase (gas-liquid) separators sending a combined produced water – condensate stream to the tank battery.

Given the conflict between what is contemplated in the rule and what we see at many of our facilities, it is unclear whether Equation W-15A for atmospheric pressure tanks receiving hydrocarbon liquids or Equation W-15B for atmospheric pressure tanks receiving produced water, should be used for tank batteries that receive less than 10 bbl/day of produced water and hydrocarbon liquid (combined). For storage tank batteries receiving a combination of produced water and hydrocarbon liquids totaling less than 10 bbl/day, EPA should clarify as to which Calculation Method 3 equation in "(j) – Hydrocarbon Liquids and Produced Water Storage Tanks" should be used to calculate GHG emissions for reporters not electing to use Calculation Methods 1 and 2. Williams believes utilizing Equation W-15A for tank batteries receiving a combination of produced water and hydrocarbon liquids would provide a conservative and prudent approach.

Response 11:

The EPA is finalizing the proposed definition of "produced water" in 40 CFR 98.238 as the water (brine) brought up from the hydrocarbon-bearing strata during the extraction of oil and gas, and can include formation water, injection water, and any chemicals added downhole or during the oil/water separation process. The EPA does not expect streams containing significant quantities of hydrocarbon liquids to meet the definition of produced water. Therefore, consistent with the proposed rule, mixtures of water and hydrocarbon liquids that do not meet the definition of produced water should be treated as hydrocarbon liquids for purposes of estimating tank emissions under 40 CFR 98.233(j).

4.4 Mud Degassing

Commenter: Kirk Frost
Comment Number: EPA-HQ-OAR-2023-0234-0389
Page(s): 3

Comment 1: Within the natural gas supply chain, substantial methane emissions occur at every section of the supply chain and even in functions that I wasn't aware of such as the mud methane degassing function. In reviewing over the documentation of the EPA docket, it is clear there are millions if not billions of tons of methane not being accounted for in the EPA greenhouse gas inventory. I have known this because I have tracked the annual emissions reporting from various transmission pipeline companies.

Response 1: The EPA acknowledges the commenter's support for the proposed regulations.

Commenter: Endeavor Energy Resources, L.P.
Comment Number: EPA-HQ-OAR-2023-0234-0381
Page(s): 11

Comment 2: EPA Should Remove or Revise Many of the Additional Emission Sources Proposed for the Onshore Petroleum and Natural Gas Production Reporting Segment.

Drilling Mud Degassing

EPA proposes to require reporters in the Onshore Petroleum and Natural Gas Production segment to report methane emissions from drilling mud degassing.[31] As proposed, reporters would be able to measure methane emissions from drilling mud either through (1) measurements taken through mudlogging and gas detection at representative wells for a particular sub-basin, which would then be extrapolated across all other wells in the sub-basin that are at the same approximate total depth, or (2) the use of emission factors and activity counts.[32] EPA also proposes additional reporting requirements depending upon the calculation methods used, such well ID numbers, the type of drilling mud used, the average mud flow rate, and the total time drilling mud is circulated in a well.[33]

Endeavor believes that EPA has not taken due account of the difficulties and costs associated with measuring methane emissions from drilling mud degassing as required under the APA, nor the ability to accurately capture such emissions as required by the IRA. It is unlikely that methane emissions are generated in a significant enough quantity during circulation of drilling mud to ensure an accurate, useful measurement and calculation by reporters or even to warrant inclusion in Subpart W and the attendant reporting burdens that follow. EPA has not provided any estimation or argument that the methane emissions are in fact material enough to warrant inclusion in Subpart W; it is arbitrary and unreasonable for EPA to impose additional reporting burdens in the absence of any clear, justifiable reason.[34] Endeavor thus recommends elimination of drilling mud degassing as a reportable emission source. For similar reasons, Endeavor opposes expansion of this proposed emission source to encompass carbon dioxide ("CO2") emissions alongside methane emissions.[35] As EPA notes, the CO2 emissions from drilling mud would be "very small" to negligible in most if not all instances, thereby making the emissions data difficult to gather and of little value.[36]

Footnotes:

[31] *Id.* at 50,305–08.

[32] *Id.* at 50,306–07.

[33] *Id.* at 50,307.

[34] *See* 5 U.S.C. § 706(2)(A); *Motor Vehicle Mfrs. Ass'n of U.S., Inc. v. State Farm Mut. Auto. Ins. Co*., 463 U.S. 29, 43 (1983) (agencies must ensure a "rational connection between the facts found and the choices made" (quoting *Burlington Truck Lines, Inc. v. United States*, 371 U.S. 156, 168 (1962))).

[35] 88 Fed. Reg. at 50,305 ("However, as noted later in this section, the EPA is seeking comment on requiring reporting of CO2 emissions from mud degassing . . . .").

[36] *Id.*

Response 2: See Section III.C.4 of the preamble to the final rule for the EPA's response to comments regarding inclusion of reporting for mud degassing and corresponding calculation methodologies.

Commenter: Pioneer Natural Resources USA, Inc.
Comment Number: EPA-HQ-OAR-2023-0234-0385
Page(s): 14

Commenter: CrownQuest Operating
Comment Number: EPA-HQ-OAR-2023-0234-0393
Page(s): 101

Commenter: Western Energy Alliance
Comment Number: EPA-HQ-OAR-2023-0234-0399
Page(s): 12-13

Commenter: American Petroleum Institute et al. (Part 1 of 2)
Comment Number: EPA-HQ-OAR-2023-0234-0402
Page(s): 66

Comment 3: Commenter 0385: **Drilling Mud Degassing Calculation Recommendation**

The Calculation Method #1 that EPA is proposing to quantify drilling mud degassing applies an emission rate derived from a representative well in the same sub-basin and at the "same approximate total depth." Pioneer request clarification on how to determine the "same approximate total depth." ***Pioneer recommends clarifying language stating that it should be determined based on similar producing formation or zone rather based solely on a physical depth.***

Commenter-0393: Proposed calculation 1 EPA is proposing to quantify drilling mud degassing by applying an emission rate from a representative well in the same sub-basin and at the "same approximate total depth." We recommend clarifying language stating it should be determined based on similar producing zones rather than it being based specifically on a physical depth.

EPA is proposing to calculate emissions from drilling mud degassing based on the total time that drilling mud is circulated in the well. We request that EPA clarify this should be done on the circulating time in the hydrocarbon bearing zones only. There is a more than decent chance that emissions will be greatly overestimated if the total mud circulation time in all zones is applied.

Commenter 0399: *Drilling Mud Degassing*

The proposed language allows for two calculation methodologies depending on the availability of mudlogging data. For both, the emissions calculation is intended to capture the estimation for the amount of formation gas that is brought to the surface entrained within the drilling mud. However EPA seems to apply the methodologies to times in the drilling process when this is not possible. For example, for each calculation, the Calculation Method 1 requests emitters to use total mud circulating time (Tr) in equation W-41 and W-42 and T_p in W-43; these factors for time should be changed to total mud circulating time below shallowest known hydrocarbon as prior to drilling through hydrocarbon bearing formations, emissions would not be present. Calculation Methodology 1 should remove circulating hours in non-hydrocarbon bearing intervals, relevant to modern horizontal well construction. For example, surface holes are drilled by a spudder rig when no hydrocarbons are present and should be excluded.

Commenter 0402: Drilling Mud Degassing

In proposed Calculation Method 1, EPA is proposing to quantify drilling mud degassing by applying an emission rate derived from a representative well in the same sub-basin and at the “same approximate total depth.” The Industry Trades request clarification on how to determine the “same approximate total depth.”

EPA has proposed that operators must use mudlogging measurements taken during the reporting year, and therefore calculate emissions using Methodology 1. The Industry Trades disagree with this requirement, as it is possible a mudlogging measure is taken at the very early stages of a drilling operation, and that measurement may not ultimately be reflective of the entire duration of the drilling operation. The Industry Trades recommend allowing reporters to use Methodology 2 for all active drilling. The Industry Trades also propose a third option (see next comment), in the event that some mudlogging data is available.

The proposed third option would serve as a combination of the currently proposed Method 1 and 2. As stated above, this would allow operators to use a combination of the two methodologies when a varying level of directly measured data is available. In this third option, mudlogging measurements would be used based on Method 1 for the period in which the data is available, and Method 2 would be used for the remaining period of drilling activity where mudlogging data is not available. This method should also allow operators to account for drilling mud degassing vapors sent to a control device.

EPA is proposing to calculate emissions from drilling mud degassing based on the total time that drilling mud is circulated in the representative well. The Industry Trades request that EPA clarify that this should be calculated based on circulating time in the hydrocarbon bearing zones only (i.e., excluding surface holes drilled by a spudder rig when no hydrocarbons are present).

One further complication of the proposed method for quantifying methane emissions from drilling mud degassing is that the concentration of natural gas (or methane) in drilling mud is not currently specifically measured and is difficult to obtain. Further, it is not measured by mud loggers in units of ppm, as the measurement instrument used is in units that are not representative of methane concentration.

Response 3: See Section III.C.4 of the preamble to the final rule for the EPA's response to comments regarding mud degassing calculation methodologies.

Commenter: CrownQuest Operating
Comment Number: EPA-HQ-OAR-2023-0234-0393
Page(s): 96, 99

Commenter: The Petroleum Alliance of Oklahoma
Comment Number: EPA-HQ-OAR-2023-0234-0398
Page(s): 9

Commenter: Western Energy Alliance
Comment Number: EPA-HQ-OAR-2023-0234-0399
Page(s): 13

Commenter: American Petroleum Institute et al. (Part 1 of 2)
Comment Number: EPA-HQ-OAR-2023-0234-0402
Page(s): 66-67

Comment 4: <u>Commenter 0393</u>: In the rule for mud degassing, a publication is referenced from 1977… 46 years ago. It references entities such as the state of New York and CenSARA (study 12 years ago) on incorporating estimates for mud degassing. This isn't even close to the same representation of different types of basins, depths, and formations. There is no attempt to justify the quantifications here, it seems like a waste of time.

…

EPA is proposing 0.2605 MT CH4 for water-based drilling muds and 0.0586 for oil-based drilling muds and 0.0586 for synthetic drilling muds. These factors were based on a study evaluating emissions from offshore drilling, this is not indicative of most onshore drilling ops in the US.

It seems appropriate to reiterate the emission factors compiled in the 2021 API Compendium for Well Drilling and mud degassing. In section 6.2 there is well-bore and porosity conditions for onshore drilling operations. These were developed specifically for onshore operations. The use of the proposed offshore emission factors for onshore drilling will drastically overstate methane emissions from onshore production mud degassing. It should be a function of the well dimensions, giving a better representation of mud degassing.

Commenter 0398: Mud Degassing - EPA proposes to add a new emission source type to subpart W for emissions from drilling mud degassing. The proposed amendments for this new source type would add calculation and reporting requirements for methane emissions from mud degassing associated with well drilling for onshore petroleum and natural gas production facilities in 40 CFR 98.232(c), 98.233(dd), and 98.236(dd). EPA is proposing two options to measure methane emissions from drilling mud degassing: measurements taken through mudlogging and gas detection at representative wells (Method 1) and use of emission factors and activity counts (Method 2). Method 2 uses the emission factors from the CenSARA study. EPA states it is not proposing to allow adjustments of the emission factors for local conditions under Method 2. EPA proposes to define the number of drilling days differently than the study. Rather than considering the first drilling day to be the day the well is spudded, EPA proposes that the total number of drilling days is the sum of all days from the first day that the borehole penetrates the first hydrocarbon-bearing zone through the completion of all drilling activity.[5]

We think EPA's proposal for mud degassing will significantly overestimate emissions. For example, EPA does not allow for adjustments to emission factors based on local conditions e.g., the formations being drilled through may be more oil producing as compared to gas producing. The first hydrocarbon-bearing zone or subsequent hydrocarbon-bearing zones may be depleted, especially in more mature producing states, like Oklahoma. Also, mud weight is critical in controlling formation pressure (and the flow of hydrocarbons into the well bore) during the drilling process. EPA and 's calculation methodology does not account for this.

Action Requested: We request EPA provide operators the ability to adjust emission factors based on local conditions and EPA must incorporate mud weight into its calculation methodology.

Footnote:

[5] EPA states it "has determined that well drilling activities are a distinct activity separate from well completion." 88 Fed. Reg., 50308.

Commenter 0399: *Drilling Mud Degassing*

Calculation Method 2 relies on two emissions factors which are based on a 1977 EPA reference and a 2014 ERG reference. This methodology includes a fixed rate of penetration that should be removed. Furthermore, Calculation Method 2 relies on total drilling days for the well (DD_p in W-44). As pointed out in Calculation Method 1, time variables should be based on the time in hours when mud is circulated deeper than the shallowest hydrocarbon bearing zones. Instead of these factors, EPA should adopt the factors developed in the 2021 API Compendium.[4] Not only do those factors represent a more contemporary understanding of emissions from drilling mud degassing, but they are also based on variables that affect the emission rate in actual conditions, namely circulation time in hydrocarbon bearing zones.

Commenter 0402: Drilling Mud Degassing

Proposed Calculation Method 2

EPA is proposing the following emission factors in MT CH4 per drilling day for drilling mud degassing: 0.2605 for water-based drilling muds, 0.0586 for oil-based drilling muds, and 0.0586 for synthetic drilling muds. The EPA based these factors on a study evaluating emissions from offshore drilling from 1977, which is both outdated, and not representative of most onshore drilling operations in the United States. Furthermore, these outdated factors are based on mud throughput, but the basis remains unclear. The Industry Trades reiterate that the emission factors compiled in the 2021 API Compendium for Well Drilling and mud degassing (Section 6.2) is appropriate for the well bore and porosity conditions for onshore drilling operations as it was developed specifically for onshore operations. Use of the proposed offshore emission factors for onshore drilling operations will significantly overstate methane emissions from onshore production mud degassing. The Industry Trades suggest that the emission factor should be derived as a function of well dimensions to better represent mud degassing emissions. Otherwise, the Industry Trades recommends that proposed methodology 2 be revised based on drilling time in hydrocarbon hole section, and not overall event days. There can be multiple days in a hydrocarbon hole section where the pumps are not circulating.

Response 4: See Section III.C.4 of the preamble to the final rule for the EPA's response to comments regarding Calculation Method 2 for mud degassing.

Commenter: Anonymous
Comment Number: EPA-HQ-OAR-2023-0234-0283
Page(s): 1

Commenter: Endeavor Energy Resources, L.P.
Comment Number: EPA-HQ-OAR-2023-0234-0381
Page(s): 11

Commenter: American Petroleum Institute et al. (Part 1 of 2)
Comment Number: EPA-HQ-OAR-2023-0234-0402
Page(s): 67

Comment 5: Commenter 0283: Why isn't there a delay in reporting for wildcat wells and delineation wells that have drilling mud degassing? Drilling and mud degassing seems like the kind of activity that an exploratory well would do. Did EPA decide that none of the information reported for this activity is sensitive?

Commenter 0381: **EPA Should Remove or Revise Many of the Additional Emission Sources Proposed for the Onshore Petroleum and Natural Gas Production Reporting Segment.**

Drilling Mud Degassing

Additionally, the non-emissions-related information that EPA proposes to require owners and operators to report—e.g., type of drilling mud used, average mud flow rate, total time drilling mud is circulated in a well—is proprietary information within our industry. Those proposed reporting requirements go beyond what is already required by state regulators, and EPA has not provided any reason why such proprietary information needs to be reported, much less how such reporting advances more accurate, consistent emissions reporting. Endeavor thus recommends elimination of the proposed non-emissions-related reporting requirements for drilling mud degassing. If, however, EPA retains these requirements in any final rule, then it should indicate that reporters can designate such information as "confidential business information" and protect the information from public disclosure.

Commenter 0402: Drilling Mud Degassing

Reporting Requirements

Reporting requirements proposed in 98.236(dd) require reporting total vertical depth of the well, and the circulation time of the drilling mud within the wellbore. The Industry Trades do not support reporting this information, as EPA did not address why the information would be requested. Furthermore, total vertical depth would not provide representative information for horizontal wells and would not improve the reported data quality.

Response 5: See Section III.C.4 of the preamble to the final rule for the EPA's response to comments regarding the addition of mud degassing as an emissions source in the onshore production segment.

4.5 Crankcase Venting

Commenter: Anonymous
Comment Number: EPA-HQ-OAR-2023-0234-0202
Page(s): 1

Commenter: Alaska Oil and Gas Association (AOGA)
Comment Number: EPA-HQ-OAR-2023-0234-0241
Page(s): 4

Commenter: Marcellus Shale Coalition (MSC)
Comment Number: EPA-HQ-OAR-2023-0234-0275
Page(s): 20

Commenter: GPA Midstream Association
Comment Number: EPA-HQ-OAR-2023-0234-0299
Page(s): 55

Commenter: Gas Turbine Association (GTA)
Comment Number: EPA-HQ-OAR-2023-0234-0384
Page(s): 3

Commenter: Interstate Natural Gas Association of America (INGAA)
Comment Number: EPA-HQ-OAR-2023-0234-0387
Page(s): 3-4

Commenter: Kirk Frost
Comment Number: EPA-HQ-OAR-2023-0234-0389
Page(s): 2

Commenter: Williams Companies, Inc.
Comment Number: EPA-HQ-OAR-2023-0234-0394
Page(s): 14

Commenter: American Petroleum Institute et al. (Part 1 of 2)
Comment Number: EPA-HQ-OAR-2023-0234-0402
Page(s): 67

Commenter: Offshore Operators Committee (OOC)
Comment Number: EPA-HQ-OAR-2023-0234-0409
Page(s): 7-8

Commenter: American Gas Association (AGA) and American Public Gas Association (APGA)
Comment Number: EPA-HQ-OAR-2023-0234-0418
Page(s): 17

Comment 1: Commenter 0202: Delete reference to gas turbines.for crankcase venting.

Reference: § 98.233 Calculating GHG emissions.

Delete references to gas turbines for "98.233(ee) Crankcase venting. For reciprocating internal combustion engines or gas turbines, calculate annual CH4 volumetric emissions from crankcase venting…" and delete reference to gas turbines in other parts of the rule.

The proposed rule in § 98.238 Definitions states:

"Crankcase venting means the process of venting or removing blow-by from the void spaces of an internal combustion engine outside of the combustion cylinders to prevent excessive pressure build-up within the engine. This does not include ingestive systems that vent blow-by into the engine where it is returned to the combustion process."

Gas turbine engines do not have cylinders or a crankcase as described in the above definition.

Commenter 0241: Natural gas turbine crankcase venting

EPA is proposing reporting of emissions from a new source, "Crankcase Venting," which requires reporting of annual methane emissions from both "reciprocating internal combustion engines or gas turbines."[2] The proposed emission factor for Equation W-45 is 2.28 standard cubic feet per hour (scf/h) per crankcase vent. This emission factor comes from the 2021 API Compendium and ultimately from an API study because it was "the most comprehensive field study of crankcase ventilation in the oil and natural sector available to date."[3]

This factor appears to only represent crankcase venting from reciprocating internal combustion engines, not natural gas turbines. The API study[4] only discusses reciprocating engines. The study's definition of crank case is, "The crank case on reciprocating engines and compressors houses the crank shaft and associated parts, and typically an oil supply to lubricate the crank shaft…"[5] The study also only referred to reciprocating engines later on in the document: "Additionally, reciprocating engines crankcase vents were checked for significant blow-by (i.e., leakage past the piston rings into the crankcase) because blow-by reduces cylinder compression that causes inefficient operation and contributes to unburned and partially burned fuel emissions."[6] There is no mention anywhere that natural gas turbines were evaluated as a part of this study.

Since the definition of crankcase within this study explicitly states that it is only applicable to reciprocating engines, and the body of the text supports that definition, then natural gas turbine crankcase vents were not evaluated as part of this study. It is arbitrary to use 2.28 scf/h per crankcase vent for natural gas turbines because turbines were not evaluated for this study.

In addition, natural gas turbines are inherently different from reciprocating engines and quantifying crankcase venting in the manner proposed does not make sense.

A reciprocating engine is a cyclic operation by nature—the piston is required to stroke back and forth inside the cylinder to complete four primary process strokes: intake, compression, power, and exhaust. The piston moves back and forth inside the cylinder of a reciprocating engine, using the piston rings to seal process gas inside the cylinder during the combustion process. This piston is connected to the crankshaft, which translates the reciprocating movement from the combustion in the cylinder to rotational movement at the output shaft. Any leakage across the piston rings will result in combustion gas in the crankcase, which needs to be vented to avoid condensation, contamination, and ongoing reliability concerns. The piston rings act as a primary seal between the combustion process and the atmosphere, and the crankcase takes on the role of a rudimentary "capture" system.

Gas turbines operate using a completely different mechanical method. There is no cyclic or reciprocating element to a gas turbine operation (no piston, piston rings, or crankcase). A gas turbine uses one (or more) rotating shafts to continuously complete all four primary combustion functions inside the gas turbine casing: intake, compression, combustion, and expansion. Since the shaft(s) are already rotating as part of the combustion process, there is no requirement to have a translation from reciprocating to rotational movement, so there is no crankshaft or crank casing to be vented. Combustion gases are ultimately routed to the atmosphere by way of the exhaust duct once the power turbine has extracted the energy. The potential leakage points for combustion gases would be at the turbine casing flanged connections or at the shaft seals, which are addressed by other parts of this rulemaking (fugitive emissions).

AOGA proposes that natural gas turbines not be included for reporting crankcase venting, as there are no crankcase vents on the natural gas turbines and any leakage would otherwise be reported as a fugitive emissions. This avoids double counting of emissions.

Footnotes:

[2] Proposed 40 C.F.R. 98.233(ee).

[3] Subpart W preamble Page 50309.

[4] Prepared for U.S. EPA Natural Gas STAR Program by Natural Gas Machinery Laboratory, Clearstone Engineering Ltd., and Innovative Environmental Solutions, Inc., Cost-Effective Directed Inspection and Maintenance Control Opportunities at Five Gas Processing Plants and Upstream Gathering Compressor Stations and Well Sites; EPA Phase II Aggregate Site Report (Mar. 2006) ("API study"), available at: https://www.epa.gov/sites/default/files/2016-08/documents/clearstone_ii_03_2006.pdf, also available in the docket for this rulemaking, Docket Id. No. EPA–HQ–OAR–2023–0234.

[5] API study at Page 14 (emphasis added).

[6] API study at Page 40 (emphasis added).

<u>Commenter 0275</u>: Crankcase Vents

Gas Turbines do not have "Crankcase vents" like engines do and thus, MSC requests clarification on the intent of these requirements. As stated in the preamble to the rule:

"Crankcase ventilation is the process of venting or removing blow-by from the void spaces of an internal combustion engine outside of the combustion cylinders to prevent excessive pressure build-up within the engine."

More specifically, the mixture of intake air and gas is pressurized inside the cylinder during the compression and power strokes and a small portion of the gas leaks into the crankcase past piston rings and valve seals. Gas turbines do not operate using pistons and therefore have no blowby past the piston rings, nor do they have a crankcase. There is no indication in any studies cited by the U.S. EPA that the crankcase vent measurement data apply to anything other than reciprocating internal combustion engine crankcase vents, therefore, it is inappropriate to apply them to gas turbines.

<u>Commenter 0299</u>: **Natural gas turbines should be excluded from the crankcase source category.**

GPA notes that natural gas turbines do not have crankcase vents, or even an equivalent emission source. As such, EPA should exclude turbines from this proposed emission source category to reduce confusion.

<u>Commenter 0384</u>: **Remove References to Crank Case Venting from Gas Turbines**

The proposed text includes numerous references to crank case venting for reciprocating engines and gas turbines. Gas turbines do not have crank cases and any reference to gas turbines associated with crankcase venting should be eliminated.

<u>Commenter 0387</u>: <u>Crankcase venting emissions estimate and EF basis</u>

Crankcase venting should **not** be associated with gas turbines / centrifugal compressors. The Proposed Rule adds this emissions source for reciprocating engines (i.e., driving reciprocating compressors) and combustion turbines (i.e., driving centrifugal compressors) with a prescribed EF used with unit counts to estimate emissions. References and applicability to combustion turbines / centrifugal compressors is erroneous and should be eliminated.

Crankcase venting is associated with *reciprocating internal combustion engines*. Crankcase ventilation systems exhaust "blow-by" that results from the in-cylinder air-fuel mixture and combustion gases leaking past the piston rings on a reciprocating engine. The pressurized mixture and combustion gases migrate into the reciprocating engine crankcase through small gaps between the piston rings and cylinder walls. Crankcase emissions may also result from reciprocating compressor seals leakage which enters the crankcase through the distance piece. This description is consistent with the proposed definition of "crankcase venting" added to §98.238. The crankcase is typically vented to atmosphere as part of normal operations to prevent excessive crankcase pressure, which can contribute to oil leaks through engine seals and affect unit performance.

Since the crankcase and related vent is associated with reciprocating engines, §98.233(ee) should eliminate reference to "gas turbines" and the definition of "Count" in Equation W-45 should be revised to eliminate that terminology. In addition, the EF basis is *unit* count (i.e., engine count) rather than vent count. INGAA recommends the following revisions to properly define the term:

"Count = Total number of ~~crankcase vents on~~ reciprocating internal combustion engines ~~or gas turbines~~."

Commenter 0389: There were a few technical comments that are good notes for the EPA to note and make corrections to the rules. One comment stated that turbines do not have cylinders and that should be corrected. There were a few others.

Commenter 0394: Crankcase Venting

…

Williams notes that gas turbines do not generate crankcase vent gas. The EPA should exclude turbines from 40 CFR § 98.233(ee) to reduce confusion.

Commenter 0402: Crankcase Venting

In general, the Industry Trades support the use of actual test data for crankcase venting when available, while still allowing the use of a provided emission factor. However, the Industry Trades … do not believe this emission source category should include gas turbines.

…

Additionally, the factor prescribed by EPA is based on an API study, [57] which only represents reciprocating engines, and not natural gas turbines. The study's definition of crank case is, "The crank case on *reciprocating engines* and compressors houses the crank shaft and associated parts, and typically an oil supply to lubricate the crank shaft…" [58] (emphasis added). The study also only referred to reciprocating engines later in the document, "Additionally, *reciprocating engines* crankcase vents were checked for significant blow-by (i.e., leakage past the piston rings into the crankcase) because blow-by reduces cylinder compression that causes inefficient operation and contributes to unburned and partially burned fuel emissions[59]" (emphasis added). There is no mention anywhere that natural gas turbines were evaluated as a part of this study.

Since the definition of crankcase within this study explicitly states that it is only applicable to reciprocating engines, and the body of the text supports that definition, then natural gas turbine crankcase vents were not evaluated as part of this study. It is arbitrary to use 2.28 scf/h per crankcase vent for natural gas turbines because turbines were not evaluated for this study.

Natural gas turbines are inherently different from reciprocating engines and quantifying crankcase venting in the manner proposed does not make sense.

A reciprocating engine is a cyclic operation by nature - the piston is required to stroke back and forth inside the cylinder to complete four primary process strokes: intake, compression, power, and exhaust. The piston moves back and forth inside the cylinder of a reciprocating engine, using the piston rings to seal process gas inside the cylinder during the combustion process. This piston is connected to the crankshaft, which translates the reciprocating movement from the combustion in the cylinder to rotational movement at the output shaft. Any leakage across the piston rings will result in combustion gas in the crankcase, which needs to be vented to avoid condensation, contamination, and ongoing reliability concerns. The piston rings act as a primary seal between the combustion process and the atmosphere, and the crankcase takes on the role of a rudimentary "capture" system.

Gas turbines operate using a completely different mechanical method. There is no cyclic or reciprocating element to a gas turbine operation (no piston, piston rings, or crankcase). A gas turbine uses one (or more) rotating shafts to continuously complete all four primary combustion functions inside the gas turbine casing: intake, compression, combustion, and expansion. Since the shaft(s) are already rotating as part of the combustion process, there is no requirement to have a translation from reciprocating to rotational movement, so there is no crankshaft or crank casing to be vented. Combustion gases are ultimately routed to the atmosphere by way of the exhaust duct once the power turbine has extracted the energy. The potential leakage points for combustion gases would be at the turbine casing flanged connections or at the shaft seals, which are addressed by other parts of this rulemaking (fugitive emissions).

The Industry Trades propose that natural gas turbines not be included for reporting crankcase venting, as there are no crankcase vents on the natural gas turbines.

Footnotes:

[57] Cost-Effective Directed Inspection and Maintenance Control Opportunities at Five Gas Processing Plants and Upstream Gathering Compressor Stations and Well Sites. EPA Phase II Aggregate Site Report prepared for U.S. EPA Natural Gas STAR Program by Natural Gas Machinery Laboratory, Clearstone Engineering Ltd., and Innovative Environmental Solutions, Inc. March 2006. Available at https://www.epa.gov/sites/default/files/2016-08/documents/clearstone_ii_03_2006.pdf and in the docket for this rulemaking, Docket Id. No. EPA–HQ–OAR– 2023–0234.

[58] Page 14 of 74 of API study.

[59] Page 40 of 74 of API study.

Commenter 0409: **Section/Paragraph Reference:** §98.234(ee) Crank Case Venting

Proposed Text: (ee) Crankcase venting. For reciprocating internal combustion engines or gas turbines, calculate annual CH4 volumetric emissions from equipment leaks from components as specified in §98.233(q)(1)(i) or (ii) or (q)(1)(v)(A) that occur during a calendar year. You must use one of the methods described in paragraph (a)(1)(ii) or (iii) or (a)(2)(ii) of this section, as applicable, to conduct leak detection(s) of equipment leaks from components as specified in §98.233(q)(1)(iii) or (q)(1)(v)(B). If electing to comply with §98.233(q) as specified in §98.233(q)(1)(iv), you must use any of the methods described in paragraphs (a)(1) through (5) of this section to conduct leak detection(s) of equipment leaks from component types as specified in §98.233(q)(1)(iv) that occur during a calendar year. Inaccessible emissions sources, as defined in 40 CFR part 60, are not exempt from this subpart. If the primary leak detection method employed cannot be used to monitor inaccessible components without elevating the monitoring personnel more than 2 meters above a support surface, you must use alternative leak detection devices as described in paragraph (a)(1) or (3) of this section to monitor inaccessible equipment leaks or vented emissions at least once per calendar year.

Comment: OOC recommends the proposed regulatory text be modified as follows:

(ee) Crankcase venting. For reciprocating internal combustion engines~~ or gas turbines~~, calculate annual CH4 volumetric emissions from equipment leaks from components as specified in §98.233(q)(1)(i) or (ii) or (q)(1)(v)(A) that occur during a calendar year. You must use one of the methods described in paragraph (a)(1)(ii) or (iii) or (a)(2)(ii) of this section, as applicable, to conduct leak detection(s) of equipment leaks from components as specified in §98.233(q)(1)(iii) or (q)(1)(v)(B). If electing to comply with §98.233(q) as specified in §98.233(q)(1)(iv), you must use any of the methods described in paragraphs (a)(1) through (5) of this section to conduct leak detection(s) of equipment leaks from component types as specified in §98.233(q)(1)(iv) that occur during a calendar year. Inaccessible emissions sources, as defined in 40 CFR part 60, are not exempt from this subpart. If the primary leak detection method employed cannot be used to monitor inaccessible components without elevating the monitoring personnel more than 2 meters above a support surface, you must use alternative leak detection devices as described in paragraph (a)(1) or (3) of this section to monitor inaccessible equipment leaks or vented emissions at least once per calendar year.

Rationale: References to gas turbines in "98.233(ee) Crankcase venting should be deleted.

The proposed rule in § 98.238 Definitions states: "Crankcase venting means the process of venting or removing blow-by from the void spaces of an internal combustion engine outside of the combustion cylinders to prevent excessive pressure build-up within the engine. This does not include ingestive systems that vent blow-by into the engine where it is returned to the combustion process."

Rationale: Turbine engines do not have cylinders, or a crankcase as described in the above definition. Therefore, the "crankcase venting" is not applicable to turbine engines.

Commenter 0418: **Subpart W reporters should have the option of using measured data to calculate their emissions or improve estimated emissions from crankcase venting.**

…

In addition, the Associations concur in INGAA's comments on the applicability of crankcase venting requirements—*i.e.*, crankcases and vents are associated with RICE, not GTs, therefore GTs should be removed from proposed 40 C.F.R. § 98.233(ee) and § 98.236(ee).

Response 1: See Section III.C.5 of the preamble to the final rule for the response to this comment.

Commenter: Public Hearing Transcript
Comment Number: EPA-HQ-OAR-2023-0234-0224
Page(s): 14 (Lisa Beal)

Commenter: American Exploration and Production Council
Comment Number: EPA-HQ-OAR-2023-0234-0295
Page(s): 20

Commenter: GPA Midstream Association
Comment Number: EPA-HQ-OAR-2023-0234-0299
Page(s): 56-56

Commenter: Independent Petroleum Association of New Mexico (IPANM)
Comment Number: EPA-HQ-OAR-2023-0234-0337
Page(s): 12-13

Commenter: Colorado Department of Public Health and Environment (CDPHE)
Comment Number: EPA-HQ-OAR-2023-0234-0373
Page(s): 5

Commenter: Endeavor Energy Resources, L.P.
Comment Number: EPA-HQ-OAR-2023-0234-0381
Page(s): 12

Commenter: Arkansas Independent Producers and Royalty Owners (AIPRO)
Comment Number: EPA-HQ-OAR-2023-0234-0382
Page(s): 15

Commenter: Pioneer Natural Resources USA, Inc.
Comment Number: EPA-HQ-OAR-2023-0234-0385
Page(s): 13

Commenter: Interstate Natural Gas Association of America (INGAA)
Comment Number: EPA-HQ-OAR-2023-0234-0387
Page(s): 3, 4, 5

Commenter: Williams Companies, Inc.
Comment Number: EPA-HQ-OAR-2023-0234-0394
Page(s): 14

Commenter: The Petroleum Alliance of Oklahoma
Comment Number: EPA-HQ-OAR-2023-0234-0398
Page(s): 9-10

Commenter: Western Energy Alliance
Comment Number: EPA-HQ-OAR-2023-0234-0399
Page(s): 10-11

Commenter: Chesapeake Energy Corporation
Comment Number: EPA-HQ-OAR-2023-0234-0400
Page(s): 18

Commenter: American Petroleum Institute et al. (Part 1 of 2)
Comment Number: EPA-HQ-OAR-2023-0234-0402
Page(s): 67

Commenter: American Gas Association (AGA) and American Public Gas Association (APGA)
Comment Number: EPA-HQ-OAR-2023-0234-0418
Page(s): 17

Comment 2: Comment 0224: However, in some cases, the rule is also too limiting or measurement requirements are unnecessarily burdensome and I'll give you a couple examples of those. Crank case vent emissions reporting is added or is proposed to be added for compressor stations and underground storage facilities. That estimate requires the use of an emissions factor and does not include an option to use measured data. It's unclear to us why that proposal or why this proposal would limit the use of measured data when it certainly can be collected.

Commenter 0295: **Crankcase Venting**

AXPC has concerns with the proposed requirement to quantify and report crankcase emissions from reciprocating engines and combustion turbines.

…

Furthermore, if EPA maintains this source category in the final rule, AXPC contends that EPA should provide the option to calculate emissions using direct measurements or OEM data, as this would meet the intent of the IRA's focus on empirical data in Subpart W reporting. Finally, AXPC recommends that EPA consider allowing the use of company-average emission factors derived from direct measurement in cases where the same make/model units are installed at many facilities. This would preserve the accuracy of the derived emission factors while balancing the resource burden and cost of conducting site-specific measurements at multiple locations where the same units are being installed, operated, and maintained under comparable conditions.

Commenter 0299: **Reporters should be allowed to directly measure crankcase vents.**

To align with the directive of the Inflation Reduction Act to incorporate empirical data, EPA should allow an option for reporters to directly measure crankcase vent emissions (in addition to the proposed emission factor approach).

We appreciate the simplicity of the emission factor approach option to represent crankcase emissions under Subpart W. It is unclear to GPA, however, if the derivation of the proposed emission factor was based on data from crankcase vents alone, or if the underlying data also incorporated rod packing emissions. GPA also questions the use of the methane composition of fuel gas in the equation (as opposed to methane composition in crankcase vents), which is comprised of an air fuel mixture along with combustion byproducts.

Commenter 0337: **40 CFR §98.233(ee) Crankcase Vents**

Equation W-45 in § 98.233(ee) calculates the annual total volumetric emissions of methane from crankcase venting on RICE or gas turbines by multiplying an EF (2.28 scf/hr/crankcase vent) x average concentration of methane in the gas stream x count of crankcase vents on the RICE or gas turbine x Total operating hours per year.

EPA should add a method based on a measurement option in addition to a default emission factor similar to that of centrifugal or reciprocating compressors, see e.g. § 98.233(o)(2) through (5) and (p)(2) through (5), where measurement data can be used to calculate emissions. This would allow for the use of more empirical data given the range in vented volume will vary with hp and gas volume compressed.

Additionally, EPA should allow for annual monitoring of crankcase vents to screen for emissions and allow for reporting zero emissions if none are detected. This would be similar to what is allowed for Reciprocating Compressors found at § 98.233()(2)(ii)(C).

We recommend modifying § 98.233(ee) to allow 2 options:

"(ee) Crankcase venting. For reciprocating internal combustion engines or gas turbines, calculate annual CH4 volumetric emissions from crankcase venting at standard conditions using:

(a) Equation W–45 of this section: ….

(b) Measurement…

(c) You may choose to use any of the methods set forth in § 98.234(a)(1) through (3) to screen for emissions. If emissions are not detected using the methods in § 98.234(a)(1) through (3), then you may assume that the volumetric emissions are zero. If emissions are detected utilizing § 98.234(a)(1) through (3), then you must follow the measurement requirements of 98.233(ee)(b)."

Commenter 0373: For **crankcase venting emissions (proposed 98.233(ee))**,

…

Beyond the emission factor approach (i.e., 2.28 scf/hr/vent) proposed by EPA, we suggest allowing the option for operators to directly measure the volume of the gas vented through each crankcase vent. That information would improve understanding of this source, including its variability based on model, unit condition, size, age, etc.

Commenter 0381: **EPA Should Remove or Revise Many of the Additional Emission Sources Proposed for the Onshore Petroleum and Natural Gas Production Reporting Segment.**

Crankcase Venting

…

To the extent EPA does retain any reporting requirements for crankcase vents, it should instead allow reporters to rely on the manufacturer's stated efficiency for a particular engine, which would likely produce more accurate emissions data than a reporter's own measurement and limit some of the burdens associated with reporting.

Commenter 0382: **Crankcase Venting:**

The proposed revisions for this new source category, in their current form, will likely significantly overstate emissions from crankcase vents on the smaller/lower horsepower models of RICE typically used in the Onshore Production segment and smaller Gathering & Boosting segment facilities as a result of the one-size fits all emission factor currently proposed. Further, the emission factor only approach fails to meet the legislative mandate of the IRA to allow reporters to use "empirical data."

As such, AIPRO proposes that EPA amend the current proposed Subpart W revisions to

…

> 2) to allow an alternative approach whereby reporters can directly measure crankcase vents to establish a facility specific emission factor.

Commenter 0385: **Crankcase Venting Calculation Recommendation**

Further, direct measurement of methane concentration in the crankcase vent stream via a bag and grab sample should be allowed to reduce this factor. The vent gas in the crankcase is made up of partially combusted and un-combusted products so their methodology proposed may be too conservative. Direct measurement should be allowed for all sources in the proposed rule to satisfy the intent of the IRA.

Commenter 0387: Measurement should be included as an optional alternative to emissions estimation using prescribed EFs

The Proposed Rule preamble acknowledges EPA's objective to address the IRA directive to include improved Subpart W emission estimates by using empirical data. INGAA supports the use of measured data to improve emission estimates. However, in some cases the Proposed Rule includes an EF-based method without the option to use measured data as an alternative. For those emission sources, measurement should be included as an alternative option used at the operator's discretion. Thus, for T&S sources, measurement (and EF development, as discussed below) should be added as an option for the following emission sources:

- Crankcase vent emission estimates as defined in §98.233(ee);

…

Methods included in Subpart W (e.g., calibrated bag, high volume sampler, and direct measurement with a meter) can be used for these measurements. For the two emission sources described above, the EFs are based on older data and/or limited datasets, thus use of measured data is an important option.

…

Measured data should be allowed as an alternative to the prescribed EF, especially since the EF is based on very limited data. The proposed methane EF for crankcase ventilation (2.28 standard cubic feet per hour per source),[8] cites the API Compendium which in turn references the "EPA Phase 2 study"[9] conducted at five natural gas-processing plants and seven gathering gas compressor stations. The first phase study was conducted at four natural gas processing plants.

These two studies are based on limited data from nearly 20 years ago at gas processing and upstream gathering and boosting facilities and may not be representative of other sectors or current operations. The Phase 2 study measured crankcase vents on 27 units and found 2 (approximately 7 percent) leaking.[10] The crankcase vent EF is based on those measurements, and the emissions were only observed on a small percentage of the engines evaluated.

…

Thus, to improve crankcase vent emissions estimates: … (2) measurement of the vent rate should be added as an option for estimating emissions

Footnotes:

[8] Compendium of Greenhouse Gas Emissions Methodologies For The Natural Gas And Oil Industry. Produced by URS Corporation for American Petroleum Institute. November 2021. Available at https://www.api.org/- /media/files/policy/esg/ghg/2021-api-ghg-compendium-110921.pdf.

[9] Cost-Effective Directed Inspection and Maintenance Control Opportunities at Five Gas Processing Plants and Upstream Gathering Compressor Stations and Well Sites. EPA Phase II Aggregate Site Report prepared for U.S. EPA; Natural Gas STAR Program by Natural Gas Machinery Laboratory, Clearstone Engineering Ltd., and Innovative Environmental Solutions, Inc. March 2006. Available at https://www.epa.gov/sites/default/files/2016-08/documents/clearstone_ii_03_2006.pdf.

[10] See Phase 2 Report, Table 5, pg. 59 of 70.

Commenter 0394: Crankcase Venting

…

Williams supports a methane emissions factor method to calculate crankcase emissions, but the calculation method proposed by the EPA needs modification to accurately reflect crankcase emissions from a variety of reciprocating engine types and manufacturers. Williams recommends the EPA offer reporters the option to measure crankcase vent emissions directly using a high flow sampler or other approved temporary measurement device listed in 40 CFR § 234.

Commenter 0398: Crankcase Venting - EPA is proposing to add 40 CFR 98.233(ee) to provide a component-level average emission factor approach for estimating emissions for crankcase ventilation based on the number of crankcase vents on reciprocating internal combustion engines (RICE) and gas turbines (GT) in the facility. Site-specific information required for the emission calculation would include the number of crankcase vents on RICE or GT, the operating time of each engine or GT, and the concentration of methane in the gas stream entering the engines or GT. If the site-specific methane concentration is unknown, the proposed provision includes an option to determine the methane concentration in the gas stream using either engineering estimates based on best available data or the provisions of 40 CFR 98.233(u)(2). The EPA request comment on whether this calculation method is appropriate and whether there are other methodologies that we should consider providing, including details on how those additional methods would be applied to this source.

Action Requested: We request EPA include the option that allows operators to conduct direct measurement of crankcase emissions that would provide the most accurate emission information.

Commenter 0399: As proposed, engine size does not appear to be considered in calculating emissions or developing the emission factor. The factor developed for crankcase venting used input data in the Technical Support Document that corresponded to natural gas storage and compressor stations, not upstream production, resulting in a significant overestimation of emissions. Gas storage compressors and compressor station engines are of a much larger scale than production facility engines and are therefore expected to have a much higher vent rate. Like blowdowns, there should be a de-minimis exemption for very small engines, or EPA should allow for the direct measurement of small volumes. While the direct measurement and test data should be allowed, EPA should still reconsider the emission factor as developed.

Recommendation: EPA should … allow for measured and test emissions to be used …

Commenter 0400: **Crankcase Venting**

EPA's Proposed Rule fails to outline procedures for operators to directly measure emissions from the crankcase vent. Instead, operators must rely on a default emission factor.[63] This proposal limits flexibility for operators to incorporate empirical data through direct measurement, and is inconsistent with CAA Section 136(h).

Chesapeake recommends that EPA develop a methodology for operators to measure crankcase venting emissions as an alternative reporting option for this source category.

Footnote:

[63] Id. at 50,308-09.

Commenter 0402: Crankcase Venting

In general, the Industry Trades support the use of actual test data for crankcase venting when available, while still allowing the use of a provided emission factor.

Commenter 0418: **F. Subpart W reporters should have the option of using measured data to calculate their emissions or improve estimated emissions from crankcase venting.**

EPA proposes to require reporting of CH_4 emissions from crankcase ventilation from RICE and GTs used in the distribution segment, [53] among others. [54] The Proposed Rule describes crankcase ventilation as the process of venting or removing blow-by from the void spaces of an internal combustion engine outside of the combustion cylinders to prevent excessive pressure build-up within the engine, but not including ingestive systems that vent blow-by into the engine where it is returned to the combustion process. EPA is proposing to provide a component-level average emission factor approach for estimating emissions from crankcase ventilation based on the number of crankcase vents in the facility.

The Associations request that EPA add the option for reporters to develop site-specific emission factors based on direct measurements for crankcase venting. The proposed CH_4 emission factor for crankcase ventilation is 2.28 scf/hour/source, which was developed based on data measured at gas processing plants, gathering compressor stations, and well sites—*i.e.*, facilities that are upstream from LDCs. For distribution segment facilities that wish to devote time and resources to developing their own emission factors for crankcase venting, this would allow for a more accurate reflection of methane emissions for this source type.

Footnotes:

[53] Proposed Rule, 88 Fed. Reg. at 50,308–09.

[54] In addition to their distribution operations, many AGA member companies also operate transmission compression, underground storage, and/or LNG storage facilities as part of the gas utility system regulated by their state's utility commission. Each of those other segments also would be affected by the proposed addition of crankcase venting as a reportable emission source under Subpart W.

Response 2: See Section III.C.5 of the preamble to the final rule for the response to this comment.

Commenter: INNIO Waukesha Gas Engines, Inc.
Comment Number: EPA-HQ-OAR-2023-0234-0343
Page(s): 2

Commenter: Colorado Department of Public Health and Environment (CDPHE)
Comment Number: EPA-HQ-OAR-2023-0234-0373
Page(s): 5

Comment 3: Commenter 0343: **Proposed Amendments to Part 98**

New and Additional Sources

Crankcase Venting

INNIO's Waukesha agrees with EPA's proposal to add calculation and reporting requirements for CH4 emissions from a new emission source type, crankcase ventilation from RICE used in the Onshore Petroleum and Natural Gas Production, Onshore Natural Gas Processing, Onshore Natural Gas Transmission Compression, Underground Natural Gas Storage, LNG Storage, LNG Import and Export Equipment, Natural Gas Distribution, and Onshore Petroleum and Natural Gas Gathering and Boosting industry segments.

…

Commenter 0373: For **crankcase venting emissions (proposed 98.233(ee))**, we agree with EPA's determination that crankcase venting emissions are not fugitive.

Response 3: The EPA acknowledges the commenters' support of the proposed revisions. The addition of requirements to calculate and report emissions from crankcase venting is finalized as proposed.

Commenter: INNIO Waukesha Gas Engines, Inc.
Comment Number: EPA-HQ-OAR-2023-0234-0343
Page(s): 2-3

Commenter: Truck & Engine Manufacturers Association (EMA)
Comment Number: EPA-HQ-OAR-2023-0234-0352
Page(s): 8

Commenter: Pioneer Natural Resources USA, Inc.
Comment Number: EPA-HQ-OAR-2023-0234-0385
Page(s): 13-14

Comment 4: <u>Commenter 0343</u>: **Proposed Amendments to Part 98**

New and Additional Sources

Crankcase Venting

…

In addition to the 2015 study published by Johnson et al. "Methane Emissions from Leak and Loss Audits of Natural Gas Compressor Stations and Storage Facilities", an additional study published by the American Chemical Society (January 2021) written by Vaughn et al, titled "Methane Exhaust Measurements at Gathering Compressor Stations in the United States" 1 , discovered that although crankcase ventilation systems were not a focus for the study, crankcase ventilation systems on 4SLB (four stroke lean burn) engines may add another 3-20% of unburned or fugitive methane emissions to each estimate. Caterpillar's Application & Installation Guide, Crankcase Ventilation Systems was cited as the data reference for the study and states "Crankcase hydrocarbon emissions are normally 3% of the total exhaust emissions tested at the mid-life of the engines. However, due to piston ring tolerances, crankcase hydrocarbon emissions can increase to 20% of the total hydrocarbon emissions". Additionally, modern and legacy engines that utilize mechanical (cam driven) fuel injection systems often have a path to leak methane into the crankcase (and out of an open crankcase breather system) as components, gaskets, or seals wear out.

Advanced breather crankcase systems are standard on most Waukesha new unit production engine models. The system utilizes a closed breather system with advanced filter and automatic regulating valve. Additionally, closed crankcase breather system upgrade kits are available for applicable engine models built since the early 1980s. These systems eliminate methane emissions from this source, by routing filtered breather emissions back to the intake of the engine, where they are ingested into the compressor of the turbocharger and combusted by the engine.

INNIO's Waukesha has no comment on whether the proposed emission factor calculation as provided in the 2021 API Compendium is appropriate or if there are other methodologies to consider however, INNIO's Waukesha recommends that the EPA clarify the meaning of ingestive systems regarding crankcase ventilation from reciprocating and internal combustion engines. In the engine manufacturing industry, an “ingestive system” may also be referred to as a closed crankcase ventilation system or a “closed breather system.”

Commenter 0352: **EPA Should Clarify the Meaning of Ingestive Systems Regarding Crankcase Ventilation from Reciprocating Internal Combustion Engines.**

For clarity, EMA submits that EPA should affirm that the crankcase ventilation calculation and reporting requirements do not apply to engines with closed crankcase ventilation systems. EPA describes crankcase ventilation as “the process of venting or removing blow-by from the void spaces of an internal combustion engine outside of the combustion cylinders to prevent excessive pressure build-up within the engine.” 88 Fed. Reg. at 50,308. EPA uses the term “ingestive systems” in the NPRM to describe a system that “vent[s] blow-by into the engine where it is returned to the combustion process.” 88 Fed. Reg. at 50,308. Within the industry, an “ingestive system” may be also referred as a “closed crankcase ventilation system” or a “closed breather system.”

Commenter 0385: **Crankcase Venting Calculation Recommendation**

…

The proposed rule states that crankcase venting "does not include ingestive systems that vent blow-by into the engine where it is returned to the combustion process". Pioneer recommends that EPA include language that also allows this vent stream to be routed to another closed vent system or unrelated process stream in order to provide operators more flexibility.

Response 4: See Section III.C.5 of the preamble to the final rule for the EPA’s response to this comment.

Commenter: American Exploration and Production Council
Comment Number: EPA-HQ-OAR-2023-0234-0295
Page(s): 20

Commenter: Endeavor Energy Resources, L.P.
Comment Number: EPA-HQ-OAR-2023-0234-0381
Page(s): 12

Comment 5: Commenter 0295: **Crankcase Venting**

AXPC has concerns with the proposed requirement to quantify and report crankcase emissions from reciprocating engines and combustion turbines.

First, AXPC does not agree that this is a significant source of emissions that should be quantified and reported for the production or gathering and boosting segments. The 2015 study that is cited as the basis for adding this source category is an extremely limited study that only involved three compressor stations (all located in the same gas play and operated by the same owner), a small number of engines (and all were 4-stroke lean burn types), and had highly variable results (from 0.3 kg/hr to 2.2 kg/hr). Based on these limiting factors, it is not appropriate for EPA to assume that crankcase emissions are 14.4% of combustion exhaust emissions from all engine types, sizes, and industry segments, and therefore not appropriate to assume this source type is contributing significantly to emissions from the sector.

Commenter 0381: **EPA Should Remove or Revise Many of the Additional Emission Sources Proposed for the Onshore Petroleum and Natural Gas Production Reporting Segment.**

Crankcase Venting

EPA proposes to add as an emission source methane emissions from crankcase ventilation from reciprocating internal combustion engines or gas turbines.[39] Endeavor recommends removing crankcase venting as an emission source from any final rule. Nearly all engines in the industry use emission controls that eliminate or minimize any released emissions, and these engines also have manufacturer-tested and -stated efficiencies. The additional burdens of measuring and reporting methane emissions from crankcase venting are thus simply not justified by the negligible emissions that would be reported. Moreover, there is simply no practical way to capture or directly measure emissions from crankcase venting, meaning that an emissions factor would likely need to be used; such calculations are not assured to produce accurate reporting as required by the IRA. The difficulties in measurement are also compounded by the fact that many in our sector lease, rather than own, their combustion engines; while owners and operators test those engines for compliance with Subpart JJJJ,[40] they have less control over them for measuring and reporting for purposes of Subpart W. Endeavor thus recommends that the emission source for crankcase venting be eliminated from any final rule.

Footnotes:

[39] *Id*. at 50,308–09.

[40] *See* 40 C.F.R. Part 60, Subpart JJJJ.

Response 5:

The EPA disagrees with commenters that crankcase venting is not a significant source of emissions. As stated in the preamble to the proposed rule, the EPA has estimated sector-wide emissions from crankcase ventilation using data from a 2015 study published by Johnson et al., *Methane Emissions from Leak and Loss Audits of Natural Gas Compressor Stations and Storage Facilities*. In this study, the audit of three natural gas compressor stations and two natural gas storage facilities yielded an average ratio of crankcase-to-exhaust emissions of 14.4 percent. The study authors compared total emissions rate (crankcase plus exhaust) against literature values of a four-cylinder lean burning engine in U.S. EPA's Compilation of Air Pollutant Emission Factors (AP-42). The literature value overpredicted the combined emissions by 11.4 percent, which slightly exceeded the calculated uncertainty for exhaust emissions of 7.2 percent. This comparison indicates the measured value offers a reasonable estimate of CH_4 loss from natural gas compressor stations and storage facilities. Based on this study, the EPA estimated that the total nationwide CH_4 emissions from crankcase ventilation that could be reported to the GHGRP would be approximately 800,000 metric tons per year, assuming crankcase emissions are 14.4 percent of combustion emissions from all proposed industry segments. For more information on the estimation of potential CH_4 emissions from crankcase venting, see the subpart W TSD, available in the docket for this rulemaking.

Additionally, the EPA is finalizing the proposed emission factor-based methodology under 40 CFR 98.233(ee)(2). We disagree that an emission factor-based methodology is inaccurate, as emission factors are developed from published empirical data. We expect this method to be low burden on reporters, as the inputs to the calculation simply require a count of RICE with crankcase vents and their respective operating hours. Therefore, we disagree that the burden for calculating emissions from this source is significant. Further, in the final rule, we've added an optional measurement methodology under 40 CFR 98.233(ee)(1) that should allow for increased flexibility and accuracy in reporting emissions from this source. Additional information on the optional measurement methodology and how it should be performed is provided in section III.C.5 of the preamble for the final rule.

Commenter: Chesapeake Energy Corporation
Comment Number: EPA-HQ-OAR-2023-0234-0400
Page(s): 17

Commenter: American Petroleum Institute et al. (Part 1 of 2)
Comment Number: EPA-HQ-OAR-2023-0234-0402
Page(s): 67

Comment 6: Commenter 0400:

In addition, Chesapeake requests that EPA expand existing mechanisms for operators to utilize flaring to reduce reported emissions. Chesapeake requests that EPA include specific provisions for flaring for … crankcase venting:

• Crankcase Venting: EPA's Proposed Rule does not provide operators with the option to route the crankcase vent line to be combusted in order to reduce vented emissions.

Commenter 0402: Crankcase Venting

In general, the Industry Trades support the use of actual test data for crankcase venting when available, while still allowing the use of a provided emission factor. However, the Industry Trades believe the emission factor for this activity … should include the ability to take credit for routing the emissions to a control device ….

…

As proposed, there is no method to reflect reductions if emission controls are developed and implemented or crankcase venting is routed to a control or combustion device. The Industry

Trades recommend adding this flexibility by including a control efficiency parameter in Equation W-45, which also has the added impact of incentivizing controls where feasible.

Response 6: See Section III.C.5 of the preamble to the final rule for the EPA's response to this comment.

Commenter: Pioneer Natural Resources USA, Inc.
Comment Number: EPA-HQ-OAR-2023-0234-0385
Page(s): 13

Commenter: Interstate Natural Gas Association of America (INGAA)
Comment Number: EPA-HQ-OAR-2023-0234-0387
Page(s): 4-5

Commenter: Williams Companies, Inc.
Comment Number: EPA-HQ-OAR-2023-0234-0394
Page(s): 14

Commenter: Downstream Natural Gas Initiative
Comment Number: EPA-HQ-OAR-2023-0234-0396
Page(s): 4

Comment 7: Commenter 0385: **Crankcase Venting Calculation Recommendation**

In the calculation for crankcase venting, the methane emissions factor should be the average concentration of methane in the exhaust stream, and not related to the inlet gas stream concentration as proposed.

Commenter 0387: A final issue is the methane content of the crankcase vent stream, which is parameter "GHGCH4" in equation W-45. This vent stream can be diluted and may have a much lower methane content than the methane content of gas stream entering the reciprocating internal combustion engine or the default value referenced. Thus, operators should have the option to measure the methane content of the crankcase gas vent and use that measured value as the basis for "GHGCH4". This should be clearly stated because it is not clear if this option is allowed under the "engineering estimates" language currently proposed. Measured (i.e., empirical) data will improve the emission estimate.

… (3) measurement of the vent stream methane content should be clearly stated as an option for estimating emissions.

Commenter 0394: Crankcase Venting

…

Additionally, the EPA incorrectly suggests in Equation W-45 that the methane content in crankcase vent gas is equivalent to the methane content in fuel gas. The intentional introduction of air into an engine cylinder on the compression stroke, combined with the conversion of methane to combustion products during the power stroke, results in a methane concentration in the crankcase vent being approximately 3-4 %.[36]

Footnote:

[36] Id.

Commenter 0396: **Crankcase Venting**

Crankcase venting is not a reported emission source under the current rule. EPA has proposed the addition of crankcase emissions for transmission and storage (underground and LNG) stations, as well as distribution systems.

As proposed, companies would calculate emissions for crankcase venting using hours of operation, an emission factor, and methane content of the gas going into the compressor. In the TSD, EPA describes crankcase gas as gas mixed with "lubricating oil mist". As a result, DSI expects that the CH4 content of crankcase gas would be lower than the CH4 content of gas going into the compressor. DSI suggests that EPA consider revising Equation W-45 to properly account for the CH4 content in the crankcase gas (e.g., allowing the CH4 content to be based on best engineering judgement, or applying a scaling factor to the CH4 content of the gas).

Response 7: See Section III.C.5 of the preamble to the final rule for the response to this comment.

Commenter: Western Energy Alliance
Comment Number: EPA-HQ-OAR-2023-0234-0399
Page(s): 10-11

Comment 8: As proposed, engine size does not appear to be considered in calculating emissions or developing the emission factor. The factor developed for crankcase venting used input data in the Technical Support Document that corresponded to natural gas storage and compressor stations, not upstream production, resulting in a significant overestimation of emissions. Gas storage compressors and compressor station engines are of a much larger scale than production facility engines and are therefore expected to have a much higher vent rate. Like blowdowns, there should be a de-minimis exemption for very small engines, or EPA should allow for the direct measurement of small volumes. While the direct measurement and test data should be allowed, EPA should still reconsider the emission factor as developed.

> **Recommendation:** EPA should … provide a de-minimis exemption for small engines.

Response 8: See Section III.C.5 of the preamble to the final rule for the response to this comment.

Commenter: American Exploration and Production Council
Comment Number: EPA-HQ-OAR-2023-0234-0295
Page(s): 20

Commenter: Arkansas Independent Producers and Royalty Owners (AIPRO)
Comment Number: EPA-HQ-OAR-2023-0234-0382
Page(s): 15

Commenter: Western Energy Alliance
Comment Number: EPA-HQ-OAR-2023-0234-0399
Page(s): 10-11

Commenter: American Petroleum Institute et al. (Part 1 of 2)
Comment Number: EPA-HQ-OAR-2023-0234-0402
Page(s): 67

Comment 9: Commenter 0295: **Crankcase Venting**

AXPC has concerns with the proposed requirement to quantify and report crankcase emissions from reciprocating engines and combustion turbines.

…

Even if this source type's contribution were significant, AXPC contends that a single emission factor in units of scf/hr per vent (as proposed) would not be representative of all engine types and sizes. If EPA maintains this source category in the final rule, AXPC recommends that EPA include separate emission factors for each engine type, and that those emission factors be expressed in units of scf/hp-hr to more accurately represent the different magnitude in emission rates that might be expected for engines of difference sizes and types.

Commenter 0382: **Crankcase Venting:**

The proposed revisions for this new source category, in their current form, will likely significantly overstate emissions from crankcase vents on the smaller/lower horsepower models of RICE typically used in the Onshore Production segment and smaller Gathering & Boosting segment facilities as a result of the one-size fits all emission factor currently proposed. Further, the emission factor only approach fails to meet the legislative mandate of the IRA to allow reporters to use "empirical data."

As such, AIPRO proposes that EPA amend the current proposed Subpart W revisions to 1) allow for a horsepower or horsepower-range specific emissions factor-based approach, and

Commenter 0399: As proposed, engine size does not appear to be considered in … developing the emission factor. The factor developed for crankcase venting used input data in the Technical Support Document that corresponded to natural gas storage and compressor stations, not upstream production, resulting in a significant overestimation of emissions. Gas storage compressors and compressor station engines are of a much larger scale than production facility engines and are therefore expected to have a much higher vent rate. …

> **Recommendation:** EPA should recalculate the factor using measured crank case emissions from the upstream segment …

Commenter 0402: Crankcase Venting

… However, the Industry Trades believe the emission factor for this activity should be derived based on horsepower in order to be more reflective of operations in the onshore production or gathering and boosting segments, …

The study cited in the TSD included an audit of three gas compressor stations and two natural gas storage sites[56]. These facilities are expected to have a much higher vent rate than in production operations due to the larger engine size required in gas compressor stations and gas storage. Therefore, the proposed average emission factor may reflect an overestimation of this source for upstream production and many smaller gathering and boosting facilities. The Industry Trades suggest that EPA considers deriving an emission factor based on engine horsepower instead of vent count, as the vent rate is correlated with engine size rather than number of vents.

Footnote:

[56] Johnson et al., 2015

Response 9: Commenters did not provide a source for a revised emission factor (e.g., an emission factor in terms of scf/hp-hr). Based on our assessment of available information, the EPA is maintaining the source of the final Calculation Method 2 emission factor, "EPA Phase II Aggregate Site Report: Cost-Effective Directed Inspection and Maintenance Control Opportunities at Five Gas Processing Plants and Upstream Gathering Compressor Stations and Well Sites, Technical Report," prepared by National Gas Machinery Laboratory, Clearstone Engineering, Ltd., and Innovative Environmental Solutions, Inc. (hereafter referred to as the "Clearstone Phase II Study"). However, for the final rule we are expressing this emission factor to be in units of measure of kilograms CH_4 per hour per source, rather than by vent count. See Section III.C.5 of the preamble to the final rule for additional response to this comment.

Commenter: GPA Midstream Association
Comment Number: EPA-HQ-OAR-2023-0234-0299
Page(s): 56

Commenter: Williams Companies, Inc.
Comment Number: EPA-HQ-OAR-2023-0234-0394
Page(s): 14

Commenter: American Petroleum Institute et al. (Part 1 of 2)
Comment Number: EPA-HQ-OAR-2023-0234-0402
Page(s): 67

Comment 10: Commenter 0299: **77. EPA should allow calculation and reporting options based on each engine instead of facility-wide averages.**

The proposed requirements seem to indicate that crankcase venting emissions calculations and reporting are to be conducted based on averages for the whole facility.122 In practice, reporters will calculate crankcase emissions per engine, and it will be easier if the calculation and reporting requirements are per-engine instead of per-facility. This eliminates an extra step of determining facility wide total and averages.

Footnote:

[122] See, e.g., Proposed 40 C.F.R. § 98.236(ee)(3) ("Average estimated time that the [RICE] or gas turbines with crankcase venting were operational in the calendar year, in hours ("T" in Equation W-45 of this subpart).").

Commenter 0394: Crankcase Venting

Williams opposes the proposed emissions factor method, which is based on a per vent approach. The emissions factor should be per reciprocating engine unit and not per vent to avoid confusion. The proposed 2.28 scfh per vent in Equation W-45 does not accurately reflect crankcase emissions per engine based on a study by CSU.[35]

…

Footnote:

[35] Characterization of Crankcase Ventilation Gas on Stationary Natural Gas Engines, Colorado State University, March 2023.

Commenter 0402: Crankcase Venting

…

EPA is proposing a reporting requirement for the average operating hours for each reciprocating internal combustion engine or gas turbine. The Industry Trades recommend the removal of this "average" data; it is duplicative and requires operators to average numbers used in calculations for the sole purpose of reporting this element. The Industry Trades recommend removing this data reporting requirement or leaving the reporting requirement on a per-site basis of total operating hours.

Response 10: See Section III.C.5 of the preamble to the final rule for the EPA's response to this comment.

Commenter: GPA Midstream Association
Comment Number: EPA-HQ-OAR-2023-0234-0299
Page(s): 56

Commenter: Truck & Engine Manufacturers Association (EMA)
Comment Number: EPA-HQ-OAR-2023-0234-0352
Page(s): 7

Commenter: American Petroleum Institute et al. (Part 1 of 2)
Comment Number: EPA-HQ-OAR-2023-0234-0402
Page(s): 67

Comment 11: Commenter 0299: **GPA seeks clarification on the term "vent" as it relates to crankcase emissions.**

EPA proposes that the emission factor of 2.28 scfh be multiplied by the number of vents.121 GPA seeks clarification on the term "vents" and how to count them, or whether this emission factor was meant to be applied to the whole engine. Vents (or "breathers" as they are sometimes called) can be manifolded together. For example, when installed within a structure, an engine's multiple crankcase vents are typically routed to a central manifold and exhausts to the exterior of the structure through a single "vent." This could be interpreted as an assigned flow value of 2.28 scfh.

Footnote:

[121] 88 Fed. Reg. at 50,309, 50,413.

Commenter 0352: **Additional Evaluation of the Crankcase Emission Factor May Assist in Determining Its Accuracy Across Oil and Gas Sources.**

EPA requested comment on the crankcase emission calculation method. In the NPRM, EPA proposes a component-level average factor approach for determining crankcase ventilation emissions based on the 2021 API Compendium of Greenhouse Gas Emissions Methodologies for the Natural Gas and Oil Industry ("2021 API Compendium"). [3] 88 Fed. Reg. at 50,308-09. Evaluation of the exact equipment and configurations evaluated by the 2021 API Compendium would assist understanding of the utility of EPA's per-vent emission calculation method and parameters for best use.

EMA provides the following comments to assist EPA in its evaluation of its proposed process. From the 2021 API Compendium itself, it is unclear whether the leak survey data included solely engine crankcase vents or also included *compressor* crankcase vents too.[4] Understanding this detail could impact the interpretation of the resulting emission factor. Additionally, not all sources use the same venting strategy, which could affect EPA's per-vent calculation method. Based on site specific requirements, the crankcase venting system may vary in configuration. Engines that are installed inside a structure often route all crankcase vents to single manifold "vent." The exact same engine installed outside of a structure may not have a centralized manifold that collects individual crankcase vents together into a single stream. The installation set-up of the reviewed sources for the 2021 API Compendium is unclear from the document. Thus, from the information in the record, it is difficult to assess whether API's emission factor is based solely on engine vents, what configurations were surveyed, and how these factors could impact the overall utility of the emission factor. This could also help assess the potential reasons for different emissions determined by different studies, as EPA noted.

Footnotes:

[3] Earlier in the NPRM, EPA notes a 2015 study that found "an average ratio of crankcase-to-exhaust emissions of 14.4 percent," that reviewed three natural gas compressor stations and two natural gas storage facilities. 88 Fed. Reg. at 50,308. Based on information that this may overestimate emissions, EPA chose to propose a flow rate of 2.28 standard cubic feet per hour per source, with the "source" being the vent.

[4] The 2021 API Compendium was based on a fugitive equipment detection program that sought to "determine cost-effective directed inspection and maintenance (DI&M) control opportunities (EPA, 2006)." 2021 API Compendium at 7-82. The program reviewed leak surveys from 5 gas process plants, 7 gathering compression stations and 12 well sites in 2004 and 2005. This survey's average total hydrocarbon (THC) emission factor for crankcase vents was 1.20E-01 THC/hr/source. }

<u>Commenter 0402</u>: Crankcase Venting

…

The Industry Trades also recommend that EPA provide clarification around how to account for crankcase vents which are manifolded together, as the reporting requirements are on a per-vent basis.

Response 11: See Section III.C.5 of the preamble to the final rule for the EPA's response to this comment.

Commenter: Truck & Engine Manufacturers Association (EMA)
Comment Number: EPA-HQ-OAR-2023-0234-0352
Page(s): 3

Comment 12: EPA Should Clarify the Limited Nature of Crankcase Ventilation Emissions
…

In any final rule, EPA should remove any ambiguity regarding reciprocating internal combustion engines ("RICE"). The NPRM addresses crankcase ventilation emissions … in the context of petroleum and natural gas systems. The NPRM does not, and should not, purport to address these issues beyond the petroleum and natural gas systems source category. As such, any language implying that the crankcase ventilation … issues apply beyond the petroleum and natural gas systems source category should be removed or edited.

For example, EPA identifies adding crankcase venting as an additional emission source in the petroleum and natural gas systems category: "We are also proposing to add calculation methodologies and requirements to report GHG emissions for several other new emission sources, including nitrogen removal units, produced water tanks, mud degassing and *crankcase venting*." 88 Fed. Reg. at 50,288 (emphasis added).[1] The subsequent text potentially creates confusion by: "proposing to … add new measurement-based methodologies … for determining combustion emissions from reciprocating internal combustion engines (RICE) and gas turbines (GT), *including* those that drive compressors, to account for combustion slip, which is not currently accounted for under the existing calculation methodologies for combustion emissions." *Id.* (emphasis added.)

…

The language is ambiguous regarding whether this action addresses RICE and GT in *any* context or solely in oil and gas sources. Such an action would be beyond the scope of the notice EPA has provided and the analysis EPA has conducted. EPA has failed to provide notice that engine manufacturers should address a rulemaking positioned solely for the oil and gas sector. Before any such action could be taken, a new notice with a genuine opportunity to comment must be provided. Further discussion and analysis of impacts, costs, benefits, and unintended consequences must be taken before making a source category-wide determination for RICE and GT, particularly in a rule that is not advertised as targeting those source categories. EPA itself acknowledges it is basing this conclusion on the *appearance* of cross-industry consistency, even though the recent studies relied upon focused on the oil and gas sector. And as noted above, EPA explicitly evaluated costs and burdens only from petroleum and natural gas industry segments.

EPA should remove any ambiguous language and clarify that the only changes for RICE are with respect to the relevant, specific oil and gas sources outlined in Subpart W.

Footnote:

[1] As noted later, the crankcase venting reporting requirement excludes closed crankcase systems.

Response 12: The EPA does not agree that revisions from proposal to the rule are required to address the commenters concerns. The requirement to report crankcase venting emissions is being finalized under 40 CFR 98 subpart W, which only covers sources in petroleum and natural gas systems. Therefore, it should be understood by reporters that emissions from crankcase venting as reported under 40 CFR 98.236(ee) are only from RICE located in one of the applicable petroleum and natural gas industry segments, as described in 40 CFR 98.230.

Commenter: CrownQuest Operating
Comment Number: EPA-HQ-OAR-2023-0234-0393
Page(s): 109

Commenter: Atmos Energy Corporation
Comment Number: EPA-HQ-OAR-2023-0234-0406
Page(s): 7

Comment 13: Commenter 0393: In this study it states, "Though all components were scanned for leaks, a thorough inventory of non-leaking components was not recorded due to time constraints and number of components." In the study when presenting findings on additional emission factors, "it was nearly impossible to use Tier 3 approach from an economic and resource standpoint." "A legitimate and reliable method of establishing a single site or natural inventory was difficult to perform due to the size of natural gas systems, variety of system designs, employed engine technology, annual throughput, limitations of measuring methods employed, and economic considerations."

It sounds like the people that provided this study quickly realized the difficulty and complexity of these systems. Throughout our comments you will see instances where we echo this sentiment when speaking of representative sampling and being able to obtain ACTUAL internal emission factors. In the conclusion of the study, it states " the engine exhaust emissions measured values were lower…including crankcase emissions, the average measured values were 11.4% lower…"

"Although sample size was limited, researchers suggested that updated EFs be developed as a method for reduced disparity among varied methods." This study is so insignificant it cannot even be calculated, without factoring in knows volumes.

How can you recommend updated EFs when most of the study showed actual emissions to be lower than the proposed EFs. It does not make sense.

Commenter 0406: [A]spects of the Proposed Rule rely on outdated study data or data derived from a limited class of reporters. … EPA is also proposing to add a component-level average emission factor approach for estimating crankcase venting emissions that was developed from a 2004/2005 study at five gas processing plants, seven gathering compressor stations, and twelve well sites.[26] These updates are not supported by the same current, representative data—instead, EPA is attempting to rely on a small subset of data to broadly expand reporting obligations, without concrete support. EPA should not finalize these requirements. Atmos Energy urges EPA to only propose new emissions reporting where those changes are supported by current, representative data. To do otherwise would impose an undue burden on operators without clear, persuasive justification for the changes.

Footnote:

[26] *Id.* 50,308.

Response 13: As discussed in other responses within this section, the EPA is providing an optional direct measurement methodology in the final rule, Calculation Method 1. Therefore, if a reporter does not feel that the emission factor methodology provided under final Calculation Method 2 accurately represents their crankcase venting emissions, the reporter may elect to directly measure emissions using Calculation Method 1. The commenters did not provide more recent studies that have been published with updated crankcase venting emission factors. Based on EPA's assessment of the available information, the EPA disagrees that the source of the proposed emission factor is outdated and is maintaining its use in the final rule.

5 Reporting for the Onshore Petroleum and Natural Gas Production and Onshore Petroleum and Natural Gas Gathering and Boosting Industry Segments

5.1 General Comments on Disaggregation

Commenter: Taxpayers for Common Sense (TCS)
Comment Number: EPA-HQ-OAR-2023-0234-0351
Page(s): 4

Commenter: Colorado Department of Public Health and Environment (CDPHE)
Comment Number: EPA-HQ-OAR-2023-0234-0373
Page(s): 3

Comment 1: Commenter 0351: *Disaggregation of Reporting Requirements*

As part of EPA's effort to improve the quality and quantity of data reported, TCS supports the proposed disaggregation of reporting requirements to at least the well-pad and gathering boosting site-level. As EPA notes, this proposal will provide taxpayers with valuable information on localized GHG emissions. This information is essential as, in addition to exacerbating the impacts of climate change, GHG emissions can also pose significant health and environmental risks to local communities. TCS supports the EPA in requiring disaggregated data where appropriate, including the reporting of major equipment types (e.g., wellhead, compressor, dehydrator) where a component-level leak is detected.

Commenter 0373: CDPHE supports the proposed changes to disaggregate reporting requirements for the Onshore Petroleum & Natural Gas Production and Gathering & Boosting segments.

Response 1: The EPA acknowledges the commenters' support of the proposed revisions. The EPA is finalizing these amendments as proposed.

Commenter: Independent Petroleum Association of America (IPAA)
Comment Number: EPA-HQ-OAR-2023-0234-0265
Page(s): 4

Commenter: Williams Companies, Inc.
Comment Number: EPA-HQ-OAR-2023-0234-0394
Page(s): 10

Commenter: Lambda Energy Resources
Comment Number: EPA-HQ-OAR-2023-0234-0405
Page(s): 2

Commenter: Wyoming Department of Environmental Quality (WDEQ)
Comment Number: EPA-HQ-OAR-2023-0234-0388
Page(s): 7

Commenter: Western Energy Alliance
Comment Number: EPA-HQ-OAR-2023-0234-0399
Page(s): 10

Comment 2: Commenter 0265: Facility Definition

When EPA set its facility definition for the GHGRP, it was based on the 25,000 mt/year on information indicating that it would exclude small wells and producers. However, experience is showing that the current structure of the definition is capturing facilities comprised of low production wells and gathering and boosting facilities (that were not part of the original threshold selection). EPA is now proposing that emissions calculations be made at the well pad level. It should also revise the facility definition to exclude low production wells and to alter the gathering and boosting calculation to limit the use of arbitrary emissions estimates based on pipeline mileage.

Commenter 0388: **4.) WDEQ respectfully requests that EPA allows for flexibility in its emissions calculation methodologies.**

WDEQ raises a similar concern regarding the proposed disaggregation of reporting requirements within the Onshore Petroleum and Natural Gas Production and Onshore Petroleum and Natural Gas Gathering and Boosting industry segments under Part 98. While the proposed disaggregated reporting to at least well-pad and site-level will provide EPA with greater specificity of reported data, it comes at the expense of a significant resource burden to undertake such reporting. WDEQ respectfully requests that EPA considers affording flexibility in its finalized reporting requirements for sites that opt to use worst-case-scenario estimates as an alternative to potentially costly and resource-encumbering direct measurements.

Commenter 0394: C. Disaggregation for the Gathering and Boosting Segment

Williams recognizes the improved detail in GHG emissions reporting by disaggregation of reporting requirements within the Onshore Petroleum and Natural Gas Production and Onshore Petroleum and Natural Gas Gathering and Boosting industry segments to at least the well-pad and gathering boosting site-level. However, entering site-specific (in addition to basin-wide) GHG emissions information in e-GGRT will take considerably more time for owners / operators. Additional staff will be required to enter separate line-item information for each site under each basin for multiple emissions sources. The EPA does not indicate whether it has fully accounted for this financial impact on companies if implemented as proposed. To reduce the impact of entering site-specific information into e-GGRT, the EPA can reasonably limit the information to be reported in e-GGRT to only that data which is needed to conduct GHG emissions calculations. Superfluous activity data information not critical to quantification of GHG emissions should be kept to a minimum. Williams highly encourages the EPA to review its current proposed reporting requirements under 40 CFR § 98.236 and streamline these requirements.

Commenter 0399: EPA is proposing to require site-level details regarding blowdown events. …

Further, within the proposed rule, EPA is not allowing blowdown events to be aggregated by facility, instead opting for line-by-line event reporting. This requirement does not increase the accuracy of the reporting program, and instead places a recordkeeping burden with no potential benefit.

Recommendation: EPA … should allow aggregation of emissions by facility.

Commenter 0405: Disaggregation of GHG emissions to the well-pad or gathering and boosting site-level are proposed in the new rule. This reporting activity will be extremely time consuming for all reporters but especially the small business with limited staff. We urge the EPA to keep the emissions reporting to a basin level to avoid possible errors and redundant data entry. Many small businesses will attempt to interpret these rules and self-report. In general, these rules should be more straightforward and easier to understand for the average operator. The cost of hiring consultants to complete GHG reporting could be prohibitive for many. It would be in the EPA's best interest for gathering accurate data to simplify reporting rules and processes as much as possible so all reports are consistent across the producing basins.

Response 2: Following consideration of these comments, the EPA is finalizing these amendments as proposed. With respect to comment on the inclusion of low production wells, the EPA did not reopen those aspects of the relevant provisions, and thus did not propose and is not taking final action on exclusion of low producing wells or changes to the 25,000 mt CO_2e applicability threshold.

The EPA expects that, in many cases, disaggregated data are already being collected by reporters to comply with existing rule requirements (well production data, equipment counts by site, etc.). As noted in the Section III.D.2 of the preamble, existing subpart W requirements specify calculation of emissions at the well level for certain sources, including Well Venting for Liquids Unloading, Completions and Workovers with Hydraulic Fracturing, Completions and Workovers without Hydraulic Fracturing, Well Testing and Associated Gas. The EPA is not changing the level at which these calculations are required to be performed, just the level at which they are reported. Thus, we expect that most of this data is already collected at this level. However, we acknowledge that reporting of disaggregated data will result in additional burden to reporters and we note that the estimated burden calculations for disaggregated reporting from Onshore Petroleum and Natural Gas Production and Onshore Petroleum and Natural Gas Gathering and Boosting industry segments reporters have been updated from proposal in this final rulemaking. See Section VI.A.2 of the preamble to the final rule for the EPA’s response to comments and for further discussion of this update.

The EPA also considered the impacts on small businesses and these impacts are discussed in Section VII.C of the preamble to the final rule and details of this analysis are presented in the memorandum, *Assessment of Burden Impacts for Greenhouse Gas Reporting Rule Revisions for Petroleum and Natural Gas Systems*, available in the docket for this rulemaking, Docket Id. No. EPA-HQ-OAR-2023-0234. As noted in this memorandum, the estimated costs per facility are based on mean costs and are likely an overestimate for small businesses. For example, the individual costs imposed on a small facility are likely to be less than the average per facility costs facility, as a small facility is likely to include fewer emissions sources requiring monitoring and reporting (e.g., a small facility may own only a small number of production wells).

Commenter: Endeavor Energy Resources, L.P.
Comment Number: EPA-HQ-OAR-2023-0234-0381
Page(s): 19

Commenter: American Petroleum Institute et al. (Part 1 of 2)
Comment Number: EPA-HQ-OAR-2023-0234-0402
Page(s): 7, 13-14

Comment 3: Commenter 0402: **EPA has not provided qualitative and quantitative justification to rationalize the proposed requirement to disaggregate current reporting levels in the Onshore Production and Onshore Gathering and Boosting industry segments.** The explicitly references existing definitions of facilities in 40 CFR 98 Subpart W, which includes basin-level reporting for the production and gathering and boosting segments. In this proposed rule, EPA has not clarified how its new proposed level of disaggregated reporting to the site-level results in additional value in understanding the key sources of emissions from a basin. A survey performed by API indicates that the proposed Information Collection Request (ICR) pertaining to the proposed rule significantly underestimates the burden for the impacted sectors that would be required to report individual site level emissions and site IDs. Due to the magnitude of the difference, EPA should provide justification in the form of both qualitative and quantitative results of the costs and benefits of this proposed change and how it aligns with the IRA.

…

Subpart W and the Waste Emissions Charge Program

EPA must present a clear rationale for adding an additional layer to sub-facility-level (i.e., site level) reporting to the onshore production and onshore gathering and boosting segments.

EPA explains in the Proposed Rule that under the current Subpart W, "GHG emissions and activity data are currently generally reported at the basin, county/sub-basin, or unit level, depending upon the specific emission source.[2] " According to EPA, this reporting method "can present challenges in the process of emissions verification, with corresponding potential impacts on data quality, and it also limits data transparency."[3] To resolve those "challenges," EPA proposes "to disaggregate reporting requirements within the Onshore Petroleum and Natural Gas Production and Onshore Petroleum and Natural Gas Gathering and Boosting industry segments."[4] Furthermore, EPA proposes to require several new site-specific data elements to be reported, including reporting information for individual well identification numbers, well pad identification numbers, and gathering and boosting site identification numbers.[5] In other words, EPA proposes to require site specific reporting in addition to facility-level aggregate reporting.

EPA correctly explains in the Proposed Rule that "[u]nder CAA section 136, an ''applicable facility'' is a facility within nine of the ten industry segments subject to subpart W, as currently defined in 40 CFR 98.230 (excluding natural gas distribution)."[6] As currently defined for onshore production and gathering and boosting, facilities in these segments are generally defined as the equipment located in a single hydrocarbon basin under common ownership or control. The meaning of the term "applicable facility" is key to implementation of the WEC because the applicability of that program and potential fees are determined on an "applicable facility" basis.[7] In the IRA, the definition of an "applicable facility" in the onshore production and gathering and boosting refers to a facility within the applicable segment, as defined in 40 CFR Part 98 at the time of passage of the bill.

Unless EPA proposes updates to facility definitions in 98.238, reporting should remain at the basin-level. Even if EPA were to propose new facility-level definitions in a future rulemaking, there are remaining concerns discussed below.

EPA's justification for the proposed sub-facility-level reporting requirements is fundamentally flawed because the Agency wholly fails to consider whether the proposed requirements will be adequate to support applicability and fee determinations under the WEC. As noted above, EPA asserts that the new sub-facility-level reporting requirements are needed because the current Subpart W approach "can present challenges in the process of emissions verification, with corresponding potential impacts on data quality, and it also limits data transparency."[8] These reasons have nothing to do with the primary purpose of this rulemaking – to satisfy the Agency's obligation to revise Subpart W to provide sufficient information for implementation of the WEC.[9] Although not related to the WEC, in EPA's Response to Comments in 2009, EPA agreed that oil and natural gas is to be reported at the "upstream" level because further disaggregation would be burdensome to the reporter.[10]

In fact, nowhere in the Proposed Rule does EPA acknowledge that a key driver (if not <u>the</u> key driver) of the proposal is to generate the facility-specific data needed to implement the WEC, nor does EPA provide any analysis or assessment as to whether the new proposed sub-facility-level reporting requirements will be sufficient for that purpose. Unless corrected in a supplemental proposal, that failure to acknowledge and assess a key factor in the rulemaking will render the final rule arbitrary and capricious. *See, e.g., Motor Vehicle Mfrs. Assn. of the United States v. State Farm Mut. Automobile Ins. Co.*, 463 U.S. 29, 43 (1983) ("Normally, an agency rule would be arbitrary and capricious if the agency has … entirely failed to consider an important aspect of the problem.") The WEC is based on the existing definitions of facilities subject to Subpart W; for that reason, there is no statutory basis to require reporting on a sub-facility-level basis. Basin-level data satisfies the Agency's obligation to revise Subpart W to provide sufficient information for implementation of the WEC.

Footnotes:

[2] 88 Fed. Reg. at 50309.

[3] *Id*.

[4] *Id*.

[5] *Id*. at 50309-10.

[6] 88 Fed. Reg. at 50285.

[7] CAA § 136(c), (e).

[8] *Id*. at 50309.

[9] CAA § 136(h).

[10] ". . . oil and other petroleum products must be reported by refineries, importers, and exporters under Subpart MM. For the proposed rule, EPA decided to require reporting at these points because reporting at natural gas and oil production wells would have been too burdensome and would have resulted in too many reporting facilities, with no improvement in data accuracy.", https://www.regulations.gov/document/EPA-HQ-OAR-2008-0508-2256.

Commenter 0381: **EPA Should Reconsider Disaggregation of Reporting for the Onshore Petroleum and Natural Gas Production Segment.**

EPA proposes to disaggregate the reporting requirements for the Onshore Petroleum and Natural Gas Production industry segment such that many emission source types that were once reported at the basin or sub-basin/county level would instead be reported at the well or well-pad level, depending on the particular emission source.[62] While Endeavor understands the appeal of greater granularity in emissions reporting, EPA underestimates how much additional personnel time it will take for reporters to gather, verify, and compile well-pad-level or well-level emissions data—additional time that is hard to come by for companies in our sector who are also needing to update operations and systems in light of the Methane Proposal and other regulatory obligations. Increased granularity would also likely double or triple the length of an owner or operator's emissions report, increasing the likelihood for errors and less accurate reporting, which is in direct conflict with the IRA. The additional costs will only be amplified if EPA finalizes reporting requirements for *more* emission sources and expanded reporting requirements (e.g., mud degassing, liquids unloading, workovers) subject to Subpart W. EPA does not appear to give sufficient attention to these concerns by proposing disaggregation of reporting requirements.

More importantly, altering the granularity of reporting is unlikely to result in more accurate reporting—the *total* emissions reported will stay materially the same at any level of granularity. Endeavor is unsure how increasing the sheer volume of reported emissions data will improve "the process of emissions verification"; verification will only become more difficult and labor intensive, not less, as the amount of data increases. It appears that EPA's primary aim is, as it states, to "obtain data that is of sufficient quality and granularity that it can be used to support a range of future climate change policies and regulations under the CAA."[63] It is simply unreasonable for EPA to have owners and operators shoulder ever-increasing reporting burdens on EPA's behalf so that the Agency can explore new regulatory burdens to place on those same owners and operators. The purpose of Subpart W is to gather emissions data, and EPA's increased emphasis on site-level or well-level obligations moves the focus further and further away from data gathering and the statutory basis for the program.

In light of the above, Endeavor urges EPA to reconsider its proposed move to disaggregate emissions reporting to the well and well-pad levels. If EPA does retain the requirements, it should provide a reason for the changes that is rooted in EPA's statutory authority and the purpose of the reporting program.

Footnotes:

[62] *Id*. At 50,309–10.

[63] *Id*. at 50,291.

Response 3: The EPA disagrees that we failed to acknowledge and assess a key factor in the rulemaking. See Section III.D of the preamble to the final rule for the EPA's response to comments regarding the rationale for disaggregating reporting requirements for the Onshore Petroleum and Natural Gas Production and Onshore Petroleum and Natural Gas Gathering and Boosting industry segments and that this is consistent with our authority, including the directives in CAA section 136(h). To the extent that commenters provided specific information related to the estimated burden required to report site level emissions and IDs, these comments are addressed in Section VI.A.2 of the preamble to the final rule. Regarding the comment that disaggregated reporting will increase the length of reports and increase the likelihood for errors, the EPA notes that, as discussed in Section II.C of the preamble to the final rule, data reported under the GHGRP undergo comprehensive verification review designed to identify and correct errors. We expect this review to be sufficiently robust to address any increase in errors resulting from additional data reported under the final rule.

Commenter: CrownQuest Operating
Comment Number: EPA-HQ-OAR-2023-0234-0393
Page(s): 114

Comment 4: Site level and well IDs are confusing and unclear what that means. EPA needs to clarify what needs an ID.

Response 4: As stated in section III.D of the preamble to the proposed rule, "the EPA is proposing to add the following data elements: well-pad ID (for Onshore Petroleum and Natural Gas Production segment) and gathering and boosting site ID (for Onshore Petroleum and Natural Gas Gathering and Boosting). These proposed data elements are hereafter collectively referred to as 'site-level IDs.'" The term "site-level ID" is not defined in the rule but is used as a short-hand in the proposed and final rule preambles when referencing both well-pad and gathering and boosting site IDs. The site-level ID is a unique and permanent identifier used to designate each reported well-pad or gathering and boosting site.

The terms "gathering and boosting site" and associated site types of "gathering compressor station", "centralized oil production site", and "gathering pipeline site" are new to this rulemaking and the definitions are being finalized as proposed.

The term "Well identification (ID) number" is defined at § 98.238 and is not reopened in this rulemaking.

5.2 Onshore Petroleum and Natural Gas Production

Commenter: American Petroleum Institute et al. (Part 1 of 2)
Comment Number: EPA-HQ-OAR-2023-0234-0402
Page(s): 72

Comment 1: **Streamline the reporting form Table AA.1.ii and AA.1.iii**

American Petroleum Institute et al. (Part 1 of 2); EPA-HQ-OAR-2023-0234-0402; 75252; page 72

4. Administrative Recommendations
4.1 Streamline Existing Reporting Forms to Reduce Duplicative Reporting and Reduce Unnecessary Submittal Errors
Due to the proposed requirement to report information on a more granular basis, the Industry Trades recommend the following streamlining efforts to reduce duplicative reporting, and to reduce the possibility of administrative error.
…
4. Remove or automate Table AA.1.ii on Tab (aa)(1). All the required information is reported in Table AA.1.iii. By repeating this information in Table AA.1.iii, it increases the possibility of data errors while not improving data transparency.
5. Remove detailed reporting elements on Tab (aa)(1) in Table A.1.iii, as the detailed information on a well-by-well basis is already included on the respective source tabs (and proposed additional sources as part of this rulemaking):
a. Well venting for liquids unloading;
b. Completions or workovers with hydraulic fracturing;
c. Completions or workovers without hydraulic fracturing;
d. Well testing; and
e. Associated gas venting and flaring.

Response 1: The EPA thanks the commenter for their suggestions to avoid duplicative reporting with the implementation of more granular reporting. The references to Table AA.1.ii and Table AA.1.iii are specific to the subpart W reporting form, and more specifically tab (aa) of the reporting form. The format for reporting data is an implementation issue. The EPA is finalizing these amendments to require disaggregated reporting as proposed. Following the final rule amendments, the EPA intends to update the subpart W reporting form to incorporate all regulatory changes. In doing so, we will seek to streamline reporting and avoid duplicative reporting while ensuring that the reporting form includes all reporting requirements.

Commenter: Lambda Energy Resources
Comment Number: EPA-HQ-OAR-2023-0234-0405
Page(s): 2

Comment 2: *Lambda Energy Resources; EPA-HQ-OAR-2023-0234-0405; 72624; page 2*

Also, in line with data entry, we suggest that EPA add a column to the current subpart W form table AA.1.iii to include the state permit number in addition to the Well ID number (API number) found in column B. An additional column would help to efficiently organize wells and categorize them correctly according to their status.

Response 2: The EPA disagrees with the commenter. We do not believe the added burden of reporting a state permit number in addition to the US well ID is warranted. The U.S. well identification number, also known as API well ID number, is a widely recognized unique identifier used by the oil and gas industry, regulators, and other stakeholders. The EPA, however, recognizes that some older legacy wells may not have a US well ID number. To address these circumstances, the existing definition of Well ID number in 40 CFR 98.236 is sufficiently flexible to allow reporters to submit a state well ID number for wells that do not have a US well ID number.

Commenter: CrownQuest Operating
Comment Number: EPA-HQ-OAR-2023-0234-0393
Page(s): 225

Comment 3: *CrownQuest Operating; EPA-HQ-OAR-2023-0234-0393; 75269; page 225*

A comment on the definition on “facility” as a whole:

In Subpart W 98.238 Definitions EPA has previously defined the reporting group and facilities as an obscure “single hydrocarbon basin” as stated below:

Facility with respect to onshore petroleum and natural gas production for purposes of reporting under this subpart and for the corresponding subpart A requirements means all petroleum or natural gas equipment on a single well-pad or associated with a single well-pad and CO2 EOR operations that are under common ownership or common control including leased, rented, or contracted activities by an onshore petroleum and natural gas production owner or operator and that are located in a single hydrocarbon basin as defined in § 98.238. Where a person or entity owns or operates more than one well in a basin, then all onshore petroleum and natural gas production equipment associated with all wells that the person or entity owns or operates in the basin would be considered one facility.

EPA has designated this as a reporting threshold of 25,000 MT per year. EPA is now proposing to keep this threshold with the obscure definition of a single hydrocarbon basin but changing the reporting facility to an unspecified sub location for analyzing data clearer. It appears EPA is attempting to mirror the Facility definition in OOOOa. EPA should keep the data level it currently has if it wants to keep the single hydrocarbon basin definition for reporting requirements rather than requiring sub facilities to report. If EPA wants to require a different facility level for reporting purposes, then it should specify what that is and use a reasonable definition with a reasonable tons per year limit for that facility. Requiring a single hydrocarbon basin test at 25,000 tons per year for a test on total operations submitting data under Subpart W then requiring data to be submitted on a different vaguely specified facility basis is not a reasonable requirement. If EPA wants to get data on a more granular level, they should change the reporting threshold to reflect that so Reporter can know which facilities would fall under the reporting thresholds and what to report.

Response 3: The EPA disagrees with the commenter and is finalizing the requirements for reporting at the well and well pad site level as proposed. The EPA did not propose to change the definition of onshore petroleum and natural gas facility and the existing definition remains, defined as all petroleum or natural gas equipment on a single well-pad or associated with a single well-pad under common ownership or common control in the producing basin. In this rulemaking, the EPA proposed changing the granularity of reporting from the previous basin and sub-basin level to the well and well pad level. See the response to Comment 3 in Section 5.1 of this document for additional information.

5.3 Onshore Petroleum and Natural Gas Gathering and Boosting

Commenter: Independent Petroleum Association of America (IPAA)
Comment Number: EPA-HQ-OAR-2023-0234-0265
Page(s): 12

Commenter: Independent Petroleum Association of America (IPAA)
Comment Number: EPA-HQ-OAR-2023-0234-0265
Page(s): 12-14

Commenter: Independent Petroleum Association of America (IPAA)
Comment Number: EPA-HQ-OAR-2023-0234-0265
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Comment 1: Commenter 0265: *Gathering and Boosting/Centralized Production Facilities*

The Gathering and Boosting category in the methane tax has an inordinately low threshold for its tax basis without any apparent justification. EPA needs to explain the source of the excess emissions fee threshold for gathering and boosting facilities and why it is appropriate. Clearly though only truly separate gathering and boosting operations should be included in it. The current Subpart W proposal creates a critical issue in this regard. The types of equipment used for gathering and boosting of natural gas can be used independently to move natural gas from production facilities to natural gas processing facilities, but it can also be used at oil and natural gas production operations as an integral part of those operations. The proposed Subpart W creates a designation of upstream operators' centralized tank batteries. "Centralized oil production sites" are defined as sites collecting oil from multiple well pads without compressors "that are part of the onshore petroleum and natural gas gathering and boosting facility that gathers hydrocarbon liquids from multiple well pads". In the proposed rule, EPA has classified centralized oil production sites under the Gathering and Boosting segment. Subpart W needs to be clarified to assure that those centralized oil production operations are included within the reporting for the production facility.

Centralized Oil Production Facility Issues

EPA has recognized centralized production sites as a facility type in the proposed rule and required its emissions to be reported at the site-level, rather than per well ID, which streamlines the reporting for tank batteries. However, there are challenges with including "centralized oil production sites" in the Gathering and Boosting segment.

First, EPA included "production" clearly in the name and it is nonsensical that centralized production sites would be considered part of the Gathering and Boosting segment.

Second, these sites are considered by many operators as part of the upstream production process as these tank batteries are likened to "production supportive facilities." Facility design efficiency gains over the years have led to centralization of production surface equipment. The centralization of surface equipment generally results in emissions reductions relative to dispersed facilities (separation and tanks installed at each well pad) because the total equipment counts are significantly reduced (fewer emission points), there is a reduction of tank batteries/spill risk, increased operational efficiencies, and better ability to site major facilities away from sensitive areas/populations. This segment classification is contradictory to previous interpretations and may have unintended consequences such as companies electing not to centralize such operations (even though consolidation serves to minimize environmental footprint) due to the more burdensome methane fee implications. Facilities comprised of centralized surface equipment are owned and operated by producers, supportive of production, and may or may not include a well head or pump jack collocated on a single pad.

However, because EPA re-defined the production segment in 2016 as "associated with a single well pad", this has created reporting confusion and centralized tank batteries have been categorized differently both by individual owners/operators, as well as other federal rules (NSPS OOOOb). For example, under the proposed OOOOb regulations, the "centralized oil production facilities" (referred to in NSPS OOOOb as "centralized production facility") are grouped under the production segment by definition rather than as Gathering and Boosting as explained below.

Currently Subpart W calls and defines the subject facility as:

"**Centralized oil production site** means any permanent combination of one or more hydrocarbon liquids storage tanks located on one or more contiguous or adjacent properties that does not also contain a permanent combination of one or more compressors that are part of the onshore petroleum and natural gas gathering and boosting facility that gathers hydrocarbon liquids from multiple well-pads. A centralized oil production site is a type of gathering and boosting site for purposes of reporting under §98.236."

Meanwhile NSPS OOOOb/OOOOc calls and defines it as:

"**Centralized production facility** means one or more storage vessels and all equipment at a single surface site used to gather, for the purpose of sale or processing to sell, crude oil, condensate, produced water, or intermediate hydrocarbon liquid from one or more offsite natural gas or oil production wells. This equipment includes, but is not limited to, equipment used for storage, separation, treating, dehydration, artificial lift, combustion, compression, pumping, metering, monitoring, and flowline. Process vessels and process tanks are not considered storage vessels or storage tanks. A centralized production facility is located upstream of the natural gas processing plant or the crude oil pipeline breakout station and is a part of producing operations."

In addition, in the Pipeline and Hazardous Material Safety Administration's ('PHMSA") proposed Gas Pipeline Leak Detection and Repair rule, PHMSA does not define or regulate any production facilities as "gathering and boosting". Specifically, as defined in API's Recommended Practice-80 and incorporated in 49 CFR 192: "The production function, in most cases, extends well downstream of the wellhead and may include several processes required to prepare the gas for transportation. In this context:

'Production Operation' means piping and equipment used for production and preparation for transportation or delivery of hydrocarbon gas and/or liquids and includes the following processes: (a) extraction and recovery, lifting, stabilization, treatment, separation, production processing, storage, and measurement of hydrocarbon gas and/or liquids; and (b) associated production compression, gas lift, gas injection, or fuel gas supply."

Both the NSPS OOOOb/OOOOc and PHMSA's name and definition of what are essentially tank batteries are much more consistent with how these facilities operate and are managed in the field. In an effort to mitigate confusion and create more rule alignment, EPA should align the name and definition of the subject facility type between Subpart W and NSPS OOOOb/OOOOc.

In this proposal, EPA claims to be striving for consistency when EPA states, on page 50288 of the proposal, "as in the 2016 rule, the proposed amendments would also allow facilities to use a consistent method to demonstrate compliance with multiple EPA programs." Also, even though EPA uses the word "gather" in the definition in OOOOb/OOOOc, these sites are still properly defined as "part of the producing operations."

Further, the fact that EPA has proposed the definition of "centralized production sites" as sites that do <u>not</u> include compressors that are part of the Gathering and Boosting segment is puzzling. If these sites are part of the Gathering and Boosting segment as EPA has proposed, why would these sites not be allowed to have compressors that are part of the Gathering and Boosting segment on them? This demonstrates that EPA does understand the distinction between gathering and boosting compressors that should appropriately be included in the Gathering and Boosting segment and centralized tank batteries that clearly should not.

As such, EPA should change both the name and definition of "centralized oil production site" in the Subpart W rule to match NSPS OOOOb/OOOOc, to align with other federal programs for consistency, and to reflect how the industry owns and operates these facilities. EPA should delete "associated with a single well pad" from the Onshore Petroleum and Natural Gas Production definition in Subpart W in order to clear up the confusion and properly have centralized production sites in the production segment where they belong.

Further, and most importantly, EPA's proposed definitions are contrary to the MERP waste emissions thresholds, where gathering and boosting sites are considered "non-production". In this language on the Waste Emission Threshold, Congress created two categories for applicability of the threshold: "Production" and "Non-Production". The Gathering and Boosting segment (segment #8) is listed under "Non-Production". Clearly, Congress did not intend for sites associated with production, such as "centralized **production** sites" to be considered gathering and boosting. EPA may have been able to impose reporting obligations for emissions from centralized tank batteries under the Gathering and Boosting segment in the past but for application of the tax, these sites should be considered production. Doing otherwise would result in an inequitable application of the tax that would most likely not be applied uniformly by all upstream operators. If EPA does not wish to clear up the confusion and include centralized production sites in the Production segment, EPA should carve out these sites for threshold determination and make these sites subject to the 0.2% threshold as Congress has clearly mandated in the law.

In addition, the categorization of a centralized production site into Gathering and Boosting could result in a backslide from the progress industry has made in minimizing its overall footprint and emission sources. Due to the higher methane taxes that may accompany categorizing production sites as Gathering and Boosting (subjecting these facilities to the 0.05% threshold instead of the 0.2% threshold) operators may be economically incentivized to migrate back to individual well pad installations, dramatically increasing the amount of equipment in the field and increasing GHG emissions.

<u>Commenter 0295</u>: **III. Designation of "Gathering and Boosting" versus "Production" Segment**

EPA is considering significant changes in its reporting requirements for the various industry segments in this Proposal. One key detail of the proposed rule involves the segment designation of upstream operators' centralized tank batteries. AXPC appreciates that EPA has recognized centralized production sites as a facility type in the Proposal and required its emissions to be reported at the site-level, rather than per well ID, which streamlines the reporting for tank batteries. However, in the Proposal rule, EPA has classified centralized oil production sites under the gathering and boosting segment, and this classification presents multiple challenges.

In the Proposal, EPA defines "Centralized oil production sites" as sites collecting oil from multiple well pads without compressors "that are part of the onshore petroleum and natural gas gathering and boosting facility." In actuality, these sites are commonly considered by upstream operators as part of the upstream production process as these facilities are likened to "production supportive facilities," and it is common practice that the upstream operator owns/operates these facilities rather than the midstream/gathering & boosting company counterpart. Upstream exploration and production companies often design their operations to include centralized production sites and operate these facilities generally in an effort to minimize environmental footprint. This contrasts with Midstream operators who traditionally operate gathering and boosting sites that are typically large compressor stations that boost pipeline gas across an entire area and provide a transportation service to upstream operators.

Facility design efficiency gains over the years have led to centralization of production surface equipment, for both operational and environmental advantages. The centralization of surface equipment generally results in emissions reductions relative to decentralized facilities (i.e., separation equipment and tanks installed at each well pad) because the total equipment counts are significantly reduced (i.e., fewer emission points). With the centralization of facilities, there is a reduction of spill risk, increased operational efficiencies (including more stable flow volumes which allows for mid and low-pressure gas capture), and increased siting advantages as there is more ability to site major facilities away from sensitive areas/populations. Facilities comprised of centralized surface equipment are owned and operated by producers, supportive of production, and may or may not include a compressor, well head or pump jack collocated on a single pad.

However, because EPA re-defined the production segment in 2016 as "associated with a single well pad," this has created a great deal of confusion with reporters, especially as production facility designs continued to evolve. Unlike the historic single well pad design of the past, modern-day production facilities are able to realize efficiencies from consolidation and centralization. This confusion has led to not only inconsistent reporting, but also unhelpful information. GHGRP information, including from Subpart W, is intended to help identify opportunities for emission reduction, to compare facilities or industries, track emissions from one year to the next, inform policy at the federal, state and local levels, and provide important information to the finance and investment communities.[2] When EPA's 2016 amendments defined the production segment in this manner, which does not align with operational design and facility purpose, it essentially lumped together unrelated emissions sources that cannot then later be used to discern meaningful emissions trends or actionable mitigation opportunities for reduction. An example of the challenges of this categorization:

An operator may have a "centralized facility" with gas lift engines for individual onsite wells, an ECD controlling a vapor recovery tower, and tanks that receive production both from the onsite wells and offsite wells. Using current definitions, the operator would report the emissions from the combustion of the engines as "production" but the emissions from the ECD as "gathering and boosting." Emissions from fugitives and pneumatics on the site may be split between the two categories even though they are on the same facility. It would be unclear where to ascribe the production volumes from this facility – "production" or "gathering and boosting" – consequently affecting the ability to calculate emissions intensities from the site altogether.

Centralized production facilities and tank batteries have also been categorized differently by other federal rules. For example, under the proposed OOOOb/c regulations, the "centralized oil production facilities" (referred to in NSPS OOOOb as "centralized production facility") are grouped under the production segment by definition, not under gathering and boosting.

In an effort to mitigate confusion and create more rule alignment, AXPC suggests that EPA align the name and definition of the subject facility type between Subpart W and NSPS OOOOb/c. Currently Subpart W calls and defines the subject facility as follows:

"**Centralized oil production site** means any permanent combination of one or more hydrocarbon liquids storage tanks located on one or more contiguous or adjacent properties that does not also contain a permanent combination of one or more compressors that are part of the onshore petroleum and natural gas gathering and boosting facility that gathers hydrocarbon liquids from multiple well-pads. A centralized oil production site is a type of gathering and boosting site for purposes of reporting under §98.236."

NSPS OOOOb/c, on the other hand, labels and defines it as follows:

"**Centralized production facility** means one or more storage vessels and all equipment at a single surface site used to gather, for the purpose of sale or processing to sell, crude oil, condensate, produced water, or intermediate hydrocarbon liquid from one or more offsite natural gas or oil production wells. This equipment includes, but is not limited to, equipment used for storage, separation, treating, dehydration, artificial lift, combustion, compression, pumping, metering, monitoring, and flowline. Process vessels and process tanks are not considered storage vessels or storage tanks. A centralized production facility is located upstream of the natural gas processing plant or the crude oil pipeline breakout station and is a part of producing operations."

The NSPS OOOOb/c facility type name and definition are more in line with how these facilities are operated and managed in the field today. In addition, the comprehensive definition in NSPS OOOOb/c, unlike the definition in the Proposal, does not establish arbitrary boundaries based on the types of equipment at a location.

Similarly, this proposed definition for Subpart W is inconsistent with PHMSA's incorporation by reference of the industry standard, see 49 C.F.R. Sec. 192.7(b)(4), API Recommended Practice 80 ("RP80), which delineates the beginning point and end point of gathering under the regulatory framework. PHMSA does not define or regulate any production facilities as gathering equipment, as RP80 provides:

"The production function, in most cases, extends well downstream of the wellhead and may include several processes required to prepare the gas for transportation. 'Production Operation' means piping and equipment used for production and preparation for transportation or delivery of hydrocarbon gas and/or liquids and includes the following processes: (a) extraction and recovery, lifting, stabilization, treatment' separation, production processing, storage, and measurement of hydrocarbon gas and/or liquids; and (b) associated production compression, gas lift, gas injection, or fuel gas supply."

EPA's proposed definition for Subpart W is therefore inconsistent with *multiple* other federal regulatory approaches, including its own pending Section 111 proposal and the current approach of the federal pipeline regulatory body.

In this Proposal, EPA claims to be striving for consistency when it states, at 88 Fed. Reg. 50,288, “as in the 2016 rule, the proposed amendments would also allow facilities to use a consistent method to demonstrate compliance with multiple EPA programs.” Also, AXPC notes that, even though EPA uses the word “gather” in the definition in OOOOb/c, these sites are still properly defined as “part of the producing operations.” Concurrent with the approach EPA took in the OOOOb/c definition, the process of gathering hydrocarbon liquids from multiple well pads does not make these sites part of gathering and boosting which is part of midstream operators' operations, and which are most often owned by a separate entity, as explained above. Also, the fact that EPA has proposed the definition of “centralized production sites” as sites that do not include compressors, which are quintessential elements of the gathering and boosting segment, is puzzling in that it speaks directly to the inherent inconsistency of defining these production sites as gathering and boosting. As such AXPC requests that EPA change both the name and definition of “centralized oil production site” in the Subpart W rule to match NSPS OOOOb/c. AXPC also strongly recommends that EPA delete “associated with a single well pad” from the Onshore Petroleum and Natural Gas Production definition in Subpart W in order to clear up the confusion and properly designate centralized production sites in the production segment where they belong.

Further and most importantly, EPA’s proposed definitions are contrary to IRA’s MERP waste emissions thresholds, where gathering and boosting sites are considered “non-production.” In the MERP language, (d) Waste Emission Threshold, Congress created two categories for applicability of the threshold: “Production” and “Non-Production.” The Gathering and Boosting segment (segment #8) is specifically listed under “Non-Production.” Clearly, Congress did not intend for sites associated with production, such as “centralized oil **production** sites” to be considered as gathering and boosting. Whether or not EPA was correct to impose reporting obligations for emissions from centralized tank batteries incorrectly under the gathering and boosting segment in the past, now that this reporting is directly tied to calculation of the MERP, these sites can only validly be considered as production sites. Doing otherwise would result in reporting program segments that are inconsistent with the statutorily delineated fee-taxing segments and clear Congressional intent. Additionally, it will lead to an inequitable application of the fee that would most likely not be applied uniformly by all upstream operators as some operators have not chosen to centralize their facilities.

EPA’s proposed categorization of centralized production facilities as gathering and boosting in this rule is arbitrary when comparing how these sites are treated under other EPA regulations, other federal regulations, common industry practice, and under the IRA statute. If EPA does not wish to clear up the confusion and align this reporting rule appropriately with other EPA rule makings by including centralized production sites in the Production segment, AXPC strongly recommends that EPA’s WEC calculation guidance carves out these production sites from the gathering and boosting category and subject them to the production threshold (.20) as Congress has clearly mandated in the law.

Finally, the categorization of a "production supportive" site into gathering and boosting could result in a backslide from the progress industry has made, and policies have encouraged, in minimizing its overall environmental footprint and emission sources. Due to the higher methane fees that may accompany categorizing production sites as gathering and boosting (subjecting these facilities to the 0.05% threshold instead of the 0.2% threshold) operators may be economically incentivized to migrate back to individual well pad installation dramatically increasing the amount of equipment in the field, creating larger overall surface disturbance and likely increasing GHG emissions, thus resulting in behaviors that run counter to the Congress's intent in the MERP.

EPA's categorization of centralized tank batteries as part of the gathering and boosting segment introduces discrepancies between this rule and other federal programs, complicates reporting requirements for companies, undermines the value of the reporting program, and when combined with the MERP WEC creates potential for incentivizing greater environmental impacts. As such, AXPC recommends that EPA change the name of the subject facility to "centralized production facility" and classify as onshore production to align with other federal programs for consistency and to reflect how the industry owns and operates these facilities. Nevertheless, if EPA chooses not to align the facility name, reporting for "centralized oil production sites" should still be required at the site-level for these types of facilities, instead of on a well-level basis, as is currently proposed.

Footnote:

[2] https://www.epa.gov/ghgreporting/ghgrp-and-us-inventory-greenhouse-gas-emissions-and-sinks

…

XVII. <u>EPA's Proposal conflicts in key aspects with the text and purpose of new CAA § 136.</u>

…

Second, EPA's proposal to group its proposed new definition of "centralized oil production site" within the "gathering and boosting" category, see 88 Fed. Reg. at 50,437/1, is inconsistent with the text and structure of CAA § 136. Congress defined "production" and "gathering and boosting" as two distinct items in a list of eight parallel categories of applicable facilities subject to the MERP charge, CAA § 136(d)(2) ("Onshore petroleum and natural gas production"), (8) ("Onshore petroleum and natural gas gathering and boosting"). EPA is therefore acting contradictory to this text and to Congress's intent when it proposes to label certain *production* facilities as *gathering and boosting* ones.

There is additional textual and structural evidence that EPA's proposed classification violates CAA Sec. 136. Congress elsewhere places category (2), onshore production, in the subset of categories it labels "Petroleum and natural gas production," see CAA Sect. 136(f)(1). By contrast, Congress places category (8), gathering and boosting, in the subset of categories it labels "*Nonproduction* petroleum and natural gas systems," see CAA Sec. 136(f)(2). This confirms that Congress defined "production" and "nonproduction" as separate and mutually exclusive categories, and that EPA is violating statutory text and Congressional intent by placing centralized *production* sites in the gathering and boosting category, which Congress itself explicitly placed in *nonproduction*.

And this mis-categorization will have consequences, because the waste emissions threshold above which a charge will be imposed on applicable facilities' emissions differs between these two categories, see id. § 136(f)(1), (2). Our comments explain in detail the technical and policy problems with EPA's approach to this issue as discussed above. Because, as explained in that earlier discussion, taking this approach will provide a perverse incentive to not centralize production, and therefore to *not* take a step likely to improve emissions intensity, this aspect of EPA's Proposal is fundamentally irrational because it will tend against emissions reduction.

As explained above, EPA cannot legally or rationally approach this Proposal in isolation from the forthcoming MERP charge implementation proposal. Even if it could, though, EPA could not rely on its choice to sever these rulemakings in order to conduct the Subpart W rulemaking without reference to the overarching purpose of CAA §, which is emissions reduction. Section 136 is titled "Methane emissions and *waste reduction incentive program* for petroleum and natural gas systems" (emphasis added). The Proposal *itself* acknowledges that this was Congress's overarching purpose in enacting CAA § 136, and the purpose of the new authorities included in that Section: "The IRA *adds authorities* under CAA section 136 to *reduce* CH4 emissions from the oil and gas sector." 88 Fed. Reg. at 50,286/1 (emphases added). This necessarily includes the authorization and direction in CAA § 136(h) to revise Subpart W. It would be internally self-contradictory, in addition to contrary to Congress's text and design, for EPA to ignore the emissions-reduction implications of its revision of Subpart W. Therefore, any aspect of this Proposal that tends to disincentivize practices that further the goal of emissions reduction is irrational, arbitrary and capricious, and contrary to Congressional text and intent.

The proposed definition of "centralized oil production site" is also inconsistent with the proposed definition and regulatory treatment of a "centralized production facility" in the pending CAA § 111 methane standards proposal for both new and existing sources, as well as PHMSA's approach, as explained in Section III above.

<u>Commenter 0339</u>: **3. Designation of "Gathering and Boosting" versus "Production" segment**

Designation of "Gathering and Boosting" versus "Production" segment EPA is considering significant changes in its reporting requirements for the various industry segments in the rule. One of the key changes involves the segment designation of upstream operators' centralized tank batteries. In the proposed rule, EPA has erroneously classified centralized oil production sites under the gathering and boosting segment which presents multiple challenges. This categorization introduces discrepancies between this rule and other federal programs and complicates reporting requirements for companies. As such, we recommend that EPA change the name of the subject facility to "centralized production facility" and retain the classification as onshore production to align with other federal programs for consistency and to reflect how the industry owns and operates these facilities.

<u>Commenter 0342</u>: 3. Designation of "Gathering and Boosting" versus "Production" segment

EPA is considering significant changes in its reporting requirements for the various industry segments in the rule. One of the key changes involves the segment designation of upstream operators' centralized tank batteries. In the proposed rule, EPA has erroneously classified centralized oil production sites under the gathering and boosting segment which presents multiple challenges. This categorization introduces discrepancies between this rule and other federal programs and complicates reporting requirements for companies. As such, we recommend that EPA change the name of the subject facility to “centralized production facility” and retain the classification as onshore production to align with other federal programs for consistency and to reflect how the industry owns and operates these facilities.

Commenter 0346: VII. Facilities Covered under Proposed Rule are Confusing and Inconsistent with IRA

As PBPA commented in its October 5, 2022 Comment Letter regarding the EPA’s proposed revisions in June of 2022:

The EPA should take great care in understanding the interaction between [the IRA], other proposed rules and the agency’s proposed revisions to the GHGRP. These revisions will have consequences on those other actions and vice versa. If those consequences result in confusion, inaccuracies in reporting, or a lack in quality of reported data, EPA’s stated intent for revisions to the GHGRP will not be achieved. Therefore, if EPA chooses to take no time to reconcile contradictions or inaccuracies between the proposed GHGRP revisions and other proposed rulemakings, it is highly likely additional proposed revisions will be needed sooner rather than later.

Not only are flare requirements inconsistent between the Proposed Rule, OOOOb and OOOOc, and the Refinery NESHAP, the Proposed Rule’s definitions are also inconsistent with the IRA and will lead to confusion and unreliable reporting.

To be clear, gathering and boosting is specifically listed under IRA as **nonproduction** for assessing the methane fee. Section 136(f) of the IRA provides:

2) NONPRODUCTION PETROLEUM AND NATURAL GAS SYSTEMS.—

With respect to imposing and collecting the charge under subsection (c) for an applicable facility in an industry segment listed in paragraph (3), (6), (7), or (8) of subsection (d), the Administrator shall impose and collect the charge on the reported metric tons of methane emissions that exceed 0.05 percent of the natural gas sent to sale from or through such facility.10

However, it appears the Proposed Rule conflates the terms in such a way that gathering and boosting are considered a part of “centralized production sites” that are considered **production** facilities. These proposed definitions are neither consistent with the Pipeline and Hazardous Material Safety Administration’s definitions, which do not include any production facilities as part of gathering, 11 nor with how such sites are regulated under OOOOa, and proposed OOOOb/c.

The Proposed Rule defines “centralized oil production site” as follows:

DEFINITION: *Centralized oil production site* means any permanent combination of one or more hydrocarbon liquids storage tanks located on one or more contiguous or adjacent properties that does not also contain a permanent combination of one or more compressors that are part of the onshore petroleum and natural gas gathering and boosting facility that gathers hydrocarbon liquids from multiple well-pads. A *centralized oil production site* is a type of gathering and boosting site for purposes of reporting under § 98.236.12

The Proposed Rule then goes on to define a "gathering and boosting site" as including centralized oil production sites within the gathering and boosting industry segment:

DEFINITION: *Gathering and boosting site* means a single gathering compressor station as defined in this section, **centralized oil production site** as defined in this section, gathering pipeline site as defined in this section, or other fenceline site within the onshore petroleum and natural gas gathering and boosting industry segment.13

The definitions included in this Proposed Rule should be harmonized with those in the IRA to provide clarity to the regulated community and ensure consistency in how facilities are characterized across regulatory programs.

Footnotes:

10 Proposed Rule at 50436.

11 See 49 C.F.R. § 192.7.

12 Proposed Rule at 50436.

13 Proposed Rule at 50437.

Commenter 0350: 3. Designation of "Gathering and Boosting" versus "Production" segment

EPA is considering significant changes in its reporting requirements for the various industry segments in the rule. One of the key changes involves the segment designation of upstream operators' centralized tank batteries. In the proposed rule, EPA has erroneously classified centralized oil production sites under the gathering and boosting segment which presents multiple challenges. This categorization introduces discrepancies between this rule and other federal programs and complicates reporting requirements for companies. As such, we recommend that EPA change the name of the subject facility to "centralized production facility" and retain the classification as onshore production to align with other federal programs for consistency and to reflect how the industry owns and operates these facilities.

Commenter 0360:

III. EPA should ensure the Production and Gathering and Boosting segments are properly defined.

EPA is considering significant changes in its reporting requirements for the various industry segments in the rule. One of the key changes involves the segment designation of upstream operators' centralized tank batteries. In the proposed rule, EPA has erroneously classified centralized oil production sites under the gathering and boosting segment which presents multiple challenges. This categorization introduces discrepancies between this rule and other federal programs and complicates reporting requirements for companies. As such, Devon recommends that EPA change the name of the subject facility to "centralized production facility" and retain the classification as onshore production to align with other federal programs for consistency and to reflect how the industry operates these facilities.

In the proposed NSPS OOOOb and OOOOc, EPA included the following definition of Centralized Production Facility:

"Centralized production facility means one or more storage vessels and all equipment at a single surface site used to gather, for the purpose of sale or processing to sell, crude oil, condensate, produced water, or intermediate hydrocarbon liquid from one or more offsite natural gas or oil production wells. This equipment includes, but is not limited to, equipment used for storage, separation, treating, dehydration, artificial lift, combustion, compression, pumping, metering, monitoring, and flowline. Process vessels and process tanks are not considered storage vessels or storage tanks. A centralized production facility is located upstream of the natural gas processing plant or the crude oil pipeline breakout station and is a part of producing operations."

This definition makes it clear that centralized production facilities are located in the upstream production segment, not the gathering and boosting segment. These facilities deliver products to midstream facilities, which is the entry point into the Gathering and Boosting segment.

This distinction is critical as it pertains to the MERP segment definitions and thresholds, as well as a reflection of, and incentive to, further reductions of actual emissions. The modern industry practice to centralize production into a single facility reduces surface land use requirements, minimizes the total number of production facilities, and allows for the most advanced technology and engineering practices to become the norm.

EPA should not disincentivize the advancement of environmentally conscious and sustainable energy production practices by proposing facility and segment definitions that do not reflect modern industry developments.

Commenter 0378: 3. EPA should not disincentivize reduction of environmental footprint through centralized facilities.

In the proposed Subpart W revisions, EPA has erroneously classified centralized oil production sites under the gathering and boosting segment, which presents multiple challenges. This categorization introduces discrepancies between this rule and other federal programs and complicates reporting requirements for companies. In addition, use of centralized production facilities for on and off-site well production reduces emissions through the minimization of equipment count, better allows for capture and sale of low pressure gas and reduces impacts to habitat by minimizing the size of surface locations. Improperly classifying these centralized production facilities as gathering and boosting could disincentivize consolidation of production facilities and thereby increase environmental footprint and overall emissions. As such, we recommend that EPA change the name of the subject facility to "centralized production facility" and retain the classification as onshore production to align with other federal programs for consistency and to reflect how the industry owns and operates these production facilities.

Commenter 0385: For example, Pioneer has significant concerns regarding EPA's proposed requirements related to "centralized production facilities" as part of the gathering & boosting segment (as opposed to the production segment where it should be classified based on its name and function). This segment classification is contradictory to previous interpretations and may have unintended consequences such as companies electing not to centralize such operations (even though consolidation serves to minimize environmental footprint) due to the more burdensome methane fee implications.

…

EPA's Proposal Conflicts in Key Aspects with the Text and Purpose of New Clean Air Act ("CAA") § 136

First, EPA's proposal to group its proposed new definition of "centralized oil production site" within the "gathering and boosting" category, *see* 88 Fed. Reg. at 50,437/1, is inconsistent with the text and structure of CAA § 136. Congress defined "production" and "gathering and boosting" as two distinct items in a list of eight parallel categories of applicable facilities subject to the MERP charge, CAA § 136(d)(2) ("Onshore petroleum and natural gas production"), (8) ("Onshore petroleum and natural gas gathering and boosting"). Further, the IRA has two heading in which to place these 8 subcategories - "PRODUCTION" and 'NON PRODUCTION". EPA is therefore acting contradictory to this text and to Congress's intent when it proposes to categorize *production* facilities as *gathering and boosting* ones. And this mis-categorization will have consequences because the waste emissions threshold above which a charge will be imposed on applicable facilities' emissions differs between these two categories, *see id*. § 136(f)(1), (2). The proposed definition of "centralized oil production site" is also inconsistent with the proposed definition and regulatory treatment of a "centralized production facility" in the pending CAA § 111 methane standards proposal for both new and existing sources as discussed in 2. below.

…

Designation of Centralized Oil Production Sites in "Gathering and Boosting" versus "Production" Segment is an Improper Application of the IRA and Contrary to Congress' Explicit Intent

EPA is considering significant changes in its reporting requirements for the various industry segments in the rule. One of the key changes involves designation of upstream operators' centralized tank batteries that EPA has named "centralized oil production sites". These are defined as sites collecting oil from multiple well pads without compressors "that are part of the onshore petroleum and natural gas gathering and boosting facility." In the proposed rule, EPA has classified centralized oil production sites under the gathering and boosting segment.

Pioneer appreciates that EPA has recognized centralized production sites as a facility type in the proposed rule. However, there are challenges and disincentives with including "centralized oil production sites" in the gathering and boosting segment.

First, EPA included "production" clearly in the name and it is nonsensical that centralized production sites would be considered part of the gathering and boosting segment.

Next, EPA's proposed definitions are contrary to IRA's Methane Emissions Reduction Plan ("MERP') waste emissions thresholds, where gathering and boosting sites are considered "Non Production". In the MERP language, (f) Waste Emission Threshold, Congress created two categories for applicability of the threshold: "Production" and "Non-Production". The Gathering and Boosting segment (segment #8) is explicitly listed under "Non-Production". Clearly Congress did not intend for sites associated with production, such as "centralized ***production*** sites" to be considered gathering and boosting. EPA may have imposed reporting obligations for emissions from centralized tank batteries under the gathering and boosting segment in the past but for application of the fee, these sites should be considered production. Doing otherwise would result in an inequitable application of the fee that would most likely not be applied uniformly by all upstream operators. If EPA does not wish to clear up the confusion and include centralized production sites in the Production segment, Pioneer strongly recommends that EPA carve out these sites for threshold determination in the IRA implementation rule and make these sites subject to the 0.2 threshold as Congress has clearly mandated in the law.

In addition, the categorization of a centralized production site into gathering and boosting could result in a backslide from the progress industry has made in minimizing its overall footprint and emission sources. Due to the higher methane fees that may accompany categorizing production sites as gathering and boosting (subjecting these facilities to the 0.05% threshold instead of the 0.2% threshold) operators may be economically incentivized to migrate back to individual well pad installation dramatically increasing the amount of equipment in the field and increasing GHG emissions.

Further, these sites are considered by many operators as part of the upstream production process as these tank batteries are likened to "production supportive facilities." Pioneer is an upstream exploration and production company and has designed and currently operates these type of sites throughout the Permian Basin (midstream operators traditionally operate gathering and boosting sites that are typically large compressor stations that boost gas across an area). Facility design efficiency gains over the years have led to centralization of production surface equipment. The centralization of surface equipment typically results in emissions reductions relative to dispersed facilities (separation and tanks installed at each well pad) because the total equipment counts are significantly reduced (fewer emission points), there is a reduction of tank batteries/spill risk, increased operational efficiencies and better ability to site major facilities away from sensitive areas/populations. This segment classification is contradictory to previous interpretations and may have unintended consequences such as companies electing not to centralize such operations (even though consolidation serves to minimize environmental footprint) due to the more burdensome methane fee implications. Facilities comprised of centralized surface equipment are owned and operated by producers, are considered in the industry as part of production. and may or may not include a well head or pump jack collocated on a single pad.

However, because EPA re-defined the production segment in 2016 as "associated with a single well pad' this has created a great deal of confusion with reporters and centralized tank batteries have been categorized differently both by individual owners/ operators, as well as other federal rules (NSPS OOOOb). For example, under the proposed OOOOb/c regulations, the "centralized oil production facilities" (referred to in NSPS OOOOb as "centralized production facilities") are grouped under the production segment by definition, not gathering and boosting as explained below:

Currently, in Subpart W "***Centralized oil production site*** *means any permanent combination of one or more hydrocarbon liquids storage tanks located on one or more contiguous or adjacent properties that does not also contain a permanent combination of one or more compressors that are part of the onshore petroleum and natural gas gathering and boosting facility that gathers hydrocarbon liquids from multiple well-pads. A centralized oil production site is a type of gathering and boosting site for purposes of reporting under §98.236*."

While NSPS OOOOb/c has a different name and definition of this as follow: "***Centralized production facility"*** *means one or more storage vessels and all equipment at a single surface site used to gather, for the purpose of sale or processing to sell, crude oil, condensate, produced water, or intermediate hydrocarbon liquid. from one or more offsite natural gas or oil production wells. This equipment includes, but is not limited to, equipment used for storage, separation, treating, dehydration, artificial lift, combustion, compression, pumping, metering, monitoring, and flowline. Process vessels and process tanks are not considered storage vessels or storage tanks. <u>A centralized production facility is located upstream of the natural gas processing plant or the crude oil pipeline breakout station and is a part of producing operations</u>*."

In addition, in the Pipeline and Hazardous Material Safety Administration's ('PHMSA") proposed Gas Pipeline Leak Detection and Repair rule, PHMSA does not define or regulate *any* production facilities as "gathering and boosting". Specifically, as defined in API's Recommended Practice-80 and incorporated in 49 CFR 192: "The production function, in most cases, extends well downstream of the wellhead and may include several processes required to prepare the gas for transportation. *'Production Operation' means piping and equipment used for production and preparation for transportation or delivery of hydrocarbon gas and/or liquids and includes the following processes: (a) extraction and recovery, lifting, stabilization, treatment, separation, production processing, storage, and measurement of hydrocarbon gas and/or liquids; and (b) associated production compression, gas lift, gas injection, or fuel gas supply*."

Both the NSPS OOOOb/c and PHMSA's name and definition of what are essentially tank batteries are much more consistent with how these facilities operate and are managed in the field. **In an effort to mitigate confusion and create more rule alignment, Pioneer suggests that EPA align the name and definition of the subject facility type between Subpart W and NSPS OOOOb/c.**

In this proposal, EPA claims to be striving for consistency when EPA states, on page 50288 of the proposal, "as in the 2016 rule, the proposed amendments would also allow facilities to use a consistent method to demonstrate compliance with multiple EPA programs." Also, Pioneer notes that even though EPA uses the word "gather" in the definition in Quad Ob/c, these sites are still properly defined as "part of the producing operations."

Further, the fact that EPA has proposed the definition of "centralized production sites" as sites that do not include compressors that are part of the gathering and boosting segment is puzzling. If these sites are part of the gathering and boosting segment as EPA has proposed, why would these sites not be allowed to have compressors that are part of the gathering and boosting segment on them? This demonstrates that EPA *does* understand the distinction between gathering and boosting compressors that should appropriately be included in the gathering and boosting segment and centralized tank batteries that clearly should not.

As such, Pioneer requests that EPA change both, the name and definition of "centralized oil production site" in the Subpart W rule to match NSPS OOOOb/c to align with, other federal programs for consistency and to reflect how the industry owns and operates these facilities.

Pioneer also strongly recommends that EPA delete "associated with, a single well pad" from the Onshore Petroleum and Natural Gas Production definition in Subpart Win order to clear up the confusion and properly have centralized production sites in the production segment where they belong.

Commenter 0399: Further, the new proposed definition of a "centralized oil production site," to be reported under the gathering and boosting segment, is contrary to IRA language, which lists the gathering and boosting segment under Nonproduction for the purposes of the methane fee assessment. The language in IRA, under the section "Waste Emissions Threshold," clearly includes Gathering and Boosting under "Nonproduction Petroleum and Natural Gas Systems" and ***not*** under "Petroleum and Natural Gas Production." This definition of "centralized oil production site" as part of the gathering and boosting segment in the proposed Subpart W revision also does not align with the definition and regulation of a "centralized production facility" in the production segment in the proposed OOOOb/c.[1] EPA needs to realign the proposed rule with the segments specified in IRA.

Footnotes:

[1] In addition, the Pipeline and Hazardous Materials Safety Administration (PHMSA), including in its proposed Gas Pipeline Leak Detection and Repair (LDAR) rule, does not define or regulate any production facilities as gathering. Specifically, as defined in American Petroleum Institute's (API) Recommended Practice (RP)80 and incorporated in 49 CFR 192: "The production function, in most cases, extends well downstream of the wellhead and may include several processes required to prepare the gas for transportation. 'Production Operation' means piping and equipment used for production and preparation for transportation or delivery of hydrocarbon gas and/or liquids and includes the following processes: (a) extraction and recovery, lifting, stabilization, treatment' separation, production processing, storage, and measurement of hydrocarbon gas and/or liquids; and (b) associated production compression, gas lift, gas injection, or fuel gas supply."

Commenter 0402: **The Industry Trades request that EPA change both the name and definition of "centralized oil production site" in the Subpart W rule to match NSPS OOOOb and EG OOOOc to align with other federal programs under production for consistency and to reflect how the industry owns and operates these facilities**. EPA has incorrectly included centralized production facilities with gathering and boosting, but should instead include them in the production segment where they belong. The Industry Trades also strongly recommend that EPA delete "associated with a single well pad" from the Onshore Petroleum and Natural Gas Production definition in Subpart W in order to clear up the confusion. Please refer to Section 3.16.

…

3.16 Gathering and Boosting versus Production Site Categorization

EPA is considering significant changes in its reporting requirements for the various industry segments in the rule. One of the key changes involves designation of upstream operators' centralized tank batteries that EPA has named "centralized oil production sites." These are defined as sites collecting oil from multiple well pads without compressors "that are part of the onshore petroleum and natural gas gathering and boosting facility." In the proposed rule, EPA has classified centralized oil production sites under the gathering and boosting segment.

The Trades appreciate that EPA has recognized centralized production sites as a facility type in the proposed rule. However, there are challenges and environmental disincentives with including "centralized oil production sites" in the gathering and boosting segment, especially when viewed through the lens of the upcoming waste emissions charge.

First, EPA included "production" clearly in the name and it is nonsensical that centralized production sites would be considered part of the gathering and boosting segment. These sites perform many of the same functions as the traditional well pad only production facilities (which are included in production), but reduce the overall environmental footprint associated with oil and gas development included emissions reductions and minimizing surface use by flowing multiple wells into on pad.

Next, EPA's proposed definitions are contrary to IRA's MERP waste emissions thresholds, where gathering and boosting sites are considered "non-production." In the MERP language, (f) Waste Emission Threshold, Congress created two categories for applicability of the threshold: "Production" and "Non-Production." The Gathering and Boosting segment (segment #8) is explicitly listed under "Non-Production." Clearly Congress did not intend for sites associated with production, such as "centralized production sites" to be considered gathering and boosting. EPA may have been able to impose reporting obligations for emissions from centralized tank batteries under the gathering and boosting segment in the past but for application of the fee, these sites should be considered production. Doing otherwise would result in an inequitable application of the fee that would most likely not be applied uniformly by all upstream operators.

EPA's proposal to group its proposed new definition of "centralized oil production site" within the "gathering and boosting" category, see 88 Fed. Reg. at 50,437/1, is inconsistent with the text and structure of CAA § 136. Congress defined "production" and "gathering and boosting" as two distinct items in a list of eight parallel categories of applicable facilities subject to the MERP charge, CAA § 136(d)(2) ("Onshore petroleum and natural gas production"), (8) ("Onshore petroleum and natural gas gathering and boosting"). EPA is therefore acting contradictory to this text and to Congress's intent when it proposes to categorize *production* facilities as *gathering and boosting* ones. And this mis-categorization will have consequences, because the waste emissions threshold above which a charge will be imposed on applicable facilities' emissions differs between these two categories, *see id*. § 136(f)(1), (2

The proposed definition of "centralized oil production site" is also inconsistent with the proposed definition and regulatory treatment of a "centralized production facility" in the pending CAA § 111 methane standards proposal for both new and existing sources.

In addition, the categorization of a centralized production site into gathering and boosting could result in a backslide from the progress industry has made in minimizing its overall footprint and emission sources. Due to the higher methane fees that may accompany categorizing production sites as gathering and boosting (subjecting these facilities to the 0.05% threshold instead of the 0.2% threshold) operators may be economically incentivized to migrate back to individual well pad installation dramatically increasing the amount of equipment in the field, increasing GHG emissions, and increasing surface use.

Further, these sites are considered by many operators as part of the upstream production process as these tank batteries are likened to "production supportive facilities." Many operators have migrated to more centralized production facilities in an effort to reduce the overall environmental footprint. As opposed to midstream operators that traditionally operate gathering and boosting sites downstream of a custody transfer meter that are typically large compressor stations that boost gas across an area, the sites in question are a less impactful way of separating and storing fluids from multiple wells and providing efficient compression for artificial lift. Facility design efficiency gains over the years have led to centralization of production surface equipment. The centralization of surface equipment typically results in emissions reductions relative to dispersed facilities (separation and tanks installed at each well pad) because the total equipment counts are significantly reduced (fewer emission points), there is a reduction of tank batteries/spill risk, increased operational efficiencies, and better ability to site major facilities away from sensitive areas/populations. This segment classification is contradictory to previous interpretations and may have unintended consequences such as companies electing not to centralize such operations due to the more burdensome methane fee implications. Facilities comprised of centralized surface equipment are owned and operated by producers, are considered in the industry as part of production, and may or may not include a well head or pump jack collocated on a single pad.

However, because EPA re-defined the production segment in 2016 as "associated with a single well pad" this has created a great deal of confusion with reporters and centralized tank batteries have been categorized differently both by individual owners / operators, as well as other federal rules (NSPS OOOOb). For example, under the proposed OOOOb/c regulations, the "centralized oil production facilities" (referred to in NSPS OOOOb as "centralized production facilities") are grouped under the production segment by definition, not gathering and boosting as explained below:

Currently, in Subpart W "Centralized oil production site means any permanent combination of one or more hydrocarbon liquids storage tanks located on one or more contiguous or adjacent properties that does not also contain a permanent combination of one or more compressors that are part of the onshore petroleum and natural gas gathering and boosting facility that gathers hydrocarbon liquids from multiple well-pads. A centralized oil production site is a type of gathering and boosting site for purposes of reporting under §98.236."

While NSPS OOOOb/c has a different name and definition of this as follows:

"Centralized production facility" means one or more storage vessels and all equipment at a single surface site used to gather, for the purpose of sale or processing to sell, crude oil, condensate, produced water, or intermediate hydrocarbon liquid from one or more offsite natural gas or oil production wells. This equipment includes, but is not limited to, equipment used for storage, separation, treating, dehydration, artificial lift, combustion, compression, pumping, metering, monitoring, and flowline. Process vessels and process tanks are not considered storage vessels or storage tanks. A centralized production facility is located upstream of the natural gas processing plant or the crude oil pipeline breakout station and is a part of producing operations."

In addition, in the Pipeline and Hazardous Material Safety Administration's ('PHMSA") proposed Gas Pipeline Leak Detection and Repair rule, PHMSA does not define or regulate any production facilities as "gathering and boosting." Specifically, as defined in API's Recommended Practice-80 and incorporated in 49 CFR 192:

"The production function, in most cases, extends well downstream of the wellhead and may include several processes required to prepare the gas for transportation. 'Production Operation' means piping and equipment used for production and preparation for transportation or delivery of hydrocarbon gas and/or liquids and includes the following processes: (a) extraction and recovery, lifting, stabilization, treatment, separation, production processing, storage, and measurement of hydrocarbon gas and/or liquids; and (b) associated production compression, gas lift, gas injection, or fuel gas supply."

Both the NSPS OOOOb/c and PHMSA's name and definition of what are essentially tank batteries are much more consistent with how these facilities operate and are managed in the field. To mitigate confusion and create more rule alignment, the Industry Trades suggest that EPA align the name and definition of the subject facility type between Subpart W and NSPS OOOOb/c.

In this proposal, EPA claims to be striving for consistency when EPA states, on page 50288 of the proposal,

"as in the 2016 rule, the proposed amendments would also allow facilities to use a consistent method to demonstrate compliance with multiple EPA programs." Also, the Trades note that even though EPA uses the word "gather" in the definition in Quad Ob/c, these sites are still properly defined as "part of the producing operations."

Further, the fact that EPA has proposed the definition of “centralized production sites” as sites that do not include compressors that are part of the gathering and boosting segment is puzzling. If these sites are part of the gathering and boosting segment as EPA has proposed, why would these sites not be allowed to have compressors that are part of the gathering and boosting segment on them? This demonstrates that EPA possibly does understand the distinction between gathering and boosting compressors that should appropriately be included in the gathering and boosting segment and centralized tank batteries that clearly should not.

As such, The Industry Trades request that EPA change both the name and definition of “centralized oil production site” in the Subpart W rule to match NSPS OOOOb and EG OOOOc to align with other federal programs under production (not gathering and boosting) for consistency and to reflect how the industry owns and operates these facilities. The Trades also strongly recommend that EPA delete “associated with a single well pad” from the Onshore Petroleum and Natural Gas Production definition in Subpart W in order to clear up the confusion and properly have centralized production sites in the production segment where they belong.

<u>Commenter 0417</u>:

EPA is considering significant changes in its reporting requirements for the various industry segments in the rule. One of the key changes involves the segment designation of upstream operators’ centralized tank batteries. In the proposed rule, EPA has erroneously classified centralized oil production sites under the gathering and boosting segment, which presents multiple challenges and would likely result in unnecessary questions concerning GHG reporting in facilities’ eGGRT accounts. This categorization introduces discrepancies between this proposed rule and other federal programs and complicates reporting requirements for companies.

The currently proposed criteria for Gathering and Boosting, along with the lower Waste Emissions Charge threshold results in higher charges for Gathering and Boosting facilities and disincentivizes the work that operators have done to consolidate production equipment for multiple wells onto fewer surface sites. This gradual evolution in facility design has had postive environmental benefits that include fewer ground disturbances, fewer impacts to wetlands, wildlife, and agriculture, reduced equipment counts, and less fugitive emissions for the same volumes of produced oil and gas. To disincentivize this environmental progress will have the unintended consequence of encouraging operators to reverse this trend and go back to building more surface sites with more emissions and lower flow to flares and control devices, thereby introducing greater difficulty in controlling emissions as facility production declines. These unintended consequences do not seem consistent with EPA’s goal of reducing emissions. Thus, the currently proposed Gathering and Boosting criteria only serve to unnecessarily inflate the Waste Emissions Charge.

NDPC requests that the EPA change the name of the subject facility to “centralized production facility” and retain the classification as onshore production to align with other federal programs for consistency and to reflect how the industry owns and operates these facilities.

Response 1: See Section III.D of the preamble to the final rule for the EPA's response to comments regarding the definition of "centralized oil production site."

Commenter: Alaska Oil and Gas Association (AOGA)
Comment Number: EPA-HQ-OAR-2023-0234-0241
Page(s): 3-4

Comment 2: EPA should revise the definition for "centralized oil production site."

EPA has determined that there is a group of sources that may not fit into the existing segment definitions, and therefore is proposing new definitions, of which "centralized oil production site" is one, which would ultimately be part of the Onshore Petroleum and Natural Gas Gathering and Boosting segment. The proposed definition of "centralized oil production site" lacks clarity and could lead to internal inconsistencies in the rule.

AOGA requests the EPA amend the definition of "centralized oil production site" in 40 C.F.R. 98.238 as follows:

Centralized oil production site means any permanent combination of one or more hydrocarbon liquids storage tanks located on one or more contiguous or adjacent properties that does not also contain a permanent combination of one or more compressors that are part of the onshore petroleum and natural gas gathering and boosting facility that gathers hydrocarbon liquids from multiple well-pads. <u>Process tanks are not considered storage tanks</u>. A centralized oil production site is a type of gathering and boosting site for purposes of reporting under §98.236.

AOGA requests EPA add "process tanks are not considered storage tanks." The addition of this clause harmonizes this definition with the definition of "centralized production facility" in proposed 40 C.F.R. 60.5430b and 5430c (NSPS OOOOb and NSPS OOOOc). Process tanks are used to handle raw product within the process before sales quality oil or gas is created. These tanks can be surge control vessels, knock out vessels, or pressurized vessels, for example. Process vessels are intended to facilitate movement of those liquids through the process, not store liquids independent of the process.

This request necessitates a definition of "process tank" because Subpart W and Subpart A do not currently define that term. AOGA proposes the following definition:

Process Tank means a tank that is used within a process (including a solvent or raw material recovery process) to collect material discharged from a feedstock storage vessel or equipment within the process before the material is transferred to other equipment within the process, to a product or by-product storage vessel, or to a vessel used to store recovered solvent or raw material. In many process tanks, unit operations such as reactions and blending are conducted. Other process tanks, such as surge control vessels and bottoms receivers, however, may not involve unit operations.

This proposed definition is taken directly from NSPS Subpart Kb (40 C.F.R. 60.111b). Including this definition adds clarity to the proposed definition of "centralized oil production site" as there may be other processes at that location, while remaining consistent with other similar storage tank/vessel rules in EPA regulations.

Response 2: The EPA is finalizing the definitions of a "centralized oil production site" and "atmospheric pressure storage tank" as proposed and is not including a definition of "process tank" as part of this rulemaking nor excluding process tanks from the "centralized oil production site" definition. An atmospheric pressure storage tank is defined as:

> *Atmospheric pressure storage tank* means a vessel (excluding sumps) operating at atmospheric pressure that is designed to contain an accumulation of crude oil, condensate, intermediate hydrocarbon liquids, or produced water and that is constructed entirely of non-earthen materials (e.g., wood, concrete, steel, plastic) that provide structural support. Atmospheric pressure storage tanks include both fixed roof tanks and floating roof tanks. Floating roof tanks include tanks with either an internal floating roof or an external floating roof.

The owner or operator of a facility reporting to subpart W must determine if the process tanks at the facility meet this definition. Process tanks that meet the definition above (including the fact that they operate at atmospheric pressure and contain hydrocarbon liquids or produced water) are expected to produce GHG emissions and, therefore, should be subject to the Subpart W reporting requirements.

Commenter: Alaska Oil and Gas Association (AOGA)
Comment Number: EPA-HQ-OAR-2023-0234-0241
Page(s): 7-11

Comment 3: Definition and scope of the gathering and boosting segment.

AOGA appreciates the clarifications on the Onshore Petroleum and Natural Gas Gathering and Boosting (G&B) industry segment. Even with the clarification, it can be difficult to discern which sources should report under the G&B rules (Subpart W) instead of the general combustion rules (Subpart C). Below, we describe our understanding of the G&B segment definition and scope with respect to common Alaska operations. If this understanding does not align with EPA's intent, then we recommend appropriate clarification in the final rule.

1. Background on Alaska drill sites and central facilities.

In Alaska, it is common for drill sites to produce a combination of crude oil, natural gas, and produced water and route theses multi-phase produced fluids to Central Facilities (CFs) for treatment prior to custody transfer to the third-party pipelines that carry sales quality oil. Each drill site consists of one or more crude oil production wells and one or more gas injection wells to provide "artificial lift" for production wells. Artificial lift involves injecting high pressure gas into the well casing annulus to assist with lifting the oil in the wellbore. Each drill site is a

“Single Well-Pad” as that term is used in Part 98 Subpart W. These drill sites are subject to the Onshore Petroleum and Natural Gas Production industry segment of Subpart W under EPA’s proposal.

Once at the surface, multi-phase produced fluids from each well are generally combined via manifold into one flowline for transport to the CFs. Drill sites are often located throughout a large geographic surface area and produced fluids from multiple drill sites are typically commingled in larger diameter infield flowlines that flow to the CFs.

At the CFs, natural gas and produced water are separated from the produced oil. Oil is treated to meet third-party oil pipeline specifications. Natural gas co-produced with crude oil is managed in gas handling equipment and prepared for use to support oil production operations. Examples of such use include fuel for combustion equipment that generates electricity, heat, and compression. Each CF gas handling train includes:

- Gas dehydration
- Hydrogen Sulfide Scavenger injection (not all CFs have this equipment)
- Gas compression
- Fuel gas piping network within the CF

Compressed gas is sent from CFs back out to the drill sites via infield flowlines for use as wellhead artificial lift and subsurface injection for reservoir pressure management. Produced water removed from the crude oil is re-used or sent back out to the drill sites via infield flowlines and injected for reservoir pressure management. Notably, there are no crude oil or produced water storage tanks located at the CFs. Vessels containing these contents are process vessels that facilitate the separation of sales crude oil from gas and produced water.

2. Applicability of Subpart W to Central Facilities

The drill sites described above report emissions pursuant to Subpart W Onshore Petroleum and Natural Gas Production industry segment (98.230(a)(2)). The CFs described above report emissions pursuant to Part 98 Subpart C. As described below, that reporting structure is not expected to change based on the proposed rule.

Part 98 Subpart W establishes the following definition for the G&B industry segment and was not modified in this proposal:

Onshore petroleum and natural gas gathering and boosting. Onshore petroleum and natural gas gathering and boosting means gathering pipelines and other equipment used to collect petroleum and/or natural gas from onshore production gas or oil wells and used to compress, dehydrate, sweeten, or transport the petroleum and/or natural gas to a natural gas processing facility, a natural gas transmission pipeline or to a natural gas distribution pipeline. Gathering and boosting equipment includes, but is not limited to gathering pipelines, separators, compressors, acid gas removal units, dehydrators, pneumatic devices/pumps, storage vessels, engines, boilers, heaters, and flares. Gathering and boosting equipment does not include equipment reported under any other industry segment defined in this section. Gathering pipelines operating on a *vacuum and gathering pipelines with a GOR less than 300 standard cubic feet per stock tank barrel (scf/STB) are not included in this industry segment (oil here refers to hydrocarbon liquids of all API gravities).*[7]

The Part 98 Subpart W G&B industry segment definition specifies three endpoints for the transport of petroleum and/or natural gas from onshore production wells.

Excerpt from §98.230(a)(9):

Onshore petroleum and natural gas gathering and boosting means gathering pipelines and other equipment used to collect petroleum and/or natural gas from onshore production gas or oil wells and used to compress, dehydrate, sweeten, ***or transport the petroleum and/or natural gas to a natural gas processing facility, a natural gas transmission pipeline or to a natural gas distribution pipeline.*** [Emphasis added.]

EPA further clarified the G&B industry segment definition was created with well-defined downstream endpoints:

A gathering and boosting system is a single network of pipelines, compressors and process equipment, including equipment to perform natural gas compression, dehydration, and acid gas removal, that has one or more well-defined connection points to gas and oil production and a **well-defined downstream endpoint**, typically a gas processing plant or transmission pipeline. **Gathering pipelines are pipelines used to transport gas from the furthermost downstream point in an onshore production facility to certain endpoints, generally either a gas processing facility or point of connection to a transmission pipeline. Compressors located along the gathering and boosting system are used to control or ''boost'' the pressure of the gas in the pipeline and keep the gas moving downstream.**[8]

This current proposal includes a revised definition for "Gathering and Boosting System" (proposed 40 CFR 98.238) which confirms the significance of a downstream endpoint:

Gathering and boosting system means a single network of pipelines, compressors and process equipment, including equipment to perform natural gas compression, dehydration, and acid gas removal, ***that has one or more connection points to gas and oil production or one or more other gathering and boosting systems and a downstream endpoint*** [emphasis added]*, typically a gas processing plant, transmission pipeline, LDC pipeline, or other gathering and boosting system.*

Addressing the potential for multi-phase flowlines and the inclusion of the "petroleum" wording into the industry segment definition, EPA reiterated the endpoints that trigger the G&B industry segment.

Similarly, the inclusion of all petroleum gathering pipelines in the Onshore Petroleum and Natural Gas Gathering and Boosting segment, including ***multiphase pipelines****, is appropriate, because gathering lines are a key component to gathering and boosting systems. Therefore, all gathering pipelines that collect petroleum and/or natural gas from onshore production gas or oil* *wells* ***and transport the petroleum and/or natural gas to a natural gas processing facility, a natural gas transmission pipeline or to a natural gas distribution pipeline are considered part of the final Onshore Petroleum and Natural Gas Gathering and Boosting segment.***[9]

As described above, the equipment at typical Alaska CFs handle the co-produced natural gas for beneficial reuse to support oil production activities (e.g., fuel supply, gas lift, reservoir pressure management) in upstream operations. Natural gas must be compressed to significant pressures for artificial lift and injection into the subsurface. The CFs provide the necessary compression to support gas injection to the drill sites and into the subsurface and transport fuel gas throughout the CF. CFs do not compress natural gas to “boost the pressure of the gas in the pipeline and keep the gas moving downstream”.

The CFs for oil production do not transport natural gas to any of the following listed endpoints:

- Natural gas processing facility
- Natural gas transmission pipeline, or
- Natural gas distribution pipeline

Additionally, the CFs do not transport petroleum to any of the following listed endpoints:

- Natural gas processing facility,
- Natural gas transmission pipeline, or
- Natural gas distribution pipeline

The EPA has introduced a new definition within this proposal for “Gathering and boosting sites” that make it clear that an operator must first be “within” the definition of the industry segment for the other cascading definitions to be applicable to a source.[10]

Since the CFs do not meet the Onshore Petroleum and Natural Gas Gathering and Boosting industry segment definition provided in §98.230(a)(9),[11] these CFs are not subject to reporting requirements for Part 98 Subpart W.

Consequently, operators of the CFs will continue to report emissions under Part 98 Subpart C. If this result does not align with EPA’s intent, we recommend clarification of the intent in the final rule.

Commenter Notes:

[7] 40 C.F.R §98.230(a)(9).

[8] Subpart W Final Rule Amendments 80 Federal Register Page 64267 dated October 22, 2015 (emphasis added).

[9] Subpart W Final Rule Amendments 80 Federal Register Page 64268 dated October 22, 2015 (emphasis added).

[10] Proposed 40 CFR 98.238 provides in relevant part: "Gathering and boosting site means a single gathering compressor station as defined in this section, centralized oil production site as defined in this section, gathering pipeline site as defined in this section, or other fence-line site within [emphasis added] the onshore petroleum and natural gas gathering and boosting industry segment." Thus, the terms "centralized oil production site", "gathering compressor station", "gathering pipeline site", and "other fence-line site" apply only to a source that has independently been determined to be within the scope of Subpart W.

[11] The Part 98 Subpart W Petroleum and Natural Gas Systems source category is defined by the industry segments described in §98.230. Owners and operators that contain sources and/or activities which satisfy the Petroleum and Natural Gas Systems source category (as described by the industry segments listed in §98.230) and meet the requirements in §98.2(a)(2) are subject to reporting under Part 98 Subpart W [40 C.F.R §98.231].

Response 3: The EPA is finalizing the referenced definitions as proposed. The owners and operators of a facility must assess the applicability of industry segment definitions to a specific facility configuration; a determination by the EPA for a given facility in response to a comment on the proposed regulations is not within the scope of this rulemaking. If the owner or operator of a "central facilit[y]" would like assistance from the EPA regarding a facility-specific situation, that owner or operator should contact the GHGRP help desk.

The EPA notes that in order for a site to be part of a "gathering and boosting system," the single network of pipelines compressors and process equipment must have "one or more connection points to gas and oil production or one or more other gathering and boosting systems" as well as "a downstream endpoint, typically a gas processing plant, transmission pipeline, LDC pipeline, or other gathering and boosting system." If the "single network of pipelines, compressors and process equipment" has the connection to an oil or gas production facility or another gathering and boosting system, but none of the gas or hydrocarbon liquids are transported to a downstream endpoint, then that network would not meet the subpart W definition of "gathering and boosting system" and could not, therefore, be part of a "facility with respect to onshore petroleum and natural gas gathering and boosting." If any of the gas or hydrocarbon liquids have a downstream endpoint, however, the "single network of pipelines, compressors and process equipment" would meet the definition of "gathering and boosting system," even if only a small amount of the gas or hydrocarbon liquids are transported to that downstream endpoint.

Commenter: GPA Midstream Association
Comment Number: EPA-HQ-OAR-2023-0234-0299
Page(s): 61

Comment 4: Commenter 0299: **86. EPA must clarify that non-operational sites do not need to be reported.**

Proposed 98.236(aa)(10)(v) requires new reporting elements for "each gathering and boosting site located in the facility." EPA should clarify that reporters are not required to report this site information for sites that are shutdown, bypassed, or otherwise have no potential for emissions.

As currently drafted, the regulatory text is unclear on this point and proposed 98.236(aa) compounds the uncertainty by specifying that "[i]f a quantity required to be reported is zero, you must report zero as the value."

Response 4: For clarification, 40 CFR 98.236(aa)(10)(v) has been amended in the final rule to specify that reporting is only required for sites for which there were emissions in the calendar year. See Section III.D of the preamble to the final rule for more information.

Commenter: GPA Midstream Association
Comment Number: EPA-HQ-OAR-2023-0234-0299
Page(s): 100

Comment 5: Proposed Change: EPA is proposing to add, as reporting element, the count of compressor stations within a basin to facilitate better understanding of G&B operations [98.236(aa)(10)(v)], at the request of GPA Midstream.

> **Comment**: In addition to collecting information on the number of gathering and boosting stations in a basin, GPA also encourages EPA to acquire additional information related to other key differences in the basins. For example, gathering systems that operate with low suction pressure will require more compression to move gas (sometimes twice as much compression), and this type of information may provide insight into differences in emissions between operators and/or basins.
>
> **Suggested text**: *98.236(aa)(10)(vi) Average gathering and booster station inlet pressure.*

Response 5: The EPA appreciates the suggestion by the commenter to collect additional information to better under gathering and boosting operations in different basins. The EPA is not incorporating the suggested amendment as part of this rulemaking but may consider this suggestion in future subpart W rulemakings.

Commenter: GPA Midstream Association
Comment Number: EPA-HQ-OAR-2023-0234-0299
Page(s): 100

Comment 6: Proposed Change: EPA is proposing to add, as reporting element, the count of compressor stations within a basin to facilitate better understanding of G&B operations [98.236(aa)(10)(v)], at the request of GPA Midstream.

> **Comment**: GPA thanks EPA for making this kind of change, as we think a change of this nature will add value when analyzing data from a G&B basin. However, recently GPA has found that limiting this count to compressor stations only does not adequately meet the intent of collecting this particular data element, which is to provide a way to "spread" the data reported across the number of facilities in the basin, so that it can be viewed and

interpreted in light of a more traditional definition of "facilities." GPA therefore suggests revising the rule to require additional information, which will provide a more complete understanding of typical equipment counts at gathering and boosting assets. Please also see the next comment where this change provides additional value.

Suggested text: new definition in 98.238 Gathering and Boosting Station *means a booster compressor station, treating facility, centralized gathering facility, metering station, or dehydration facility.*

98.236(aa) (10)(v) The number of ~~compressor stations~~ *gathering and booster stations* in the facility.

Response 6: This comment was included as an attachment to the commenter's letter, but it is a comment on the 2022 GHGRP Proposal and is not relevant to the 2023 Subpart W Proposal.

6 Natural Gas Pneumatic Device Venting and Natural Gas Driven Pneumatic Pump Venting

6.1 General Comments

Commenter: Kathairos Solutions, Inc.
Comment Number: EPA-HQ-OAR-2023-0234-0228
Page(s): 1-2

Commenter: Terra Energy Partners (TEP)
Comment Number: EPA-HQ-OAR-2023-0234-0234
Page(s): 2

Commenter: Environmental Defense Fund, et al.
Comment Number: EPA-HQ-OAR-2023-0234-0413
Page(s): 21-22

Comment 1: Commenter 0228: Kathairos Solutions, an oil and gas service company committed to reducing emissions from the energy industry. Our first technology eliminates methane emissions from pneumatic devices, which are routinely used in upstream oil and gas operations and make up a significant portion of global methane emissions. As you are aware, the environmental toll of routine methane venting from pneumatics is staggering. We estimate 70 million tons of CO2 equivalent is emitted from over 350,000 well sites in the United States. **We are writing to convey our support for the proposed Subpart W revisions given the positive impact they will have on the country's emission reporting and methane reduction efforts.**

Kathairos' technology eliminates methane venting from pneumatics by replacing the power gas used to actuate the pneumatic devices at a wellsite. Nitrogen (a clean, inert gas) replaces natural gas as a power gas to pressure the various pumps and controllers in operation. We install a specialized cryogenic tank at the well site and fill the tank with liquid nitrogen. The tank is tied into the existing pneumatic systems (no device swap-outs necessary), releasing the nitrogen in gaseous form at the pressures and quantities needed for everyday operations. The Kathairos tanks are manufactured in the USA by Chart Industries, a global leader in cryogenic manufacturing.

Over the past two years, we have experienced rapid adoption across the industry, with fast growing demand for our methane elimination services. As of September 2023, our operations have expanded across 15 regions in North America, with over 1000 tanks deployed in the past year and a half alone. We are currently active in the following basins:

Bakken/ Williston - ND, MO	Anadarko – OK
Powder River – WY	Barnett – TX
Denver/ Niobrara – CO, WY	Permian – TX, NM
Wind River, Green River – WY	Eagle Ford – TX
Piceance – CO	Haynesville – TX, LA
Uinta – UT	North Marcellus – PA
San Juan – NM	South Marcellus/ Utica – PA, WV, OH

The nitrogen-based solution has become the preferred zero-vent solution for North America's largest oil and gas companies. Not only is it economical, eliminating methane from well sites for as little as $3,000/year, it is highly reliable, with no moving parts or batteries that need to be replaced. No on-site power is needed, and the system works based on thermodynamic principles alone. Our technology has created growth for job opportunities across our USA operations: to deliver nitrogen, to produce nitrogen, and to manufacture and install tanks. These jobs are permanent, high-quality, and highly local to the regions served. We have the potential to reduce millions of tons of CO2 emissions annually and advance efforts to meet methane reduction targets with minimal cost to the oil and gas industry.

<u>Commenter 0234</u>: Historically, pneumatic controllers have been TEP's largest source of reported emissions under Subpart W. …. The current Subpart W calculation methodologies, however, are outdated, imprecise, and not an accurate calculation of emissions, particularly for pneumatic devices. This isn't particularly surprising, as the original purpose of the Greenhouse Gas Reporting Program was not to collect a fee, but to support further study and estimation of GHG emissions. It was understood from the beginning that the calculation and reporting methodologies would be further developed and refined over time.

The Proposed Subpart W Amendments Would Allow for Use of Empirical Data to Better Calculate Emissions

The Subpart W Amendments include three separate calculation methods for pneumatic controllers, all of which result in empirical data to better calculate emissions:

- Method 1 allows for direct measurement of the supply gas to a pneumatic controller or group of controllers. Under this method, controllers sharing a supply source can be aggregated and emissions are allocated.
- Method 2 allows for direct measurement of the vents of a pneumatic controller. Controllers may not be aggregated and must be tested for at least 15 minutes not to exceed 5 years.
- Method 3 is emission factor based but requires a two-minute OGI inspection for each controller. If the controller is found to be correctly operating, an emission factor of 2.82/scf/hr may be used. But if it is found to be malfunctioning, a higher emission factor of 16.1 scf/hr should be used.

TEP appreciates the flexibility given to the regulated community to balance empirical data collection with cost considerations for each method. This approach allows Subpart W reporting to be more reflective of emissions from pneumatic devices than the current methodology.

<u>Commenter 0413</u>: 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 underreporting 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.

Response 1: We appreciate the support for the addition of measurement options. Under the GHGRP subpart W, the EPA has and will continue to review and verify reported emissions and, if necessary, follow-up with reporters that appear to misreport pneumatic device emissions.

Commenter: Marcellus Shale Coalition (MSC)
Comment Number: EPA-HQ-OAR-2023-0234-0275
Page(s): 5

Commenter: American Exploration and Production Council
Comment Number: EPA-HQ-OAR-2023-0234-0295
Page(s): 25

Commenter: Independent Petroleum Association of New Mexico (IPANM)
Comment Number: EPA-HQ-OAR-2023-0234-0337
Page(s): 4

Commenter: Chesapeake Energy Corporation
Comment Number: EPA-HQ-OAR-2023-0234-0400
Page(s): 7

Comment 2: Commenter 0275: Pneumatic Pumps

The MSC supports the proposed clarification of the term "T" – time, allowing the time to be adjusted to the hours a pump operated as defined in the proposed equation W-2C.

A pneumatic pump releases a specified amount of gas when it operates. The amount of gas released during each operation is directly relational to the fluid being moved by the pump and the specifications of the pump. Therefore, if available, an operator can utilize the specifications of the pump and company records to determine how much fluid was pumped and/or actuations occurred and calculate the emissions. While this methodology is expected to be more accurate than the proposed measurement techniques, the MSC recognizes that this information is not always available and alternative options should remain in the rule.

Below is what we believe would be the most accurate method to calculate emissions from pneumatic pumps based on the known amount of gas emitted per cycle (if this is known) and the number of cycles per year (using company records). The first factor is the emission factor (EF), which can be generated based on the volume of gas emitted per pump cycle based on manufacturer specifications. It is not necessary to measure the pump emission rate as this rate is not typically variable. The second factor in the equation that can be improved is the estimated number of pump cycles using company records such as the amount of fluid pumped in a year or an automated mechanism to record how many times a pump actuates. A suggested additional calculation methodology following this practice is as follows, which is a similar formula as the proposed Eq. W-2C:

$Es_{,I} = GHG_i * EF * C_p$

Where:

$Es_{,I}$ = Annual total volumetric GHG emissions at standard conditions in standard cubic feet per year from all natural gas-driven pneumatic pump venting, for GHGi.
GHGi = Concentration of GHGi, CH_4, or CO_2, in produced natural gas as defined in paragraph (u)(2)(i) of this section.
EF = The volume of gas emitted per pump cycle based on manufacturer specifications.
C_p = The number of pump cycles per calendar year using engineering estimates and company records.

Commenter 0295: **Pneumatic Pumps**

AXPC supports the proposed clarification of the term "T" – time, allowing the time to be adjusted to the hours a pump operated as defined in the proposed equation W-2C.

AXPC also suggests the addition of a new equation that would allow even more accurate reporting of this source as an option as follows:

> A pneumatic pump releases a specified amount of gas when it operates. The amount of gas released during each operation is directly relational to the fluid being moved by the pump and the specifications of the pump. Therefore, if available, an operator can utilize the specifications of the pump and company records to determine how much fluid was

pumped and/or actuations occurred and calculate the emissions. While this methodology is expected to be more accurate than the proposed measurement techniques, AXPC recognizes this information is not always available and alternative options should remain in the rule.

Below is what we believe would be the most accurate method to calculate the emissions from pneumatic pumps based on the known amount of gas emitted per cycle (where this is known) and the number of cycles per year (using company records). The first factor is the emission factor (EF), which can be generated based on the volume of gas emitted per pump cycle based on manufacturer specifications. It is not necessary to measure the pump emission rate as this rate is not typically variable. The second factor in the equation that can be improved is the estimated number of pump cycles using company records such as the amount of fluid pumped in a year or an automated mechanism to record how many times a pump actuates. A suggested additional calculation methodology following this practice is as follows, which is a similar formula as the proposed Eq. W-2C:

$$Es_{,I} = GHGi * EF *Cp$$

Where:

$Es_{,I}$ = Annual total volumetric GHG emissions at standard conditions in standard cubic feet per year from all natural gas driven pneumatic pump venting, for GHGi.
GHGi = Concentration of GHGi, CH_4, or CO_2, in produced natural gas as defined in paragraph (u)(2)(i) of this section.
EF = The volume of gas emitted per pump cycle based on manufacturer specifications or engineering estimates.
C_p = The number of pump cycles per calendar year using engineering estimates and company records

<u>Commenter 0337</u>: **40 CFR § 98.233(c) Pneumatic Pumps**

"Calculation Method 2 in § 98.233(c) states, "When you measure the emissions from natural gas driven pneumatic pumps at a well-pad or gathering and boosting site, you must measure all pneumatic pumps that are vented directly to the atmosphere at the well-pad or gathering and boosting site during the same calendar year." Measuring vent volume on all pumps is burdensome. If direct measurement of emissions from pneumatic pumps is required, EPA should allow the use of those measurements on a subset of pumps to create site-specific emission factors similar to the site-specific leaker factors for equipment leaks. This would allow for the use of more empirical data without the burden of measuring every pump. As EPA recognizes in the Proposed Rule preamble, “Empirical data can be defined as data that are collected by observation and experiment. There are many forms of empirical data that can be used to quantify GHG emissions.” 88 Federal Register at 50286.

Measurements on double diaphragm pumps under Calculation Method 2 in 98.233(c) may not be feasible because of the intermittent nature of these pumps. As an alternative to direct measurement on diaphragm pumps, EPA should allow the use of original equipment manufacturer information both to ease the measurement burden and to achieve to the goal of using empirical data. *Id* at 50286.

Commenter 0400: **EPA should include an alternate Calculation Method for pneumatic pumps based on pump specifications and past operating records.**

Each pneumatic pump releases a specific amount of gas when it operates, which is directly related to the fluid being moved by the pump and the specifications of the pump. Operators can therefore use pump specifications and past operating records to determine, with great accuracy, how much fluid was pumped and the number of actuations that occurred, which can in turn be used to calculate resulting emissions with a high degree of accuracy. Using these inputs to calculate emissions for pneumatic pumps would more accurately measure emissions than the Calculation Methods outlined in EPA's Proposed Rule.

Chesapeake recognizes that pump specifications and company operating records may not be uniformly available for all covered pumps. Given this limitation, Chesapeake strongly encourages EPA to include the following calculation method for pneumatic pump emissions based on the known amount of gas emitted per cycle and number of cycles per year, as an alternative Calculation Method in the Final Rule. This method is similar to EPA's proposed formula in Eq. W-2C:[22]

$$Es_{,I} = GHG_i * EF * C_p$$

$Es_{,I}$ is the annual total volumetric GHG emissions at standard conditions in standard cubic feet per year from all natural gas driven pneumatic pump venting, for GHG_i.

GHG_i is the concentration of GHG_i, CH_4, or CO_2 in produced natural gas, as defined in 40 C.F.R. § 98.233(u)(2).

EF is the volume of gas emitted per pump cycle based on manufacturer specifications.

C_p is the number of pump cycles per calendar year based on engineering estimates and company records.

Chesapeake's proposed method includes two key revisions: (1) calculating the emission factor ("EF") based on the volume of gas emitted per pump cycle based on manufacturer specifications, and (2) using company records (e.g., the amount of fluid pumped in a year, the number of times a pump actuated) to estimate the number of pump cycles per year. In calculating the EF, it would not be necessary to directly measure the pump emission rate, because this rate is not typically variable. This revised methodology strikes a better balance between generating more accurate emissions data and greatly simplifying the process for operators, which will lead to more sustainable reporting procedures in the long-term.

Footnote:

[22] *Id.* at 50,386.

Response 2: Generally, these commenters want to use engineering calculations or manufacturers information to estimate natural gas driven pneumatic pump emissions. We find that this emission estimation method will likely underestimate emissions because the suggested emission calculation equations rely on the design volume emitted per pump cycle, which will not account for excess emissions that may occur from malfunctioning pneumatic pumps. Therefore, we have not included engineering calculations for natural gas driven pneumatic pumps in the final rule. Regarding the suggestion to allow measurements on a subset of pumps to create site-specific emission factors, see Section III.E.1.b of the preamble to the final rule for our response to these comments.

Commenter: CrownQuest Operating
Comment Number: EPA-HQ-OAR-2023-0234-0393
Page(s): 118, 125

Commenter: American Petroleum Institute et al. (Part 1 of 2)
Comment Number: EPA-HQ-OAR-2023-0234-0402
Page(s): 18, 19

Comment 3: Commenter 0393: For pneumatics w/o flow measurement, proposing operators to measure each gas emission from EACH such controller or calculate each emission from all controllers (Calculation Method 2). The complete cycle of measurements completed in no more than 5 years. The manpower, record-keeping, and reporting burden for this amount of data vs the benefit of performing this work seems lopsided. For operators, if we had the ability to direct measure a "set" of devices to develop a representative emission factor number would be useful.

This is overly burdensome reporting burden by eliminating these with OOOOb and OOOOc.

Also, with all the proposed rules for the phasing out of pneumatic controllers to other technologies such as instrument air applications, please realize that the EPA's proposed compliance timeline of 60 days is not even close to enough time. An API member survey was taken that covered 11 basins. The anticipated supply chain delay could be greater than 36 months.

…

As stated by many trades, OOOOb/c will virtually eliminate intermittent bleed pneumatic devices, should be taken out of the proposed rule.

Commenter 0402: Pneumatic Devices

Given the proposed zero-emitting standard in NSPS OOOOb and EG OOOOc, EPA should alleviate the burden with measuring and monitoring emissions across the proposed methodologies from natural gas driven pneumatic controllers during their transitional phase out in upcoming years.

Under NSPS OOOOb and EG OOOOc (§60.5390b and §60.5394c), EPA has proposed a zero-emitting standard for natural gas driven pneumatic controllers that, if finalized as proposed, will result in the elimination of methane venting from natural gas driven pneumatic devices, with the exception of those located in Alaska at a site without power. As part of separate comments on the EPA proposed NSPS OOOOb and EG OOOOc, several of the Industry Trades recommended there be limited exceptions to the zero-emitting standard where not feasible and to use the leak detection and repair program monitoring to confirm proper functioning of pneumatic controllers EPA should consider the requirements and timelines that it is proposing across NSPS OOOOb, EG OOOOc, and Subpart W to promote efficiency across the programs and focus on emission reductions.

Given the potential changes to pneumatics under OOOOb and OOOOc, the time period and practicality of using several of the proposed methods for Subpart W may be minimal. As proposed, Method 1 in §98.233(a)(1) requires installation of permanent flowmeters on equipment that will eventually be removed from service. As proposed, Method 2 would require direct measurements on all natural gas driven pneumatic devices over a several year period that corresponds to expected timelines under NSPS OOOOb and EG OOOOc. Method 2 would require purchasing new measurement equipment and training technicians on their operation, which would have a limited window of use with timelines in NSPS OOOOb and EG OOOOc.

Based on the complexities noted above, Method 3 will likely be utilized by many operators for Subpart W reporting. While the Industry Trades support the intent of proposed Method 3, this option also currently includes undue burden for estimating emissions from devices that will, for the majority, not be in operation within the next decade.

…

Note that both Method 2 and 3 provide time horizons for conducting flow measurements or monitoring surveys up to a 5-year cycle depending on the industry segment in which a facility is located. For both onshore production and gathering and boosting, EPA has proposed that operators measure/monitor approximately the same number of devices each year. This timing directly coincides with the implementation of NSPS OOOOb/EG OOOOc and complicates how an operator might track monitoring or measurement results as equipment changes at a facility. Over time, it may be impossible to monitor the same count year-over-year as the total count of natural gas driven devices will reduce over time.

Response 3: We recognize that the number of natural gas pneumatic devices will decrease due to the requirements of NSPS OOOOb/c; however, given the importance of natural gas pneumatic devices to the methane emissions from oil and gas facilities and the directives in CAA section 136(h), we consider it necessary to revise the methods for estimating emissions from natural gas devices. As facilities switch to non-natural gas devices, then the requirements will not apply. Nevertheless and after consideration of these and other comments, the EPA is finalizing a fourth calculation method that provides a default population emission factor for all devices. This eliminates the proposed requirement to measure or monitor any natural gas pneumatic device except for those devices for which the natural gas supply flow is already being measured using a meter capable of meeting the requirements of § 98.234(b). Regarding the suggestion to allow measurements on a subset of devices to create site-specific emission factors, see Section III.E.1.b of the preamble to the final rule for our response to these comments.

Commenter: Range Resources Corporation
Comment Number: EPA-HQ-OAR-2023-0234-0397
Page(s): 5-6

Comment 4: <u>EPA needs to clarify that solenoid devices are not considered pneumatic devices for the purposes of subpart W reporting.</u>

Range previously submitted comments to EPA explaining that the Agency needs to confirm that solenoid devices are not included in pneumatic device equipment counts because emissions from solenoid actuations are rare and EPA's technical basis for the regulation of pneumatic device emissions excluded review of solenoid devices. Oil and gas solenoid valves serve a number of functions in the oil and gas production sector, including managing combustion system pilot and main line fuel shutoff and control. The proposed revisions to subpart W suggest that solenoid devices will not be included in the pneumatic device equipment counts, but EPA should make this a definitive point.

First, EPA did not previously determine an emissions factor for solenoids. If EPA intended for its emissions factors to apply to solenoid devices, it would have determined the specific emissions factor for that type of device or included measured emissions from solenoid devices in the initial development of the intermittent bleed pneumatic devices emissions factor. It would be inappropriate to apply an emissions factor to solenoid devices unless the proposed factor for intermittent bleed pneumatic devices accounts for how solenoid devices operate.

Second, the technical backup information that EPA provided in support of its Proposed Rule confirms that EPA did not develop information on the volume of emissions from solenoid devices. This can be seen in the chart below, which shows the number of devices represented in each study cited by EPA in support of its subpart W emissions factors and the number of solenoid devices evaluated in each of those studies.

Study	Number of devices represented	Number of solenoid operated valves represented
GRI/EPA 1996	19	0
Allen et al. 2015	377	Not divulged
Thoma et al. 2017	80	0*
Prasino 2013	519	0
OIPA 2014	680	0*
DOE 2019 (Zimmerle)	86	4
API 2019 (Tupper)	308	Not divulged

*EPA's Technical Support omits these studies from the development of its proposed emissions factors.

It appears that solenoids were excluded from these studies because emissions from solenoids are rare. Indeed, this fact was recognized in the report, National Risk Management Research Laboratory and United States Environmental Protection Agency, GRI-94/0257.29, EPA600/R96-08, Methane Emissions from the Natural Gas Industry, Volume 12: Pneumatic Devices, Final Report 29-30 (1996) ("Methane Emissions from the Natural Gas Industry, Volume 12"), which has stood as the basis for pneumatic device emissions factors in subpart W. That report states: "Because these devices are rare, or rarely bleed, they were ignored for the purpose of this study." Methane Emissions from the Natural Gas Industry, Volume 12, at 29-30. The lack of clarification has led to varying interpretations between basins and operators resulting in inconsistent emissions reporting.

Response 4: We did not specifically exclude solenoid devices in the proposed rule and, based on our understanding of the solenoid devices, they meet the definition of a natural gas intermittent bleed pneumatic device. In 40 CFR 98.6, "[i]ntermittent bleed pneumatic devices mean automated flow control devices powered by pressurized natural gas and used for automatically maintaining a process condition such as liquid level, pressure, delta-pressure and temperature. These are snap-acting or throttling devices that discharge all or a portion of the full volume of the actuator intermittently when control action is necessary, but does not bleed continuously." In reviewing the description of solenoid devices in the GRI/EPA report, it is clear that the solenoid devices were excluded because these devices are rarely used in the field, not because they rarely emit natural gas. Specifically, on p. 30 of Volume 12 as cited by the commenter, the report states: "The solenoid "snap-acting" controller acts like the pneumatic snap-acting controller, except that its signal is not a weak mechanical signal but an electrical one… The solenoid either opens a valve that puts full supply gas pressure to the top of the valve actuator or closes off that supply and vents the actuator to the atmosphere. Like snap-acting pneumatic relays, it only bleeds when the actuator is depressed… These devices are rare since electronic signals are infrequently used in the gas industry."

Because natural gas solenoid devices vent natural gas and meet the definition of intermittent bleed pneumatic devices, we consider that solenoid devices are one type of natural gas intermittent bleed devices and that their emissions should be determined and reported under the natural gas pneumatic device venting provisions for intermittent bleed devices within subpart W.

Commenter: Atmos Energy Corporation
Comment Number: EPA-HQ-OAR-2023-0234-0406
Page(s): 7

Comment 5: Chemical injection pumps. EPA should clarify its definition of "pumps" in the Final Rule. The Proposed Rule appropriately did not expand pneumatic pumps to the natural gas distribution industry segment. However, the rule defines "pump" as "a device used to raise pressure, drive, or increase flow of *liquid streams* in closed or open conduits."[22] Atmos Energy operates small odorizer and methanol injection pumps on our natural gas distribution systems. These injection pumps are intermittent devices and can cycle several times per minute. However, each stroke is very small (e.g., 0.00005 scf per stroke for odorizer injection pumps, 0.008 scf per stroke for methanol injection pumps). Atmos Energy requests that EPA clarify whether it intended to include these small odorant and methanol injection pumps as part of the pneumatic device emission source category or whether they are considered "pumps."

Footnote:

[22] 40 C.F.R. § 98.238 (emphasis added).

Response 5: With respect to clarifying the definition of pump, we find the definition in 40 CFR 98.238 as cited by the commenter is clear and that small odorizer and methanol injection pumps meet this definition. They also may be natural gas driven pneumatic pumps, which are defined in 40 CFR 98.6 as follows: "*Natural gas driven pneumatic pump* means a pump that uses pressurized natural gas to move a piston or diaphragm, which pumps liquids on the opposite side of the piston or diaphragm." The commenter correctly notes that natural gas driven pneumatic pumps at natural gas distribution facilities are not subject to the natural gas driven pneumatic pump emission calculation and reporting requirements in 40 CFR 98.233(c) and 40 CFR 98.236(c), respectively. Natural gas driven pneumatic pumps, including odorizer and methanol chemical injection pumps, are not pneumatic devices. The definitions of high-bleed pneumatic devices, low-bleed pneumatic devices, and intermittent bleed pneumatic devices in 40 CFR 98.6 each specify that the device must be used for "maintaining a process condition such as liquid level, pressure, delta-pressure and temperature." Odorizer and methanol injection pumps do not meet these pneumatic device definitions.

Commenter: GPA Midstream Association
Comment Number: EPA-HQ-OAR-2023-0234-0299
Page(s): 25

Comment 6: Appendix A

Table of changes GPA supports as proposed.

Subpart	Citation	Change

…		
W	98.233(c)	Natural gas pneumatic pump venting: Natural gas driven pumps reported under 98.233(e) *Dehydrator vents* do not need to be reported under 98.233(c) *Natural gas driven pneumatic pump venting*

Response 6: We appreciate the support for this proposed revision and we are finalizing as proposed.

6.2 Direct Measurement Methods for Natural Gas Pneumatic Devices and Natural Gas Pneumatic Pumps

Commenter: Marcellus Shale Coalition (MSC)
Comment Number: EPA-HQ-OAR-2023-0234-0275
Page(s): 7-8

Commenter: Arkansas Independent Producers and Royalty Owners (AIPRO)
Comment Number: EPA-HQ-OAR-2023-0234-0382
Page(s): 10

Commenter: Wyoming Department of Environmental Quality (WDEQ)
Comment Number: EPA-HQ-OAR-2023-0234-0388
Page(s): 6

Commenter: Range Resources Corporation
Comment Number: EPA-HQ-OAR-2023-0234-0397
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Commenter: Chesapeake Energy Corporation
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Commenter: Chesapeake Energy Corporation
Comment Number: EPA-HQ-OAR-2023-0234-0400
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Comment 1: Commenter 0275: Pneumatic Controllers

The MSC not only believes that additional technology is currently available to perform measurements accurately but that technology will continue to improve over time with more measurement options becoming available. The regulation should include an allowance to utilize new technologies if they are proven through an independent assessment such as the Methane Emissions Technology Evaluation Center (METEC). To prove such technologies, the U.S. EPA should develop a set of minimum requirements, such as probability of detection and quantification accuracy parameters, that need to be assessed and achieved by an independent third-party certification process and allow such records to be submitted with annual reports to verify certification. One example of technology that may be a candidate for consideration is Quantitative Optical Gas Imaging (QOGI). The MSC strongly encourages the option to use new, proven technology to provide the most accurate data through reasonable measurement and estimation methods, as this information is related to the IRA and proposed SEC rules.

Commenter 0382: Natural Gas Pneumatic Device Vents:

Intermittent bleed Pneumatic Devices:

AIPRO generally supports EPA's proposal to allow multiple calculation methods for determining emissions from natural gas driven intermittent bleed pneumatic devices. That said, there are concerns with each proposed method as described below:

- Calculation Method 1 – Direct measurement with flow monitoring device
    - AIPRO supports this calculation method as an alternative for reporters that have or can cost-effectively install flow monitoring devices to directly measure fuel gas supplied to intermittent bleed pneumatic devices. That said, for many, if not most, reporters that do not already have flow monitoring devices installed, it will be cost prohibitive to install these devices and currently this is the only proposed method that fully allows the use of "empirical data" as mandated by the IRA. As such, AIPRO encourages the EPA to amend calculation Methods 2 & 3 as described below.

Commenter 0388: **WDEQ respectfully requests that EPA allows for flexibility in its emissions calculation methodologies.**

WDEQ raises concerns regarding certain revisions EPA has proposed for reporting requirements and calculation methodologies under subpart W, specifically those that pertain to direct measurement methods for natural gas pneumatic devices and pneumatic pumps. It is WDEQ's understanding that undertaking such direct measurements through surveys of pneumatics is technically challenging, very resource intensive, and lacks a standardized methodology. These measurements could be especially difficult for small business operators to undertake, in a manner similar to the resource burden challenges such operators will face in implementing OGI survey compliance requirements in the supplemental proposal to the methane rule. WDEQ previously estimated that, for its Compliance Program staff, initial training costs alone to certify staff in operating OGI cameras would be roughly $80,000 to $100,000 - and the cost of purchasing and regularly maintaining necessary OGI equipment to comply with the requirements was estimated at $1.3 million. There are also additional costs associated with the 1,400 survey hour requirement (including 40 hours in the past 12 months) necessary to qualify Senior OGI camera operators in Appendix K, as well as the initial field training requirements for other operators.[7] Small business operators will likely face significant economic challenges in obtaining the necessary training and equipment to perform this work, or in hiring qualified contractors to perform it. The proposed Greenhouse Gas Reporting Rule raises similar concerns.

WDEQ raises concerns that there may not be proportionate environmental benefits to the onerous workload and additional costs associated with direct measurements from pneumatic devices. Those emissions are already captured in WDEQ's New Source Review (NSR) permitting process, which captures worst-case-scenario actual-site emissions or potential-to-emit (PTE) calculated emissions that consider the worst-case possibility. In either scenario, WDEQ's NSR permitting already accounts for worst-case-scenario emissions and EPA's proposal that significantly increases the cost and workload associated with obtaining direct measurements does not seem likely to result in additional environmental benefits.

Footnote:

[7] WDEQ comments on Supplemental Proposal to Methane Rule, signed by WDEQ Director Todd Parfitt on February 13, 2023; submitted to EPA via Regulations.gov (Docket ID No. EPA-HQ-OAR-202 1-0317)

Commenter 0397: **EPA's adoption of direct measurement for quantifying pneumatic device emissions will allow for more accurate emissions reporting but additional revisions are needed to accomplish the goal of the Inflation Reduction Act.**

Range appreciates that EPA has added direct measurement of emissions from pneumatic devices as an option and is no longer requiring use of default emissions rates that are unreliable. Range is committed to accurate and comprehensive greenhouse gas ("GHG") emission reporting and for this reason has used direct measurement in the past to quantify its GHG emissions from pneumatic devices. Nevertheless, EPA must ensure that there is adequate flexibility in the application of direct measurement protocols while also giving due consideration to varying facility designs and equipment that are tailored for producing-basins across the United States. Additionally, as more fully described below, EPA must still take further action to ensure compliance with the Infrastructure Reduction Act's direction to "ensure the reporting under [subpart W] … are based on empirical data … accurately reflects the total methane emissions … from the applicable facilities, and allow owners and operators of applicable facilities to submit empirical emissions data …." Inflation Reduction Act, Pub. L. No. 117-169 § 60113, 136 Stat. 1818, 2076 (2022).

The final rule should ensure that operators can use the best available empirical evidence to report directly measured emissions.

EPA indicates in the Proposed Rule that it will continue to allow the use of a default emissions factor for continuous bleed pneumatic devices consistent with existing regulations and in combination with optical gas imaging ("OGI") for intermittent pneumatic devices. The use of a default emissions factor is referred to as "Method 3" in the Proposed Rule. As previously explained in great deal by Range to EPA—including our December 16, 2019 letter regarding GHG emissions reporting from intermittent bleed pneumatic devices, Range's October 6, 2022 comments on EPA's previously proposed revisions to Subpart W, and our November 16, 2022 meeting—the use of a default emissions factor can often lead to inaccurate GHG reporting, especially for intermittent pneumatic devices.

EPA is also adopting direct measurement methods for natural gas pneumatic devices and natural gas pneumatic pumps. One of the proposed methods of direct measurement is to install a monitoring device on a natural gas supply line dedicated to one or more pneumatic devices. This method—which EPA designates as "Method 1"—will likely be impractical for operators in the near-term because sites generally are not designed with monitoring on the supply side of a line, although this could present opportunities for direct measurement in the future, but given the unknowns, it would need to be further studied and verified.

Finally, EPA is proposing a "Method 2" for measurement of pneumatic device emissions using one of the methods in 40 C.F.R. § 98.234(b) through (d). See 88 Fed. Reg. at 50311. Those methods include: (1) flow meters, composition analyzers, pressure gauges, or a consensus-based standards organization method; (2) vent bags; or (3) a high volume sampler. This "vent measurement method" presents opportunities for operators to accurately measure emissions from pneumatic devices.

In the final rule, EPA should explain that reliable measurement methodologies which ensure the accurate direct measurement of emissions are allowed even if not expressly identified in the regulations. For example, it would be useful to explain that Method 2 permits the use of diaphragm type gas meters (e.g., house gas meters) to measure emissions. While the use of these meters is clearly allowed under 40 C.F.R. § 98.234(b) through (d), the final rule would benefit from a more fulsome explanation that devices which reliably measure gas can be utilized by operators for meeting their reporting obligations.

Commenter 0400: **EPA's Final Rule should revise the methodologies for calculating reported emissions values for pneumatic device and pneumatic pump emissions to capture emissions data more accurately from current equipment and technologies.**

Chesapeake strongly encourages EPA to recognize that, in many ways, cost-effectiveness is driven by flexibility and finalize calculation methodologies for pneumatic device and pneumatic pump emissions that provide appropriate flexibility for operators in estimating emissions across a broad range of emissions sources.

Subpart W currently requires greenhouse gas emissions reporting for natural gas pneumatic device venting[14] and natural gas pneumatic pump venting.[15] The reported values are calculated using default population emission factors multiplied by the number of devices and the average time the devices are supplied with natural gas.[16]

EPA's Proposed Rule seeks to improve the accuracy of the data collected and clarify certain practices related to emissions reporting for pneumatic devices and pumps by introducing new calculation methods based on measurements and leak screening.[17] Specifically, the Proposed Rule seeks to incorporate data collected from direct measurement at a facility by outlining the following three methods:

- "Calculation Method 1" is based on direct measurement of natural gas supply by a flow monitoring device. This method would be required for pneumatic devices or pneumatic pumps vented to atmosphere that are downstream from a flow monitoring device installed on a natural gas supply line. [18]

- "Calculation Method 2" requires operators to measure the natural gas emissions from each pneumatic device or pump vented directly to the atmosphere at regular intervals, using one of the methods outlined in the existing Subpart W regulations.[19] The frequency of the required intervals would depend on the industry segment and the number of devices at the facility.
- "Calculation Method 3" applies to intermittent bleed pneumatic devices that vent to the atmosphere. This method is based on existing leak detection methods under Subpart W but requires a monitoring duration of at least 2 minutes or until a malfunction is identified. Under this method, emissions are calculated using either a default emission factor for "properly functioning" devices, or a malfunctioning device emission factor for devices where a "leak" is observed for more than 5 seconds. [20] Pneumatic pumps that vent directly to the atmosphere would continue to use the current default emission factors.[21]

Adopting multiple methodologies appropriately recognizes that facilities may have a variety of on-the-ground conditions that impact available methods used to calculate emissions. However, EPA's proposed Calculation Methods for pneumatic devices and pumps are still too limited, overlooking important practical considerations that would more efficiently and accurately inform operator calculations.

EPA should revise these requirements to include more workable calculation methods, as detailed below, that account for considerations specific to the covered devices. Doing so would better align the final requirements with Congress' directive in CAA Section 136(h) to incorporate empirical data where possible.

…

EPA should incorporate flexible mechanisms for measuring emissions from intermittent vent controllers to account for new technologies.

EPA has proposed the use of high-volume samplers to obtain measurements from intermittent vent controllers. [29] However, this requirement fails to account for significant limitations in the ability of existing technologies to accurately measure emissions from intermittent vent controllers. Operations manuals specify that high-volume samplers are intended to be used for continuous, steady-state emission streams.[30] These devices are ill-suited for measuring the variable, intermittent streams emitted by intermittent vent controllers.

Aside from high-volume samplers, EPA proposes that operators could use calibrated bags to measure emissions from these devices. [31] However, calibrated bags introduce substantial uncertainty because of the variability in the technique and training of the user, bag volume accuracy, and difficulties capturing low- and high-end emission rates. Relying on this technology would therefore undermine EPA's goal of increasing data accuracy in emissions reporting and would be inconsistent with Congress' directive in CAA Section 136(h) to increase accuracy through use of available empirical data where possible.

Chesapeake expects that technology used to collect emission measurements from intermittent vent controllers will improve over time. To account for these improvements, Chesapeake encourages EPA to include a specific allowance in the regulations allowing operators to utilize new technologies to measure emissions, provided that they can make a showing that these technologies are accurate. EPA should incorporate minimum requirements to facilitate review and use of new technologies, including through third part review and verification of detection and quantification parameters. It would be beneficial for both EPA and operators to build this flexibility into the regulations now.

Footnotes:

[14] 40 C.F.R. § 98.233(a).

[15] 40 C.F.R. § 98.233(c).

[16] 88 Fed. Reg. at 50,310.

[17] *Id*.

[18] *Id*.

[19] *Id*. at 50,311.

[20] *Id*. at 50,313-4.

[21] *Id*. at 50,314.

[29] *Id*.

[30] *See e.g.*, SEMTECH HI-FLOW 2 Fugitive Methane Sampler Manual, Document 9510-235, Revision 1.09 at 31- 32.

[31] 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 (June 2023) at 59.

Response 1: These commenters generally request additional measurement and calculation methodologies. Based on consideration of this and other comments received, we are adding Calculation Method 4 that allows the use of population emission factors for all types of natural gas pneumatic devices. We disagree with commenters that asserted we should include a provision that allows any "reliable" measurement method, even though it is not specifically included in the rule, because "reliable" can be subjective and may be misconstrued to allow less accurate methods for quantifying pneumatic device emissions than appropriate in a manner inconsistent with the directives in CAA section 136(h). We specifically note that quantitative OGI is not considered an acceptable measurement method. Dry gas meters appropriately calibrated and operated are specifically allowed under 40 CFR 98.364(b). We allow calibrated bagging to determine gas flow rates from a number of sources and its application to the pneumatic device vent is comparable to its use for other sources, except that we added provisions that the collection of emissions must extend beyond 15 minutes until the bag is filled.

For our response to commenters' requests to allow operators to use new technologies, see the discussion in Section II.B of the preamble to the final rule regarding requests for the use of advanced technologies to quantify emissions from other emission sources in Subpart W beyond "other large release events".

Commenter: Marcellus Shale Coalition (MSC)
Comment Number: EPA-HQ-OAR-2023-0234-0275
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Commenter: GPA Midstream Association
Comment Number: EPA-HQ-OAR-2023-0234-0299
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Commenter: Chesapeake Energy Corporation
Comment Number: EPA-HQ-OAR-2023-0234-0400
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Commenter: Atmos Energy Corporation
Comment Number: EPA-HQ-OAR-2023-0234-0406
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Comment 2: Commenter 0275: The MSC requests a methodology be established to estimate emissions from intermittent bleed pneumatic devices more accurately using engineering estimates to determine the volume of gas emitted per actuation and company records to determine the number of actuations. This type of calculation methodology would be more accurate for some intermittent pneumatic device operations such as liquid level controllers. Intermittent bleed pneumatic controllers are widely utilized in the field to control liquid levels. The single largest factor that is most variable is how often the controller actuates which is function of the throughput, size of vessel, and levels that indicate when the controller is set to actuate. A vessel receiving very low production will have very few actuations. This should be able to be reflected in the equations utilizing company records such as the amount of fluid pumped in a year or an automated mechanism to record how many times a controller actuates. A suggested calculation methodology is as follows:

The first factor is the emission factor (EF), which can be developed by determining the volume of gas emitted per controller actuation. The EF can be estimated with high accuracy using engineering information such as length and diameter of tubing, valve diaphragm, and pressure, manufacturer data, or measurement data, if available. The second factor in the equation is the number of actuations (C_p) which can be determined using company records such as the amount of fluid pumped in a year or an automated mechanism to record how many times a controller actuates. These parameters can be reliably estimated since they are either physical dimensions or directly proportional to commonly measured parameters. A suggested additional calculation methodology similar to the proposed Eq. W-2C for pumps follows:

$Es,_I = GHGi * EF * C_p$

Where:

$Es,_I$ = Annual total volumetric GHG emissions at standard conditions in standard cubic feet per year from all natural gas driven pneumatic intermittent venting controllers, for GHGi.
GHGi = Concentration of GHGi, CH4, or CO2, in produced natural gas as defined in paragraph (u)(2)(i) of this section.
EF = The volume of gas emitted by controller per actuation based on manufacturer data, engineering estimates using data such as length and diameter of tubing, valve diaphragm, and pressure of the gas being emitted, or measurement, if available.
C_p = The number of pneumatic controller actuations per calendar year using engineering estimates and company records, including but not limited to throughput, pressure switch data, liquid level data, manual operator logs, or other records.

Commenter 0299: **EPA should allow reporters to use manufacturer data for device bleed rates.**

Similar to above, GPA's recommendation that EPA allow for the use of OEM/manufacturer specification data is not limited to continuous low bleed pneumatic controllers but should be allowable for all natural gas driven pneumatic controllers and pumps. EPA has clearly shown that OEM/manufacturer data is empirical data by allowing it in the revised methane slip calculation methodologies for reciprocating internal combustion engines ("RICE") and natural gas turbines. 62 Allowing OEM specification data for pneumatic controllers and pumps will incentivize the use of better performing devices in the near term while the proposed EG OOOOc requirement for zero-bleed devices is being implemented (if finalized).

Footnote:

[62] *Id*. at 50,356.

Commenter 0400: **EPA should include an alternate Calculation Method for pneumatic devices based on design specifications and past operating records.**

Similar to the above proposal for pneumatic pumps, EPA's final rule should incorporate an additional Calculation Method that uses engineering estimates to determine the volume of gas per actuation and company records to determine the number of actuations. Using these metrics will improve the accuracy of calculated emissions while significantly reducing compliance burdens for operators.

Chesapeake strongly encourages EPA to include the following calculation method for pneumatic device emissions as an alternative Calculation Method in the Final Rule:

$Es_{,I} = GHG_i * EF * C_p$

$Es_{,I}$ is the annual total volumetric GHG emissions at standard conditions in standard cubic feet per year from all natural gas driven intermittent pneumatic devices, for GHG_i.

GHG_i is the concentration of GHG_i, CH_4, or CO_2 in produced natural gas, as defined in 40 C.F.R. § 98.233(u)(2).

EF is the volume of gas emitted by pneumatic device per actuation based on engineering estimates, including length and diameter of tubing, valve diaphragm, and pressure of the gas being emitted.

C_p is the number of pneumatic device actuations per calendar year using engineering estimates and company records, including but not limited to throughput, pressure switch data, liquid level data, and manual operator logs.

Chesapeake's proposed method includes two key revisions: (1) calculating the emission factor ("EF") based on volume of gas emitted per controller actuation, and (2) using available information (e.g., the amount of fluid pump in a year, the number of a times a device actuated) to estimate the number of actuations. In calculating the EF, it would not be necessary to directly measure the device emission rate, because the rate can be estimated with high accuracy using information already available to the operator (e.g., length and diameter of tubing, valve diaphragm, pressure). This revised methodology strikes a better balance between generating more accurate emissions data and reducing compliance burdens.

Commenter 0406: **EPA should revise Method 2 to limit compliance burdens and avoid unnecessary reporting requirements.**

Method 2 applies to all pneumatic devices without a flow monitoring device installed on the natural gas supply link, and it requires reporters to measure emissions at regular intervals from each pneumatic device vented directly to the atmosphere.[12] For intermittent bleed devices, Method 2 only allows a reporter to calculate the physical actuation volume after a team has been dispatched to the site for measurement and finds no measurable flow rate (i.e., the properly-operating intermittent device is not actuating during the measurement activity).[13]

Underestimated costs. Atmos Energy strongly encourages EPA to further analyze the cost-effectiveness of this proposal and either (1) remove reporting requirements for pneumatic device venting for natural gas distribution companies or (2) streamline reporting requirements by allowing operators to incorporate manufacturer data and engineering calculations without a failed measurement prerequisite. Requiring direct measurement of emissions at each device at regular intervals will impose much higher compliance costs on operators than considered in the Proposed Rule. Atmos Energy operates over 73,000 miles of distribution pipeline across eight states. In our eight reporting natural gas distribution "facilities," Atmos Energy operates nearly 1,300 pneumatic devices and chemical injection pumps, with the vast majority of these devices being individually located. If the Proposed Rule is finalized, Atmos Energy would be required to individually measure each of these 1,300 devices at regular intervals, which amounts to tens of thousands of dollars in compliance costs every year.

Further, for intermittent bleed devices, requiring operators to attempt to measure emissions during actuation is infeasible in many cases. Generally, depending on the function of the intermittent bleed device, the number of actuations each year can be very low. The chance of a Method 2 measurement coinciding with an intermittent device actuation is extremely low for most of these devices. Provided that the intermittent device is operating properly, the reporter would then follow Method 2, §98.233(a)(2)(v) to estimate emissions using design data and engineering calculations. The prerequisite failed measurement attempt for these likely circumstances would result in unnecessary waste of resources and would increase indirect emissions activity based on traveling to often-remote device locations.

EPA estimated the cost of these new compliance requirements as $161,370 *across the entire industry segment*.[14] With 163 reporting sources,[15] EPA's estimate assumes a cost of less than $1,000 per distribution company. But Atmos Energy would easily exceed this amount by engaging a contractor to travel across multiple states to measure each individual pneumatic device—and these compliance costs are not offset by any meaningful increase in reporting accuracy or overall emissions measurements. These measurements (or measurement attempts in the case of Method 2 and intermittent bleed devices) would provide only minimal improvements in reporting accuracy for an emissions source category that is a minimal contributor to the distribution segment's total GHG emissions.

<u>Overlap with related rules</u>. Atmos Energy requests that EPA consider its proposed new source performance standards and emission guidelines existing sources in the crude oil and natural gas source category[16] (OOOOb and OOOOc) that would require the use of zero-emission pneumatic controllers and pumps. Given the stringent requirements of that proposed rule, any emissions measured for these devices would be *de minimis*, and costs to directly measure the emissions would be wholly disproportionate to any purported reporting benefit. Therefore, Atmos Energy strongly encourages EPA to include the impact of that rule on emissions from this emission source category in its reassessment of the cost-benefit analysis of the Proposed Rule.

Nevertheless, if EPA determines it must expand the pneumatic device venting source category to the natural gas distribution industry segment, Atmos Energy strongly encourages EPA to streamline reporting requirements. Specifically, Atmos Energy requests that EPA make the following revisions to its proposed reporting methodology:

> (1) EPA should revise its proposed methodology to include a smaller sampling subset, like the methodology for emissions from metering and regulating stations.[17] This approach would prevent reporters from having to conduct leak surveys at facilities located hundreds of miles apart.
>
> (2) EPA should also allow operators to use engineering calculations as a stand-alone method to calculate emissions. By allowing operators to take advantage of a broader range of 6 acceptable emissions measurement options, EPA can still increase the accuracy of reported emissions while striking a better balance with compliance costs.

Atmos Energy recommends that EPA allow operators the option to use manufacturer data and engineering calculations to estimate emissions. The ability to use manufacturer data to calculate emissions would incentivize operators to select lower emitting devices when purchasing equipment and designing facilities and would streamline emissions calculations, while still increasing accuracy compared to existing requirements. This approach would produce cost-effective data improvements and better account for operational challenges in implementation, given the significant number of devices subject to reporting requirements at natural gas facilities.

Footnotes:

[12] *Id.* 50,311.

[13] *Id.* 50,381.

[14] Assessment of Burden Impacts for Proposed Greenhouse Gas Reporting Rule: Revisions and Confidentiality Determinations for Petroleum and Natural Gas Systems (June 2023), Docket: EPA-HQ-OAR-2023-0234 at 32.

[15] *Id.* 34.

[16] 87 Fed. Reg.74,702 (Dec. 6, 2022).

[17] For metering and regulating stations, EPA considered the burden of measuring every metering and regulating run on a distribution system and developed a methodology whereby leak surveys are required at transmission-distribution stations, and the results of those leak surveys are used to develop a facility-specific emission factor that is applied to the metering-regulating stations that are not at transmission-distribution stations. See 88 Fed. Reg. at 50,353, 50,405.

Response 2: These commenters generally request the use of engineering calculations or manufacturers information to estimate natural gas pneumatic device emissions without measurement or monitoring requirement to confirm proper operation (no emissions when intermittent bleed device is not actuating) in part due to the reported burden associated with measurement or monitoring of these devices. We find that the engineering calculation method suggested by the commenters, which relies on the design volume emitted per device actuation and an estimated number of actuations per year, will likely underestimate emissions because it will not account for excess emissions that may occur from malfunctioning pneumatic devices. Therefore, we have not included provisions to solely use engineering calculations for natural gas pneumatic devices in the final rule. Nonetheless, after considering these and other comments, the EPA is finalizing a fourth calculation method that provides a default population emission factor for all devices. This eliminates the proposed requirement to measure or monitor any natural gas pneumatic devices except for those devices for which the natural gas supply flow is already being measured using a meter capable of meeting the requirements of § 98.234(b). Furthermore and as noted in Section III.E.1.b of the preamble to the final rule, for facilities in the production and gathering and boosting industry segments, we are finalizing provisions that allow facilities to measure emissions from some sites using calculation method 2 and use the default emission factors for other sites within the facility.

Commenter: Independent Petroleum Association of New Mexico (IPANM)
Comment Number: EPA-HQ-OAR-2023-0234-0337
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Comment 3: 40 CFR § 98.233(a) Pneumatic Devices

If direct measurement of emissions from pneumatic devices is allowed under § 98.233(a)(2), EPA should allow the use of those measurements on a subset of devices to create site-specific emission factors similar to the site-specific leaker factors for equipment leaks or liquids unloading. This would allow for the use of more empirical data without the burden of measuring every device.

Additionally, in § 98.233(a)(2)(i), the Proposed Rule states, "When you measure the emissions from natural gas pneumatic devices at a well-pad or gathering and boosting site, you must measure all natural gas pneumatic devices that are vented directly to the atmosphere at the well-pad or gathering and boosting site during the same calendar year." Reporters should not be required to measure all devices onsite when measurements are taken.

We recommend that this provision be revised to, "When you measure the emissions from natural gas pneumatic devices at a well-pad or gathering and boosting site, you must measure all natural gas pneumatic devices of a single type that are vented directly to the atmosphere at the well-pad or gathering and boosting site during the same calendar year." This would allow for some continuity across calculation methods since some methods are specific to device type (i.e. continuous high-bleed, continuous low-bleed, or intermittent bleed). The pneumatic devices used today are similar, or exactly the same, as the devices used in a massive multi-company, multi-basin study completed ~20 years ago. I am not aware of a simple measurement device or technique to accurately measure such low flowrates at low pressures. This is one reason emission factors per device type were established at that time for use in EPA emission estimation calculations.

Response 3: A significant portion of measurement costs are associated with bringing a measurement crew out to a given facility. The additional cost of measuring the emissions from all devices compared to a subset of devices is small. We sought to ensure that facilities that deploy measurement teams do not cherry-pick which devices they select to measure, to best ensure accuracy of total emissions reported and consistency with CAA section 136(h). To this end and because the incremental measurement cost is low, we are finalizing this requirement as proposed and not allowing different methods to be applied to different devices at the same well-pad site or gathering and boosting site. However, we are not finalizing the proposed requirement that facilities must measure all of the sites within their facility across a 5-year cycle for the Onshore Petroleum and Natural Gas Production and Onshore Petroleum and Natural Gas Gathering and Boosting segments, which we anticipate will address some of the concerns raised. With respect to measuring low flows, we note that high volume samplers have been used to measure emissions from pneumatic device venting in numerous literature studies. Also, for malfunctioning devices, the flow rates may not be as low as expected. If the flows are too low to accurately measure (below detection limit of method), then we allow the use of engineering calculations with estimated number of annual actuations for determining emissions from those devices, so we have adequately addressed concerns associated with measurement methods when the emissions are low (no malfunctions and infrequent actuations). Finally, as explained in Section III.E.1.b of the preamble to the final rule, we are not allowing the use of a limited number of measurements to develop a facility-specific emission factor.

Commenter: MiQ
Comment Number: EPA-HQ-OAR-2023-0234-0392
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Commenter: Environmental Defense Fund, et al.
Comment Number: EPA-HQ-OAR-2023-0234-0413
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Comment 4: Commenter 0392: **Pneumatic Devices**

Preamble III.E: *"We are proposing that, if a flow monitoring device is installed on the natural gas supply line dedicated to one or a combination of pneumatic devices, or the natural gas supply line dedicated to one or more pneumatic pumps, that are vented directly to the atmosphere, then the measured flow must be used to calculate the emissions from the pneumatic devices or pneumatic pumps, as applicable, downstream of that flow monitor. We are also proposing to require this calculation method when the flow is continuously measured in a supply line that serves both pneumatic devices and natural gas driven pneumatic pumps that are all vented directly to the atmosphere. The flow monitor would be required to meet the requirements specified in existing 40 CFR 98.234(b)."*

MiQ Comments: Some Operators within the MiQ certification program meter natural gas supply lines to pneumatic devices and other areas of gas consumption across their facility. The allowance of this type of flow monitoring will allow for fit-for-purpose, site-specific methods of quantifying GHG emissions from pneumatic devices. This methodology will reduce reliance on generic emission factors that do not account for the actual operation of an individual operator's fleet of pneumatic devices. Flow measurement that is segregated for pneumatic devices and pumps will be able to measure any periods of time of excess flow and properly include periods of time of higher-than-normal emissions. With pneumatic devices as the largest source of process emissions in the oil and gas industry, allowing for more representative calculation methodologies is critical and will likely be a heavily used option for many operators, considering the potential tax implications.

If EPA is requiring this calculation for continuous flow measurement, MiQ requests clarification if an additional requirement will be in place for operators currently with flow measurement installed to increase their operational and calibration practices meet 40 CFR 98.234(b) or 98.3(i). EPA should be aware that many operators voluntarily meter their gas, but likely do not sufficiently prioritize operation or calibration of these meters since there are currently no regulatory drivers to do so. While this will provide operators with a driver, there are other options that operators could default back to. **We request clarification around this proposed requirement, and generally support EPA mandating this to bring all field flow measurements up to a single standard.**

Commenter 0413: *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.

Response 4: Regarding the allowed flow measurement options in 40 CFR 98.233(a)(2)(iii), first we note that the use of a temporary meter for the flow rate can be installed in the supply line to the device or in the vent line from the device. For post-device flow meters, there could be some issues with higher back pressures impacting the measured flow, but generally this will seldomly occur, and only when flow rates are much higher than expected. In any case, we note that the use of post-device flow meters is optional and reporters will be able to estimate emissions under other calculation methodologies provided in the final rule in situations where measurements using post-flow meters are not technically feasible. We cited vane anemometers as an example of a temporary flow meter because this type of temporary meter would exert limited back pressure. Regarding the bagging method, we included specific provisions that sampling must be continued until the bag is filled, which will ensure the method is used properly and likely result in a better average emissions rate because the sampling period will be longer. We maintain that, based on the currently available data, the final measurements methods are reasonable and appropriate for measuring emissions from pneumatic device vents. Nonetheless, we expect that most measurement crews measuring emissions via Calculation Method 2 will use high volume samplers due to the ease of use of this device relative to installing a temporary flow meter or using the bagging method. Additionally, we require facilities to report the type of measurement method used when applying Calculation Method 2. Therefore, we can evaluate the reported data to determine if there is any bias when using one measurement method over another and adjust the allowed methods in future rulemakings accordingly. Finally, 40 CFR 98.234(b) specifies that any flow meters used to measure reported quantities in 40 CFR 98.233, must be operated and calibrated according to the procedures in 40 CFR 98.3(i). We confirm that this applies to continuous flow meters used in Calculation Method 1 or temporary flow meters used in Calculation Method 2.

Commenter: Environmental Defense Fund, et al.
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Comment 5: … 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.

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 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.

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 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 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.

Footnotes:

[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.

[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)

[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).

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

[55] *Id*.

Response 5: See Section III.E.1.b of the preamble to the final rule for our response to these comments.

Commenter: Independent Petroleum Association of America (IPAA)
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Commenter: Arkansas Independent Producers and Royalty Owners (AIPRO)
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Commenter: The Petroleum Alliance of Oklahoma
Comment Number: EPA-HQ-OAR-2023-0234-0398
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Commenter: Environmental Defense Fund, et al.
Comment Number: EPA-HQ-OAR-2023-0234-0413
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Comment 6: Commenter 0265: Further, under proposed Calculation Method 2, EPA proposes to require a 15-minute vent rate sampling period for each pneumatic device, except isolation valve actuators, which would only be required to be sampled for a minimum of 5 minutes. See excerpt below:

> We are proposing a reduced monitoring duration for isolation valve actuators specifically because these devices actuate very infrequently, and the monitoring is targeted to confirm the valve actuators are not malfunctioning (i.e., emitting when not actuating) rather than to develop an average emission rate considering some limited number of actuations." (FR p. 50311)

A reduced monitoring frequency of only 5 minutes is adequate to confirm a pneumatic device is not malfunctioning. It is not only true for isolation valve actuators, but for all intermittent bleed pneumatic devices. Accordingly, EPA should amend the proposed rule to only require a 5-minute sampling period for all devices. The currently proposed 15-minute sampling period is overly burdensome and unnecessary to accurately estimate emissions.

Commenter 0382:

- Further, under proposed Calculation Method 2, EPA proposes to require a 15-minute vent rate sampling period for each pneumatic device, except isolation valve actuators, which would only be required to be sampled for a minimum of 5 minutes. See excerpt below: ***"We are proposing a reduced monitoring duration for isolation valve actuators specifically because these devices actuate very infrequently, and the monitoring is targeted to confirm the valve actuators are not malfunctioning (i.e., emitting when not actuating) rather than to develop an average emission rate considering some limited number of actuations."*** (FR p. 50311)
- AIPRO agrees that a reduced monitoring frequency of only 5 minutes is adequate to confirm a pneumatic device is not malfunctioning. It is not only true for isolation valve actuators, but for all intermittent bleed pneumatic devices. Accordingly, AIPRO proposes that EPA amend the proposed rule to only require a 5-minute sampling period for all devices. The currently proposed 15-minute sampling period is overly burdensome and unnecessary to accurately estimate emissions.

Commenter 0398: EPA states that "[f]or intermittent bleed devices, the lack of any emissions during a 5-minute or 15-minute period, as applicable, would indicate that the device did not actuate, and that the device is seating correctly when not actuating."

Manufacturers of intermittent bleed devices can provide the best information on how to determine a properly functioning device in less time, and operators can use optical gas imaging (OGI) equipment or have experience and knowledge to make this determination in less time.

Action Requested: We request EPA allow operators to follow manufacturers' specifications and/or guidelines, use OGI or other similar equipment and/or operator knowledge and experience to determine a properly functioning device in less time (e.g., it may only take a few seconds). EPA should not dictate the time to make such a determination.

Commenter 0413: Method 2: Volumetric flow rate based on 15-minute measurement

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 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.

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

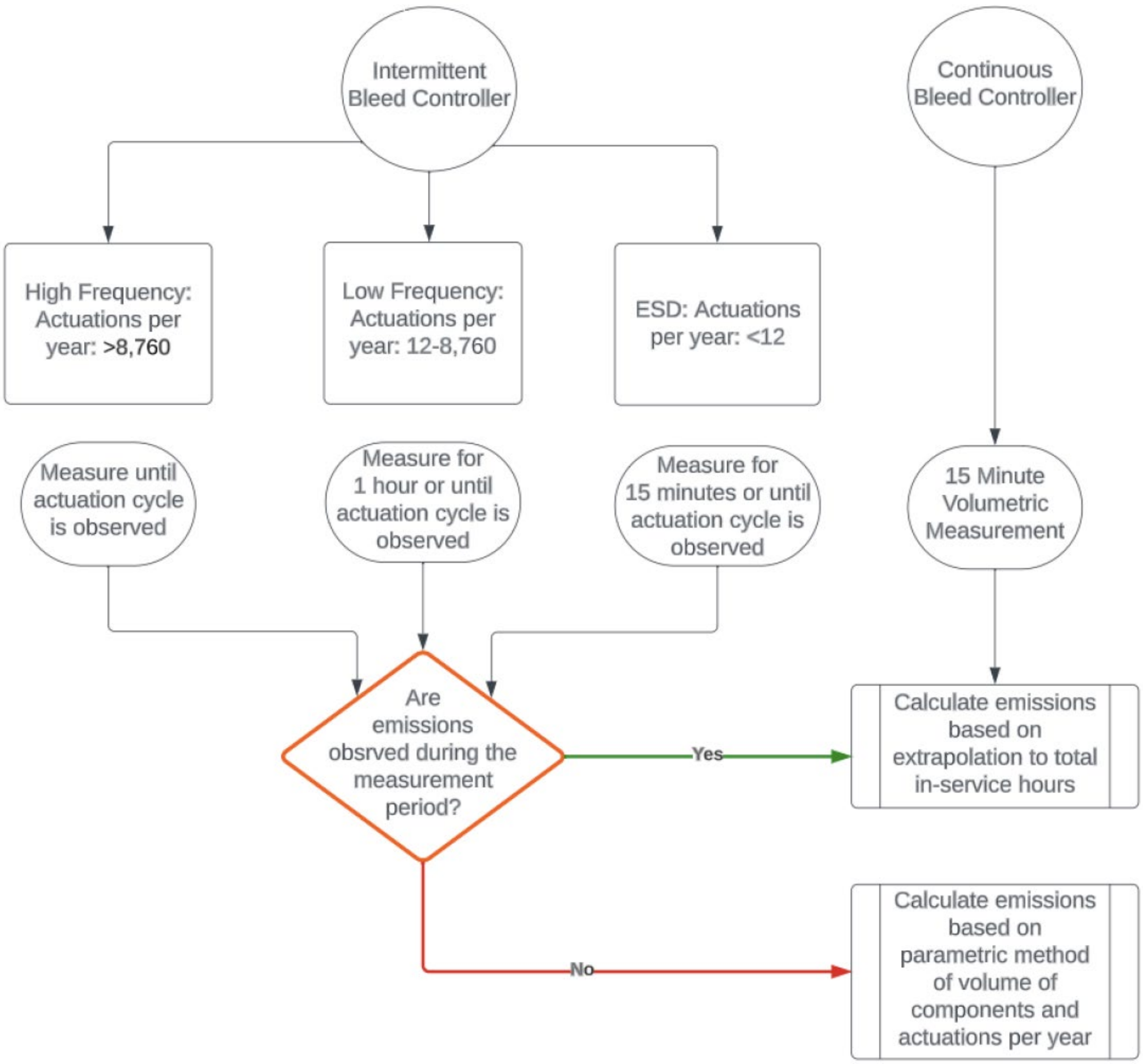
Type	Number of actuations per year	Measurement interval required
High actuation frequency (e.g. gas processing unit liquid level controllers or separator dump valve)	>8,760	Until actuation cycle is observed
Low actuation frequency (e.g. temperature and pressure controller)	12-8,760	1 hour (or until actuation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

Footnotes:

[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.)

[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.

Response 6: After reviewing these comments on the duration requirements for calculation method 2 measurements, we are finalizing the calculation method as proposed. We find a significant difference between intermittent bleed devices that may actuate once every 3 to 10 minutes and isolation valve actuators that may actuate once a month. We assessed that the approach of measuring emissions across multiple actuations for intermittent bleed devices with a 15-minute sampling duration would be much more likely to result in representative emissions from these devices relative to reducing the sampling time to 5-minutes for all devices. On the other hand, while longer sampling periods may result in more representative emissions, we find that the 15-minute sampling period will result in adequately accurate emission estimates. While some controllers exhibit sporadic patterns of excess emissions (malfunction intermittently), the 15-minute sampling period conducted across a large number of devices will accurately reflect this behavior (in other words: 15-minute periods overlapping an intermittent malfunction would overstate the emissions from that device; 15-minute periods not overlapping an intermittent malfunction would understate the emissions from that device; but for a large sampling of devices the cumulative emissions would still be accurate). Because facilities that have natural gas pneumatic devices commonly have a large number of devices, extending the sampling period for each device is not necessary to accurately determine the cumulative emissions across all of the devices.

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Commenter: Ascent Resources, LLC
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Commenter: Permian Basin Petroleum Association (PBPA)
Comment Number: EPA-HQ-OAR-2023-0234-0346
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Commenter: Arkansas Independent Producers and Royalty Owners (AIPRO)
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Commenter: The Petroleum Alliance of Oklahoma
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Commenter: American Petroleum Institute et al. (Part 1 of 2)
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Comment 7: Commenter 0265: Under proposed Calculation Method 2, EPA proposes to require the vent rate for every pneumatic device to be directly measured every 5 years. This measurement frequency is overly burdensome and unnecessary to determine a statistically representative average vent rate for devices of the same type (i.e., intermittent bleed). EPA should amend the proposed rule to only require 10% of devices to be surveyed each year.

Commenter 0339: For pneumatic devices, the EPA is proposing options for onshore producers to conduct measurement surveys or monitoring programs on all controllers over a 5-year period. The language requires reporters to "measure all" or "monitor each" in sections 98.233(a)(3). The population of pneumatic controllers at onshore production well pads is dynamic – a controller that is in service on one well pad at the beginning of a 5-year measurement or monitoring program may not be there at the end of the program. Ascent requests that the EPA softens the language to allow for instances where not all controllers can be measured or monitored. Alternately, the EPA could change this requirement to monitoring at all well pads rather than each controller in the 5-year period to help deal with the dynamic nature of the controller.

Commenter 0346: Pneumatics

Calculation Method 2. PBPA recommends that instead of requiring direct measurement of emissions from each pneumatic device under Calculation Method 2, operators should be allowed to base emission calculations on a representative sample. As discussed in the Oil and Gas Methane Partnership 2.0 guidance document, Reconciliation and Uncertainty in Methane Emissions Estimates for OGMP2.0, a site-level measurement conducted for a statistically representative sample should be a sufficient basis for emission calculations. While more complex sites with smaller populations may require more sampling, simple sites with robust populations require less sampling and certainly do not require direct measurement of each source:

For example, a population of valves or even simple production sites with fewer sources would require fewer measurement samples to characterize compared to a population of complex central tank batteries. Similarly, pipe segments, meter runs, and pressure regulating stations are likely simple. The sampling recommendations are provided in terms of the percentage of the total population that should be sampled. Directionally, as a population size increases, a smaller percentage of the sites will require measurement, though the absolute number of facilities may increase. Selection of sampling size should consider technical, time and resource constraints.[7]

Footnote:

[7] Oil and Gas Methane Partnership 2.0 guidance document, Reconciliation and Uncertainty (U&R) in Methane Emissions Estimates for OGMP2.0, at 11.

Commenter 0382:

- Under proposed Calculation Method 2, EPA proposes to require the vent rate for every pneumatic device to be directly measured every 5 years. This measurement frequency is overly burdensome and unnecessary to determine a statistically representative average vent rate for devices of the same type (i.e., intermittent bleed). AIPRO proposes that EPA should amend the proposed rule to only require 10% of devices to be surveyed each year.

Commenter 0398: For production and gathering and boosting, EPA is proposing that a complete cycle of measurements for all pneumatic devices be completed in no more than 5 years. For other industry sectors, EPA proposes 5 years for facilities with 101 or more natural gas pneumatic devices.

Some operators may have thousands of pneumatic devices spread out over a significant geographic area. We question whether the 5-year period will be adequate to allow operators to conduct such measurements. We are concerned there will not be adequate measurement equipment and qualified technical staff to conduct such measurements in the 5-year period. Also, if an operator acquires a considerable number of properties with many pneumatic devices, it may be difficult to complete direct measurements in a timely manner.

Action Requested: We request EPA allow operators to use other options such as a representative sample for similar devices located at other facilities or allow operators to request an extension to the 5-year time frame for good cause (e.g., number of pneumatics, geographic area, available measurement equipment and/or technical staff to conduct such measurements) to measure all pneumatic devices.

Commenter 0402: Method 2 – Suggest Improvement in Measurement Cycle and Alternative Approach

The Industry Trades generally support EPA's Calculation Method 2 to distribute measurement campaigns over multiple years where flow monitors are not permanently installed, with the following amendments:

1. Since the as-proposed NSPS OOOOb and EG OOOOc require phase out of this equipment and numerous operators have been reducing these equipment counts voluntarily, it is not possible to monitor the same number of controllers each year since equipment counts will be simultaneously declining. Instead, **EPA should require the annual inspections to cover at least 20% of the population of pneumatic controllers at a facility** that have not already been inspected pursuant to Subpart W within the previous 4 years, provided that each device remaining in service at the end of the first five years has received at least one inspection over the five-year period.
2. Additionally, EPA should allow operators to **directly measure a representative sample of pneumatic devices in lieu of the entire population**. This approach ensures accuracy of reported emissions but recognizes the vast geographic dispersion of upstream sites. Additionally, API performed a study on the count of pneumatics at upstream sites and provided that in comments regarding the supplemental OOOOb rulemaking.[14] The time

required to drive to each site would be unnecessary when a smaller, representative sample accurately reflects the emissions from these devices. Lastly, this approach is incorporated in several voluntary programs (e.g., OGMP 2.0), retains the accuracy of reported emissions, considers the large geographic dispersion of upstream sites, is consistent with the approach proposed for equipment leaks, improves accuracy over generic emission factor-based estimates, and is more cost effective. The representative emission factor approach would require measurement of a representative sample of pneumatic devices to determine a "facility" specific emission factor.

Footnote:

[14] https://www.regulations.gov/comment/EPA-HQ-OAR-2021-0317-2428.

Response 7: See Section III.E.1.b of the preamble to the final rule for our response to these comments.

Commenter: GPA Midstream Association
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Page(s): 26

Comment 8: The midstream industry cannot reasonably meter gas to pneumatic controllers and pumps.

GPA disagrees with the proposed addition of the requirement to use metered supply gas volume data for calculating emissions from pneumatic devices and pumps. This is a very uncommon configuration at midstream facilities, and in most cases would be infeasible to implement. Supply gas sent to pneumatic devices could potentially be originating from several different points at the facility, with each of these supply gas deliveries potentially having different compositions (inlet/field gas, fuel gas, process gas, etc.). Furthermore, it would be even less likely that compositional data for all supply gas streams would be available at every supply gas delivery point. GPA also expects that most of the piping for these supply gas delivery systems would be very small in diameter (< ½" in many cases) and could not feasibly be connected to any metering/analyzer equipment. GPA recommends the proposed requirement to use measured volumetric and composition supply gas data be removed entirely or at most be an optional method.

Response 8: Calculation Method 1 is optional if there is not an upstream flow meter already installed and if reporters do not elect to install one; however, if a facility has an upstream flow meter installed or elects to install one, reporters must use Calculation Method 1 for the pneumatic devices downstream of the flow meter because this will provide the most accurate measure of the device's emissions.

Commenter: GPA Midstream Association
Comment Number: EPA-HQ-OAR-2023-0234-0299
Page(s): 24-25

Comment 9: Any survey requirements must be adjusted for devices outside of a fence-line.

It is unclear how pneumatic devices located along the pipeline but not at a fence-line site[59] should be monitored. It is not reasonable to mandate monitoring for all intermittent pneumatics within a basin but outside a fence-line in a single year. As noted above in Comment 21, these devices are geographically dispersed. Further, because of the shifting landscape of natural gas pneumatic controllers, it is not practical for EPA to mandate monitoring "approximately the same number of devices each year." GPA suggests the following changes to the proposed regulatory text:

> *98.233(a)(3)(ii)(B) For facilities in the onshore petroleum and natural gas production and onshore petroleum and natural gas gathering and boosting industry segments, you must monitor all natural gas intermittent bleed pneumatic devices at your facility at least once every 5 years. ~~If you elect to monitor your pneumatic devices over multiple years, you must monitor approximately the same number of devices each year.~~ When you monitor the emissions from natural gas pneumatic devices at a well-pad or gathering and boosting site, you must monitor all natural gas intermittent bleed pneumatic devices that are vented directly to the atmosphere at the well-pad or gathering and boosting site during the same calendar year, except devices located outside of a fence-line site.*

Footnote:

[59] Proposed 40 C.F.R. § 98.238 ("*Gathering and boosting site means a single gathering compressor station as defined in this section, centralized oil production site as defined in this section, gathering pipeline site as defined in this section, or other fence-line site within the onshore petroleum and natural gas gathering and boosting industry segment*.").

Response 9: As noted in Section III.E.1.b of the preamble to the final rule, the EPA has decided to provide a fourth calculation method that provides a default population emission factor for all devices. This eliminates the requirement to measure or monitor all natural gas pneumatic devices at a facility. For facilities in the production and gathering and boosting industry segments, as noted in Section III.E.1.b of the preamble to the final rule, we are finalizing provisions that allow facilities to measure emissions from some sites using calculation method 2 and use default emission factors for other sites within that facility. Devices outside the "fence-line site" would still be required to either be measured or apply the default emission factor.

6.3 Intermittent Bleed Pneumatic Device Surveys

Commenter: GPA Midstream Association
Comment Number: EPA-HQ-OAR-2023-0234-0299
Page(s): 17

Commenter: Permian Basin Petroleum Association (PBPA)
Comment Number: EPA-HQ-OAR-2023-0234-0346
Page(s): 6

Comment 1: Commenter 0299: The following is a list of substantive proposed changes that GPA expressly supports.

…

- Including a new option to survey natural gas intermittent bleed pneumatic devices and calculate emissions based on properly functioning devices and malfunctioning devices [98.233(a)(3)(ii)];[42]

Footnote Reference:

[42] See Comment 21 requesting retention of the default emission factor for intermittent bleed controllers.

Commenter 0346: Pneumatics

Calculation Method 3. PBPA recommends that under Calculation Method 3, it should not be assumed that malfunctioning devices have, in fact, been malfunctioning for the entire year. Instead, the malfunction should be assumed to extend to the most recent inspection date or the previous reporting year, whichever is less. However, if there is data indicating that the malfunction occurred at some time after the most recent inspection date or during the most recent reporting year, the more recent date may be used for calculating emissions.

Furthermore, PBPA recommends that operators may treat inspections for malfunctioning devices as representative samples that may be used to calculate emissions for those devices that are not inspected. Consistent with our recommendation above, when a sufficient number of inspections have been conducted, operators should be able to rely on this representative sample instead of monitoring each device individually.

Response 1: We appreciate the support of the proposed Calculation Method 3. When only one monitoring event is performed during the year, for the reasons discussed in Section III.E.2 of the preamble to the final rule, we maintain that assuming the emissions identified during the monitoring event are representative of the emissions present during the year is reasonable and provides the most accurate assessment of the emission. If multiple monitoring surveys are conducted, then the assumed duration of malfunction-level emissions can be reduced (based on the time between monitoring surveys). These provisions are being finalized as proposed. See Section III.E.2.b of the preamble to the final rule for our response to the comments regarding using representative monitoring.

Commenter: Kathairos Solutions, Inc.
Comment Number: EPA-HQ-OAR-2023-0234-0228
Page(s): 2

Commenter: Independent Petroleum Association of America (IPAA)
Comment Number: EPA-HQ-OAR-2023-0234-0265
Page(s): 11-12

Commenter: Diversified Energy Company
Comment Number: EPA-HQ-OAR-2023-0234-0267
Page(s): 2, 4

Commenter: Marcellus Shale Coalition (MSC)
Comment Number: EPA-HQ-OAR-2023-0234-0275
Page(s): 7-8

Commenter: American Exploration and Production Council
Comment Number: EPA-HQ-OAR-2023-0234-0295
Page(s): 16, 17

Commenter: GPA Midstream Association
Comment Number: EPA-HQ-OAR-2023-0234-0299
Page(s): 24

Commenter: Independent Petroleum Association of New Mexico (IPANM)
Comment Number: EPA-HQ-OAR-2023-0234-0337
Page(s): 2

Commenter: Ascent Resources, LLC
Comment Number: EPA-HQ-OAR-2023-0234-0339
Page(s): 2-3

Commenter: Permian Basin Petroleum Association (PBPA)
Comment Number: EPA-HQ-OAR-2023-0234-0346
Page(s): 5, 6

Commenter: Ovintiv Inc.
Comment Number: EPA-HQ-OAR-2023-0234-0350
Page(s): 2-3

Commenter: Marathon Oil Company
Comment Number: EPA-HQ-OAR-2023-0234-0378
Page(s): 3

Commenter: Williams Companies, Inc.
Comment Number: EPA-HQ-OAR-2023-0234-0394
Page(s): 11

Commenter: The Petroleum Alliance of Oklahoma
Comment Number: EPA-HQ-OAR-2023-0234-0398
Page(s): 10-11, 12

Commenter: Western Energy Alliance
Comment Number: EPA-HQ-OAR-2023-0234-0399
Page(s): 12

Commenter: Chesapeake Energy Corporation
Comment Number: EPA-HQ-OAR-2023-0234-0400
Page(s): 9-10

Commenter: American Petroleum Institute et al. (Part 1 of 2)
Comment Number: EPA-HQ-OAR-2023-0234-0402
Page(s): 9, 18, 19

Commenter: Environmental Defense Fund, et al.
Comment Number: EPA-HQ-OAR-2023-0234-0413
Page(s): 37-38

Commenter: North Dakota Petroleum Council (NDPC)
Comment Number: EPA-HQ-OAR-2023-0234-0417
Page(s): 8

Comment 2: Commenter 0228: Following review of Subpart W, with our interest surrounding changes and revisions to Section E pertaining to pneumatics, **we do not have any significant objections regarding the proposed calculation methods or reporting requirements.**

The metering and monitoring technologies contemplated in the revisions are generally accurate and available. **Furthermore, existing population-based emission factors are simply not accurate and misrepresent actual methane emissions.** Given the closed-loop nature of the Kathairos nitrogen-based solution, we are able to precisely measure the amount of methane that otherwise would have been vented from a particular wellsite. By tracking nitrogen consumption in the tank and applying a gas equivalency factor, we are able to continuously track site vent rates and changes over time. In virtually all cases, our customers' best estimates of their vented emissions have been inaccurate and are only known for certain once a nitrogen tank begins operating on site. In many cases, our customers' original estimates are extremely different from the actual vent rates (in both directions!). As such, we support the EPA's proposed revisions which seek to improve the accuracy to emissions reporting.

We also wanted to emphasize that companies which have voluntarily undertaken efforts to reduce or eliminate their emissions should not face undue burdens with respect to reporting. **Eliminating emissions should always be the easiest course of action from a reporting and compliance standpoint.** There was nothing we noticed in the proposed revisions that would suggest otherwise. However, we did want to highlight this as EPA develops the reporting and data entry frameworks to support this regulation. Administrative ease (or burden) directly impacts companies' decisions to invest in critical emission reduction technologies.

Commenter 0265: Retain a Calculation Method Similar to the Current Subpart W Regulations

EPA should allow a fourth calculation method similar to the method in the current Subpart W rules and that which was included in the 2022 proposed rule, that allows small operators to use a single whole gas emissions factor-based approach for calculating emissions from intermittent bleed pneumatic devices. EPA suggests that such an alternative is unnecessary because of the Subpart OOOOb and OOOOc proposals. However, neither of those are finalized and alternative approaches to managing emissions have been proposed. In particular, the Subpart OOOOc Emissions Guidelines are not binding on states and state regulations may continue to allow natural gas driven pneumatic controllers.

The current EF for intermittent pneumatic controllers is 13.5 scf/hour/component. This EF was developed in the mid-1990s based on data collected from 19 controllers. It is hardly an example of robust data acquisition. Since then, the validity of this EF has been consistently questioned. It has become a higher profile issue as various environmental lobbying groups have produced reports based on the GHGI that is largely developed using the GHGRP.

Over the years other studies have been done to address this EF. However, the quality of EPA's 2022 analysis of this EF that has been such a target is wanting. In general, EPA discusses six studies that have been done with information on intermittent pneumatic controllers for production operations (GRI/EPA 1996, Allen, Thoma, Prasino, OIPA and API 2019). Additionally, EPA assessed a Department of Energy study on Gathering and Boosting operations (DOE G&B). In each case EPA discusses the limitations of the studies – short sampling times with assumptions about the activation period for intermittent controllers, emissions that are calculated rather than measured, and classification issues. Then, EPA eliminates two studies (Thoma, OIPA) apparently because of their use calculated emissions (which were far lower than some of the other studies). Subsequently, it produced the following summary table:

Device Type	Whole Gas Emission Factor (scf/hr/device)					
	Subpart W[a]	GRI/EPA (1996e)[b]	Allen *et al.* (2015)	Prasino Group (2013a)[c]	DOE G&B Study (2019)	API Field Study (2019)
Low continuous bleed pneumatic devices	1.39	27.3[b]	13.6[d]	6.1	7.6	2.6
High continuous bleed pneumatic devices	37.3		22.8	10.4	19.3	16.4
Intermittent bleed pneumatic devices	13.5	13.5	6.0[d]	4.2	11.1	9.2

Next, EPA averaged the intermittent factors for these studies to produce a new EF of 8.8 scf/hr. However, this appears to include the EF from the DOE G&B study; if it had not, the EF would appear to be 8.2 scf/hr. If EPA had included the Thoma and OIPA studies instead of the DOE G&B study, the EF would be 6.8 scf/hr. None of these calculations appear to be weighted based on the number of controllers tested. Consequently, for example, the 19 controllers in the GRI/EPA 1996 study are treated equally with the 128 controllers in the Prasino report. If EPA had weighted the data and used the Thoma and the OIPA studies, the EF would be closer to 3.7 scf/hr/device.

EPA should include a fourth calculation option that provides a single EF and that EF should be 3.7 scf/hr/device.

Commenter 0267: **Specific Proposed Rules Which Stifle Technology or Disincentivize Emission Reduction**

EPA Requested Comments on Default Emission Factors for Intermittent Bleed Pneumatics

EPA has requested comment on the use of a default emission factor of 8.8 scf/hr/device for intermittent bleed devices under an alternative calculation methodology (as Calculation Method 4). Diversified supports the use of a default factor for intermittent bleed devices as an alternative option to direct measurement. However, an option to use two factors (one for properly operating devices and one for malfunctioning devices) as outlined in the June 2022 proposed rules for operators who conduct surveys, or the option to use the single default factor for operators who do not conduct surveys. This approach would incentivize malfunction surveys and the associated emission reductions. The most recent EPA approach would disincentivize emission reduction and not meet the requirements of the IRA to be empirically based.

Requested Action: Use a two-factor approach for pneumatics where malfunction surveys are conducted.

Commenter 0275: Pneumatic Controllers

The MSC supports the ability to use a malfunctioning factor and malfunction records coupled with a properly operating factor for intermittent vent controllers.

Uncertainty exists around the accuracy of intermittent pneumatic controller measurements further demonstrating the need for a blanket emission factor. The U.S. EPA proposed the use of high flow samplers to measure intermittent pneumatic controller vents. However, pages 31 and 32 of the latest Semtech Hi-Flow 2 Fugitive Methane Sampler Manual Document 9510-235 Revision: 1:09 appears to demonstrate the instrument's capabilities are for continuous, steady-state emissions streams rather than the intermittent and variable nature of intermittent pneumatic device emissions. The only remaining method proposed by the U.S. EPA is measurement using calibrated bags. Calibrated bags are known to introduce measurement uncertainties due to the following reasons: a) technique and training of the user; b) veracity of the bag volume; c) low-end emission rate limits so that the bag inflates without having the plume partially exit the bag during a measurement; and d) high-end emission rate limits so that the bag inflates over a duration that can be reliably timed with a stopwatch. Therefore, the MSC requests the retention of the option to use a blanket emission factor for intermittent pneumatic controllers for instances when an operator does not have data or resources to follow the other proposed methods.

…

4. The U.S. EPA requested comment on the use of a default emission factor of 8.8 scf/hr per device for intermittent bleed devices under Calculation Method 4. The MSC recommends the use of a default factor for intermittent bleed devices as an alternative option to monitoring. Additionally, the U.S. EPA referenced the use of 2.3 scf/hr for intermittent bleed devices but had concerns that this factor would underestimate emissions from malfunctioning devices. The MSC proposes a dual factor approach for properly operating intermittent bleed devices and malfunctioning devices. The U.S. EPA previously proposed 0.3 scf/hr for properly operating intermittent bleed devices and, as discussed in the Technical Support Document (TSD), the properly operating emission factor should be a maximum of 2.3 scf/hr. The MSC understands that a malfunctioning emission factor would have a higher value.

Commenter 0295: **Pneumatic Controller**

AXPC is in favor of proposed rule changes allowing for the use of site-specific measurement data to estimate emissions from pneumatic devices for operators who elect to do so, but also supports EPA retaining default population emission factors as a calculation option. In particular, AXPC recommends that EPA include a default emission factor for intermittent bleed devices as Calculation Method 4 per the discussion in the preamble. Given the large number of intermittent bleed devices and the large number of individual production sites impacted, site-specific monitoring would be extremely resource intensive and ultimately obsolete. As operators weigh the compliance burdens under Subpart W along with anticipated requirements of NSPS OOOOb/OOOOc that would eliminate the use of certain pneumatics, they may prioritize investing capital to replace such gas-driven pneumatic devices (to reduce actual emissions) vs. the expense of monitoring equipment and personnel (to measure actual emissions).

…

Additionally, EPA has requested comment on the use of a default emission factor of 8.8 scf/hr/device for intermittent bleed devices under an alternative calculation methodology (as Calculation Method 4). AXPC supports the use of a default factor for intermittent bleed devices as an alternative option to direct measurement. However, AXPC would recommend that the rule provide operators with the option to use one of two methods:

3. Use two factors: one for properly operating devices and one for malfunctioning devices as outlined in the June 2022 proposed rules (method for operators who conduct surveys)
4. Use the single default factor of 8.8 scf/hr (method for operators who do not conduct surveys.)

Commenter 0299: **EPA should retain population emission factors for intermittent bleed pneumatics.**

While GPA supports EPA's proposal to allow surveys for malfunctioning intermittent bleed controllers, it is unreasonable to eliminate the default population count emission factor for intermittent bleed devices while retaining the default emission factors for high and low continuous bleed devices. Although it is presumed that the promulgation of NSPS OOOOb and EG OOOOc will ultimately minimize natural gas driven pneumatic device venting (with exceptions for safety or operational demand) at facilities subject to these regulations, GPA anticipates it will be many years before the EG OOOOc-implementing requirements result in zero-emitting pneumatic devices.

Operators should not be forced into a cumbersome direct measurement requirement for a single type of pneumatic device. GPA believes the removal of the default emission factors and the addition of a monitoring requirement for intermittent bleed pneumatic devices constitutes an overreach within Subpart W. The monitoring requirement for intermittent bleed devices, which mainly serve as a detection method for malfunctioning devices, seemingly mandates an unlawful compliance standard as a part of a rule that simply requires the reporting of emissions. As previously stated in the General Comments section above, any requirements that go beyond reporting into the area of emission reduction or compliance should be addressed in an appropriate NSPS, NESHAP, or other CAA provision— not in a data collection rule.

Additionally, there are intermittent bleed pneumatic controllers on pipelines (such as emergency shutdown valves and valves associated with pigging). These controllers are often remote, scattered across miles of pipeline, and can be difficult to access. These controllers are not subject to NSPS OOOOb and EG OOOOc.[56,57] EPA is therefore incorrect in its assertion that "few" intermittent bleed devices will exist and those that do will be subject to monitoring per NSPS OOOOb and EG OOOOc.[58] GPA members envision needing to use contractors to implement these surveys, and the remote nature of these valves would add significant expense and burden. Retaining the emission factors for these controllers would ease this expense and burden.

Footnotes:

[56] Proposed 40 C.F.R. § 60.5365b(d) ("Each pneumatic controller affected facility, which is the collection of natural gas-driven pneumatic controllers <u>at a well site, centralized production facility, onshore natural gas processing plant, or a compressor station</u>. Natural gas-driven pneumatic controllers that function as emergency shutdown devices and pneumatic controllers that are not driven by natural gas are exempt from the affected facility, provided that the records in §60.5420b(c)(6)(i)(A) or (B) are maintained, as applicable.") (emphasis added).

[57] *Id*. § 60.5386c(d) ("Each pneumatic controller designated facility, which is the collection of natural gas-driven pneumatic controllers <u>at a well site, centralized production facility, onshore natural gas processing plant, or a compressor station</u>. Natural gas-driven pneumatic controllers that function as emergency shutdown devices and pneumatic controllers that are not driven by natural gas are exempt from the designated facility, provided that the records in §60.5420c(c)(5)(i)(A) or (B) are maintained, as applicable.") (emphasis added).

[58] 88 Fed. Reg. at 50,312.

<u>Commenter 0337</u>: **40 CFR § 98.233(a) Pneumatic Devices**

We are in support of retaining an intermittent bleed emission factor as 8.8 scf/hr/device as an option within § 98.233(a)(3) Calculation Method 3.

<u>Commenter 0339</u>: **Pneumatic Controllers**

We are in favor of proposed rule changes allowing for the use of site-specific measurement data to estimate emissions from pneumatic devices for operators who elect to do so, but also support EPA retaining default population emission factors as a calculation option. In particular, we recommend that EPA include a default emission factor for intermittent bleed devices as Calculation Method 4 per the discussion in the preamble. Given the large number of intermittent bleed devices and the large number of individual production sites impacted, site-specific monitoring would be extremely resource intensive. As operators weigh the compliance burdens under Subpart W along with anticipated requirements of NSPS OOOOb/OOOOc, they may prioritize investing capital to replace such gas-driven pneumatic devices (to reduce actual emissions) vs. the expense of monitoring equipment and personnel (to measure actual emissions).

Commenter 0346: Pneumatics

Calculation Method 4. With regard to Calculation Method 4, EPA requested comment regarding potential revisions to the intermittent bleed pneumatic device population emission factors. PBPA supports EPA incorporating the default population count factor 8.8 scf/hr/device for unmonitored devices, similar to how it proposes a default population count factor of 6.8 for low bleed devices. Then as proposed, for operators that choose to monitor their intermittent devices, the factor of 2.82 scf/hr/device would be applied to properly functioning devices, and the factor of 16.2 would be applied to malfunctioning intermittent bleed pneumatic devices.

Commenter 0350: **Pneumatic Controllers**

We are in favor of proposed rule changes allowing for the use of site-specific measurement data to estimate emissions from pneumatic devices for operators who elect to do so, but also support EPA retaining default population emission factors as a calculation option. In particular, we recommend that EPA include a default emission factor for intermittent bleed devices as Calculation Method 4 per the discussion in the preamble. Given the large number of intermittent bleed devices and the large number of individual production sites impacted, site-specific monitoring would be extremely resource intensive. As operators weigh the compliance burdens under Subpart W along with anticipated requirements of NSPS OOOOb/OOOOc, they may prioritize investing capital to replace such gas-driven pneumatic devices (to reduce actual emissions) vs. the expense of monitoring equipment and personnel (to measure actual emissions).

Commenter 0378: **Pneumatic controller emissions data calculation methodologies should be flexible.**

We are in favor of the proposed Subpart W revision allowing for the use of site-specific measurement data to estimate emissions from pneumatic devices for operators who elect to do so, but also support EPA retaining default population emission factors as a calculation option. Given the large number of intermittent bleed devices and the large number of individual production sites impacted, site-specific monitoring would be extremely resource intensive and provide little benefit as the currently proposed OOOOb/c requires the elimination of this source category over the next few years. As we seek to minimize emissions from our operations and comply with the anticipated requirements of NSPS OOOOb/OOOOc, it makes considerably more sense to focus resources on removal of pneumatic devices rather than measuring them. We also recommend that EPA include a default emission factor for intermittent bleed devices as Calculation Method 4 per the discussion in the preamble.

Commenter 0394: Williams supports the three options proposed in Subpart W for calculating emissions from pneumatic controllers. Each option has distinct advantages and disadvantages and provides reporters needed flexibility to select the most appropriate option based on site-specific equipment considerations.

Reporters currently have the option to use an emission factor for both continuous high bleed and low bleed pneumatic controllers. Williams supports the EPA's consideration of a fourth method allowing an emission factor for intermittent pneumatic controllers. Sufficient historical data supports the EPA's proposed emission factor of 8.8 scfh for intermittent bleed pneumatic controllers. This would be a pragmatic option for reporters to consider and potentially pursue.

Commenter 0398: **Direct Measurement Methods for Natural Gas Pneumatic Devices and Natural Gas Pneumatic Pumps**

EPA is proposing that operators must either install a flow monitoring device on the natural gas supply line dedicated to one or a combination of pneumatic devices, or the natural gas supply line dedicated to one or more pneumatic pumps, that are vented directly to the atmosphere, and then the measured flow must be used to calculate the emissions from the pneumatic devices or pneumatic pumps, as applicable or conduct direct measurements of the emissions from the devices (88 Fed. Reg. 50311). However, for natural gas driven pneumatic pumps that do not have or do not elect to install a flow meter dedicated to measuring the flow of natural gas supplied to one or a combination of pneumatic pumps vented directly to the atmosphere, EPA proposes to require that the reporter either measure the natural gas emissions from each such pneumatic pump at the facility as specified in proposed 40 CFR 98.233(c)(2) or calculate emissions from each such pneumatic pump at the facility using the default emissions factor as specified in proposed 40 CFR 98.233(c)(3).

We support EPA allowing reporters to use a variety of options (e.g., direct measurement, EFs, engineering estimates, representative samples or other options) to report emissions from various sources. Not all options work for every operator in every scenario so it is important that EPA allow operators flexibility to use the most appropriate methodology to report emissions that fit their specific situation. In the case of pneumatic pumps, EPA is proposing to allow for EFs as an option. However, it is unclear why EPA is not allowing the option to use EFs for all pneumatic devices instead of only for pneumatic pumps.

Action Requested: We request EPA allow operators flexibility by providing a variety of options (including EFs) that operators can use to report emissions from various sources.

…

Revisions to Emission Factors

EPA states that none of the three proposed calculation methods described in section III.E.1 and 2 of the preamble would allow the use of the current default population emission factor methodology for intermittent bleed pneumatic devices. EPA proposes to remove the population emission factors for intermittent bleed pneumatic devices from existing Tables W–1A, W–3B, and W–4B and not include them in proposed Table W–1. EPA requests comment on whether it should retain the use of default population emission factors as an alternative calculation methodology (as Calculation Method 4) for sites, i.e., include in the final rule an option for sites to not conduct measurements or monitor intermittent bleed devices.

As previously stated, EPA should allow operators flexibility to choose the methodologies (e.g., EFs, direct measurement, engineering calculations, representative sampling, and other similar options) that best fit their situation to report emissions.

Action Requested: We support EPA retaining the use of population EFs.

Commenter 0399: *Pneumatic Devices*

EPA's proposal to require the direct measurement of intermittent bleed controllers appears to be needlessly punitive. Knowing that this equipment will be phased out upon implementation of OOOOc, the measurement requirement as proposed becomes obviated, aside from the enhanced burden it places on operators that have intermittent bleed controllers in place. When EPA considers that most installations that chose intermittent bleed controllers did so to reduce emissions as compared to continuous bleed controllers, that punitive nature of the requirement is also aimed at operators who were attempting to do the right thing by reducing emissions. Rather than spending resources to install flow meters, or measure emissions, or monitor for proper function per Subpart W, operators would prefer to allocate those resources to removing or retrofitting these devices to eliminate these emissions per OOOOb/c. The GHGRP program should focus its more burdensome requirements on emissions measurement and detection that will not be phased out by a new rulemaking. Regarding the proposed factors, the Alliance agrees that a default population count factor for intermittent devices should be allowed, in addition to the factors for properly operating or malfunctioning intermittent devices that are monitored. A default population count factor is allowed for low bleeds, and so should as such should also be allowed for intermittent devices.

> **Recommendation:** EPA should remove the direct measurement requirement for intermittent devices and allow for emission factors for properly operating and malfunctioning controllers as in the current rule.

Commenter 0400: **EPA should retain its default population emission factors for intermittent bleed pneumatic devices.**

EPA is proposing to remove the default population emission factors for intermittent bleed pneumatic devices because none of the proposed Calculation Methods allow for the use of the current default population emission factor methodology for these devices.[26]

Chesapeake encourages EPA to retain the default emission factors as an alternate "Calculation Method 4" for intermittent bleed pneumatic devices. Allowing operators to continue relying on these default values increases compliance flexibility and provides an alternative for operators with more limited resources, who may not have the data or resources to comply with the other proposed Calculation Methods.

For intermittent bleed pneumatic devices in the Onshore Petroleum and Natural Gas Production and the Onshore Petroleum and Natural Gas Gathering and Boosting industry segments, EPA indicated that current data would support a default population emission factor of 8.8 scf/hour.[27] Chesapeake agrees that this value reasonably captures the volume of gas emitted from these devices.

For intermittent bleed pneumatic devices in other applicable industry segments, EPA indicated that an emission factor of 2.3 scf/hr/device may be appropriate—however, EPA expressed concern that this factor "would likely underestimate emissions from devices that are malfunctioning."[28] To address this issue, Chesapeake recommends that EPA adopt a dual factor approach for properly functioning intermittent vent controllers and malfunctioning controllers, similar to the proposed Control Method 3. Properly functioning devices would be subject to the existing 2.3 scf/hr/device emission factor, but malfunctioning controllers would be subject to a higher emission factor in order to ensure that emissions are appropriately captured.

Footnotes:

[26] 88 Fed. Reg. at 50,314.

[27] *Id*.

[28] *Id*.

<u>Commenter 0402</u>:

- **While the Industry Trades support the flexibility to measure GHG emissions from intermittent bleed pneumatic devices, we request that EPA retain the option to use default population emission factors for sources subject to other regulatory programs.** The Industry Trades do not agree with the requirements to measure and monitor emissions from intermittent bleed devices, especially for sources that will be phased out under the impending methane rules. Please refer to Section 3.1.

…

Pneumatic Devices

Given the proposed zero-emitting standard in NSPS OOOOb and EG OOOOc, EPA should alleviate the burden with measuring and monitoring emissions across the proposed methodologies from natural gas driven pneumatic controllers during their transitional phase out in upcoming years.

…

Therefore, the Industry Trades offer the following recommendations, which we describe in more detail in the following comments:

- For natural gas driven pneumatic controllers that are not measured under Method 1 or Method 2 or monitored for proper function under Method 3, EPA should allow the use of the single whole gas population emission factor for intermittent-bleed devices (refer to Section 3.1.1).

…

Retain Whole Gas Emission Factor Approach for Intermittent-Bleed Devices

While operators should have the *option* to measure and monitor emissions from those devices, it should not be *required* for sources expected to be phased out as required in other regulatory programs, as this would result in undue capital investment without creating additional value to stakeholders. The proposed methods are highly inefficient and unnecessary considering the required 15-minute measurement time per device or monitoring each device (i.e., OGI or Method 21 screening) for 2 minutes or until a malfunction is identified. The additional burden is not justified considering:

- Any accuracy gain is expected to be temporary considering that proposed federal air quality rules require all pneumatic devices to be transitioned to zero emitting devices;
- Continuous bleed pneumatic devices, a higher emitting source, are allowed to report using an emission factor approach; and
- It penalizes operators who have invested in cleaner technology by replacing continuous high-bleed controllers with intermittent-bleed devices by requiring them to be measured or monitored.

Therefore, **EPA should retain the option to use the default whole gas population emission factor for intermittent bleed pneumatic devices**, as has been proposed under Method 3 for both continuous high-and low-bleed pneumatic devices. Consistent with the derivations used for new emission factors for high and low bleed continuous pneumatic controllers in Table 5-11 of the Technical Support Document for this Rule, EPA suggests the use of 8.8 scf/hr./device for intermittent bleed pneumatic devices, based on a meta-analysis of a variety of field studies. Moreover, many operators are actively working toward voluntarily eliminating most of these sources as they either fall under current or anticipated upcoming state or federal regulations requiring either source control or a zero emissions standard for this equipment. Implementing a burdensome monitoring program for sources that will soon become less significant doesn't make sense. Operators have collectively performed thousands of retrofits to convert continuous high-bleed pneumatic devices into intermittent bleed devices. Operators who acted swiftly should not face more burdensome greenhouse gas accounting requirements, nor should further near-term retrofits be discouraged by imposing disproportionate accounting burdens.

Commenter 0413: *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 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.

Commenter 0417: Pneumatic Controllers

We appreciate the proposed rule changes allowing for the use of site-specific measurement data to estimate emissions from pneumatic devices for operators who elect to do so, but also support EPA retaining default population emission factors as a calculation option. Given the large number of intermittent bleed devices and the large number of individual production sites impacted, site-specific monitoring would be extremely resource intensive. As operators weigh the compliance burdens under Subpart W along with anticipated requirements of NSPS OOOOb/OOOOc, they may prioritize investing capital to replace or retrofit such gas-driven pneumatic devices (to reduce actual emissions) versus the expense of monitoring equipment and personnel (to measure actual emissions).

NDPC recommends that the EPA include a default emission factor for intermittent bleed devices as Calculation Method 4 per the discussion in the preamble.

Response 2: See Section III.E.3.b of the preamble to the final rule for our response to these comments.

Commenter: EnerVest Operating, LLC
Comment Number: EPA-HQ-OAR-2023-0234-0229
Page(s): 3

Commenter: Range Resources Corporation
Comment Number: EPA-HQ-OAR-2023-0234-0397
Page(s): 4-5

Commenter: CrownQuest Operating
Comment Number: EPA-HQ-OAR-2023-0234-0393
Page(s): 127

Commenter: Atmos Energy Corporation
Comment Number: EPA-HQ-OAR-2023-0234-0406
Page(s): 6-7

Commenter: Environmental Defense Fund, et al.
Comment Number: EPA-HQ-OAR-2023-0234-0413
Page(s): 30-34

Commenter: Environmental Defense Fund, et al.
Comment Number: EPA-HQ-OAR-2023-0234-0413
Page(s): 35-36

Commenter: American Petroleum Institute et al. (Part 1 of 2)
Comment Number: EPA-HQ-OAR-2023-0234-0402
Page(s): 22

Commenter: Arkansas Independent Producers and Royalty Owners (AIPRO)
Comment Number: EPA-HQ-OAR-2023-0234-0382
Page(s): 12-13

Comment 3:

<u>Commenter 0229</u>: Intermittent Bleed Devices

The proposed dwell time of 5 minutes is unacceptable. The snap action controller should be allowed to be manually actuated.

- We propose a lower dwell time or manually actuate the controller to see it in operation.
- It has been the experience that if there is a leak or improperly seated stem on the snap action controller, it is readily apparent. There is no benefit to waiting 5 minutes.

Depending on the configuration, there could be up to 40-60 snap action controllers on one site for multi-well pad sites. Time, cost, inclement days, access to remote areas and the addition of personnel and equipment must be considered. We ask that the 5-minute dwell time be reduced substantially on intermittent bleed (snap action) devices.

<u>Commenter 0382</u>:

- Additionally, the proposed dwell time of two minutes per device is overly burdensome, unnecessary to differentiate properly operating v. malfunctioning intermittent bleed pneumatic devices and is also inconsistent with leak survey requirements from existing New Source Performance Standards ("NSPS"). AIPRO proposes that the EPA should amend the two-minute dwell time requirement to align with existing NSPS leak survey requirements, or better yet, remove the specific requirements from the proposed Subpart W revisions all together and refer to the existing NSPS requirements.

<u>Commenter 0413</u>: d. Method 3: Leaker factor for intermittent pneumatic controllers

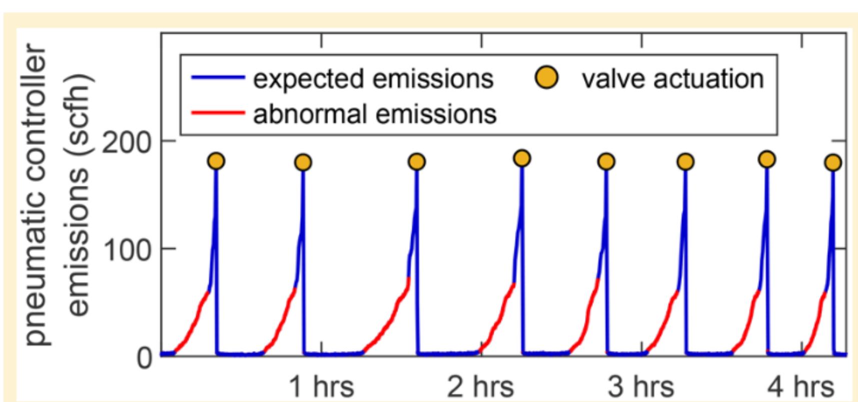
EPA has proposed a Method 3 for intermittent pneumatic controllers that would allow operators to inspect their controllers and apply a different emission factor based on whether or not the controller is found to be malfunctioning. As CATF and EDF noted in our 2022 comments (and we expand upon in these 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 (e.g. temperature and pressure controller)	12-8,760	15 minutes (or until 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

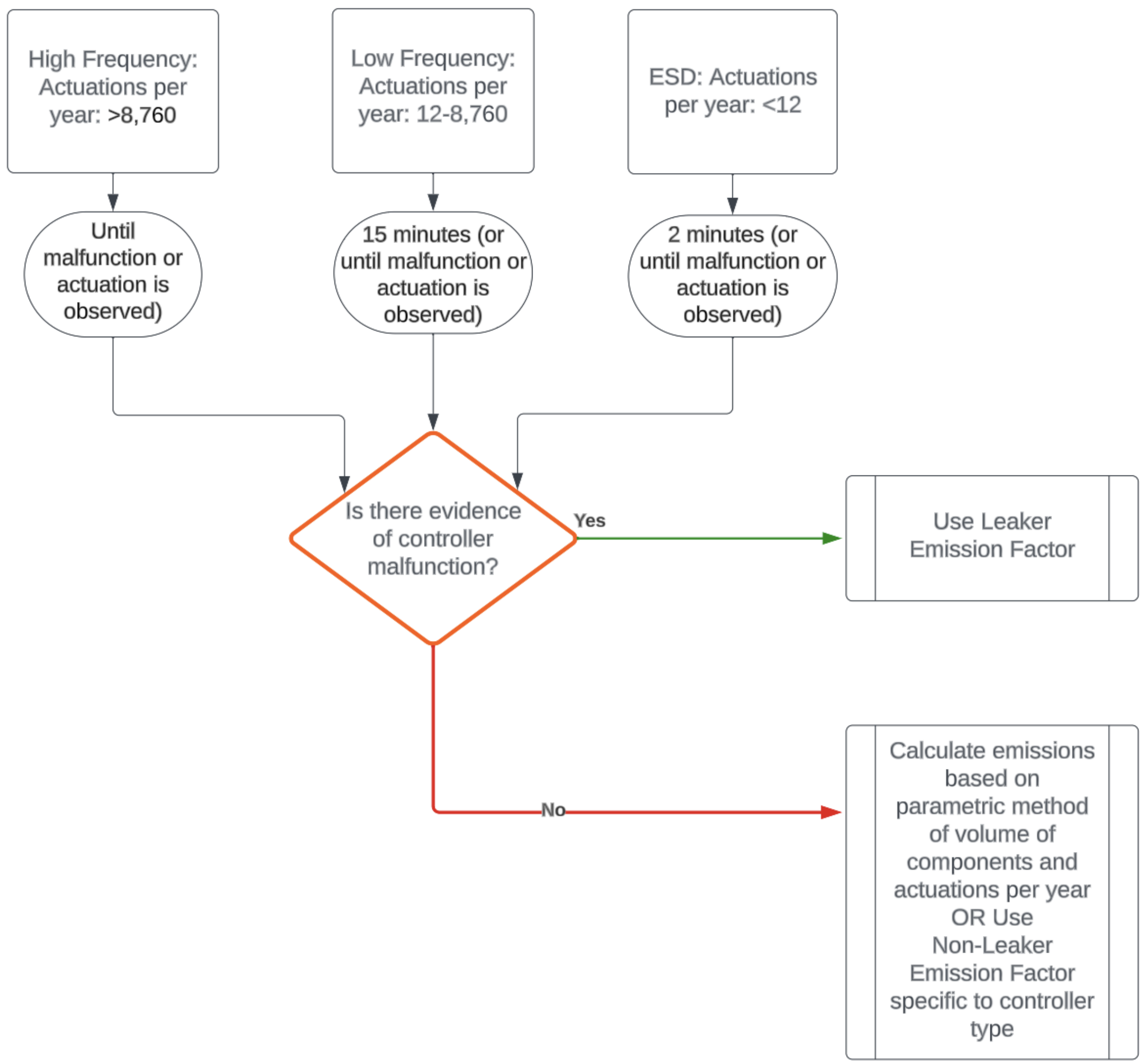
actuating controllers nor underestimating emissions for frequently actuating controllers. However, if EPA finds that this approach is too burdensome for Method 3 (despite proposing it for Method 2), it could alternatively create different emission factors for non-malfunctioning controllers for each of 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), 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:



Footnotes:
[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."
[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.
<Immediately Referenced Footnotes
[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.
[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).
[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.)>

Commenter 0397: **Comment #4: Calculation Method 3 applied to intermittent pneumatic devices will result in inaccurate reporting.**

The use of Method 3 for intermittent pneumatic devices will result in the reporting of some malfunctioning devices that are, in fact, working properly. As the Proposed Rule explains, under Method 3, if a "leak" is observed from the intermittent bleed pneumatic device for more than five seconds during a device actuation, then the device is considered to be "malfunctioning" and a malfunctioning device emission factor needs to be applied to that device. However, some intermittent pneumatic devices are designed to actuate for longer than five seconds (e.g., some throttling dump valves and snap acting safety shutdown valves).
The final rule should confirm that a throttling pneumatic device should not be assumed to be malfunctioning or leaking merely because it actuates for longer than five seconds. Rather, the final rule should provide that an operator must make an engineering determination confirmed by field inspections that a throttling pneumatic device is actually malfunctioning before using the malfunctioning device emission factor. Unless EPA implements this modification to the rule, calculation Method 3 will result in an inaccurate overreporting of emissions.

Commenter 0402:

3.1.4 Intermittent-Bleed Device Survey Improvements
…
Intermittent bleed device surveys should include additional flexibility by allowing audio, visual, and olfactory (AVO) inspections.
Operators should be able to take credit for any surveys, provided those surveys satisfy the intent of the rule. Based on the proposed rule for NSPS OOOOb, facilities subject to NSPS OOOOb monitoring would be required to use non-emitting pneumatic devices. Some facilities that are not subject to NSPS OOOOb may conduct LDAR for state, federal, or voluntary programs and may wish to screen pneumatic controllers while on-site and use that empirical observation of properly functioning or malfunctioning for GHGRP reporting.

While many of these regulatory programs would meet the technology options provided in 98.234(a) for use in monitoring properly functioning pneumatic devices, additional flexibility should be incorporated by allowing the use of AVO. AVO is appropriate because AVO inspections can be used to detect that an intermittent device is continuously venting through feeling the gas exit port, as previously stated.

Commenter 0406: Intermittent bleed devices. Method 3 of the Proposed Rule would allow a reporter to apply a "leaker factor" for calculating emissions from intermittent bleed pneumatic devices. A critical part of this calculation is the determination of whether a device is "malfunctioning" or not. EPA is proposing that a device would be considered "malfunctioning" if "any leak is observed when the device is not actuating or if a leak is observed for more than five seconds during device actuation."[21] This definition is overbroad and would identify "leaks" during normal operations. For instance, intermittent bleed devices vent during actuation—EPA's Proposed Rule would treat this intermittent venting as a "leak" and would define the bleed device as malfunctioning if actuation and associated venting lasted longer than five seconds. Many intermittent bleed devices would be considered "malfunctioning" during normal operations—actuation time is determined based on valve size (i.e., pipe diameter), flow, and pressure, and EPA's proposed five-second interval is too short for larger pipe diameters. As an industry rule of thumb, valve opening and closing is one to two seconds per inch of pipe diameter. Therefore, the Proposed Rule would mistakenly designate devices on pipes six inches or greater in diameter as "malfunctioning." Atmos Energy operates hundreds of intermittent bleed devices on pipelines that are six inches or greater in diameter. EPA should revise this methodology to clarify that intermittent venting for more than five seconds does not indicate a malfunction of the device and allow for the use of actual operating parameters and engineering estimates to quantify emissions from intermittent bleed devices.

Commenter 0413: 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 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.

Footnotes

[63] Id. at Table 2. Both Category B and Category C are considered malfunctions. Range represents study's low and high limit assumptions. <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.>

[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.
<Immediately Referenced Footnotes
[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.
[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).>

Commenter 0393: Calculation method 3: would require operators to measure ALL pneumatic devices for " monitoring duration of at least 2 minutes or until a malfunction is identified". The recordkeeping and reporting burden vs the benefit of this exercise seems skewed. As mentioned above, the ability to direct measure a set of pneumatics to be applied to all our pneumatics in the field (same type of devices) seems more appropriate. There are thousands of these in place and measuring all of them is a waste. A representative sample of 5-10 devices would be sufficient.

Response 3: We consider the proposed 2-minute dwell time requirement to be reasonable. Shorter durations are too likely to miss devices that are malfunctioning only when actuating. Longer dwell times, while likely to find a few additional malfunctioning devices, makes the method much more burdensome to apply without a significant improvement in the estimated emissions. We also maintain that the 5-second duration of emissions is reasonable for the vast majority of pneumatic devices. However, as discussed in Section III.E.2.b of the preamble to the final rule, we are including provisions for facilities to *a priori* identify those select devices that are expected to have actuation emissions lasting longer than 5 seconds (like an isolation valve on a 12-inch pipe) and the actuation time for those devices. Facilities will be required to specifically identify those devices using a tagging system or similar method that indicates the expected actuation time for the device.

With regard to AVO inspections of intermittent bleed devices, although this method may be appropriate to detect emissions in certain situations where no emissions should be occurring, we do not believe this is an adequate method for intermittent bleed device inspections. For example, an AVO inspection in between device actuations could lead to false positives due to natural gas lingering in the vicinity of the device from actuations. Conversely, intermittent bleed devices may be leaking in between actuations in a manner that would not be detectable through AVO inspections.

Commenter: MiQ
Comment Number: EPA-HQ-OAR-2023-0234-0392
Page(s): 4

Commenter: Williams Companies, Inc.
Comment Number: EPA-HQ-OAR-2023-0234-0394
Page(s): 11

Commenter: American Exploration and Production Council
Comment Number: EPA-HQ-OAR-2023-0234-0295
Page(s): 16

Comment 4:

Commenter 0392:

98.233(a)(3)(iii) and (iv) methods for calculating emissions from intermittent bleed pneumatic devices.
MiQ Comments: MiQ supports Calculation Method 3 for intermittent bleed pneumatic controllers because it more effectively applies current and future requirements of oil and gas operators and apply it to a calculation that should more accurately assess methane emissions. Modeling each pneumatic devices as operating in a bimodal fashion based on empirical leak inspection data (either malfunctioning or properly functioning), will increase accuracy of emissions reporting of pneumatic devices. A co-benefit of this option is that many operators will be required or incentivized to conduct more leak inspections of pneumatic devices in the time period before their facilities are subject to NSPS OOOOc guidelines that will by and large remove vented pneumatic devices from service. MiQ thinks this is a lower resource, fit for purpose way to support better emissions quantification while allowing operators to spend resources elsewhere. MiQ recommends the EPA reduce the time requirement in 98.233(a)(3)(ii)(B) and (C) to an annual requirement. This is based on MiQ's baseline requirement to perform one source-level equipment leak inspection annually across the Facility, including on pneumatic controllers. We believe this is not an onerous requirement, will not unreasonably increase the monitoring burden on operators of intermittent bleed pneumatic devices, and will lead to more representative and comparable data across operators. This recommendation effectively removes the necessity of Equation W-1D.

Commenter 0295:

The proposed 5-year cycle for measuring emissions from every pneumatic device, while well intentioned, is needlessly aggressive. Operations have hundreds, if not thousands, of locations amongst which similar emissions groups of pneumatic devices can be derived. An installed pneumatic device of a similar age, production service, well completion methodology and geology would not have variable enough emissions to require each device's emissions to be measured. Furthermore, a representative sample given the age and service of the component may be more accurate than a measurement event which was taken 4 years past. Also, the forthcoming OOOOb/c are expected to require that pneumatics be included in LDAR surveys thereby muting the impact of malfunctioning pneumatics. For all of these reasons, AXPC recommends that the Agency allow operators to develop their own specific pneumatic device measurement plan for similar service type and manufacturer devices which would permit measurement and allow for the development of representative emissions for a population of pneumatic devices in service. The estimation of properly operating pneumatic controllers based on equipment specific engineering calculations, which can be accurately assessed with piping volume, manufacturer actuation data, and average actuation frequency is set forth in the Oil and Gas Methane Partnership guidance for Pneumatics[5] , or as an example, operators could derive emissions in a manner like so:

1. Measure emissions from 20% of each venting pneumatic device type (Make/model & service type) in use in the first year of service
2. Measure emissions from 20% of each in 2-5 years of service
3. Measure emissions from 20% of each in 5-15 years of service
4. Measure emissions from 20% of each in over 15 years of service

The above schedule would reduce spending, ensure accuracy, and allow industry to focus dollars on facility upgrades that reduce emissions rather than measure them. Industry leaders, investors, and the public could agree workplaces, environment and communities would be better served by emission reduction rather than emission measurement. If an operator chooses to measure emissions from pneumatic devices EPA should allow the use of an OGI camera like QL320.
Footnote:
5 https://ogmpartnership.com/wp-content/uploads/2023/02/Pneumatics-TGD-SG-approved.pdf

Commenter 0394: Williams supports the proposed scanning frequency of intermittent bleed pneumatic controllers for the gathering and boosting segment. However, the EPA should revise the scanning frequency for transmission and storage facilities with less than 100 intermittent bleed pneumatic devices, setting a scanning frequency of every other year. The EPA does not require an annual scan in other segments and thus, it would be appropriate to reduce the frequency for transmission and storage facilities with a lower count of intermittent bleed pneumatic devices.

Response 4: See Sections IIIE.1.b and III.E.2.b of the preamble to the final rule for our response to these comments.

Commenter: David Allen
Comment Number: EPA-HQ-OAR-2023-0234-0235
Page(s): 1-3

Commenter: David Allen
Comment Number: EPA-HQ-OAR-2023-0234-0235
Page(s): 3-4

Commenter: Independent Petroleum Association of America (IPAA)
Comment Number: EPA-HQ-OAR-2023-0234-0265
Page(s): 10-11

Commenter: Pioneer Natural Resources USA, Inc.
Comment Number: EPA-HQ-OAR-2023-0234-0385
Page(s): 11-13

Commenter: Arkansas Independent Producers and Royalty Owners (AIPRO)
Comment Number: EPA-HQ-OAR-2023-0234-0382
Page(s): 12-13

Commenter: American Petroleum Institute et al. (Part 1 of 2)
Comment Number: EPA-HQ-OAR-2023-0234-0402
Page(s): 18, 20-21

Commenter: American Exploration and Production Council
Comment Number: EPA-HQ-OAR-2023-0234-0295
Page(s): 16

Comment 5:

Commenter 0295:

Finally, the proposed default emission factor for properly functioning intermittent controllers (2.82 scf/hr) is likely to over-estimate emissions. AXPC recommends the default emission factor of 0.3 scf/hr for properly functioning intermittent pneumatic controllers.

Commenter 0402:

- EPA should allow an optional estimation of properly operating intermittent-bleed pneumatic controllers using equipment-specific engineering calculations, or a facility-specific properly operating emission factor based on direct measurement. We elaborate on the details further in Section 3.1.3.
- Amend the proper functioning and malfunctioning emission factors for intermittent-bleed devices to include all relevant studies (refer to Section 3.1.3).

…
3.1.3 Method 3 – Suggested Amendments to Improve Intermittent-Bleed Device Monitoring
The Industry Trades also generally support EPA's Calculation Method 3; however, **EPA should amend Calculation Method 3 in three important ways**:

1. **EPA should allow the use of a whole gas emission factor as an option for intermittent-bleed devices**, for the reasons stated in Section 3.1.1.
2. **EPA should amend Equation W-1C to more accurately reflect available empirical data on emissions from properly functioning pneumatic controllers**, including a broader suite of field data to improve accuracy. Emission factors should incorporate data from additional relevant studies, [15,16,17] one of which is the API Study "Pneumatic Controller Inventory and Measurement at 67 Oil and Gas Sites in the Western United States," where the data and results have been appended to this letter in Annex A. We encourage EPA to utilize the data from this API study, since the API dataset adds 263 additional measurements of intermittent bleed controllers and cover a wide cross section of the industry sectors (production and gathering and boosting sites)[18] while the Zimmerle et al study only evaluated sites with compression; thus, the resulting bifurcated emission factors would be more accurate and representative. Specifically, **the Industry Trades**

recommend revision of Eq. W-1C: [19]

$$E_i = GHG_i \times \left[\sum_{z=1}^{x} \{ \mathbf{20.0} \times T_{mal,z} + \mathbf{0.9} \times (T_{t,z} - T_{mal,z}) \} + (\mathbf{0.9} \times Count \times T_{avg}) \right] \quad (Rev.Eq.W-1C)$$

Where:
20.0 = Whole gas emission factor for properly functioning intermittent-bleed controllers, scf/hr.
0.9 = Whole gas emission factor for malfunctioning intermittent-bleed controllers, scf/hr

3. **EPA should allow for the optional estimation of properly operating pneumatic controllers based on equipment specific engineering calculations**, which can be accurately assessed with piping volume, manufacturer actuation data, and average actuation frequency, [20]**or the development of a facility specific properly operating emission factor through direct measurement** of a representative sample of devices across a facility.

$$E_i = GHG_i \times \left[\sum_{z=1}^{x} \{ 16.1 \times T_{mal,z} + EF_z \times (T_{t,z} - T_{mal,z}) \} + \sum_{y=1}^{y} \{ EF_y \times T_{t,y} \} \right]$$

Where:
z = Count of intermittent bleed pneumatic devices that malfunctioned during the reporting period,
y = Count of intermittent pneumatic devices that properly operated over the entire duration of the reporting period, and
EF = Properly operating emission factor for the specific device or facility.

Footnotes:
[14] https://www.regulations.gov/comment/EPA-HQ-OAR-2021-0317-2428.
[15] Raw data and linked analyses/reports available at http://dept.ceer.utexas.edu/methane/study/. Accessed September 24, 2023.
[16] David T. Allen, Adam P. Pacsi, David W. Sullivan, Daniel Zavala-Araiza, Matthew Harrison, Kindal Keen, Matthew P. Fraser, A. Daniel Hill, Robert F. Sawyer, and John H. Seinfeld. *Environmental Science & Technology* 2015 *49* (1), 633- 640. DOI: 10.1021/es5040156
[17] API Study "Pneumatic Controller Inventory and Measurement at 67 Oil and Gas Sites in the Western United States" attached in Annex A and data provided by attachment as an Excel file within this docket.
[18] Note that EPA's comment in the TSD regarding being near or below the OGI threshold for properly functioning controllers using the API field study's emission factor would be resolved by combining the Zimmerle, API, and other relevant datasets to derive properly functioning and malfunctioning emission factors as shown below in Revised Eq. W-1C (the proposed properly functioning emission factor of 0.9 scf/hr/device is equivalent to ~17 g/hr, which is above the OGI detection limit). EPA also speculates in the TSD that the API field study included many zero emitting measurements due to the short measurement duration. However, as discussed in the attached paper (see Annex A, pp. 4), the measured emission data points that were below half the effective resolution were conservatively assumed to be half the effective resolution for the minimum instantaneous emission rate in all the analyses. Further, the Allen *et al* 2014 paper

conducted a sensitivity analysis which showed that actuations that were just missed by the measurement timeline at 15 minutes had a very small effect on the overall population emission factor estimate.

[19] See Annex F Analysis to support amendment to Calculation 3 for Intermittent Bleed Devices.

[20] https://ogmpartnership.com/wp-content/uploads/2023/02/Pneumatics-TGD-SG-approved.pdf.

Commenter 0385:

Potential High Bias Exists in the Default Emission Rate for Properly Functioning Intermittent Pneumatic Controllers

Pioneer concurs with the comments submitted by David Allen, the Norbert Dittrich-Welch Chair in Chemical Engineering, the Director of the Center for Energy and Environmental Resources, and the co-Director of the Energy Emissions Modeling and Data Lab at the University of Texas at Austin, on this rulemaking as follows:

"The default emission rate for normally operating pneumatic controllers proposed by the EPA (2.82 scf/hr) is based on the work of Zimmerle, et al. (2019) and Luck, et al. (2019), which report emissions from pneumatic controllers in gathering and boosting operations. The study is unique in reporting very long duration measurements from pneumatic controllers. Measurement durations were typically multiple days, in contrast to measurements in other studies which had typical durations of less than an hour. A total of 40 intermittent vent controllers were sampled and 15 of these measurements were defined as controllers that were properly functioning. As noted by the EPA, Zimmerle, et al. (2019) and Luck, et al. (2019) caution against using the data from their small sample of controllers to develop national emission factors, nevertheless, the EPA argues that these are the best data available for establishing average emission rates for properly functioning intermittent controllers.

While the Zimmerle, et al. (2019) and Luck, et al. (2019) data are the best long duration data currently available for estimating emission factors for intermittent pneumatic controllers at gathering and boosting stations, *the data are not representative of emission rates at production facilities, particularly for properly functioning intermittent controllers*. The emission rates for properly functioning pneumatic controllers are determined by numbers of controller actuations and the volume emitted with each actuation. Gathering and boosting stations handle larger volumes of gas than production sites since they gather gas from multiple production sites. Larger gas volumes are likely to lead to larger numbers of actuations. In addition, the primary function of a gathering and boosting site is compression (boosting). Data on controller emissions at production sites, categorized by the type of equipment that the controller is servicing, is largest for pneumatic controllers associated with compressors. Allen, et al (2015) report a national average of 14.0 scf/hr for controllers (both properly functioning and not properly functioning) associated with compressors, which is approximately three times the average emission rate for controllers in service of other equipment (5.0 scf/hr for both properly functioning and not functioning properly).

Potential alternatives for the default emission rate for production sites

There are multiple alternatives for estimating a default emission rate for normally operating pneumatic controllers.

1. One approach would be to use the emission factor for properly functioning intermittent pneumatic controllers developed by the American Petroleum Institute (API, 2019). This

data set sampled 164 properly functioning intermittent controllers of which 44 had actuations during the measurement period. This is a much larger data set than the Zimmerle, et al. (2019) and Luck, et al. (2019) data set, and the controllers in the API study were almost exclusively on production sites. The emission factor derived in the AP/ study is 0.28 scf/hr, an order of magnitude lower than EPA 's proposed value.

2. Another alternative would be to base the emission factor for properly functioning intermittent controllers on the data of Allen, et al. (2015). Allen, et al. (2015) found an average emission rate for all pneumatic controllers of 5.5 scf whole gas/hr and attributed 95% of the emissions to malfunctioning controllers. This means that properly functioning controllers had an emission rate of 0.28 scf of whole gas per hour, a rate nearly identical to the results from the API study. This estimated emission rate for properly functioning controllers was dominated by a relatively large number of measurements for which a sampling time of 15 minutes did not lead to an observed actuation or otherwise measurable emission (241 devices out of the 377 devices of all types with measurements). This is consistent with actuation frequencies observed in the API study, which had actuations observed in 44 out of 164 properly functioning controllers. Recognizing that controllers with no emissions during the observation period (typically 15 minutes) might not have zero emissions over a longer time period, Allen et al. (2015) conducted an analysis to establish an upper bound on the emission rate for properly operating controllers. The analysis used estimated actuation frequencies and observed volumes emitted per actuation. In the Supporting Information (Section S5), the analysis concludes that '"Overall, the study average emission rate for controllers would be expected to increase by 2%-6% if the measurement period had been extended indefinitely. This estimate is based on data for controllers in separator level control service, the most common type of service observed in the study, and a type of service that is likely to result in regular actuations." Taking a mid-point value from this analysis would result in a 4% increase in the study average of 5.5 scf/hr of whole gas (4.9 scf/hr of methane), which would lead to an emission rate increase of 0.2 scf/h, attributed to properly functioning controllers. *This would suggest an emission rate upper bound of 0.5 scf/hr for all properly functioning controllers, including high and low bleed controllers. For the observed volume per actuation (0.3 scf/actuation), this upper bound suggests an average of approximately 2 actuations per hour*. In contrast, EPA's proposed emission rate for properly operating pneumatic controllers of 2.82 scf/hr suggests an actuation frequency of ~10/hr. An average actuation frequency of ~10/hr implies that virtually every controller sampled for 15 minutes would have an actuation, which is not consistent with either the API (2019) or Allen, et al. (2015) measurements at production sites.

Other approaches are possible, but use of the average emission rate for properly operating pneumatic controllers from gathering and boosting sites is not appropriate for production sites. The proposed default emission factor for properly functioning intermittent controllers (2.82 scf/hr) is likely to over-estimate emissions from these devices at production sites and could have a significant impact on total estimated emissions from the natural gas and petroleum production sectors. ***A default emission factor of 0.3 scf/hr is recommended for properly functioning intermittent pneumatic controllers***."

Commenter 0265:

The currently proposed EFs for Calculation Method 3 vary significantly from the 2022 proposed rule, see table below, without sufficient basis. From available information, it appears that EPA used the Zimmerle study to develop its 2023 proposal. However, these values are based on controllers under very different operating conditions than those in the oil and natural gas production component of the industry. Experts who have evaluated the 2023 proposal conclude that the 2022 factors are more appropriate. EPA should amend the proposed leaker factors to align with the 2022 proposed rule, which was consistent with the "API Field Measurement Study: Pneumatic Controllers" (Tupper 2019)

	Whole Gas EF – Properly Operating Intermittent Bleed Pneumatic Device	Whole Gas EF – Malfunctioning Intermittent Bleed Pneumatic Device
2022 Proposed Rule	0.03 scf/hr/device	24.1 scf/hr/device
2023 Proposed Rule	2.82 scf/hr/device	16.1 scf/hr/device

Commenter 0235:

Overview of proposed methods for estimating emissions from pneumatic controllers
The EPA proposes three calculation methods for estimating emissions from pneumatic controllers. Method 1 relies on measuring the gas fed to the controllers. Method 2 relies on measuring the gas vented from the controllers. For intermittent controllers where measurements of feed or vented gas are not available, EPA proposes a calculation method based on identifying properly and improperly functioning controllers. For intermittent controllers, the EPA proposes that:
"all intermittent bleed pneumatic devices that vent to the atmosphere at the well-pad, gathering and boosting site, or facility, as applicable, would be required to be monitored according to the leak detection methods in 40 CFR 98.234(a)(1) through (3), but with a monitoring duration of at least 2 minutes or until a malfunction is identified."
"Under Calculation Method 3, if a ''leak'' is observed from the intermittent bleed pneumatic device for more than 5 seconds during a device actuation, then the device is considered to be ''malfunctioning'' and the malfunctioning device emission factor (similar to a leaker emission factor) would be applied to that device. Emissions from intermittent bleed pneumatic devices that were not observed to be malfunctioning would be calculated based on the default emission factor for ''properly functioning'' intermittent bleed pneumatic devices." (Federal Register, 88, 50313, August 1, 2023).
In the Technical Support Document for the proposal (page 62), the EPA proposes an emission rate of 2.82 scf/hr for the emission rate for "properly functioning" devices.
Significance of the default emission rate for properly functioning intermittent controllers
The EPA proposes multiple methods for determining emission rates for pneumatic controllers, however, the installation of in-line flow meters (Method 1) and the sampling of individual controllers (Method 2) are both likely to require significant time to implement. In addition, the EPA notes that proposed methane emission mitigation rules could lead to future replacement of pneumatic controllers that vent with zero-emission devices. This will also require significant time to implement. This suggests that calculation method 3 for pneumatic controllers is likely to be widely implemented in the initial reporting years for the new rule. Since intermittent pneumatic controllers are the most widely deployed pneumatic controller device type, and since

measurement campaigns have consistently reported that most controllers function properly (e.g., Allen, et al., 2015; API, 2019), the number of devices to which a "properly functioning intermittent pneumatic controller" emission factor would be applied is large. A rough estimate of the emissions that could be associated with normally operating pneumatic controllers, if the default emission rate of 2.82 scf/hr is applied to approximately 1,000,000 pneumatic controllers in oil and gas operations1 is:
2.82 scf/hr/device * 8760 hr/yr * 1,000,000 devices = 25 billion cubic feet/yr (bcf/yr)
Twenty five bcf/yr is approximately 0.07% of the gas produced in the United States per year, meaning that just emissions from normally operating pneumatic controllers would represent approximately a third of a frequently used target for total methane emissions from oil and gas production operations (0.2%).
Potential high bias in the default emission rate for properly functioning intermittent controllers
The default emission rate for normally operating pneumatic controllers proposed by the EPA (2.82 scf/hr) is based on the work of Zimmerle, et al. (2019) and Luck, et al. (2019), which report emissions from pneumatic controllers in gathering and boosting operations. The study is unique in reporting very long duration measurements from pneumatic controllers. Measurement durations were typically multiple days, in contrast to measurements in other studies which had typical durations of less than an hour. A total of 40 intermittent vent controllers were sampled and 15 of these measurements were defined as controllers that were properly functioning. As noted by the EPA, Zimmerle, et al. (2019) and Luck, et al. (2019) caution against using the data from their small sample of controllers to develop national emission factors, nevertheless, the EPA argues that these are the best data available for establishing average emission rates for properly functioning intermittent controllers.
While the Zimmerle, et al. (2019) and Luck, et al. (2019) data are the best long duration data currently available for estimating emission factors for intermittent pneumatic controllers at gathering and boosting stations, the data are not representative of emission rates at production facilities, particularly for properly functioning intermittent controllers. The emission rates for properly functioning pneumatic controllers are determined by numbers of controller actuations and the volume emitted with each actuation. Gathering and boosting stations handle larger volumes of gas than production sites since they gather gas from multiple production sites. Larger gas volumes are likely to lead to larger numbers of actuations. In addition, the primary function of a gathering and boosting site is compression (boosting). Data on controller emissions at production sites, categorized by the type of equipment that the controller is servicing, is largest for pneumatic controllers associated with compressors. Allen, et al (2015) report a national average of 14.0 scf/hr for controllers (both properly functioning and not properly functioning) associated with compressors, which is approximately three times the average emission rate for controllers in service of other equipment (5.0 scf/hr for both properly functioning and not functioning properly).

Footnotes:

[1] The number of intermittent controllers in natural gas production operations, as reported in the 2021 Greenhouse Gas Emission Inventory (April, 2023) is 512,401 (Annex Table 3.6-21). The number of intermittent controllers in petroleum production operations, as reported in the 2021 Greenhouse Gas Emission Inventory (April, 2023) is 512,401 (Annex Table 3.5-17).

Zimmerle, D., Bennett, K., Vaughn, T., Luck, B., Lauderdale, T., Keen, K., Harrison, M., Marchese, A., Williams, L., & Allen, D. 2019. Characterization of Methane Emissions from Gathering Compressor Stations: Final Report. Prepared for the U.S. Department of Energy under Contract No. DE-FE0029068. October 2019 Revision. http://dx.doi.org/10.25675/10217/194544. Includes appendices, supporting volumes, and data for supporting volumes, all available at https://mountainscholar.org/handle/10217/195489.
Luck, B., Zimmerle, D., Vaughn, T., Lauderdale, T., Keen, K., Harrison, M., Marchese, A., Williams, L., Allen, D., Multiday Measurements of Pneumatic Controller Emissions Reveal the Frequency of Abnormal Emissions Behavior at Natural Gas Gathering Stations, Environmental Science & Technology Letters, 6, 348-352, doi: 10.1021/acs.estlett.9b00158 (2019).
Allen, D.T., Pacsi, A., Sullivan, D., Zavala-Araiza, D., Harrison, M., Keen, K., Fraser, M., Hill, A.D., Sawyer, R.F., and Seinfeld, J.H. Methane Emissions from Process Equipment at Natural Gas Production Sites in the United States: Pneumatic Controllers, Environmental Science & Technology, 49 (1), 633–640, doi:10.1021/es5040156 (2015).

<u>Commenter 0235</u>:

Potential alternatives for the default emission rate for production sites
There are multiple alternatives for estimating a default emission rate for normally operating pneumatic controllers.

1. One approach would be to use the emission factor for properly functioning intermittent pneumatic controllers developed by the American Petroleum Institute (API, 2019). This data set sampled 164 properly functioning intermittent controllers of which 44 had actuations during the measurement period. This is a much larger data set than the Zimmerle, et al. (2019) and Luck, et al. (2019) data set, and the controllers in the API study were almost exclusively on production sites. The emission factor derived in the API study for properly functioning intermittent controllers is 0.28 scf/hr, an order of magnitude lower than EPA’s proposed value.
2. Another alternative would be to base the emission factor for properly functioning intermittent controllers on the data of Allen, et al. (2015). Allen, et al. (2015) found an average emission rate for all pneumatic controllers of 5.5 scf whole gas/hr and attributed 95% of the emissions to malfunctioning controllers. This means that properly functioning controllers of all types had an emission rate of 0.28 scf of whole gas per hour, a rate nearly identical to the results from the API study. This estimated emission rate for properly functioning controllers was dominated by a relatively large number of measurements for which a sampling time of 15 minutes did not lead to an observed actuation or otherwise measurable emission (241 devices out of the 377 devices of all types with measurements). This is consistent with actuation frequencies observed in the API study, which had actuations observed in 44 out of 164 properly functioning controllers. Recognizing that controllers with no emissions during the observation period (typically 15 minutes) might not have zero emissions over a longer time period, Allen et al. (2015) conducted an analysis to establish an upper bound on the emission rate for properly operating controllers. The analysis used estimated actuation frequencies and observed volumes emitted per actuation. In the Supporting Information (Section S5), the analysis concludes that “Overall, the study average emission rate for controllers [all

types] would be expected to increase by 2%-6% if the measurement period had been extended indefinitely. This estimate is based on data for controllers in separator level control service, the most common type of service observed in the study, and a type of service that is likely to result in regular actuations." Taking a mid-point value from this analysis would result in a 4% increase in the study average of 5.5 scf/hr of whole gas (4.9 scf/hr of methane), which would lead to an emission rate increase of 0.2 scf/h, attributed to properly functioning controllers. This would suggest an emission rate upper bound of 0.5 scf/hr for all properly functioning controllers, including high and low bleed controllers. For the observed volume per actuation (0.3 scf/actuation), this upper bound suggests an average of approximately 2 actuations per hour. In contrast, EPA's proposed emission rate for properly operating pneumatic controllers of 2.82 scf/hr suggests an actuation frequency of ~10/hr. An average actuation frequency of ~10/hr implies that virtually every controller sampled for 15 minutes would have an actuation, which is not consistent with either the API (2019) or Allen, et al. (2015) measurements at production sites.

Other approaches are possible, but use of the average emission rate for properly functioning pneumatic intermittent controllers from gathering and boosting sites is not appropriate for production sites. Because the API data are the most current, and because the estimates based on the data of Allen, et al. (2015) are consistent with the API data, I recommend using a value of 0.3 scf/hr as a default emission rate for properly functioning pneumatic controllers.
Comment Summary
The proposed default emission factor for properly functioning intermittent controllers (2.82 scf/hr) is likely to over-estimate emissions from these devices at production sites and could have a significant impact on total estimated emissions from the natural gas and petroleum production sectors. A default emission factor of 0.3 scf/hr is recommended for properly functioning intermittent pneumatic controllers.

Footnotes:

American Petroleum Institute, API Field Measurement Study: Pneumatic Controllers EPA Stakeholder Workshop on Oil and Gas November 7, 2019 - Pittsburgh PA, available at: https://www.epa.gov/sites/default/files/2019-11/documents/ghgi_nov2019workshop_tupper2.pdf
Zimmerle, D., Bennett, K., Vaughn, T., Luck, B., Lauderdale, T., Keen, K., Harrison, M., Marchese, A., Williams, L., & Allen, D. 2019. Characterization of Methane Emissions from Gathering Compressor Stations: Final Report. Prepared for the U.S. Department of Energy under Contract No. DE-FE0029068. October 2019 Revision. http://dx.doi.org/10.25675/10217/194544. Includes appendices, supporting volumes, and data for supporting volumes, all available at https://mountainscholar.org/handle/10217/195489.
Luck, B., Zimmerle, D., Vaughn, T., Lauderdale, T., Keen, K., Harrison, M., Marchese, A., Williams, L., Allen, D., Multiday Measurements of Pneumatic Controller Emissions Reveal the Frequency of Abnormal Emissions Behavior at Natural Gas Gathering Stations, Environmental Science & Technology Letters, 6, 348-352, doi: 10.1021/acs.estlett.9b00158 (2019).
Allen, D.T., Pacsi, A., Sullivan, D., Zavala-Araiza, D., Harrison, M., Keen, K., Fraser, M., Hill, A.D., Sawyer, R.F., and Seinfeld, J.H. Methane Emissions from Process Equipment at Natural

Gas Production Sites in the United States: Pneumatic Controllers, Environmental Science & Technology, 49 (1), 633–640, doi:10.1021/es5040156 (2015).

Commenter 0382:

• Calculation Method 3 – Intermittent bleed Pneumatic Device Surveys

- As EPA acknowledges in its proposed revisions to the GHGRP rule, it is possible to identify and distinguish malfunctioning or "leaking" intermittent bleed pneumatic devices from properly operating intermittent bleed pneumatic devices via leak surveys (see below).
  "As part of our review to characterize pneumatic device emissions, we found a significant difference in the emissions from intermittent bleed pneumatic devices that appeared to be functioning as intended (short, small releases during device actuation) and those that appeared to be malfunctioning (continuously emitting or exhibiting large or prolonged releases upon actuation). For natural gas intermittent bleed pneumatic devices, it is possible to identify malfunctioning devices through routine monitoring using optical gas imaging (OGI) or other technologies." (FR p. 50312)
- As such, AIPRO generally supports this alternative method for calculating emissions from intermittent bleed pneumatic devices for reporters that are unable to justify the costs associated with proposed calculation Methods 1 & 2, even though it does not allow the use of empirical data.
- …
- The currently proposed EFs for Method 3 vary significantly from the 2022 proposed rule (see table below) without sufficient basis. AIPRO proposes that EPA should amend the proposed leaker factors to align with the 2022 proposed rule, which was consistent with the "API Field Measurement Study: Pneumatic Controllers" (Tupper 2019)

	Whole Gas EF – Properly Operating Intermittent Bleed Pneumatic Device	**Whole Gas EF – Malfunctioning Intermittent Bleed Pneumatic Device**
2022 Proposed Rule	0.03 scf/hr/device	24.1 scf/hr/device
2023 Proposed Rule	2.82 scf/hr/device	16.1 scf/hr/device

Response 5: See Section III.E.2.b of the preamble to the final rule for our response to these comments.

Commenter: Permian Basin Petroleum Association (PBPA)
Comment Number: EPA-HQ-OAR-2023-0234-0346
Page(s): 5, 6

Commenter: American Petroleum Institute et al. (Part 1 of 2)
Comment Number: EPA-HQ-OAR-2023-0234-0402
Page(s): 18-19, 21-22

Comment 6:

Commenter 0402:

- Allow the duration of an intermittent-bleed device malfunction to be determined by repair date or the last monitoring survey (refer to Section 3.1.4).

…
3.1.4 Intermittent-Bleed Device Survey Improvements
The duration of an intermittent bleed device malfunction should be determined by repair date or other detection approaches, in addition to traditional survey repair verifications. Operators will have a clear indicator that a malfunctioning device has been returned to properly operating condition based upon the repair date or other detection approaches. EPA should allow for such information to be used for the time input into the malfunctioning controller emission estimation equation, which aligns with EPA's efforts to increase the quality / accuracy of the reported data. For example, while conducting AVO inspections, operators can detect that an intermittent device is continuously venting by feeling the gas exit port.
The Industry Trades also support EPA's proposal to retain the option for an operator to apply engineering estimates to determine the time in which the device was in service, in lieu of the default 8760 hours.

Commenter 0346: Pneumatics

…
Calculation Method 3. PBPA recommends that under Calculation Method 3, it should not be assumed that malfunctioning devices have, in fact, been malfunctioning for the entire year. Instead, the malfunction should be assumed to extend to the most recent inspection date or the previous reporting year, whichever is less. However, if there is data indicating that the malfunction occurred at some time after the most recent inspection date or during the most recent reporting year, the more recent date may be used for calculating emissions.
Furthermore, PBPA recommends that operators may treat inspections for malfunctioning devices as representative samples that may be used to calculate emissions for those devices that are not inspected. Consistent with our recommendation above, when a sufficient number of inspections have been conducted, operators should be able to rely on this representative sample instead of monitoring each device individually.

Response 6: We disagree with commenters that the time assigned to an individual leak or malfunction should end upon repair. If, for example, monitoring surveys were conducted in January and repaired in January, then according to the commenters' suggestion, there would be malfunctions only in the month of January and none for the next 11 months. It is unreasonable to expect that all of the malfunctioning devices found the next year did not start prior to January 1. If only one inspection is conducted during the year, we maintain that the fraction of leaking devices found during the survey is representative of the average emissions at the facility.

Therefore, to accurately calculate the annual emissions based on the survey results, we must assume the leak occurred for the entire year. If multiple inspections occur during the calendar year, then the leak duration is assumed to start at the start of the year or the last inspection date, whichever is sooner, as suggested by the commenter. We maintain that each monitoring inspection is representative of the time period associated with the monitoring period and the proposed and final calculation method reflects that. We are finalizing the duration parameters as proposed.

Commenter: GPA Midstream Association
Comment Number: EPA-HQ-OAR-2023-0234-0299
Page(s): 79

Comment 7: Natural Gas Pneumatic Device Venting

Proposed Change: EPA is proposing an option to survey natural gas intermittent bleed pneumatic devices at an onshore petroleum and natural gas production facility or an onshore petroleum and natural gas gathering and boosting facility.

> **Comment**: The proposed requirements for natural gas intermittent bleed pneumatic devices are *per device* and not for *all* intermittent bleed pneumatic devices located at an onshore petroleum and natural gas gathering and boosting facility (i.e., an entire basin). This makes sense, because (as proposed by EPA) pneumatic devices would also be individually subject to OOOOb or an applicable approved state plan or applicable Federal plan contained in part 62, and it will be years before all intermittent bleed pneumatic devices in a G&B basin are subject to such requirements. EPA must therefore clarify that the survey requirement for intermittent bleed pneumatics using equation W-1B applies on a device-by-device basis. Alternatively, EPA could clarify that a "complete" survey refers only to a survey of all intermittent bleed pneumatic devices that are complying with the monitoring requirements of § 98.233(a)(6).
>
> **Suggested text**: *98.233(a)(6)(ii) You must ~~conduct at least one complete~~ survey the pneumatic device ~~monitoring survey~~ at least once in a calendar year. If you ~~conduct multiple complete~~ survey the pneumatic device ~~monitoring surveys~~ multiple times in a calendar year, you must use the results from each ~~complete pneumatic device monitoring~~ survey when calculating emissions using Equation W-1B.*

Response 7: The rule includes description of what is considered a complete survey for pneumatic devices and refers to all devices at a well-pad site or gathering and boosting site and not basin-wide requirements for the production and gathering and boosting industry segments. In that regard, we consider we have addressed the commenter's concern, but we do not apply the methods on a per device approach. The suggested rule edits essentially allow re-monitoring of selected devices after a repair has been completed. As noted in Response 6 in this section, this will generally lead to under-estimation of the average emissions from the facility. We are not revising the rule requirements based on this comment.

6.4 Revisions to Emission Factors

Commenter: Public Hearing Transcript
Comment Number: EPA-HQ-OAR-2023-0234-0224
Page(s): 14 (Lisa Beal)

Commenter: Interstate Natural Gas Association of America (INGAA)
Comment Number: EPA-HQ-OAR-2023-0234-0387
Page(s): 5

Commenter: Interstate Natural Gas Association of America (INGAA)
Comment Number: EPA-HQ-OAR-2023-0234-0387
Page(s): 7-8

Commenter: Environmental Defense Fund, et al.
Comment Number: EPA-HQ-OAR-2023-0234-0413
Page(s): 36-37

Commenter: Environmental Defense Fund, et al.
Comment Number: EPA-HQ-OAR-2023-0234-0413
Page(s): 37-38

Comment 1:

Commenter 0413: *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.

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.

Footnote:

[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 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).

Commenter 0413: **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. 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.

Footnote:

[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).

Commenter 0224: However, in some cases, the rule is also too limiting or measurement requirements are unnecessarily burdensome and I'll give you a couple examples of those.

…

Another is pneumatic device emissions which are relatively insignificant for the T&S segment, but the proposal adds ongoing annual measurement of the mag device vent rates, typically for all pneumatics located at T&S facilities. The empirical evidence currently available which is pretty extensive clearly shows the minor contribution of these emissions to the overall transmission and storage sector emissions. As such, we believe the rule should include less frequent measurement or a simplified pathway for developing improved emission factors for transmission and storage pneumatics based on the amount of measured data.

Commenter 0387: **Pneumatic device emission estimates for T&S should include EF-based options, especially since this source is a relatively small contributor for the T&S sector.**

As discussed in Comment 1, measurement requirements should not be overly prescriptive and burdensome, and the need for ongoing measurement should consider the relative importance of the emissions source. Despite a wealth of data indicating that pneumatic device emissions are a relatively small contributor for the T&S segments, the Proposed Rule adds measurement of pneumatic venting and, based on typical facility device counts, would require measurement either annually or every two years at compressor stations and storage facilities. INGAA recommends retaining current methods that allow EF-based calculations for estimating pneumatic device emissions for T&S, including intermittent devices. EPA requested feedback on whether to retain a "Calculation Method 4" for intermittent devices that relies on EFs,[12] and INGAA strongly supports retaining the EF option for T&S and retaining the current T&S pneumatic device EFs. Measurement should be included as an option.

If mandatory measurement is retained for T&S, EPA should add a pathway to develop updated EFs and allow EF use after adequate data is collected in initial years. In fact, an IRA-based program could address this perceived data gap to avoid unnecessary burden and costs associated with this relatively minor T&S emissions source. As proposed, the new requirements would double site survey times for T&S facilities, and EPA has not adequately justified this incremental cost for a small emissions source.

Available information from the EPA Annual Inventory Report, Subpart W as summarized in a Pipeline Research Council International (PRCI) report[13], and more recent Subpart W data available online indicate that pneumatic devices comprise a relatively small percentage of T&S emissions. Additional details are included in INGAA's February 2023 comments[14] on proposed amendments to the methane NSPS for natural gas systems, but example information includes:

- The EPA Annual Inventory GHG Report indicates T&S pneumatic devices comprise approximately 3% of total T&S sector emissions;
- The PRCI report that compiled 2011 – 2016 data shows that a facility-level EF for the larger compressor stations subject to the GHGRP based on Subpart W device counts is lower than the GHGi EF used by EPA, implying lower emissions that EPA estimates;
- A paper from Zimmerle, et al.[15] based on an Environmental Defense Fund and industry sponsored study noted that the GHGi over-estimates T&S pneumatic device emissions; and
- In more recent years, voluntary and mandatory programs have likely resulted in further decreases in T&S pneumatic device emissions, and NSPS amendments and federal guidelines for existing sources will further decrease these emissions.

This information supports use of EFs rather than measurement for T&S pneumatic devices; at a minimum, measurement should be required for a short time span to facilitate the adequacy of current EFs and develop, as needed, updated EFs. Ongoing measurement every year or every two years is not necessary for T&S pneumatic devices. If retained, mandatory measurement criteria should include an efficient pathway for developing updated EFs, and/or an IRA funded Methane Emissions Reduction Program (MERP) project could be devised to collect and analysis Subpart W measurement data to develop updated EFs after a year or two of measurements are completed.

Footnotes:

[12] 88 Fed. Reg. 50,314.

[13] PRCI Catalog No. PR-312-16202-R03, "Methane Emissions from Transmission and Storage Subpart W Sources," August 2019.

[14] INGAA Comments, Docket Document Number EPA-HQ-OAR-2021-0317-2483, February 13, 2023.

[15] EPA-HQ-OAR-2023-0234-0051

Commenter 0387: Emission estimation should not be limited to mandatory, ongoing measurement, especially for emission sources that are relatively minor contributors to segment emissions

While INGAA supports measurement-based estimates, other options are viable and measurement criteria should not be overly prescriptive. For example, as discussed in Comment 3, the Proposed Rule adds measurement for T&S pneumatic devices, and annual (or bi-annual) measurements will be typical at most T&S facilities based on device counts. Pneumatic devices are a relatively minor contributor for the T&S segment and EF-based approaches should be retained. At a minimum, a streamlined path for efficient development of improved T&S pneumatic device EFs should be included in the rule. Ongoing annual measurement is not warranted for such sources.

Response 1: See Section III.E.3.b of the preamble to the final rule for our response to these comments.

Commenter: Williams Companies, Inc.
Comment Number: EPA-HQ-OAR-2023-0234-0394
Page(s): 10-11

Commenter: Independent Petroleum Association of New Mexico (IPANM)
Comment Number: EPA-HQ-OAR-2023-0234-0337
Page(s): 2-3

Commenter: Arkansas Independent Producers and Royalty Owners (AIPRO)
Comment Number: EPA-HQ-OAR-2023-0234-0382
Page(s): 13-14

Commenter: Atmos Energy Corporation
Comment Number: EPA-HQ-OAR-2023-0234-0406
Page(s): 6

Commenter: GPA Midstream Association
Comment Number: EPA-HQ-OAR-2023-0234-0299
Page(s): 25

Comment 2:

Commenter 0337: **40 CFR § 98.233(a) Pneumatic Devices**

EPA has long recognized that a continuous low-bleed pneumatic device is defined with a bleed rate of less than 6 scf/hr. See e.g. GHG MRR (40 CFR § 98.6 “High-bleed pneumatic devices”) and NSPSOOOO and OOOOa. In the “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,” (Technical Support Document), discussing the Allen study, the authors explain, "Specifically, 90 percent of the facility-designated low bleed devices were designated as intermittent devices by the study authors. In our analysis of the data, we used the company assignments because this most closely

reflects the way controllers are categorized when reporting GHG emissions under Subpart W. For controllers that were not classified by the facilities, we assigned all of these controllers to the intermittent category because the large majority of devices (85 percent) not classified by the facilities were classified as intermittent devices by the study authors." We believe that such inconsistent classifications of devices within the studies invalidates the EPA's proposed reliance on variability of the results as a rationale to adjust the default emission factors.
EPA should not adjust the default emission factors to reflect some reporter's improper designation of a device or to account for malfunctioning devices. Doing so will falsely inflate emissions from reporters who properly classify their devices and maintain them in proper working order. Moreover doing so does not support the EPA's goal of empirical data.

Commenter 0382:

ii. Low-bleed Pneumatic Devices:
• EPA is proposing a population emissions factor of 6.8 scf/hour/component for low-bleed pneumatic devices which is inconsistent with the definition for the same type of device, which includes a vent rate of less than 6 scf/hr.
• AIPRO recommends that the agency align the population emission factor with the current definition. Further, AIPRO recommends an alternative calculation methodology whereby reporters can determine actual vent rates for low-bleed (and all other types of pneumatics) via approved quantification method(s) (i.e., High-Flow Sampler) in lieu of using one-size fits all emissions factors.

Commenter 0406: **EPA should revise the Method 3 calculation to account for operational realities and ensure consistency across regulations.**

Atmos Energy urges EPA to address the following elements of the Method 3 calculation so that it reflects operational realities and is consistent with other applicable regulations:
Continuous low bleed devices. EPA is proposing to apply a default emissions factor of 6.8 standard cubic feet per hour (scfh) for continuous low bleed pneumatic devices.[18] However, this default value is inconsistent with related requirements under existing 40 C.F.R. Part 60, Subparts OOOO and OOOOa.[19] Utilizing this calculation methodology for continuous low bleed devices would cause affected facilities to be out of compliance with the Subpart OOOO and OOOOa requirement that "each pneumatic controller affected facility … have a bleed rate less than or equal to 6 [scfh]."[20] Atmos Energy encourages EPA to align the different thresholds and compliance requirements across regulations to ease the burden on operators and avoid inconsistency.
Footnotes:
18 *Id* 50,314.
19 *See e.g.*, 40 C.F.R. §§ 60.5356a(d), 60.5415b(h).
20 *See e.g.*, 40 C.F.R. §§ 605390(c)(1), 60.5390a(c)(1).

Commenter 0299: **EPA must change the default emission factor for low bleed pneumatic controllers to align with the definition of low bleed pneumatic controllers.**

GPA disagrees with the proposed revisions to the default population count emission factor for continuous low bleed pneumatic devices at gathering and boosting facilities.[60] NSPS OOOOa defines a low bleed pneumatic controller as having a bleed rate =6 standard cubic feet per hour ("scfh"). The newly revised emission factor of 6.8 scfh[61] directly contradicts the rate for the compliance standard for the exact same piece of equipment, and thus it inherently provides an indication of non-compliance with an already established standard of performance if the device is subject to the NSPS.
GPA also believes the proposed emission factor directly contradicts what EPA considers to be empirical data. An emission factor greater than the 6 scfh standard immediately presumes the device (or some population of devices) is malfunctioning. OEM datasets for continuous low bleed pneumatic controllers often specify bleed rates much lower than 6 scfh, allowing a buffer to account for any periods of malfunction. EPA has proposed to allow use of OEM data for other sources, and GPA recommends expanding this same provision to include low bleed pneumatic controllers. To not allow the use of those same data here would be arbitrary and capricious.

Footnotes:

[60] See 88 Fed. Reg. at 50,438, Table W-1.

[61] Id.

Commenter 0394: **D. Pneumatic Devices**

The EPA must correct the erroneously high emission factor of 6.8 standard cubic feet per hour (scfh) proposed for a low bleed (continuous) pneumatic device in the proposed Subpart W Rule. Existing NSPS regulations OOOO[26] and OOOOa[27] define a low bleed pneumatic device as one that vents to the atmosphere at a rate = 6 scfh. EPA does not fully explain its reasoning for an emission factor that is higher than the regulatory requirement for these devices.
The EPA should allow reporters to use OEM/manufacturer provided data as an emissions factor for all properly functioning pneumatic devices. The EPA has previously recognized that manufacturer provided data can be considered as empirical data.

Footnotes:

[26] See 40 C.F.R. § 60.5390(c)(1) ("Each pneumatic controller affected facility constructed, modified or reconstructed on or after October 15, 2013, at a location between the wellhead and a natural gas processing plant or the point of custody transfer to an oil pipeline must have a bleed rate less than or equal to 6 standard cubic feet per hour.") (emphasis added).
[27] See 40 C.F.R. § 60.5390a(c)(1) ("Each pneumatic controller affected facility at a location other than at a natural gas processing plant must have a bleed rate less than or equal to 6 standard cubic feet per hour.") (emphasis added).

Response 2: See Section III.E.3.b of the preamble to the final rule for our response to these comments.

Commenter: Independent Petroleum Association of America (IPAA)
Comment Number: EPA-HQ-OAR-2023-0234-0265
Page(s): 6-8

Commenter: Arkansas Independent Producers and Royalty Owners (AIPRO)
Comment Number: EPA-HQ-OAR-2023-0234-0382
Page(s): 4-7

Commenter: Arkansas Independent Producers and Royalty Owners (AIPRO)
Comment Number: EPA-HQ-OAR-2023-0234-0382
Page(s): 12-13

Comment 3:

Commenter 0382:

iii. To see an illustration of the absurdity, EPA need look no farther than its own proposed GHGRP revisions for calculating emissions associated with intermittent bleed pneumatic devices, both those from the 2022 proposed rule (Docket ID No. EPA-HQ-OAR-2019-0424) and those from the 2023 proposed rule that is the focus of these comments (Docket ID No. EPA–HQ–OAR– 2023–0234). The first obvious observation is that the EPA cannot itself decide how to accurately calculate emissions from pneumatic devices, as evidenced by the widely varying proposed revisions, see example below:

• Current GHGRP - Subpart W rules require reporters to calculate emissions from intermittent bleed pneumatic devices by:
  - Utilizing Equation “W-1”, where
  - EFt = 13.5 scf/hr/component for intermittent bleed pneumatic device vents (from Table W-1A), and
  - Tt = Average estimated number of hours in the operating year the devices, of each type “t”, were operational using engineering estimates based on best available data. Default is 8,760 hours. (every hour of every day in a year)

• From the 2022 Proposed GHGRP – Subpart W revisions for calculating emissions from intermittent bleed pneumatic devices, the EPA proposal allowed one of two calculation methods:
  - Utilize Equation “W-1A”, where
  - EFt = 8.8 scf/hr/component for intermittent bleed pneumatic device vents (from Table W-1A), **which represents a nearly 35% reduction compared to the current emissions factor**, and
  - Tt = Average estimated number of hours in the operating year the devices, of each type ‘‘t’’, were in service (i.e., supplied with natural gas) using engineering estimates based on best available data. Default is 8,760 hours. (every hour of every day in a year)

  OR

  - Utilize Equation “W-1B”, which contemplates an entirely new proposed alternative calculation methodology allowing reporters that perform approved leak surveys (i.e., LDAR surveys with OGI cameras) to identify properly operating v. malfunctioning intermittent bleed pneumatic devices, and
  - Proposes an EF of 24.1 scf/hr/component for malfunctioning/leaking devices and specifies the method for determining the amount of time a device was assumed to be leaking, and

- Proposes an EF of 0.30 scf/hr/component for properly operating devices and specifies the method for determining the amount of time a device was assumed to be leaking. **This represents a nearly 98% reduction from the current required EF for intermittent bleed pneumatic devices.**

• And now in its latest proposed GHGRP – Subpart W revisions for calculating emissions from intermittent bleed pneumatic devices, the EPA proposal allows one of three calculation methods. Proposed "Calculation Method 3" is most analogous to the alternative method from the 2022 Proposed Rule and allows for the following:

- Utilize Equation "W-1C", which, similar to the method described above, allows reporters that perform approved leak surveys (i.e., LDAR surveys with OGI cameras) to identify properly operating v. malfunctioning intermittent bleed pneumatic devices, and
- Proposes an EF of 16.1 scf/hr/component for malfunctioning/leaking devices and specifies the method for determining the amount of time a device was assumed to be leaking, and
- Proposes an EF of 2.82 scf/hr/component for properly operating devices and specifies the method for determining the amount of time a device was assumed to be leaking. **This represents a nearly 80% reduction from the current required EF for intermittent bleed pneumatic devices.**

• Although many Subpart W reporters, including multiple AIPRO members, currently perform OOOOa compliant LDAR surveys utilizing OGI cameras (in-line with the proposed GHGRP revisions) and are able to identify properly operating devices v. malfunctioning devices, the current rules do not allow the data to be used. And, as such, significantly overstates GHG emissions from intermittent bleed pneumatic devices.

• To demonstrate how GHG emissions from intermittent bleed pneumatic devices are significantly overstated by the current GHGRP Subpart W rules v. EPA's proposed revisions from both 2022 and 2023, see the hypothetical scenario below:

Comparison of Methane Emissions Associated with Intermittent-Bleed Pneumatic Devices as Determined by Current GHGRP "Eq. W-1" v. 2022 Proposed GHGRP "Eq. W-1A" AND "Eq. W-1B" v. 2023 Proposed GHGRP "Eq. W-1C" (aka "Calculation Method 3")	
Assumptions: – One Subpart W Reporter – 100 Intermittent-bleed Pneumatic Devices @ 20 Locations – Performs compliant OGI leak surveys at all 20 locations one-time per annum – Identifies 10 malfunctioning (i.e. leaking) Devices (10% leak rate) – Remaining 90 Devices, verified to be operating normally – Uses default of 8760 hours for device "operating" (current rule) and "In-service" (proposed rule) times – Produces dry gas with a 98% CH4 Fraction	
Current – "Eq. W-1"	$E_{s,i} = \sum_{t=1}^{3} Count_t * EF_t * GHG_i * T_t$ (Eq. W-1) **100 devices x 13.5 scf/hr/device x 0.98 CH4 % x 8760 hours = 11,589,480 scf CH4 emissions**
2022 Proposed – "Eq. W-1A"	$E_{s,i} = \sum_{t=1}^{3} Count_t * EF_t * GHG_i * T_t$ (Eq. W-1A) **100 devices x 8.8 scf/hr/device x 0.98 CH4 % x 8760 hours = 7,554,624 scf CH4 emissions**
2022 Proposed – "Eq. W-1B"	$E_i = GHG_i * \left[\left(24.1 * \sum_{z=1}^{x} T_z\right) + \left(0.3 * Count * T_{avg}\right)\right]$ (Eq. W-1B) **0.98 CH4 % x [(24.1 scf/hr/device x 10 leaking devices x 8760 hours) + (0.3 scf/hr/device x 90 non-leaking devices x 8760 hours)] = 2,300,726 scf CH4 emissions**
2023 Proposed – "Eq. W-1C"	$E_i = GHG_i \times \left[\sum_{z=1}^{x}\{16.1 \times T_{mal,z} + 2.82 \times (T_{t,z} - T_{mal,z})\} + (2.82 \times Count \times T_{avg})\right]$ (Eq. W-1C) **0.98 CH4 % x [10 leaking devices ((16.1 scf/hr/device x 8760 hours) + (2.82 scf/hr/device (8760 hours – 8760 hours)) + (2.82 scf/hr/device x 90 non-leaking devices x 8760 hours)] = 3,560,975 scf CH4 emissions**
Summary – In the scenario above, current GHGRP requirements ("Eq. W-1") overstate methane emissions associated with intermittent-bleed pneumatic devices by approx. 35% compared to 2022 proposed GHGRP alternative 1 ("Eq. W-1A"); by approx. 80% compared to 2022 proposed GHGRP alternative 2 ("Eq. W-1B"); and by approx. 69% compared to 2023 proposed GHGRP Calculation Method 3 ("Eq. W-1C").	

• This example demonstrates that the agency is well aware current GHGRP rules and associated mandated calculation methodologies significantly overstate emissions for intermittent bleed pneumatic devices. Yet, the agency utilized historical data from its GHGRP as the basis for policy development, such as the requirements in proposed NSPS OOOOb and EG OOOOc, which will require the Oil & Gas industry, amongst other things, to transition to zero-emitting pneumatic devices. **This is estimated to come at the cost of hundreds of millions of dollars or more to the industry and will likely cause many marginal/low-rate wells to be shut-in as a result of being uneconomic. This will further suppress supplies of oil & gas and likely inflate energy costs for end users. And, all the while, not actually reduce real emissions as advertised by the agency, because, again, in many cases emissions are significantly overstated by the current rules.**

Commenter 0265: Intermittent Pneumatic Controllers

EPA is proposing a series of different emissions calculations for intermittent pneumatic controllers – one of the largest emissions sources at production facilities based on the current EF. While using more accurate analysis is highly desirable, these proposals have not been independently verified by EPA. Additionally, this approach requires much higher data

acquisition for each controller which could be burdensome for smaller companies. At the same time EPA eliminates the EF for intermittent pneumatic controller rather than modify what has clearly been a flawed EF.
Each EF carries with it a history of its development and evolution. Intermittent pneumatic controllers used in oil and natural gas production have been an example of the challenge of developing accurate information. Intermittent pneumatic controllers operate only when they activate. Correspondingly, they emit when they activate unless they are failing for some reason. Intermittent pneumatic controllers are one of the most pervasive pieces of equipment at oil and natural gas production facilities. Consequently, they are one of the largest emissions sources for these operations. At issue is the validity of the EF and the proposed revisions for this equipment. To illustrate the issue, EPA need look no farther than its own proposed GHGRP revisions for calculating emissions associated with intermittent-bleed pneumatic devices, both those from the 2022 proposed rule (Docket ID No. EPA-HQ-OAR-2019-0424) and those from the 2023 proposed rule that is the focus of these comments (Docket ID No. EPA–HQ–OAR–2023–0234; FRL–10246–01–OAR). The first obvious observation is that the EPA cannot itself decide how to accurately calculate emissions from pneumatic devices, as evidenced by the widely varying proposed revisions.
The current GHGRP - Subpart W rules require reporters to calculate emissions from intermittent bleed pneumatic devices by:
Utilizing Equation “W-1”, where
- EFt = 13.5 scf/hr/component for intermittent-bleed pneumatic device vents (from Table W-1A), and
- Tt = Average estimated number of hours in the operating year the devices, of each type “t”, were operational using engineering estimates based on best available data. Default is 8,760 hours. (every hour of every day in a year)
In the 2022 Proposed GHGRP – Subpart W revisions for calculating emissions from intermittent bleed pneumatic devices, the EPA proposal allowed one of two calculation methods:
- Utilize Equation “W-1A”, where
- EFt = 8.8 scf/hr/component for intermittent-bleed pneumatic device vents (from Table W1A), and
- Tt = Average estimated number of hours in the operating year the devices, of each type ‘‘t’’, were in service (i.e., supplied with natural gas) using engineering estimates based on best available data. Default is 8,760 hours (every hour of every day in a year). **This represents a nearly 35% reduction compared to the current emissions factor,**
OR
- Utilize Equation “W-1B”, which contemplates an entirely new proposed alternative calculation methodology allowing reporters that perform approved leak surveys (i.e. LDAR surveys with OGI cameras) to identify properly operating v. malfunctioning intermittent-bleed pneumatic devices, and
- Proposes an EF of 24.1 scf/hr/component for malfunctioning/leaking devices and specifies the method for determining the amount of time a device was assumed to be leaking, and
- Proposes an EF of 0.30 scf/hr/component for properly operating devices and specifies the method for determining the amount of time a device was assumed to be leaking. **This represents a nearly 98% reduction from the current required EF for intermittent bleed pneumatic devices.**

And, now in its latest proposed GHGRP – Subpart W revisions for calculating emissions from intermittent-bleed pneumatic devices, the EPA proposal allows one of three calculation methods. Proposed “Calculation Method 3” is most analogous to the alternative method from the 2022 Proposed Rule and allows for the following:
- Utilize Equation “W-1C”, which, similar to the method described above, allows reporters that perform approved leak surveys (i.e., LDAR surveys with OGI cameras) to identify properly operating v. malfunctioning intermittent-bleed pneumatic devices, and
- Proposes an EF of 16.1 scf/hr/component for malfunctioning/leaking devices and specifies the method for determining the amount of time a device was assumed to be leaking, and
- Proposes an EF of 2.82 scf/hr/component for properly operating devices and specifies the method for determining the amount of time a device was assumed to be leaking. **This represents a nearly 80% reduction from the current required EF for intermittent bleed pneumatic devices.**

Although many Subpart W reporters currently perform OOOOa compliant LDAR surveys utilizing OGI cameras, in-line with the proposed GHGRP revisions, and are able to identify properly operating devices versus malfunctioning devices, the current rules do not allow the data to be used. And, as such, significantly overstates GHG emissions from intermittent-bleed pneumatic devices.

To demonstrate how GHG emissions from intermittent-bleed pneumatic devices are significantly overstated by the current GHGRP Subpart W rules versus EPA’s proposed revisions from both 2022 and 2023, see the hypothetical scenario below:

Comparison of Methane Emissions Associated with Intermittent-Bleed Pneumatic Devices as Determined by Current GHGRP “Eq. W-1” v. 2022 Proposed GHGRP “Eq. W-1A” AND “Eq. W-1B” v. 2023 Proposed GHGRP “Eq. W-1C” (aka “Calculation Method 3”)	
Assumptions: – One Subpart W Reporter – 100 Intermittent-bleed Pneumatic Devices @ 20 Locations – Performs compliant OGI leak surveys at all 20 locations one-time per annum – Identifies 10 malfunctioning (i.e. leaking) Devices (10% leak rate) – Remaining 90 Devices, verified to be operating normally – Uses default of 8760 hours for device “operating” (current rule) and “In-service” (proposed rule) times – Produces dry gas with a 98% CH4 Fraction	
Current – “Eq. W-1”	$E_{s,i} = \sum_{t=1}^{3} Count_t * EF_t * GHG_i * T_t$ (Eq. W-1) **100 devices x 13.5 scf/hr/device x 0.98 CH4 % x 8760 hours = 11,589,480 scf CH4 emissions**
2022 Proposed – “Eq. W-1A”	$E_{s,i} = \sum_{t=1}^{3} Count_t * EF_t * GHG_i * T_t$ (Eq. W-1A) **100 devices x 8.8 scf/hr/device x 0.98 CH4 % x 8760 hours = 7,554,624 scf CH4 emissions**
2022 Proposed – “Eq. W-1B”	$E_i = GHG_i * \left[\left(24.1 * \sum_{z=1}^{x} T_z\right) + (0.3 * Count * T_{avg})\right]$ (Eq. W-1B) **0.98 CH4 % x [(24.1 scf/hr/device x 10 leaking devices x 8760 hours) + (0.3 scf/hr/device x 90 non-leaking devices x 8760 hours)] = 2,300,726 scf CH4 emissions**
2023 Proposed – “Eq. W-1C”	$E_i = GHG_i \times \left[\sum_{z=1}^{x}\{16.1 \times T_{mal,z} + 2.82 \times (T_{t,z} - T_{mal,z})\} + (2.82 \times Count \times T_{avg})\right]$ (Eq. W-1C) **0.98 CH4 % x [10 leaking devices ((16.1 scf/hr/device x 8760 hours) + (2.82 scf/hr/device (8760 hours – 8760 hours)) + (2.82 scf/hr/device x 90 non-leaking devices x 8760 hours)] = 3,560,975 scf CH4 emissions**
Summary – In the scenario above, current GHGRP requirements (“Eq. W-1”) overstate methane emissions associated with intermittent-bleed pneumatic devices by approx. 35% compared to 2022 proposed GHGRP alternative 1 (“Eq. W-1A”), by approx. 80% compared to 2022 proposed GHGRP alternative 2 (“Eq. W-1B”) and by approx. 69% compared to 2023 proposed GHGRP Calculation Method 3 (“Eq. W-1C”).	

This example demonstrates that the agency is well aware that current GHGRP rules and associated mandated calculation methodologies significantly overstate emissions for intermittent bleed pneumatic devices.

Commenter 0382:

• Lastly, AIPRO proposes that EPA should allow a fourth calculation method similar to the method in the current Subpart W rules and that which was included in the 2022 proposed rule, which allows small operators to use a single whole gas emissions factor-based approach for calculating emissions from intermittent bleed pneumatic devices. AIPRO would propose using

3.70 scf/hr/device consistent with IPAA's comments submitted on July 21, 2023, in response to Docket No. EPA-HQ-OAR-2019-0424.

Response 3: We recognize that there is significant variability in the emissions from intermittent bleed pneumatic devices, largely due to the number of malfunctioning devices and the type of malfunction (whether continuously bleeding or exhibiting excess emissions when actuating). The commenters suggest that the differences between the suggested population emission factor and the equation factors indicates that EPA is confused and overstating the emissions from intermittent bleed devices. However, the different approaches proposed are all in reasonable agreement based on the high fraction of devices found to be malfunctioning during the studies. The commenters assume a much lower fraction of malfunctioning devices than was found in the two different studies delineating the emissions from correctly operating and malfunctioning intermittent bleed devices. If the fraction of malfunctioning devices is set at the fraction observed in these studies, one would find that the equations and the default intermittent bleed device emission factors are in reasonable agreement. Regarding the comment requesting a fourth calculation method using a single whole gas emission factor and concerns with burden associated with measuring and monitoring devices, we note that EPA is finalizing a fourth calculation method that provides a default population emission factor for all devices. This eliminates the proposed requirement to measure or monitor any natural gas pneumatic devices except for those devices for which the natural gas supply flow is already being measured using a meter capable of meeting the requirements of § 98.234(b).

Commenter: GPA Midstream Association
Comment Number: EPA-HQ-OAR-2023-0234-0299
Page(s): 79

Comment 4: Proposed Change: EPA is proposing revisions to emission factors for pneumatic devices in the G&B segment.

> Comment: GPA supports using recent studies to update these emission factors and believes an update is necessary to ensure emission estimates better align with actual emissions. In the Technical Support Document Table 2-11, EPA presents these proposed emission factors, along with alternative emission factors developed by excluding zero emissions measurements from the studies used to develop the factors. GPA supports using the data from the studies, inclusive of the zero emissions values, and therefore recommends that EPA adopt the emission factors presented in Table 2-11 and not adopt the alternative emission factors. It would not be appropriate to exclude valid data points simply because they indicated zero emissions.

Response 4: We understand the commenter's suggestion that we include the zero emission for devices that did not actuate during the measurement period, but we maintain that these devices are very unlikely to have zero emissions if the measurement would have been conducted over several hours or several days. Consequently, the average emission factor calculated when including these zero values was considered to represent the lower range of the true emissions factor. We also calculated and included the alternative emission factor value disregarding the zero emission measurements in Table 2-11 of the proposal TSD to put an upper bound on the potential bias in the emission factor if the devices with zero emissions had average emissions closer to those devices that had measurable emissions during the study. Thus, we considered the two emission factors presented for the Allen study in Table 2-11 of the proposal TSD to provide the bounds for that study's emission factor. When calculating the average emission factor across all studies, we used the midrange value of these two factors to represent our best estimate of the central tendency value of the intermittent bleed pneumatic device emission factor from the Allen study. This central tendency value was then averaged with the other study emission factors to develop the intermittent bleed pneumatic device emission factor of 8.8 scf/hr/device. This emission factor was included in our 2022 GHGRP Proposed Rule. In the 2023 Subpart W Proposal we instead proposed that measurement methods must be used for all intermittent bleed pneumatic devices. In the final rule, we are finalizing an intermittent bleed pneumatic device emission factor of 8.8 scf/hr/device for production and gathering and boosting facilities consistent with our 2022 GHGRP Proposed Rule because this is the most accurate central tendency value considering all available data.

Commenter: CrownQuest Operating
Comment Number: EPA-HQ-OAR-2023-0234-0393
Page(s): 131

Comment 5:

[In reference to 2015 GHGI memo] This study tries to justify the egregious increase in proposed emission factors through a handful of independent studies. Once again, it is not a viable exercise to cherry pick and try to blanket these numbers across all areas of the country and basins. As mentioned in other comments we provided, the proposed emission factor increases have a drastic effect on reportable GHG emissions, some to the tune of 300%. This seems very unrealistic, especially with all the data that EPA has from submitted OGI LDAR survey results. You will see in our comments that we are a proponent for representative sampling and the ability to test and develop internal EFs based off actual measurement. In the study the EPA is asking for data, it is already provided to them through millions of LDAR surveys, it is our ask that they use it.

This study is cherry picking other studies that are over/underrepresenting data.

Response 5: This comment is in reference to a memorandum developed for the GHG Inventory and is not pertinent to the subpart W proposed emission factors. Also, it is not clear to EPA, and the commenter did not provide adequate specificity regarding, how the OGI LDAR surveys help establish pneumatic device emission factors.

6.5 Hours of Operation of Natural Gas Pneumatic Devices

Commenter: Independent Petroleum Association of America (IPAA)
Comment Number: EPA-HQ-OAR-2023-0234-0265
Page(s): 8-10

Commenter: Arkansas Independent Producers and Royalty Owners (AIPRO)
Comment Number: EPA-HQ-OAR-2023-0234-0382
Page(s): 10-12

Comment 1:

Commenter 0265: IPAA generally supports EPA's proposal to allow multiple calculation methods for determining emissions from natural gas driven intermittent-bleed pneumatic devices. However, there are concerns with each proposed method as described below:

Calculation Method 1 – Direct measurement with flow monitoring device
This calculation method as an alternative for reporters that have or can cost-effectively install flow monitoring devices to directly measure fuel gas supplied to intermittent-bleed pneumatic devices. For many, if not most, reporters that do not already have flow monitoring devices installed, it will be cost prohibitive to install these devices and currently this is the only proposed method that fully allows the use of "empirical data" as mandated by the IRA. Consequently, EPA should amend calculation Methods 2 & 3 as described below.
Calculation Method 2 – Direct measurement of device vent rates and use of "In-service" times
This proposed calculation method allows reporters to use empirical data in the form of direct measurement to determine vent rates from intermittent-bleed pneumatic devices. Unfortunately, this method, as proposed, is only a half-solution, in-terms of allowing empirical data, because it still requires reporters to use the non-empirical factor of "in-service (i.e., supplied with natural gas)" hours to calculate emissions.
Under proposed Calculation Method 2, reporters are required to determine emissions using the actual "number of hours the pneumatic device was in-service (i.e., supplied with natural gas) in the calendar year" for devices where vent rates were measured AND to use proposed "Eq. W1B" for devices that did not have vent rates directly measured during the calendar year. Variable "Tt" in proposed Eq. W-1B, requires reporters to determine the "Average estimated number of hours in the operating year the devices of each type "t", were in-service (i.e., supplied with natural gas) using engineering estimates based on best available data. Default is 8,760 hours." In both instances the requirement to determine emissions based on the concept of "in-service" hours completely contradicts the IRA mandate to allow the use of "empirical data."
Interestingly, EPA proposes that, absent any measured volume during a 5-minute or 15-minute sampling period, as applicable, reporters can use "company records or engineering estimates" to estimate per actuation emissions and actuation cycle counts to estimate emissions. See the proposed rule excerpt below:
For intermittent bleed devices, the lack of any emissions during a 5-minute or 15- minute period, as applicable, would indicate that the device did not actuate and that the device is seating correctly when not actuating. As such, we are proposing that engineering calculations would be made to estimate emissions per activation and that company records or engineering estimates would be used to assess the number of actuations per year to calculate the emissions from that device for the reporting year." (FR p. 50311)

This approach represents “empirical data” consistent with the IRA mandate and would yield more accurate emissions estimates for intermittent-bleed pneumatic devices. As such, EPA should amend the Calculation Methods 2 & 3 to allow the use of this approach more broadly, in lieu of the “In-service” hours concept and not only when there is a lack of emissions measured during a sampling period, but in all cases.

Commenter 0382:

• Calculation Method 2 – Direct measurement of device vent rates and use of “In-service” times

- AIPRO generally supports this proposed calculation method, at least the aspect that allows reporters to use empirical data in the form of direct measurement to determine vent rates from intermittent bleed pneumatic devices. Unfortunately, this method, as proposed, is only a half-solution in-terms of allowing empirical data because it still requires reporters to use the non-empirical factor of “in-service (i.e., supplied with natural gas)” hours to calculate emissions.
- Under proposed Calculation Method 2, reporters are required to determine emissions using the actual “number of hours the pneumatic device was in-service (i.e., supplied with natural gas) in the calendar year” for devices where vent rates were measured AND to use proposed “Eq. W-1B” for devices that did not have vent rates directly measured during the calendar year. Variable “T_t” in proposed Eq. W1B, requires reporters to determine the “Average estimated number of hours in the operating year the devices of each type “t”, were in-service (i.e., supplied with natural gas) using engineering estimates based on best available data. Default is 8,760 hours.” In both instances the requirement to determine emissions based on the concept of “in-service” hours completely contradicts the IRA mandate to allow the use of “empirical data.”
  Interestingly, EPA proposes that, absent any measured volume during a 5-minute or 15-minute sampling period, as applicable, reporters can use “company records or engineering estimates” to estimate per actuation emissions and actuation cycle counts to estimate emissions (the “in-service” hours concept is completely absent in this scenario). See the proposed rule excerpt below:
  “For intermittent bleed devices, the lack of any emissions during a 5-minute or 15-minute period, as applicable, would indicate that the device did not actuate and that the device is seating correctly when not actuating. As such, we are proposing that engineering calculations would be made to estimate emissions per activation and that company records or engineering estimates would be used to assess the number of actuations per year to calculate the emissions from that device for the reporting year.” (FR p. 50311)
- AIPRO supports this approach, as it represents “empirical data” consistent with the IRA mandate and would yield more accurate emissions estimates for intermittent bleed pneumatic devices. As such, AIPRO proposes that EPA should amend Calculation Methods 2 & 3 to allow the use of this approach more broadly (in lieu of the “Inservice” hours concept) and not only when there is a lack of emissions measured during a sampling period, but in all cases.

Response 1: See Section III.E.4.b of the preamble to the final rule for our response to these **comments.**

Commenter: Arkansas Independent Producers and Royalty Owners (AIPRO)
Comment Number: EPA-HQ-OAR-2023-0234-0382
Page(s): 8-9

Commenter: Arkansas Independent Producers and Royalty Owners (AIPRO)
Comment Number: EPA-HQ-OAR-2023-0234-0382
Page(s): 12-13

Commenter: Independent Petroleum Association of America (IPAA)
Comment Number: EPA-HQ-OAR-2023-0234-0265
Page(s): 10-11

Comment 2:

Commenter 0265: Calculation Method 3 – Intermittent-bleed Pneumatic Device Surveys

As EPA acknowledges in its proposed revisions to the GHGRP rule, it is possible to identify and distinguish malfunctioning or "leaking" intermittent-bleed pneumatic devices from properly operating intermittent-bleed pneumatic devices via leak surveys (see below).
As part of our review to characterize pneumatic device emissions, we found a significant difference in the emissions from intermittent bleed pneumatic devices that appeared to be functioning as intended (short, small releases during device actuation) and those that appeared to be malfunctioning (continuously emitting or exhibiting large or prolonged releases upon actuation). For natural gas intermittent bleed pneumatic devices, it is possible to identify malfunctioning devices through routine monitoring using optical gas imaging (OGI) or other technologies. (FR 50312)
This alternative method for calculating emissions from intermittent bleed pneumatic devices should be included for reporters that are unable to justify the costs associated with proposed calculation Methods 1 & 2, even though it does not allow the use of empirical data.
However, proposed calculation Method 3, in its current form, like the current Subpart W rules, will still likely overstate emissions from intermittent bleed pneumatic devices significantly, because it continues to rely upon the use of one-size fits all leaker emissions factors and a determination of "in-service" hours based on a default of 8760 hours (every hour of every day in a reporting year). This approach, even though properly operating devices are confirmed via approved leak surveys, requires reporters to assume properly operating intermittent bleed pneumatic devices are leaking continuously or nearly continuously.
Properly operating intermittent bleed pneumatic devices, as acknowledged by the agency, do not vent continuously. By design and definition, intermittent-bleed pneumatic devices only vent ("process emissions") when they actuate. Therefore, EPA should amend Calculation Methods 3 to allow reporters to use "company records or engineering estimates" to determine actuation cycle counts, when the data is available, in lieu of the "In-service" hours concept. This approach would allow the use of "empirical data" and yield more accurate emissions estimates.

Commenter 0382:

- That said, proposed calculation Method 3, in its current form, like the current Subpart W rules, will still likely overstate emissions from intermittent bleed pneumatic devices significantly because it continues to rely upon the use of one-size fits all leaker emissions factors and a determination of "in-service" hours based on a default of 8760 hours (every hour of every day in a reporting year). Even though properly operating devices are confirmed via approved leak surveys, this approach requires reporters to assume the properly operating devices are leaking continuously or nearly continuously.

- Properly operating intermittent bleed pneumatic devices, as acknowledged by the agency, do not vent continuously. By design and definition, intermittent bleed pneumatic devices only vent ("process emissions") when they actuate. Therefore, AIPRO proposes that EPA should amend Calculation Methods 3 to allow reporters to use "company records or engineering estimates" to determine actuation cycle counts, when the data is available, in lieu of the "In-service" hours concept. This approach would allow the use of "empirical data" and yield more accurate emissions estimates.

Commenter 0382:

f. Potential for "double-counting" of emissions from certain sources due to certain requirements:
i. Under current GHGRP rules as well as proposed GHGRP revisions, there are multiple scenarios where emissions may be "double-counted", some of these include the following:
…

- Pneumatic devices assumed to be venting continuously (when using default "operating" or "in-service" hours of 8760 as directed by the rule) under population count methodology for the pneumatic emissions source category AND leaking continually if included in component count approach for the fugitive emission source category.

…
ii. AIPRO encourages EPA to identify and eliminate all potential double-counting scenarios. AIPRO, again, welcomes the opportunity to collaborate with the agency on this effort.

Response 2: See Section III.E.4.b of the preamble to the final rule for our response to these comments. Additionally, there is no double counting of emissions in the proposed calculation method 3 because pneumatic device venting emissions are not required to and should not be quantified and reported under the equipment leaks source category. Furthermore, the final rule does not provide a component count approach for quantifying equipment leak emissions. Instead, reporters subject to the requirements of 98.233(r) apply default population emission factors to major equipment counts, and these default population emission factors do not include emissions from pneumatic device venting.

Commenter: Independent Petroleum Association of New Mexico (IPANM)
Comment Number: EPA-HQ-OAR-2023-0234-0299
Page(s): 105

Commenter: Independent Petroleum Association of New Mexico (IPANM)
Comment Number: EPA-HQ-OAR-2023-0234-0337
Page(s): 2

Commenter: Environmental Defense Fund, et al.
Comment Number: EPA-HQ-OAR-2023-0234-0413
Page(s): 39

Comment 3:

Comments on "in service" revisions

<u>Commenter 0299</u>: Appendix A

Table of changes GPA supports as proposed.

Subpart	Citation	Change
…		
W	98.233(a)(1), 98.233(a)(6), 98.236(b)(2)	Natural gas pneumatic device venting: Clarify hours of operation means hours in service
W	98.233(c)(1), 98.236(c)(4)	Natural gas pneumatic pump venting: Clarify hours of operation means hours in service

<u>Commenter 0337</u>: **40 CFR § 98.233(a) Pneumatic Devices**

The rule should provide additional clarity around the definition of operating hours. In various places in the proposed § 98.233(a), it states: number of hours in the operating year that the devices "were in service (i.e. supplied with natural gas)." Additional clarity should be provided so that reporters can apply hours accurately. There are numerous situations where an intermittent bleed device may be supplied with natural gas during a time when the associated site is not operating, an associated well is not flowing, or the associated equipment is not operating. In these cases, the device could be receiving a signal but there is no potential for actuation since the process variable being controlled cannot occur.
The preamble to the Proposed Rule provides the type of clarity missing from the rule language. "This proposed revision would emphasize the EPA's intent that the average number of hours used in equation W–1 should be the number of hours that the devices of a particular type are in service (i.e., the devices are receiving a measurement signal and connected to a natural gas supply that is capable of actuating a valve or other device as needed)."
We recommend that the definition of the "T" variable in equations W-1B, W-1C, and W-1D should be revised from "…were/was in service (i.e., supplied with natural gas)…" to "…were in service (i.e., the devices are receiving a measurement signal, connected to a natural gas supply, capable of actuating a valve or other device as needed, and the process variable being controlled can occur given the status of the equipment."

<u>Commenter 0413</u>: *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.

Footnote:

[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-usclimate-bill.

Response 3: We recognize the importance of correctly reporting the time pneumatic devices are "in service" consistent with how the emission factors are developed. We disagree with the commenter suggesting additional restrictions be applied to the time the device is "in service." For continuous bleed devices, the devices would still be emitting when supplied with natural gas even though the process unit is not operating. For intermittent bleed devices, we understand the commenter's intentions but a significant portion of the emissions from intermittent bleed devices comes from malfunctioning devices and these devices can still emit natural gas when the device is not actuating. Therefore, we determined that the time variable is best defined as the time the device is in service (i.e., supplied with natural gas) without any additional qualifiers, and is the most consistent with CAA section 136(h).

6.6 Natural Gas Pneumatic Devices and Natural Gas Driven Pneumatic Pumps Routed to Control

Commenter: GPA Midstream Association
Comment Number: EPA-HQ-OAR-2023-0234-0299
Page(s): 79-80, 105

Comment 1: <u>Natural Gas Driven Pneumatic Pump Venting</u>

Proposed Change: EPA is proposing that if a pump switches from uncontrolled to controlled during the year, reporters should calculate emissions using both uncontrolled and controlled calculation methods and adjust the time in equation W-2. EPA is also proposing to collect counts of the total number of pumps in addition to the number of controlled pumps and uncontrolled pumps since a pump can be both controlled and uncontrolled during the year.

> **Comment**: This requirement is unnecessarily precise and overly burdensome given the very limited number of sources this provision would apply to, even as operators eliminate or control natural gas driven pneumatic pumps. One of the goals of this rulemaking is to streamline implementation, and a requirement to develop and use a mix of partial-year

calculation methods for a small number of sources would introduce unnecessary complexity contrary to EPA's overarching goals for this rulemaking. This proposed change would also imply that emissions must be calculated *per pump* instead of *per collection of pumps* as equation W-2 otherwise allows. To address these issues in a reasonable and accurate manner, GPA proposes that sources apply the calculation method that represents operation during the majority of the year.

Similarly, collecting data on the total number of pumps in addition to the number of controlled pumps and uncontrolled pumps for the purposes understanding "how often pneumatic pumps are both controlled and vented directly to the atmosphere in the same year" is overly burdensome and unnecessary. Uncontrolled pumps that become controlled will generally switch mid-year (i.e., not on January 1), and will switch just once. Pumps will not move in and out of being controlled throughout the year. Simply collecting the number of controlled pumps and uncontrolled pumps and assessing changes over time should provide sufficient information for EPA to understand pump control changes.[24]

Suggested text:

98.233(c) Natural gas driven pneumatic pump venting. Calculate emissions from natural gas driven pneumatic pumps venting directly to the atmosphere as specified in paragraphs (c)(1) and (2) of this section. Calculate emissions from natural gas driven pneumatic pumps routed to flares, combustion, or vapor recovery systems as specified in paragraph (c)(3) of this section. If a pump was vented directly to the atmosphere for part of the year and routed to a flare, combustion, or vapor recovery system during another part of the year, calculate emissions based on how the pump operated most of the year. You do not have to calculate emissions from natural gas driven pneumatic pumps covered in paragraph (e) of this section under this paragraph (c).

98.233(c)(3) Calculate emissions from natural gas driven pneumatic pumps routed to flares, combustion, or vapor recovery systems as specified in paragraphs (c)(3)(i) or (ii) of this section, as applicable. ~~*If a pump was vented directly to the atmosphere for part of the year and routed to a flare, combustion, or vapor recovery system during another part of the year, then calculate emissions from the time the pump vents directly to the atmosphere as specified in paragraphs (c)(1) and (2) of this section and calculate emissions from the time the pump was routed to a flare or combustion as specified in paragraphs (c)(3)(i) and (ii) of this section, as applicable.*~~ *For emissions that are collected in a vapor recovery system that is not routed to combustion, paragraphs (c)(1), (2), (3)(i), and (3)(ii) do not apply and no emissions calculations are required.*

…

Appendix A

Table of changes GPA supports as proposed.

Subpart	**Citation**	**Change**

…		
W	98.233(c), 98.233(c)(3)	Natural gas pneumatic pump venting: Clarify emissions from pumps routed to flares, combustion, or vapor recovery systems are not reported under 98.233(c)

Footnote:

[24] Indeed, it is questionable whether this information is truly useful and otherwise consistent with the scope of the GHGRP generally, EPA's regulatory needs, or the authority granted under section 114.

Response 1: We disagree with the commenter's request regarding allowing a reporter to calculate emissions for a pump that is both controlled and uncontrolled during a year using only the methodology that applies to the operating mode that represents operation during the majority of the year. According to section 136 of the CAA, the EPA is directed to revise reporting under subpart W to ensure it accurately reflects the total methane emissions and waste emissions from the applicable facilities. Calculating both controlled emissions and uncontrolled emissions per facility based on actual controlled and uncontrolled operation is needed to meet this directive.

We also disagree with the commenter's statement that calculating both controlled emissions and uncontrolled emissions for pumps that operate in both modes during the year implies that emissions must be calculated per pump instead of per collection of pumps. To calculate uncontrolled emissions, a reporter enters the applicable total count of uncontrolled pumps and the average operating time of those pumps in Equation W-2C of the final rule (currently Equation W-2 and was Equation W-2 in the 2022 proposed amendments). As in the current methodology, the operating hours when the pump is uncontrolled must be known for each uncontrolled pump in order to calculate the average operating hours to use in Equation W-2C. If a particular pump was both controlled and uncontrolled during the year, then the operating hours for that pump to use in calculating the collective average should be only the hours when the pump was uncontrolled. Similarly, calculating controlled emissions from flares is based on characteristics of either the aggregated stream to the flare or on the characteristics of individual streams; the reporter is not required to calculate controlled emissions per flare.

We agree with the commenter that it is likely that few pumps will be both uncontrolled and controlled in only a single year and that the switch will most likely be from uncontrolled to controlled. Thus, we disagree with the commenter's statement that it is overly burdensome to report such pumps both in the count of uncontrolled pumps and in the count of controlled pumps because, as the commenter noted, this situation is expected to apply to only a limited number of pumps. We also believe that including a pump that operates in both modes in the reported count of uncontrolled pumps and in the count of controlled pumps (as well as in the total count of pumps) will help with verification where a facility's reporting includes such situations. For example, if such reporting indicates that a facility had a high number of pumps that were both controlled and uncontrolled in a particular year, that may be a reason for also reporting unexpectedly low average operating hours, which may reduce correspondence requesting clarification from reporters in eGGRT.

Commenter: Independent Petroleum Association of New Mexico (IPANM)
Comment Number: EPA-HQ-OAR-2023-0234-0337
Page(s): 3-4

Commenter: Chesapeake Energy Corporation
Comment Number: EPA-HQ-OAR-2023-0234-0400
Page(s): 8-9

Commenter: Environmental Defense Fund, et al.
Comment Number: EPA-HQ-OAR-2023-0234-0413
Page(s): 39

Comment 2:

Commenter 0337: **40 CFR § 98.233(a) Pneumatic Devices**

The Proposed Rule does not clearly address how to report natural gas driven pneumatic devices whose emissions are captured or routed to existing processes or equipment and do not vent any gas; additional clarity is needed in the Proposed Rule. Section 98.233(a)(7) appears to address routing emissions to vapor recovery systems, but the language is not specific. For example, the proposed rule is clear on this issue for pumps, § 98.233(c)(4) states, "For emissions that are collected in a vapor recovery system that is never routed to combustion during the reporting year, paragraphs (c)(2) and (3) and paragraphs (c)(4)(i) and (ii) of this section do not apply and no emissions calculations are required."
We recommend that § 98.233(a)(7) should be revised to include the same language. "For emissions that are collected in a vapor recovery system that is never routed to combustion during the reporting year, paragraphs (a)(7)(i) and (ii) of this section do not apply and no emissions calculations are required."
In addition, the proposed rule does not specifically address how to report pneumatic devices whose emissions are routed to a combustion device that is not required to report emissions under § 98.233(z). Section 98.233(a)(7)(ii) should be revised to read, "If emissions from any natural gas pneumatic devices were routed to combustion units, you must calculate and report emissions as specified in subpart C of this part or calculate emissions as specified in paragraph (z) of this section and report emissions from the combustion equipment as specified in § 98.236(z), as applicable. If the combustion device meets the conditions and reports in accordance with 98.233(z)(6) & (7), no emissions calculations are required."
This approach would align with how states like New Mexico treat routed devices. For example, in 20.2.50.122 NMAC, "'Routed pneumatic controller'" means a pneumatic controller of any type that releases natural gas to a process, sales line, or to a combustion device instead of directly to the atmosphere." Subpart W and OOOOb/c should recognize the major reductions in vented methane that will have been achieved by routing of pneumatic controllers. Doing so will support the EPA goal for the Proposed Rule of reporting empirical data.

Commenter 0400: **EPA should incorporate control efficiency into its Calculation Methods for pneumatic devices.**

EPA's proposed calculation methods for pneumatic devices fail to capture emissions reductions from capture and control equipment. These methods will require operators to incur significant additional compliance burdens while preventing them from obtaining credit for emissions reduction measures. These methods will also *decrease* reporting accuracy by introducing a significant reporting error. Reported emissions cannot be accurate without accounting for control efficiency.

Ensuring that operators are able to obtain credit for these reductions is critical to supporting continuing investment in carbon capture technologies. The Intergovernmental Panel on Climate Change has recognized that carbon capture could play a significant role in achieving climate stabilization goals.[23] EPA has also recognized that carbon management using these technologies "is critical for reliable power in some regions, for industry decarbonization, and counterbalancing truly hard to decarbonize emissions."[24]

By failing to account for control efficiency, EPA is disincentivizing important emissions reductions and decreasing the accuracy of emissions reporting, in contravention of the express directives of Congress in CAA Section 136. As EPA noted in its original reporting rule, "[a]ccurate and timely information on GHG emissions is essential for informing many future climate change policy decisions."[25] EPA cannot make these informed decisions without adequately accounting for control efficiency.

Chesapeake encourages EPA to incorporate control efficiency in its Calculation Methods to ensure that reported emissions are representative of actual emissions. This approach aligns with existing quantification methods in Subpart W, which account for control methods through vapor recovery systems, see § 98.236(j)(1)(xii), or flares, see § 98.236(j)(1)(xiv).

FOOTNOTES

[23] See IPCC Special Report: Carbon Dioxide Capture and Storage – Summary for Policymakers (2005), https://www.ipcc.ch/site/assets/uploads/2018/03/srccs_summaryforpolicymakers-1.pdf.

[24] EPA Presentation, Carbon Capture and Storage (Aug. 2022), https://www.epa.gov/system/files/documents/2022-09/August%202022%20CCS%20Information%20Session.pdf.

[25] Mandatory Reporting of Greenhouse Gases, 74 Fed. Reg. 56,260, 56,265 (Oct. 30, 2009).

Commenter 0413:

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.

Response 2: In our 2023 Subpart W Proposal for natural gas pneumatic devices, we included provisions to account for natural gas pneumatic devices that are vented to controls rather than to the atmosphere. We consider that the clarification requested was provided in 40 CFR 98.233(a)(7) (40 CFR 98.233(a)(8) in the final rule) that "…During periods when natural gas pneumatic device emissions are collected in a vapor recovery system that is not routed to combustion, paragraphs (a)(1) through (3) and (a)(7)(i) and (ii) of this section do not apply and no emissions calculations are required." For devices where the gas is recovered and never routed to combustion, we consider the language proposed at 40 CFR 98.233(a)(7) clearly indicated that no calculations apply. However, the language proposed at 40 CFR 98.233(c)(4) did not directly address how to handle cases where the emission may be routed to combustion for some periods and recovered for other periods. Therefore, we are finalizing the language proposed at 40 CFR 98.233(a)(7) regarding periods when vapor recovery is used and not routed to combustion in the final provisions at 40 CFR 98.233(a)(8) and (c)(4). We also consider the language proposed at 40 CFR 98.233(a)(7)(ii) (40 CFR 98.233(a)(8)(ii) in the final rule) and (c)(4)(ii) to clearly state how to report the emissions from devices and pumps routed to combustion units. While we agree that, if these vapors are routed to a combustion device that meets the conditions and reports in accordance with 40 CFR 98.233(z)(6) and (7), no additional emissions calculations are required, we do not consider that clarification to be critical. That is a direct result of calculating emissions "…as specified in paragraph (z) of this section…" Therefore, we did not add additional language to further clarify the language at 40 CFR 98.233(a)(8)(ii) and (c)(4)(ii) as requested by the commenter. With respect to the commenter's suggestion that we must account for the control efficiency for devices whose emissions are captured and controlled, we consider that the proposed rule requirements fully account for control efficiencies of flares, combustion devices, and recovery system and we are finalizing those provisions as proposed.

Commenter: GPA Midstream Association
Comment Number: EPA-HQ-OAR-2023-0234-0299
Page(s): 80

Comment 3: RFC: EPA requests comment on whether pneumatic pumps are routed to vapor recovery systems and whether there are other controls that should be addressed with these new provisions.

> **Comment**: GPA members were not aware of examples of pneumatic pumps being routed to vapor recovery systems; the emissions from pumps are typically too low to justify using a vapor recover unit for control. GPA members are not aware of other control methods for pneumatic pumps other than flares or combustion.

Response 3: We appreciate the commenter's information. The EPA is finalizing requirements as proposed regarding calculation and reporting of controlled emissions only from flares and combustion. Additionally, as proposed, the final rule specifies that emissions calculations are not required for pumps that route emissions to vapor recovery, but the count of such pumps must be included in both the total count of pumps and in the collective count of pumps routing emissions to flares, combustion, or vapor recovery.

Commenter: GPA Midstream Association
Comment Number: EPA-HQ-OAR-2023-0234-0299
Page(s): 81

Comment 4: RFC: EPA requests comment on whether flared emissions associated with natural gas driven pneumatic pumps should continue to be reported as flare stack emissions under 40 C.F.R. § 98.236(n) or should be reported in the natural gas driven pneumatic pumps emission source under 40 C.F.R. § 98.236(c).

> **Comment**: These emissions should continue to be reported under section 98.236(n). This source is too small to justify the work of parsing out its emissions from the total flare emissions.

Response 4: We agree with the commenter and continue to only require flared emissions from pumps to be reported under 40 CFR 98.236(n).

7 Acid Gas Removal Unit Vents

7.1 Reporting of Methane Emissions from Acid Gas Removal Units

Commenter: Environmental Defense Fund, et al.
Comment Number: EPA-HQ-OAR-2023-0234-0413
Page(s): 75-76

Comment 1: 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 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.

Response 1: The EPA acknowledges the commenter's support of the proposed revisions. The EPA is finalizing these amendments mostly as proposed. Specific proposed provisions for which the EPA received and considered public comments and determined that it is appropriate to finalize requirements that differ from the proposed rule are discussed elsewhere in this document and in Section III.F of the preamble to the final rule.

Commenter: GPA Midstream Association
Comment Number: EPA-HQ-OAR-2023-0234-0299
Page(s): 29

Commenter: American Petroleum Institute et al. (Part 1 of 2)
Comment Number: EPA-HQ-OAR-2023-0234-0402
Page(s): 22-23

Comment 2: <u>Commenter 0299</u>: **EPA should allow Calculation Methods 2, 3, or 4 to determine CH_4 and CO_2 emissions…**

…

We also have reservations regarding the reliability of utilizing Method 3 (mass balance) for estimating methane emissions from AGRUs. Typically, operators rely on data from facility (or site) inlet and outlet streams, and employing a methane mass balance across the entire site poses two significant challenges:

5. In ideal conditions where flow and composition measurements are perfectly accurate, there is a theoretical risk of double-counting methane losses from other sources such as fugitive emissions or compressors; and
6. In practical terms, the volume of methane vented from AGRUs is generally negligible when compared to the overall methane flow through a facility. Consequently, using this method could potentially yield negative methane emissions values or otherwise inaccurate estimates.

Commenter 0402: Acid Gas Removal and Nitrogen Removal Units

Proposed Methods for Methane Emissions

The proposed mass balance approach for quantifying emissions will not lead to accurate reporting for methane emissions.

EPA proposes to report methane along with CO2 from Acid Gas Removal Units (AGRUs) and Nitrogen Removal Units (NRUs). The Industry Trades believe that the proposed methodology in Equation W-4C (a mass balance approach) will not lead to accurate reporting for methane emissions. Since the solubility of methane in amine is very low, the difference in methane concentration in the inlet and outlet processed gas stream will be negligible. Therefore, the ability to discern a difference in inlet versus outlet methane composition will make it difficult (if not impossible) to accurately determine methane emissions using a mass balance approach. Further, sampling the high-pressure acid gas stream at the inlet of the AGRU contactor poses a significant safety concern… For these reasons, the Industry Trades recommend removing this methodology for methane emissions reporting.

Response 2: See Section III.F.1 of the preamble to the final rule for the EPA's response to comments regarding use of Calculation Method 3.

Regarding the commenter who indicated that reporters often use the composition of the natural gas at the facility level, the requirements for determining the compositions for Calculation Method 3 are detailed in 40 CFR 98.2332(d)(7) and (8). Both sections indicate that the available methods include a continuous analyzer or quarterly sampling of the inlet and the outlet of the AGR or NRU, or use of pipeline quality natural gas specifications in lieu of measurements of the outlet of the AGR or NRU. If the reporter has concerns that Calculation Method 3 might double-count emissions from other sources, that might be an indication that the compositions of the gas at the inlet and/or outlet of the facility are not the same as the composition of the inlet and/or outlet natural gas, respectively, for the AGR or NRU, in which case the reporter may elect to collect additional samples from the AGR or NRU inlet, or elect to use Calculation Method 4 to calculate emissions.

Regarding the concerns with sampling the inlet gas due to H_2S content, the EPA did not propose and is not finalizing changes to the requirements for determining the composition of the inlet gas stream for Calculation Method 3 in 40 CFR 98.236(d)(7). Calculation Method 3 is only one of the options provided for reporters who do not have a CEMS or vent meter on the AGR stack. For the EPA's response to comments regarding concerns with sampling the inlet gas for Calculation Method 4, see Section 7.3 of this document.

Commenter: GPA Midstream Association
Comment Number: EPA-HQ-OAR-2023-0234-0299
Page(s): 30

Comment 3: For calculation method 4 (process simulation), methane content of outlet natural gas should not be a required simulation input.

For Calculation Method 4, EPA is proposing to add the CH_4 content of the outlet natural gas as a parameter that must be used to characterize emissions [98.233(d)(4)(v)], but this is not analogous to the acid gas content of the outlet natural gas as the proposal erroneously states. The methane content of the outlet natural gas is not an input required for process simulation, and as such should not be considered a required parameter for this method.

~~98.233(d)(4)(v) CH4 content of outlet natural gas.~~

Response 3: We are finalizing the amendment as proposed. The EPA notes that 40 CFR 98.233(d)(4) indicates that the listed parameters "must be used to characterize emissions" but does not necessarily indicate that each of the listed parameters is intended to be an input to the simulation software. Some of the parameters are inputs to the simulation software and some are calculated by the software. The EPA generally expects that the parameters related to the inlet natural gas will be the inputs to the simulation software, but the parameters that are not inputs must be determined by the simulation software to characterize the emissions. For reporters using Calculation Method 4, each of the parameters in 40 CFR 98.233(d)(4) must be reported in 40 CFR 98.236(d)(2)(iii).

7.2 Selection of Calculation Method

Commenter: GPA Midstream Association
Comment Number: EPA-HQ-OAR-2023-0234-0299
Page(s): 26-30, 81

Comment 1: … GPA specifically requests that Method 2 not be required if a vent meter is present.

In the current and proposed Subpart W for AGRUs, EPA requires Calculation Method 2 if a vent meter is installed, which mandates quarterly sampling of the acid gas stream. EPA should make this method optional because Calculation Method 2 requires quarterly sampling of sour gas. This is a difficult and potentially dangerous sample to take because of the inherent safety concerns (high H_2S), and therefore many facilities sample this stream quarterly only for the purposes of complying with this rule. In the preamble EPA notes for other sources that:

Emissions can be reliably calculated for sources such as tanks and glycol dehydrators using standard engineering first principle methods such as those available in API 4697 E&P Tanks and GRI-GLYCalc™. Using such software also addresses safety concerns that are associated with direct emissions measurement from these sources. For example, sometimes the temperature of the emissions stream for glycol dehydrator vent stacks is too high for operators to safely measure emissions.[63]

EPA should apply the same concern for safety to AGRUs; the sour gas stream being measured has the potential to be lethal.

Further, EPA proposes that glycol dehydrators must use modeling results from other compliance programs. There are state permit-mandated modeling requirements for AGRUs that reporters should be able to use for the GHGRP, but this proposed rule would instead force reporters to depart from those results and regularly collect dangerous samples. Because EPA seeks consistency between the GHGRP and other compliance requirements for glycol dehydrators, it should do the same for AGRUs.

There is a plethora of literature available showing that process simulators agree well with plant data over a wide range of operating conditions, especially for AGRUs. Specifically for methane, the figure below is an excerpt from Mamrosh et al.[64] This shows a parity plot where the experimental value is graphed on the x-axis and the simulation value on the y-axis, such that the parity line is the experimental data, and the simulation predictions are the points shown on the graph. In this source, the error bars shown are those of the experimental data. This research report utilizes an equilibrium constant K-value (a representation of solubility) for convenience in comparing Vapor-Liquid Equilibrium data. This shows that process simulators are typically very accurate at predicting methane content from AGRUs.

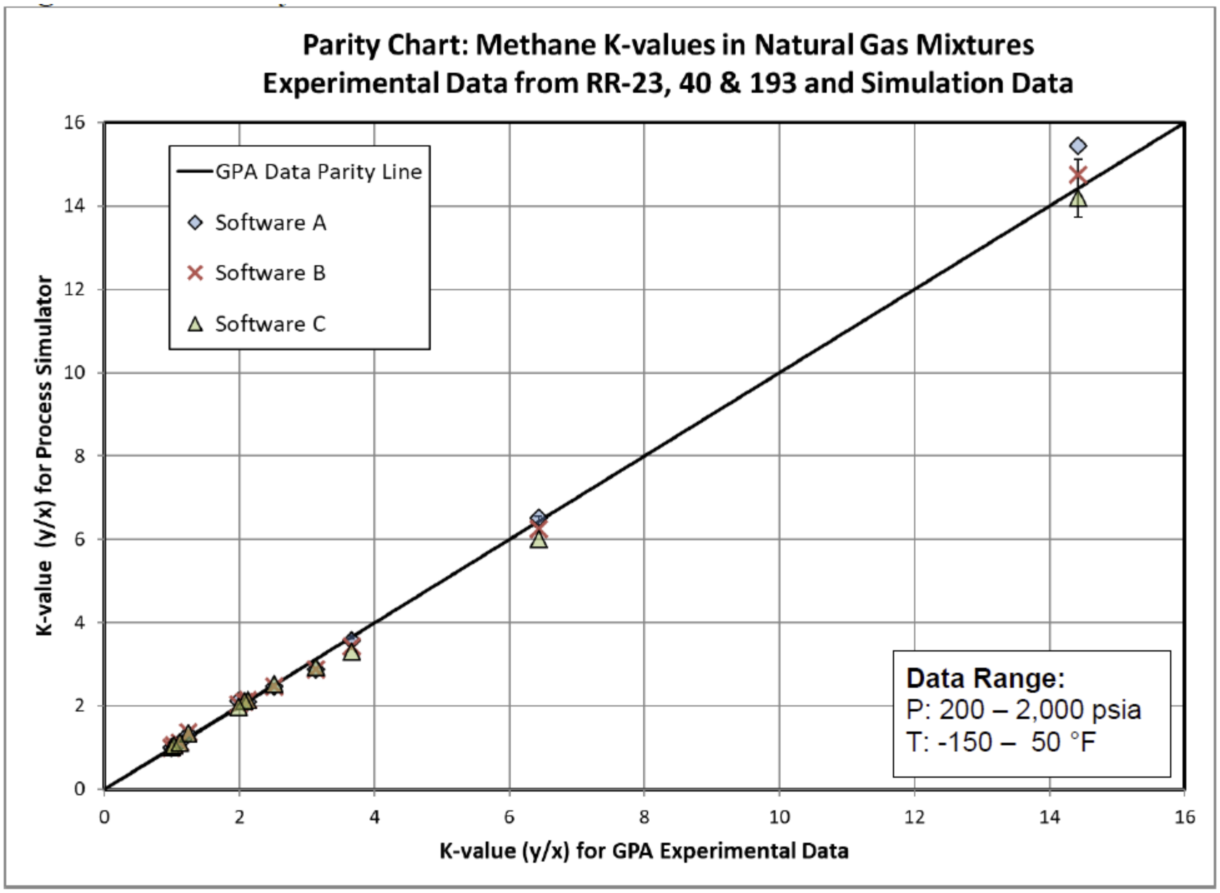


Figure 1: Copied from "Figure 3.1.1 Parity plot for Methane K-values for Data from RR-23, 40, and 193" from Mamrosh et al.

Similarly for CO_2 in AGRUs, the figure below from Pieronek et al.[65] shows very good agreement between data and simulation.

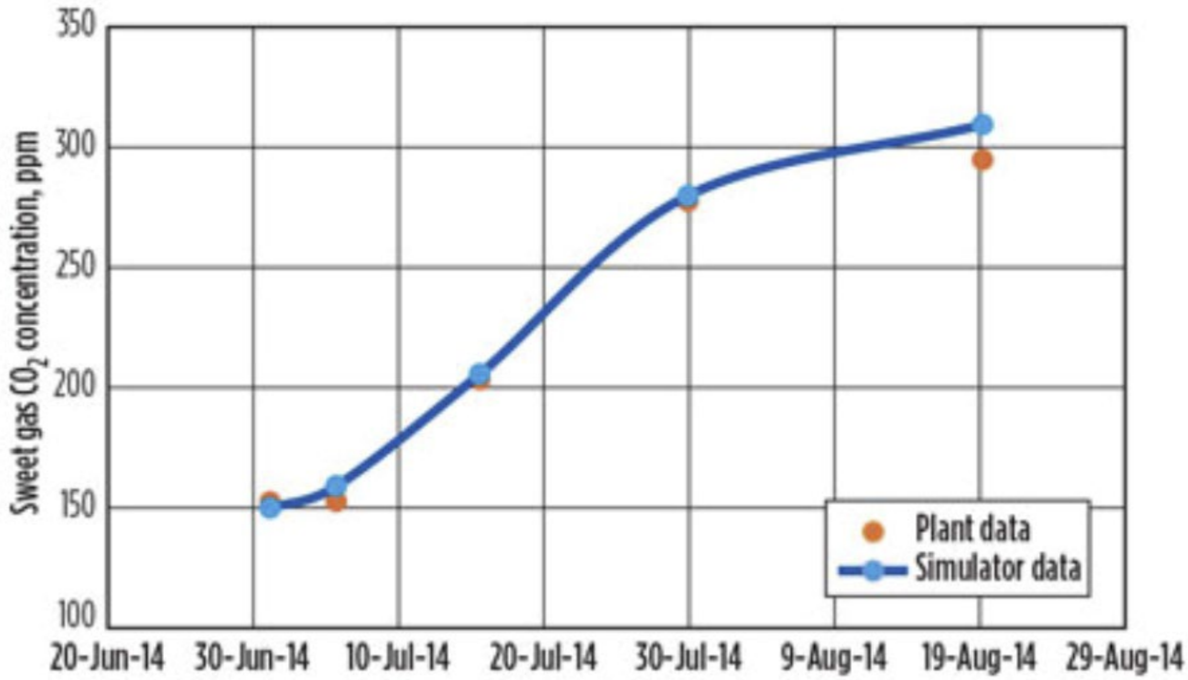


Figure 2. Copied from "Fig. 2. Simulator vs. operating data for sweet gas CO2 concentration" in Pieronek et al.

Many other literature sources exist that also show good agreement between process simulation software and operating data.[66,67,68,69,70,71,72,73,74,75,76,77] As such, Method 4 should be allowed for use even if a vent meter is present.

…

To address these issues, GPA proposes the following revision to the proposed regulatory text:

> 98.233(d)(2) Calculation Method 2. For CO_2 emissions, if a CEMS is not available but a vent meter is installed, ~~use~~ the CO_2 composition and annual volume of vent gas can be used to calculate emissions using Equation W-3 of this section. For CH_4 emissions, if a vent meter is installed, including the volumetric flow rate monitor on a CEMS for CO_2, you may use the CH_4 composition and annual volume of vent gas to calculate emissions using Equation W-3 of this section.

…

Acid Gas Removal Units ("AGRUs")

Comment: For AGRUs, EPA is still requiring that, if present, acid gas vent meter data must be used [Calculation Method 2, 98.233(d)(2)]. EPA should make this method optional. The acid gas vent is a difficult stream to measure. Good measurement can be achieved on streams that have controlled flow rates with decent pressure and consistent composition. This is often not the case on acid gas vents (which tend to have varying flow rates, varying composition, and low pressure). Additionally, Calculation Method 2 requires quarterly sampling of sour gas. This is a difficult sample to take because of the inherent safety concerns (high H_2S), and therefore many facilities would only sample it quarterly to comply with this rule. In contrast, plant inlet and residue gas are generally sampled frequently, and as such, Calculation Methods 3 or 4 may yield more accurate emission estimates than Calculation Method 2.

> **Suggested text**: *98.233(d)(2) Calculation Method 2. If a CEMS is not available but a vent meter is installed, you may use the CO2 composition and annual volume of vent gas to calculate emissions using Equation W-3 of this section.*

Footnotes:

[63] *Id*. at 50,289.

[64] D. Mamrosh, et al., "RR-247 Comparison of GPA Midstream Data to Simulation Software Predictions," GPA MIDSTREAM ASSOCIATION RESEARCH REPORT, Project 111 (Feb. 2021).

[65] M. Pieronek, et al., "Optimize capacity and efficiency for an amine unit," GAS PROCESSING & LNG (Apr. 2015), http://gasprocessingnews.com/articles/2015/04/optimize-capacity-and-efficiency-for-an-amine-unit.

[66] N.S. Darani, et al., "Simulation and Optimization of the Acid Gas Absorption Process by an Aqueous Diethanolamine Solution in a Natural Gas Sweetening Unit," ACSOMEGA (Apr. 30, 2021), https://pubs.acs.org/doi/10.1021/acsomega.1c00744.

[67] Y. Zheng, et al., "Simulation and pilot plant measurement for CO_2 absorption with mixed amines," ENERGY PROCEDIA 4: 299-06 (2011), available at https://www.sciencedirect.com/.
68 A. Erfani, et al., "Simulation of an operational amine based CO_2 removal plant as an example of CO_2 capture at coal-fired power plants," PETROLEUM AND COAL, https://www.vurup.sk/wpcontent/uploads/dlm_uploads/2017/07/pc_1_2015_boroojerdi_323_2.pdf.

[69] D. Mamrosh, et al., "RR-250 Comparison of GPA Midstream Data to Simulation Software Predictions," GPA MIDSTREAM ASSOCIATION RESEARCH REPORT, Project 182 (Feb. 2021).

[70] I.M.S. Larsen, "Simulation and validation of CO2 mass transfer processes in aqueous MEA solutions with Aspen Plus at CO_2 Technology Centre Mongstad," Master's Thesis, Telemark University College, Norway (2014), https://www.ieaghg.org/docs/General_Docs/PCCC3_PDF/3_PCCC3_4C_Hamborg.pdf.

[71] K.A. Sætre, "Evaluation of process simulation tools at TCM", Master Thesis, University College of Southeast Norway, 2016.

[72] L.E. Øi, et al., "Comparison of Simulation Tools to Fit and Predict Performance Data of CO_2 Absorption into Monoethanol Amine at CO_2 Technology Centre Mongstad (TCM)," PROCEEDINGS OF THE 59TH CONFERENCE ON SIMULATION AND MODELLING (SIMS 59) (Sept. 26-28, 2018), Oslo Metropolitan University, Norway, https://ep.liu.se/ecp/153/032/ecp18153032.pdf.

[73] S. Moioli & L. Pellegrini, "2013 Regeneration section of CO_2 capture plant by MEA scrubbing with a rate-based model," CHEMICAL ENGINEERING TRANSACTIONS (2013), https://www.aidic.it/cet/13/32/309.pdf.

[74] S. S. Warudkar, et al., "Influence of stripper operating parameters on the performance of amine absorption systems for post-combustion carbon capture: Part I. High pressure strippers," INT. J. GREENHOUSE GAS CONTROL (2013), https://porousmedia.rice.edu/resources/Stripper%20High%20Pressure.pdf.

[75] E. Alfadala & E. Al-Musleh, "Simulation of an acid gas removal process using methyldiethanolamine; an equilibrium approach," PROCEEDINGS OF THE 1ST ANNUAL GAS PROCESSING SYMPOSIUM (Jan. 10-12, 2009), https://www.sciencedirect.com/science/article/abs/pii/B978044453292350033X.

[76] X. Luo, et al., "Comparison and validation of simulation codes against sixteen sets of data from four different pilot plants," ENERGY PROCEDIA (Feb. 2009), https://www.sciencedirect.com/science/article/pii/S1876610209001659.

[77] J. Polasek & J. Bullin, "Selecting amines for sweetening units," ENERGY PROGRESS, 146–149 (Sept. 1984), https://www.osti.gov/biblio/5979009.

Response 1: See Section III.F.1 of the preamble to the final rule for the EPA's response to this comment.

7.3 Calculation Method 4

Commenter: Arkansas Independent Producers and Royalty Owners (AIPRO)
Comment Number: EPA-HQ-OAR-2023-0234-0382
Page(s): 16

Commenter: American Petroleum Institute et al. (Part 1 of 2)
Comment Number: EPA-HQ-OAR-2023-0234-0402
Page(s): 22-23

Comment 1: Commenter 0382: Acid Gas Removal Units:

i. AIPRO specifically incorporates the comments prepared by API for proposed revisions to Subpart W for Acid Gas Removal and Nitrogen Removal Units. Further, AIPRO emphasizes the safety concerns raised by API related to sampling inlet gas streams to these devices. Inlet gas streams to these devices can contain dangerous levels of hydrogen sulfide (H2S) and places workers at risk if required to perform inlet stream sampling under Method 4. As such, AIPRO suggests that EPA amend the requirements for this method or remove it all together.

Commenter 0402: Acid Gas Removal and Nitrogen Removal Units

Proposed Methods for Methane Emissions

[S]our gas sampling poses a significant safety concern.

…

EPA is proposing a requirement to perform direct sampling of gas streams into these units at least annually. The Industry Trades remind EPA that these streams can also contain dangerous levels of hydrogen sulfide (H2S), and any work near or around these units that is not necessary for the optimal function of the equipment should be limited to protect the personnel responsible for performing these tasks. The Industry Trades recommend removing the prescriptive sampling requirements for these streams and allow reporters to use representative samples or direct site-specific samples if deemed to be appropriate.

For the simulation method (Method 4), the Industry Trades recommend that EPA clarify that representative measurements can be one time, annual or a more frequent measurement as deemed appropriate for the facility's operation.

Response 1: The proposed requirements to measure certain inputs for Calculation Method 4 included flexibilities so long as certain requirements were met. The EPA specified in 40 CFR 98.233(d)(4) that if an applicable parameter must be measured, the reporter must "collect measurements reflective of representative operating conditions over the time period covered by the simulation." Under this provision, reporters have the option to conduct representative sampling or use direct site-specific samples (as suggested by the commenter) if those samples would be representative of the AGR inlet stream during operating conditions over the time period covered by the simulation. The EPA expects that most reporters already have some sort of sampling or measurement in place at some point upstream of the AGR to evaluate the acid gas species and contents that will be in the AGR inlet stream, at a minimum so that the amount of solvent used in the AGR and other AGR operating conditions can be adjusted as needed to effectively remove the acid gases (*i.e.*, "necessary for the optimal function of the equipment" as noted by Commenter 0402). The EPA expects that these measurements can be used to meet the requirements in 40 CFR 98.233(d)(4) and that the reporters do need not need to install additional monitors or send out personnel to take additional frequent samples of the inlet gas. Therefore, the EPA is finalizing these requirements as proposed.

Regarding the frequency of measurement, as indicated in the preamble to the 2023 Subpart W Proposal, we proposed that reporters would collect measurements reflective of representative operating conditions over the time period covered by the simulation. Importantly, we proposed that the parameters that must be used to characterize emissions should reflect operating conditions over the time period covered by the simulation rather than just over the calendar year.

Under this proposed change, reporters could continue to run the simulation once per year if the parameters are determined to be representative of operating conditions over the entire year. Alternatively, reporters would be allowed to or may determine that is necessary to conduct periodic simulation runs to cover portions of the calendar year, as long as the entire calendar year is covered. The reporter would then sum the results at the end of the year to determine annual emissions. In that case, the parameters for each simulation run would be determined for the operating conditions over each corresponding portion of the calendar year.

As noted above, these requirements are finalized as proposed; therefore, the measurements may be taken once per year where parameters are determined to be representative of operating conditions over the entire year, or the measurements may be taken multiple times per year, where the measurements are reflective of representative operating conditions over shorter time periods. The EPA did not propose and is not finalizing an amendment that would allow the measurement to be conducted one time, as it is expected that there will be some variability in the gas received for treatment in an AGR or in the operation of the AGR itself that would result in one-time measurements no longer being representative of the operating conditions.

Commenter: The Petroleum Alliance of Oklahoma
Comment Number: EPA-HQ-OAR-2023-0234-0398
Page(s): 12-13

Commenter: American Petroleum Institute et al. (Part 1 of 2)
Comment Number: EPA-HQ-OAR-2023-0234-0402
Page(s): 23

Commenter: Environmental Defense Fund, et al.
Comment Number: EPA-HQ-OAR-2023-0234-0413
Page(s): 76

Comment 2: Commenter 0398: Acid Gas Removal (AGR) Unit Vents

EPA proposes that reporters would provide the solvent type and, for amine-based solvents, the general composition. Reporters would choose the solvent type option from a pre-defined list that most closely matches the solvent type and, for amine-based solvents, the general composition, used in their AGR. The standardized response options would include the following: ‘‘SelexolTM,’’ ‘‘Rectisol®,’’ ‘‘PurisolTM,’’ ‘‘Fluor SolventSM,’’ ‘‘BenfieldTM,’’ ‘‘20 wt% MEA,’’ ‘‘30 wt% MEA,’’ ‘‘40 wt% MDEA,’’ ‘‘50 wt% MDEA,’’ and ‘‘Other (specify).’’ EPA states that trade names are more commonly used among AGR operators and therefore more readily available, improve verification of reported data and better characterize AGR vent emissions. EPA states that if reporters use more than one type of solvent in their AGR during the year, the proposed reporting requirement specifies that reporters would select the option that corresponds to the solvent used for the majority of the year.

EPA provides no real justification as to why trade name information is required or how it is more accurate than the solvent composition used in the AGR unit.

Action Requested: We request EPA remove the requirement to report trades name information or provide more clarification as to how this provides more accurate emission information.

Commenter 0402: Reporting Requirements for AGRUs and NRUs

Some of the proposed reporting requirements for AGRUs and NRUs are duplicative and unnecessary, so should be removed.

…

EPA is proposing to include solvent type in data reporting; the Industry Trades does not believe this information to be beneficial or helpful in validating the reported information, and EPA did not address why this element is to be reported in the TSD. The Industry Trades recommend that the EPA remove this unnecessary reporting requirement.

Commenter 0413: *Proposed changes in calculation methodologies for CH4 emissions from AGR vents:*

…

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.

Response 2: In addition to the rationale provided in the preamble to the 2023 Subpart W Proposal for this amendment, we note that the various solvents work differently in how they react with the various acid gases; for example, some are more effective at removing reduced sulfur or H_2S while others are more effective at removing CO_2. As noted in the preamble to the 2023 Subpart W Proposal, we have found it difficult to use this data element to identify the solvent type for purposes of verification of Calculation Method 4 emissions because the "solvent weight" is the only data element related to the identification of the solvent that is currently collected and the densities of common amine-based solvents are fairly close in value. In order to verify the reported emissions and ensure that reported emissions are accurate, identification of the solvent used is needed. Therefore, we are finalizing this amendment as proposed.

Commenter: GPA Midstream Association
Comment Number: EPA-HQ-OAR-2023-0234-0299
Page(s): 30-31

Comment 3: Technical corrections

In the AGRU sections of the rule, the term *"acid gas content"* should be replaced with *"CO_2 content."* The term "acid gas" can also include other acidic components in a gas stream such as

H_2S. To ensure a clear understanding of requirements, EPA should make the language plain and not use undefined terminology.

Response 3: According to existing 40 CFR 98.238, "acid gas means hydrogen sulfide (H_2S) and/or carbon dioxide (CO_2) contaminants that are separated from sour natural gas by an acid gas removal unit." The "acid gas content" of the AGR inlet and the AGR outlet are needed for purposes of calculating and reporting emissions under Calculation Method 4. The contents of both H_2S and CO_2 are needed to calculate CO_2 and CH_4 emissions correctly from the AGR. Therefore, the EPA did not propose and is not finalizing a change from "acid gas content" to "CO_2 content" for Calculation Method 4.

7.4 Control of AGR Emissions

Commenter: American Petroleum Institute et al. (Part 1 of 2)
Comment Number: EPA-HQ-OAR-2023-0234-0402
Page(s): 23

Commenter: Environmental Defense Fund, et al.
Comment Number: EPA-HQ-OAR-2023-0234-0413
Page(s): 76

Comment 1: Commenter 0402: Reporting Requirements for AGRUs and NRUs

Some of the proposed reporting requirements for AGRUs and NRUs are duplicative and unnecessary, so should be removed.

EPA proposes that those operators sending gas from an AGRU or NRU to a control device also report associated details regarding the combustion device (flare ID, gas flow rate, etc.). Requiring this information to be reported on this tab of the Subpart W reporting form could cause duplicative reporting with sources on other tabs (e.g., flares), and is ultimately not relevant to reporting by itself. The Industry Trades recommend removing this requirement. Reporting this level of detail is also inconsistent with EPA's 2022 proposed revisions, which greatly streamlined the reporting requirements for flares.

Commenter 0413: *Proposed changes in calculation methodologies for CH4 emissions from AGR vents:*

…

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.

Response 1: As described in more detail in Section III.N.2 of the preamble to the final rule, reporters that route emissions to a flare from an AGR will report applicable AGR activity data under 40 CFR 98.236(d)(1) as well as flare-specific activity data, including the flare ID, a stream ID for the stream routed to the flare, whether the gas was routed to the flare the whole year, and an indication of how the flow rate and composition for the stream from the AGR were calculated. If AGR-specific calculation methods were used to determine the flow rate and composition, reporters will also provide the information under 40 CFR 98.236(d)(2) that corresponds to the calculation method used to determine the flow and composition of the gas routed to the flare, as is currently required.

As discussed in Section III.N of the preamble to the final amendments and Section 15 of this document, there are a few differences between the proposed and finalized provisions for calculating and reporting emissions from flares. However, the final amendments for AGRs routed to flares are consistent with the provisions for most other emission sources routed to flares.

Commenter: Anonymous
Comment Number: EPA-HQ-OAR-2023-0234-0366
Page(s): 1

Comment 2: For acid gas removal units, EPA explained how to calculate emissions routed to a flare or to combustion, but there is no mention of vapor recovery systems like for other units like dehydrators or pneumatic devices. EPA should add a sentence that explains how to handle emissions routed to vapor recovery systems.

Response 2: See Section III.F.1 of the preamble to the final rule for the EPA's response to this comment.

Commenter: GPA Midstream Association
Comment Number: EPA-HQ-OAR-2023-0234-0299
Page(s): 30

Commenter: American Petroleum Institute et al. (Part 1 of 2)
Comment Number: EPA-HQ-OAR-2023-0234-0402
Page(s): 23

Comment 3: Commenter 0299: **EPA must clarify that gases sent to acid gas injection wells or geologically sequestered should not be reported as emissions under Subpart W.**

AGRU vent streams are sometimes sent to acid gas injection wells or sequestered underground. These sequestered gas streams are not emissions, and reporters should not be required to report them as such (or pay fees on the sequestered gases). EPA has indicated in the past that sequestered gas streams must be reported under Subpart W by noting that:

EPA disagrees with the modifications suggested by the commenter. In the final rule establishing the GHG Reporting Program (74 FR 56260, October 30, 2009), EPA was clear that subpart methods and calculation procedures must be followed whether or not there is subsequent injection underground or geologic sequestration. The GHG Reporting Program is not an emissions inventory; rather it is a reporting program that collects data to inform future climate change policies.[78]

With the methane fee now relying on the emissions data reported under the GHGRP to impose fees, EPA needs to make conforming changes and recognize that the GHGRP is not simply "collect[ing] data to inform future climate change policies." Moving forward with anything different would be in direct conflict with the intent of the Inflation Reduction Act. As such, any gas streams injected underground or geologically sequestered need to be exempted from the reporting requirements of Subpart W. Acid gas injection is generally considered an effective method of reducing emissions to the atmosphere[79] and should be acknowledged as such in Subpart W instead of potentially penalizing reporters who utilize this technology.

Footnotes:

[78] EPA, Response to Comments Regarding Mandatory Greenhouse Gas Reporting Rule Subpart W – Petroleum and Natural Gas: EPA's Response to Public Comments at 1475, Docket ID No. EPA-HQ-OAR-2009-0923-0582-31 (Nov. 30, 2010) ("EPA 2010 Response to Comments Document").

[79] S. Wong, et al., "Economics of Acid Gas Reinjection: An Innovative CO2 Storage Opportunity," Greenhouse Gas Control Technologies – 6th International Conference (Oct. 2002), https://www.sciencedirect.com/science/article/abs/pii/B9780080442761502701.

Commenter 0402: Reporting Requirements for AGRUs and NRUs

…

Finally, the Industry Trades request clarity from EPA around reporting activities such as acid gas injection through Subparts W, PP and UU. The proposed requirement to report CO2 sent offsite under Subpart PP is duplicative of CO2 supplier reporting. Regarding the WEC, it will be absolutely critical that industry has a clear understanding of exactly how emissions are to be accounted for between these subparts without over-reporting, double counting, or allowing some operators to not report under these subparts at all (creating an economic disadvantage as it is unclear how some activities which result in producing CO2 are to be accounted for in the various rules).

Response 3: See Section III.F.1 of the preamble to the final rule for the EPA's response to the comment regarding reporting under subpart W of AGR vent streams sent to acid gas injection wells or sequestered underground.

The EPA did not reopen or propose to change the applicability of supplier subparts such as Subparts PP and UU. In this rulemaking, the EPA is clarifying what emissions must be reported under Subpart W, but amendments to references to other subparts within Subpart W do not affect the applicability of supplier subparts, nor do they impact a reporter's responsibility to evaluate the applicability of other subparts of the GHGRP and report under all the subparts that apply. As such, comments on supplier subparts are out of scope of this rulemaking.

Commenter: Environmental Defense Fund, et al.
Comment Number: EPA-HQ-OAR-2023-0234-0413
Page(s): 76

Comment 4: *Proposed changes in calculation methodologies for CH4 emissions from AGR vents:*

…

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.

Response 4: As described in Section III.F of the preamble to the final rule, based on consideration of public comments on the AGR requirements, the EPA is finalizing provisions for AGR vents routed to vapor recovery that are similar to the provisions for dehydrators and atmospheric storage tanks routed to vapor recovery systems. The provisions are generally consistent with the commenter's suggestion of determining emissions from the vent prior to the vapor recovery system and then adjusting those emissions to account for the quantity of emissions recovered versus emissions released directly to the atmosphere. However, the provisions for dehydrators and atmospheric storage do not require reporters to track the use of the recovered gas through the facility or system and then report those emissions as dehydrator emissions or storage tanks emissions when they are eventually released to the atmosphere from a different process unit; however, we note that reporting requirements related to the process unit from which they are released may apply. Similarly, the final provisions for AGRs do not require reporters to track the distribution of those gasses.

7.5 Reporting of Flow Rates

Commenter: Environmental Defense Fund, et al.
Comment Number: EPA-HQ-OAR-2023-0234-0413
Page(s): 76

Comment 1: 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.

Response 1: The EPA acknowledges the commenter's support of the proposed revisions. The EPA is finalizing these amendments as proposed.

8 Dehydrator Vents

8.1 Selection of Appropriate Calculation Methodologies for Glycol Dehydrators

Commenter: GPA Midstream Association
Comment Number: EPA-HQ-OAR-2023-0234-0299
Page(s): 17

Comment 1: The following is a list of substantive proposed changes that GPA expressly supports.

…

- Allowing Calculation Method 2 (process simulation) for glycol dehydrators with an annual average daily natural gas throughput that is less than 0.4 MMscf per day [98.233(e)];

Response 1: The EPA acknowledges the commenter's support of the proposed revisions. The EPA is finalizing this amendment as proposed.

8.2 Controlled Dehydrators

Commenter: GPA Midstream Association
Comment Number: EPA-HQ-OAR-2023-0234-0299
Page(s): 35

Comment 1: EPA should remove the requirement to calculate "maximum potential annual vented emissions."

Proposed 98.233(e)(4)(i) specifies that:

When emissions from dehydrator(s) are calculated using Calculation Method 1 or 2, calculate maximum potential annual vented emissions as specified in paragraph (e)(1) or (2) of this section, and calculate an average hourly vented emissions rate by dividing the maximum potential annual vented emissions by the number of hours that the dehydrator was in operation.[89]

EPA should remove the requirement to calculate the "maximum potential annual vented emissions." First, EPA cannot mandate that reporters use simulations from other compliance programs and then also mandate procedures for how to run the process simulation because this could cause direct conflict in requirements. Second, proposed 98.233(e)(1) indicates simulation inputs should "represent the operating conditions," not represent maximum emissions, which similarly could conflict with compliance programs. Assuming worst-case conditions is required to determine a maximum potential case, which does not reflect actual operations and does not further the EPA's goal of accurately determining emissions. Additionally, because EPA allows for multiple simulations to cover the reporting period, the term "annual" should be removed.

To address these issues, GPA suggests the following changes be made to the proposed regulatory text:

98.233(e)(4) When emissions from dehydrator(s) are calculated using Calculation Method 1 or 2, calculate ~~maximum potential annual~~ vented emissions as specified in paragraph (e)(1) or (2) of this section, and calculate an average hourly vented emissions rate by dividing the ~~maximum potential annual~~ calculated vented emissions by the number of hours that the dehydrator was in operation.

Footnote:

[89] *Id*. at 50,389-90.

Response 1: See Section III.G of the preamble to the final rule for the EPA's response to this comment.

Commenter: GPA Midstream Association
Comment Number: EPA-HQ-OAR-2023-0234-0299
Page(s): 36

Comment 2: Technical corrections

Proposed 98.233(e)(4) (*"Emissions vented directly to atmosphere from dehydrators routed to a vapor recovery system, flare, or regenerator firebox/fire tubes "*) directs the reporter to calculate only those emissions directly vented to the atmosphere.[91] The introduction paragraph 98.233(e), however, implies that uncontrolled emissions are calculated and then adjusted downward to account for control. As a result, GPA suggests that the following correction be made to proposed 98.233(e):

98.233(e) …If emissions from dehydrator vents are routed to a vapor recovery system, you must calculate ~~adjust~~ the emissions ~~downward~~ according to paragraph (e)(4) of this section.

Footnote:

[91] Proposed 40 C.F.R. § 98.233(e)(4) (*"If the dehydrator(s) has a vapor recovery system, routes emissions to a flare, or routes emissions to a regenerator firebox/fire tubes and you use Calculation Method 1 or Calculation Method 2 in paragraph (e)(1) or (2) of this section, calculate annual emissions vented directly to atmosphere from the dehydrator(s) during periods of time when emissions were not routed to the vapor recovery system, flare, or regenerator firebox/fire tubes as specified in paragraphs (e)(4)(i) and (ii) of this section. If the dehydrator(s) has a vapor recovery system or routes emissions to a flare and you use Calculation Method 3 in paragraph (e)(3) of this section, calculate annual emissions vented directly to atmosphere from the dehydrator(s) during periods of time when emissions were not routed to the vapor recovery system or flare as specified in paragraph (e)(4)(iii) of this section"*) (emphases added).

Response 2: See Section III.G of the preamble to the final rule for the EPA's response to this comment.

Commenter: GPA Midstream Association
Comment Number: EPA-HQ-OAR-2023-0234-0299
Page(s): 105

Comment 3: Appendix A

Table of changes GPA supports as proposed.

Subpart	Citation	Change
…		
A	98.6	Clarify dehydrator vapor recovery does not include fire-box/fire tubes

Response 3: The EPA acknowledges the commenter's support of the proposed revisions. The EPA is finalizing this amendment as proposed.

8.3 Calculation Method 1 for Glycol Dehydrators

Commenter: GPA Midstream Association
Comment Number: EPA-HQ-OAR-2023-0234-0299
Page(s): 33-34

Commenter: American Petroleum Institute et al. (Part 1 of 2)
Comment Number: EPA-HQ-OAR-2023-0234-0402
Page(s): 24-25

Comment 1: Commenter 0299: **EPA must revise requirements for simulation input parameter measurements.**

For large glycol dehydrators, EPA is proposing to require that certain input parameters are based on actual measurements at the unit level to improve the accuracy of the reported emissions for these sources. Some of the items proposed to be based on actual measurements are not reasonable, as described below.

Feed natural gas flow rate: It is common for booster stations to have measurement only on the discharge gas. Measurement of gas coming in is not direct and would be based on wellhead volumes, which are difficult data to maintain and collect because wells come on and off. EPA should clarify this measurement can be based on facility discharge meters or wellhead meters. Otherwise, reporters may be forced by this rule to install inlet gas metering, which would be enormously expensive and would take years to install, likely involving facility shutdowns to do so and provide little additional precision in emission reporting. GPA suggests the following change to the proposed regulatory text:

98.233(e)(1)(i) Feed natural gas flow rate (~~must be measured~~ based on measured data).

Feed natural gas water content: This is not typically measured and is instead calculated by the process simulation based on contactor temperature and pressure with an assumption of saturated gas, which is a technically sound assumption. EPA should remove this measurement requirement. GPA suggests the following change to the proposed regulatory text:

98.233(e)(1)(ii) Feed natural gas water content ~~(must be measured)~~.

Wet natural gas composition: EPA proposes that reporters must use the simulation results used from other compliance programs. However, not all compliance programs require annual composition analysis. As such, EPA needs to clarify whether reporters are compelled to use the simulation(s) from other compliance programs (which may not be utilizing a gas analysis pulled during the reporting year) or if reporters can (or must) run a new simulation with an analysis pulled during the reporting year.

Commenter 0402: Dehydrators

Proposed Measurement Data

The proposed measurement requirements are burdensome and will not increase the accuracy of the emissions estimates; therefore, engineering estimates for parameters should be allowed.

EPA is proposing to require direct measurement of some parameters for large dehydrators. Specifically, EPA is proposing to require direct measurement of the feed natural gas flow rate, feed natural gas water content, and wet natural gas temperature and pressure at the absorber inlet. The Industry Trades do not believe that direct measurement of these parameters is appropriate nor that it would result in more accurately reported emissions. Sampling the feed natural gas water content, gas temperature and pressure will provide an instantaneous snapshot view of the operational conditions of a unit that operates year-round, and in potentially varying operating conditions, during which these parameters may shift.

In some instances, facilities are not equipped with a meter upstream of the dehydration unit; instead, the gas is measured at the outlet of the facility. As a result, collecting direct measurement of feed natural gas flowrate will require extensive modifications without increasing the quality of the reported data. Dehydrator emissions are not directly proportional to natural gas throughput; in other words, the inlet gas rate to the dehydrator alone does not correlate with dehydrator emissions. Instead, glycol recirculation pump rate, configuration (e.g., flash tank separator, stripping gas) and operating pressures do impact emissions, and are known by operations in order to maintain optimum operating conditions. Requiring operators to install, calibrate and maintain meters at the inlet to the dehydrators would be costly while not addressing the accuracy of the elements that do meaningfully impact actual emissions. Therefore, the

Industry Trades request that engineering estimates of the parameters used in the simulation software continue to be included as an option, especially considering the parameters represent annual averages.

Response 1: See Section III.G of the preamble to the final rule for the EPA's response to this comment.

Commenter: Range Resources Corporation
Comment Number: EPA-HQ-OAR-2023-0234-0397
Page(s): 11

Comment 2: Dehydrator emissions simulations should be based on one set of parameters regardless of whether simulations are conducted periodically as long as operating conditions remain the same.

EPA needs to clarify the measurement frequency of model input parameters for dehydrators. Under proposed 40 C.F.R. § 98.233(e), operators are to use software to simulate emissions from their dehydrators, incorporating parameters based on engineering estimates, process knowledge, best available data and, if necessary, by adjusting those parameters to represent the operating conditions over the period covered by the simulation. See 88 Fed. Reg. at 50319. Where a parameter must be measured, the operator must collect measurements reflective of representative operating conditions for the time period covered by the simulation. Specifically, operators are permitted to "[d]etermine the number of simulations and associated time period such that the simulations cover the entire reporting year (i.e., if you calculate emissions using one simulation, use representative parameters for the operating conditions over the calendar year; if you use periodic simulations to cover the calendar year, use parameters for the operating conditions over each corresponding appropriate portion of the calendar year)." 88 Fed. Reg. at 50389 (to be codified at 40 C.F.R. § 98.233(e)(1)).

Under the Proposed Rule, an operator can conduct one simulation on an annual basis using one set of parameters collected by the operator. Additionally, an operator may conduct periodic simulations. Conducting periodic simulations assists an operator in ensuring that it fully complies with the regulations in a timely manner that allows for any potential errors to be addressed in subsequent simulations. However, EPA seems to be proposing a disincentive to these periodic simulations by requiring an operator to perform field measurements to establish the parameters for the simulation every time that operator performs a simulation. In other words, it would be much more cost effective to perform a simulation once a year, rather than periodically, even though periodic simulations would result in more accurate and timely information. EPA should clarify in the final rule that, even if an operator performs periodic simulations, the operator only needs to collect the parameters incorporated into that simulation once. EPA also might include an exception to that clarification where an operator has reason to know that certain parameters have changed since the last simulation, in which case the operator could be obligated to recollect only those parameters that have changed.

Response 2: The EPA acknowledges the commenter's concern. The proposed requirements to measure certain inputs for Calculation Methods 1 and 2 were not prescriptive in the manner suggested by commenter. The EPA specified in 40 CFR 98.233(e) that if an applicable parameter must be measured, the reporter must "collect measurements reflective of representative operating conditions over the time period covered by the simulation."

Regarding the frequency of measurement, as indicated in the preamble to the 2023 Subpart W Proposal, we proposed that reporters would collect measurements reflective of representative operating conditions over the time period covered by the simulation. In addition, we proposed that the parameters that must be used to characterize emissions should reflect operating conditions over the time period covered by the simulation rather than just over the calendar year. Under this proposed change, reporters could continue to run the simulation once per year with parameters that are determined to be representative of operating conditions over the entire year. Alternatively, reporters would be allowed to conduct periodic simulation runs to cover portions of the calendar year, as long as the entire calendar year is covered. The same measurement may be used in simulations covering different portions of the calendar year if the measurement is reflective of operating conditions over the time period of the simulation for which it is used. The reporter would then sum the results at the end of the year to determine annual emissions. In that case, the parameters for each simulation run would be determined for the operating conditions over each corresponding portion of the calendar year.

Requirements for measurement frequency for 40 CFR 98.233(e)(1)(i) through (xi) are being finalized as proposed; for these input parameters, the measurements may be taken once per year where parameters are determined to be representative of operating conditions over the entire year, or the measurements may be taken multiple times per year, where the measurements are reflective of representative operating conditions over shorter time periods. However, given the significant burden noted by commenters, the EPA is finalizing a reduced measurement frequency schedule; see Section III.G of the preamble to the final rule for more information.

Commenter: GPA Midstream Association
Comment Number: EPA-HQ-OAR-2023-0234-0299
Page(s): 34

Comment 3: In the preamble, EPA proposes that Calculation Method 1 (process simulations) must be used if that method is otherwise used for environmental compliance or reporting purposes, "including but not limited to compliance with Federal or state regulations, air permit requirements, annual inventory reporting, or *internal review*."[87]

Although GPA understands the intent of this concept (see additional consideration in Comment 37 below), it should be limited to compliance programs only, and not apply to "internal review." Simulations run for purposes other than compliance may not meet the GHGRP's goal of estimating emissions as accurately as possible. In addition to accurately calculating emissions, process simulators are used for a multitude of other reasons internally in industry. These uses can range from exploring possible engineering adjustments or adding additional equipment for various processes that may never be implemented to various other "what-if" scenarios at the facility (for example worst-case safety scenarios for relief valve sizing), which do not apply to annual emissions estimations. Even if the models are representative, it will be extremely difficult to ensure that any process simulation conducted for any “internal” purpose is included in the GHGRP.

Additionally, while the preamble language is clear, the proposed regulatory text language is not. The regulatory text language should be strengthened to convey EPA’s intent as expressed in the preamble, as GPA suggests below in Comment 37, and similarly in Comment 51 as applied to atmospheric storage tanks.

Footnote:

[87] *Id*. at 50,319 (emphasis added).

Response 3: See Section III.G of the preamble to the final rule for the EPA’s response to this comment.

Commenter: GPA Midstream Association
Comment Number: EPA-HQ-OAR-2023-0234-0299
Page(s): 34-35

Comment 4: Clarification is needed in using simulations for compliance and reporting under Subpart W.

As noted in the previous comment, EPA proposes that Calculation Method 1 (process simulations) must be used if that method is otherwise used for environmental compliance or reporting purposes, and further states reporters “must use the results of the model to determine annual mass emissions.”

While GPA understands the desire for consistent reporting across programs where possible, this is unclear on multiple fronts and may add unexpected complications. First, “the model” is not defined and could be interpreted as the exact same model with the exact same input parameters as any of the listed regulations, requirements, or reports. Reporting expectations under Subpart W may be different than these other purposes. Especially in terms of “air permit requirements”[88] mentioned in the preamble, it is ambiguous if this requirement would necessitate using input parameters from the initial air permit application, which would almost certainly not accurately reflect the current year’s operations. GPA assumes this was not the intent, but the language is vague. If this requirement is included in the final rule, EPA should clarify that the appropriate input parameters specified in 98.233(e)(1)(i) through (xi) should be applied to any models used for reporting with Method 1. GPA suggests replacing “the model” with “this method” for clarity, as shown below.

Additionally, this requirement could unduly restrict reporters to a single software program to perform calculations. If this is intended for application on a per-reporting-year basis, this may not be as burdensome, as it is reasonable that a reporter will likely have access to a particular software for a given reporting year. However, with the current language, this could be interpreted as requiring the same model in the same software over many years. If a reporter acquires a new software program that meets the requirements of 98.233(e)(1), they should be allowed to use it for Method 1 calculations, even if they used a different software program to calculate emissions in the past or for other purposes. Furthermore, requirement might be unworkable in the case of a change in ownership. This is because when assets are sold, simulation files may not be transferred to the owner, or the buyer may not have access to the same software program used by the seller. In such cases, requiring the same software or the same model may be impossible.

GPA requests that EPA reconsider the necessity of this requirement given these complexities and potential confusion around implementation. However, if this provision is included in the final rule, GPA suggests the following regulatory text combining these clarity concerns with those from Comment 36 above:

98.233(e) If you are required to or elect to use the method in paragraph (e)(1) of this section for compliance with federal or state regulations, air permit requirements, or annual inventory reporting, you must use the results of ~~the model~~ this method to determine annual mass emissions.

Footnote:

[88] *Id*. at 50,319 (emphasis added).

Response 4: See Section III.G of the preamble to the final rule for the EPA's response to this comment.

Commenter: GPA Midstream Association
Comment Number: EPA-HQ-OAR-2023-0234-0299
Page(s): 33

Comment 5: EPA must clarify reporting requirements for simulation inputs.

For glycol dehydrators that use Calculation Method 1 (process simulation), EPA says, "If paragraph (e)(1)(i) through (xi) of this section indicates that an applicable parameter must be measured, collect measurements reflective of representative operating conditions for the time period covered by the simulation" [98.233(e)(1)]. GPA supports this proposed language.

In the reporting section, however, EPA instructs reporters to report this data as "annual average." But "annual average" implies a different standard than "measurements reflective of representative operating conditions." GPA assumes EPA's intent is that "annual average" is supposed to capture the case of more than one simulation covering the reporting period, and the data reported here is to be the average of the inputs to each simulation. If this is the case, however, EPA must clarify this interpretation. GPA also notes that the term "annual average" can be confusing if the glycol dehydrator is not operating for a portion of the year.

Response 5: See Section III.G of the preamble to the final rule for the EPA's response to this comment.

Commenter: Texas Commission on Environmental Quality (TCEQ)
Comment Number: EPA-HQ-OAR-2023-0234- 0349
Page(s): 3-4

Comment 6: TCEQ encourages EPA to allow flexibility regarding calculation of emissions using measured operating conditions, design parameters, or air permit PTE basis for applicable facilities.

The proposal seeks to revise existing calculation methodology to include the use of certain empirical data obtained at the facility for glycol dehydrators under §98.233(e)(1) for determining source emissions with modeling software such as GRI-GLYCalcTM. The proposal also acknowledges that calculated emissions for dehydrators in some cases may be based on "worst-case scenarios" in lieu of actual operating conditions. (Sec. II.B.) The use of worst-case scenarios to determine facility emissions is a common approach in the determination of PTE for air permitting processes in Texas. Although the GHGRP is a reporting rule, the calculation methodologies included within can be used when establishing representations for determining authorized PTE emission rates in various air permitting mechanisms for subject facilities.

As stated in the comments provided by TCEQ regarding EPA's proposal for New Source Performance Standards and Emission Guidelines to reduce GHG emissions (in the form of methane emissions) and VOC emissions from both new and existing sources in the oil and natural gas industry (Methane Rule Proposal), TCEQ does not currently have a minor source permitting pathway for methane (or other GHG) emissions to be included in a permit authorization. Specifically, 30 Texas Administrative Code (TAC) Chapters 106 and 116 do not allow GHGs to be permitted in Texas for minor sources. The State of Texas statutes governing TCEQ's air permitting program, specifically Texas Health and Safety Code, §382.05102, only allow TCEQ to authorize GHG emissions to the extent that authorization is required under federal law. However, the GHGRP is sometimes used by existing minor GHG sites to estimate fugitive emissions to determine PSD applicability for GHGs2. The rule, 40 CFR Part 98, may also be referenced in permit conditions for continuous compliance demonstration for sites that are subject to GHG permitting as a result of triggering PSD for GHGs.

The proposal indicates that EPA's intent is to allow applicable sources that conduct modeling of emission representations for environmental compliance or reporting purposes, such as compliance with Federal or state regulations, air permit requirements, annual inventory reporting, or internal review, to also use those results for reporting under the GHGRP. (Sec. III.G.1.) Additionally, EPA's memo which approved the use of ProMax software for compliance with 40 CFR Part 63, Subpart HH indicates that input parameters "must be representative of the actual operating conditions" and does not specify that any parameters must be measured when using "worst case" representations3.

…

EPA should allow for the flexibility to use long established methodologies through these various means for the GHGRP for the purpose of consistency and to minimize the need to conduct multiple sets of emissions calculations for the same facility.

Footnotes:

2 https://www.tceq.texas.gov/assets/public/permitting/air/Guidance/NewSourceReview/fugitive-guidance.pdf

3 https://www.epa.gov/system/files/documents/2022-03/ravichandran-bre-promax-alt-final_147_signed.pdf

Response 6: The EPA acknowledges the commenter's concern. The EPA has noted that, in some cases, the data used to calculate emissions are not based on actual operating conditions but instead based on "worst case scenarios" or other estimates. The EPA asserts that the accuracy of reported emissions is improved by using actual operating conditions as measured at the unit. The EPA is finalizing the requirement as proposed and maintains the requirement that certain input parameters are based on actual measurements at the unit, reflective of representative operating conditions.

Commenter: GPA Midstream Association
Comment Number: EPA-HQ-OAR-2023-0234-0299
Page(s): 36

Comment 7: EPA should not require separate reporting of flash tanks and still vent emissions.

EPA is proposing under 98.236(e) to require separate reporting of emissions for a modeled glycol dehydrator's still vent and flash tank vent. EPA claims the proposed data elements are included in the output files from the modeling software used for glycol dehydrators, and therefore, this provision is not expected to be difficult for reporters to implement.[90]

EPA is incorrect that this results in minimal additional burden, however, because GLYCalc is still widely used (and is often required to be used by permit), and EPA proposes that reporters are required to use simulation results from other compliance programs. Unfortunately, GLYCalc does not output data in a useful format for automation, so the results have to be manually transferred from GLYCalc to the system or spreadsheet the reporter is using. This requirement therefore adds significant additional reporting burden resulting from the manual transfer of both flash tank vent emissions and still vent emissions.

…

Appendix A

Table of changes GPA supports as proposed.

Subpart	Citation	Change
…		
A	98.6	Clarify dehydrator vents include still and flash

Footnote:

[90] Id. at 50,320

Response 7: The EPA is not finalizing the requirement to require reporting of simulation results from other compliance programs. EPA is instead requiring that if a facility performs emission modelling for other program requirements that meet the requirements of 40 CFR 98.233(e)(1), they must also use 40 CFR 98.233(e)(1) for reporting under subpart W. See Section III.G of the preamble to the final rule. The EPA disagrees with the commenter's assertions that the inclusion of these data elements add significant reporting burden. The proposed data elements are included in the output files and the requirement is expected to improve the quality of the data collected. The EPA is finalizing these amendments as proposed.

Commenter: GPA Midstream Association
Comment Number: EPA-HQ-OAR-2023-0234-0299
Page(s): 17

Comment 8: The following is a list of substantive proposed changes that GPA expressly supports.

…

- Not finalizing or reproposing additional reporting elements for glycol dehydrators that were proposed in the 2022 Proposed Rule;
- Including ProMax as an example software program for calculating emissions from glycol units [98.233(e)]

Response 8: The EPA acknowledges the commenter's support of the proposed revisions. The EPA is finalizing these amendments as proposed.

Commenter: GPA Midstream Association
Comment Number: EPA-HQ-OAR-2023-0234-0299
Page(s): 81

Comment 9: Proposed Change: EPA is proposing to collect many new reporting elements for glycol dehydrators: flash tank control technique, regen still vent control technique, flash tank vent gas flow rate, regenerator still vent gas flow rate, concentrations of CH_4 and CO_2 in flash tank vent gas, concentrations of CH_4 and CO_2 in regenerator still vent gas, type of stripping gas used, and flow rate of stripping gas [98.236(e)].

Comment: EPA should strike these new requirements. GPA originally asked EPA to develop an emission factor for dehydrators with throughputs greater than 0.4 MMscf per day but less than 3 MMscf per day. We requested an emission factor because this group of glycol dehydrators does not generally have an obligation to run an annual emission simulation other than for compliance with the GHGRP (dehydrators with throughput greater than 3 MMscf per day run an annual emission simulation to comply with NESHSAP HH), and running these additional simulations solely for GHGRP compliance was time consuming and burdensome. However, EPA recently approved use of BRE Promax simulations (which accommodates bulk runs and provides data exports in GHGRP "friendly" format) for NESHAP HH compliance. This change streamlines running dehydrator simulations for the GHGRP, and GPA members can more easily include these small dehydrators into annual process simulations. As such, GPA is no longer requesting an emission factor for these small dehydrators, and EPA's additional data requests are unnecessary. More importantly, all of these additional reporting requirements add burden and complexity, and EPA does not need to understand the precise details of dehydrators (an already well-regulated emission source) to collect and validate the reported greenhouse gas emissions.

Response 9: This comment was included as an attachment to the commenter's letter, but it is a comment on the 2022 GHGRP Proposal, which are not relevant to this final rule. The commenter also submitted comments on the 2023 Subpart W Proposal related to this source, included earlier in this section.

8.4 Desiccant Dehydrators

Commenter: GPA Midstream Association
Comment Number: EPA-HQ-OAR-2023-0234-0299
Page(s): 31, 82, 105

Comment 1: EPA should eliminate desiccant dehydrators as a source category, as EPA proposed in the June 2022 Proposal.

As EPA previously acknowledged in its June 2022 Subpart W proposal,80 desiccant dehydrators are a very small source of GHG emissions under the annual GHGRP. Desiccant dehydrators have negligible quantitative impact to the methane waste fee. EPA's decision in this proposal to "resurrect" desiccant dehydrators as an emissions source, and to require the reporting of 18 separate data elements for this source category, is unjustified.[81] EPA claims that the proposed retention of the source category and addition of the 18 new reporting elements is justified because "CAA section 136(h) directs the EPA to ensure that reporting under subpart W reflects total CH4 emissions, and we are no longer proposing to remove this source."[82] EPA's proposal collects minimal, if any, additional CH4 emission data versus the current rule and instead collects dissections of data for emissions that EPA already characterized as being very small. Although EPA proposes to expand the source category to include molecular sieve dehydrators (which we also do not think is justified; see Comment 31 below), EPA acknowledged in the 2022 proposal that the small emissions reported under this source category already appear to include emissions from molecular sieve dehydrators.[83] GPA encourages EPA to act on its previous June 2022 proposal to remove desiccant dehydrators from reporting, allowing petroleum and natural gas companies to focus their attention on other more significant sources.

…

RFC: EPA requests comment on advantages and disadvantages of an alternative to require reporting on devices with desiccant that absorb water under a desiccant dehydrator emission source.

> **Comment**: The distinction between these two equipment types ("devices with desiccant that absorb water" vs "devices containing materials that absorb water") is very subtle and not generally understood by reporters. A Google search will show that molecular sieve dehydrators are often called desiccant dehydrators. EPA should not retain a reporting source for "devices with desiccant that absorb water." As noted by EPA, this is a small emission source, and retaining this source will only result in continued confusion by reporters on which non-glycol dehydrators to report or not report.

…

Appendix A

Table of changes GPA supports as proposed.

Subpart	Citation	Change
…		
A	98.6	Update dehydrator definition to remove desiccant; remove definition of "desiccant"

Footnotes:

80 87 Fed. Reg. at 36,920, 36,986 (June 21, 2022) ("Based on the data reported to date, the emissions from these sources are less than 0.1 percent of total reported emissions from dehydrator vents (in RY2020, desiccant dehydrators contributed 760 mtCO2e of the total 3.35 million mtCO2e from all dehydrator vent emissions.")).

81 88 Fed. Reg. at 50,321

82 Id.

83 87 Fed. Reg. at 36,986 ("In addition, it appears that a significant percentage of the emissions reported to date may be from molecular sieve dehydrators….").

Response 1: Section III.G.6 of the preamble to the 2023 Subpart W Proposal explained why the EPA did not propose to remove desiccant dehydrators as a source type, including the CAA section 136(h) requirement to ensure that reporting under subpart W accurately reflects total CH_4

emissions. As a result, we also did not propose to remove the definition of "desiccant" or to remove desiccant from the definition of "dehydrator" in the 2023 Subpart W Proposal. We are finalizing the reporting requirements for desiccant dehydrators in 40 CFR 98.236(e) largely as proposed, with clarifying corrections and updates as described in section III.G.5 of the preamble to the final rule.

We disagree with the commenter's assertion that reporters will be confused about which non-glycol dehydrators to report or not report. We recognize that the definitions of "dehydrator" and "desiccant" in existing 40 CFR 98.6 are confusing. Thus, we proposed and are finalizing as proposed, several changes to clarify these definitions. For example, the final definition of "desiccant" indicates that molecular sieves are a type of desiccant. See Section III.G.6 of the preamble to the proposed rule and Section III.G.5 of the preamble to the final rule for additional information regarding the changes to these definitions. With these changes, we believe the final rule clearly describes the types of dehydrators that are subject to the desiccant dehydrator emission calculation requirements in 40 CFR 98.233(e)(3) of the final rule. Additionally, 40 CFR 98.233(e)(3) of both the existing rule and the final rule clearly indicate that desiccant dehydrator emissions calculated according to 40 CFR 98.233(e)(3) are not to be calculated separately using the method for blowdown vent stacks in 40 CFR 98.233(i). Similarly, 40 CFR 98.233(i) of both the existing rule and the final rule clearly state that the blowdown vent stack emission calculation methods in 40 CFR 98.233(i) do not apply to desiccant dehydrator blowdown venting before reloading.

Commenter: GPA Midstream Association
Comment Number: EPA-HQ-OAR-2023-0234-0299
Page(s): 31-32

Commenter: American Petroleum Institute et al. (Part 1 of 2)
Comment Number: EPA-HQ-OAR-2023-0234-0402
Page(s): 24

Comment 2: Commenter 0299: **If EPA retains desiccant dehydrators as a source category, it should not include molecular sieve dehydrators in that source category.**

EPA proposes to add "molecular sieves" to the definition of "Desiccant" in § 98.6 and require reporting on these sources.[84] GPA opposes this for the reasons below.

As BP America, Inc. explained in its prior comment to EPA (Comment Number EPA-HQ-OAR-2009-0923-1305-12), molecular sieves are solid-bed dehydrators that are usually located at natural gas processing plants to remove water from natural gas. In these dehydrator vessels, wet natural gas is passed through a large bed of solid adsorbent media commonly comprised of zeolites (microporous aluminosilicate materials). As the wet gas contacts the surface of the particles of desiccant material, water is adsorbed onto the surface of these particles. Passing through the entire desiccant bed, almost all water is adsorbed onto the desiccant material, leaving the dry natural gas to exit the contactor.

Natural gas processing plants typically have two molecular sieve vessels in parallel so that one vessel can be in service mode, and the other in regeneration mode (in preparation for switching beds). When the adsorbent media in one molecular vessel is water-loaded, it is typically regenerated by passing hot natural gas through the adsorbent media to dry it and prepare it for subsequent use. The hot natural gas is recycled back to the plant inlet; no gas is released to the atmosphere.

GPA further notes that molecular sieve beds have a long life with desiccant media changeouts typically occurring every 5 to 10 years depending upon application. During these changeouts, natural gas in the molecular sieve vessel is typically blown down to flare or other control devices prior to opening the top hatches. This greatly reduces any type of GHG emissions. Any emissions that do result would be reported either under the control device or as a blowdown since these vessels tend to be larger than 50 cubic feet physical volume. If any of these vessels are less than 50 cubic feet physical volume, their small size and infrequent emissions further justifies excluding them from the GHGRP.

Importantly, in its response to BP America's comment cited above, EPA made the following determination: "With regard to the term desiccant dehydrator, EPA intended that only desiccant dehydrators using a hydrophilic salt material are included under subpart W, and thus, molecular sieve dehydration is not included."[85]

GPA fully supports this previous determination by EPA and suggests that it remain in effect since greenhouse gas emissions from molecular sieves continue to be minimal and can be reported under the blowdown emission source category.

Footnotes:

[84] 88 Fed. Reg. at 50,322.

[85] EPA 2010 Response to Comments Document at 1727.

Commenter 0402: Dehydrators

Desiccant Dehydrators

Molecular sieve dehydrator emissions are expected to be extremely infrequent (i.e., once every 5-10 years), and should be categorized as blowdown emissions.

EPA is also proposing to add molecular sieve units to the desiccant dehydrator category. Molecular sieves are closed systems with no emissions to the atmosphere, except when the desiccant must be changed which is infrequent; typically, only once every 5-10 years. Furthermore, emissions from opening a molecular sieve dehydrator would be an activity considered by most operators to be a blowdown event – and should be accounted for under the blowdown category rather than under dehydrators. Categorizing molecular sieves under the desiccant dehydrator category not only raises confusion but could potentially result in double counting of the blowdown emissions.

Response 2: The EPA is finalizing revisions to the definition of "dehydrator" and desiccant in 40 CFR 98.6 as proposed to include "molecular sieves." As noted in Section II of the preamble to the 2023 Subpart W Proposal, the EPA developed the current subpart W monitoring and reporting requirements to use the most appropriate monitoring and calculation methods, considering both the accuracy of the emissions calculated by the proposed method and the size of the emission source based on the methods and data available at the time of the applicable rule promulgation. For this proposal, the EPA re-evaluated the existing methodologies to determine if they are likely to accurately reflect emissions at an individual facility and whether refinements to the applicability and existing emissions calculation methodologies were needed. In this case, reporters may have been reporting emissions from the opening of a molecular sieve dehydrator as blowdown emissions, but only if the physical volume is greater than 50 cubic feet. For the openings that are reported, they are likely categorized as "other" event types, so the quantity of emissions from molecular sieve dehydrators is not clear. The EPA is finalizing the clarification that molecular sieves dehydrators are desiccant dehydrators to better characterize emissions from this industry and ensure that reporting under subpart W accurately reflects total CH_4 emissions.

Commenter: GPA Midstream Association
Comment Number: EPA-HQ-OAR-2023-0234-0299
Page(s): 32-33

Comment 3: If EPA retains the desiccant dehydrator source category, the Agency needs to change the reporting elements.

…

GPA also notes that the desiccant reporting section makes frequent reference to routing emissions to "regenerator firebox/fire tubes."[86] This appears to be lifted from the glycol dehydrator section and may be a mistake by EPA. We are not aware of desiccant dehydrators (molecular sieve or otherwise) with this configuration. It might be more appropriate to reference non-flare combustion calculations.

…

Technical corrections

Proposed 98.236(e)(3)(vii)(B) should be changed as follows because 98.236(e)(3) specifies reporting requirements for desiccant dehydrators, not glycol dehydrators:

98.236(e)(3)(vii)(B) Total volume of gas ~~from the flash tank~~ to a regenerator firebox/fire tubes, in standard cubic feet

Footnote:

[86] See, e.g., 88 Fed. Reg. at 50,319-21.

Response 3: See Section III.G.5 of the preamble to the final rule for the EPA's response to this comment.

Commenter: GPA Midstream Association
Comment Number: EPA-HQ-OAR-2023-0234-0299
Page(s): 32

Comment 4: If EPA retains the desiccant dehydrator source category, the Agency needs to change the reporting elements.

The proposed reporting structure for the desiccant dehydrator source category adds reporting burden in two ways: (1) requiring reporting only on "opened" dehydrators; and (2) aggregating data across the facility or site only on "opened" dehydrators. While the current rule requires reporting on an aggregated basis, it does not have all the data dissections that EPA proposes here, and thus the current aggregation is not difficult. All the data are collected and calculated on a per-equipment basis, and as such, it is much more straightforward to report on a per-equipment basis than as aggregates. For reporters that use databases to handle the massive calculation and reporting burden of Subpart W, it is easier to report per-equipment regardless of whether the vessel was opened or not. If EPA retains this source category (which for the reasons discussed in Comment 31 above, we think it should not), EPA should restructure the reporting section to require only the reporting of a simple list of each desiccant dehydrator, what type it is, whether it was controlled, how many times it was opened (including zero), volume, and emissions.

…

Response 4: Although the EPA appreciates the feedback from this commenter, the EPA did not propose and is not finalizing requirements to report emissions for desiccant dehydrators by individual dehydrator. The EPA is finalizing as proposed the disaggregation of emissions reporting to the well-pad site or gathering and boosting site level, as applicable, and the burden estimate for this rulemaking reflects that level of aggregation.

Commenter: GPA Midstream Association
Comment Number: EPA-HQ-OAR-2023-0234-0299
Page(s): 16

Comment 5: EPA must limit reporting elements only to those data required to verify emissions.

Reporting under this rule is an enormous annual effort. GPA recognizes the value in reporting GHG emissions and the need for certain information to verify those emissions. In many places, however, EPA adds unnecessary math in a reporting element. For example, 98.236(e)(3)(ii)(A) askes for "T*he total number of opened desiccant dehydrators* [98.236(e)(3)(ii)(A)]." This is <u>not</u> an input into an equation. This requirement seems to exist solely to see if reporters can add two other reporting elements together ("*The number of opened desiccant dehydrators that used deliquescing desiccant* [98.236(e)(3)(ii)(B)]" and "*The number of opened desiccant dehydrators that used regenerative desiccant*" [98.233(e)(3)(ii)(C)]). EPA should eliminate these extraneous reporting elements that are duplicative of other data it is already collecting and that simply add steps to reporters without any additional information to be gained.

Response 5: See Section III.G.5 of the preamble to the final rule for the EPA's response to these comments.

Commenter: GPA Midstream Association
Comment Number: EPA-HQ-OAR-2023-0234-0299
Page(s): 32

Comment 6: If EPA retains the desiccant dehydrator source category, the Agency needs to change the reporting elements.

…

Further, EPA should be aware that a molecular sieve dehydrator may have multiple control routing (e.g., vapor recovery followed by flare). Thus, the "counts" of dehydrators by control technique may not align with counts of total desiccant dehydrators.

…

Response 6: The EPA was aware at the time of proposal that a few desiccant dehydrators have more than one control and thus will be included in more than one count, such as both the "total number of dehydrators at the facility that routed to a vapor recovery system" and the "total number of dehydrators routed to a flare." The counts of desiccant dehydrators routed to controls such as vapor recovery and flares provide an indication of the prevalence of the types of controls for this source type. It is also expected to help with verification of reported emissions from flares or non-flare combustion units in some situations.

Commenter: American Petroleum Institute et al. (Part 1 of 2)
Comment Number: EPA-HQ-OAR-2023-0234-0402
Page(s): 24

Comment 7: Dehydrators

Desiccant Dehydrators

Reporting requirements for desiccant dehydrators should be streamlined for a source type that is not a significant contributor to GHG emissions.

In the late-2022 proposed changes, EPA appeared to be moving away from requiring detailed information reported for desiccant dehydrators; however, in the current proposal (August 1st, 2023), EPA is requiring more reporting details. Emissions from desiccant dehydrators are periodic and can be very infrequent in nature. The Industry Trades support reducing the overall reporting requirements on these units as they are not significant contributors to annual GHG emissions.

Response 7: The EPA has reviewed the existing and proposed data elements and determined that the data elements finalized in this rulemaking are useful for the verification of reported data and for improving our characterization of the emissions sources. See Section III.G of the preamble to the final rule for the EPA's summary of final reporting amendments.

9 Liquids Unloading

Commenter: EnerVest Operating, LLC
Comment Number: EPA-HQ-OAR-2023-0234-0229
Page(s): 3-4

Commenter: Endeavor Energy Resources, L.P.
Comment Number: EPA-HQ-OAR-2023-0234-0381
Page(s): 18

Commenter: Arkansas Independent Producers and Royalty Owners (AIPRO)
Comment Number: EPA-HQ-OAR-2023-0234-0382
Page(s): 15

Commenter: CrownQuest Operating
Comment Number: EPA-HQ-OAR-2023-0234-0393
Page(s): 165

Commenter: Range Resources Corporation
Comment Number: EPA-HQ-OAR-2023-0234-0397
Page(s): 11-12

Commenter: Western Energy Alliance
Comment Number: EPA-HQ-OAR-2023-0234-0399
Page(s): 13

Commenter: American Petroleum Institute et al. (Part 1 of 2)
Comment Number: EPA-HQ-OAR-2023-0234-0402
Page(s): 25-26

Comment 1: Commenter 0229: Liquid Unloading Using Methods 2 & 3

- Language stated: "EPA is proposing that reporters with liquids unloadings must calculate emissions from unloadings for each well at least once every 3 consecutive calendar years or more frequently using Calculation Method 1 to ensure that the engineering equations accurately and consistently represent the quantity of emissions from unloading events."
    - It is arguably not feasible to "measure" liquid unloading for each well every three years as it would require the installation of additional separators, properly sized meters and additional burden not considered in the cost analysis. There is also no "reconciliation" language to ameliorate variances in measured vs engineering estimates. There is no language to specify a percent of acceptable error and adds ambiguity to the process.
    - The flow of the well, as unloading, would be variable and therefore difficult if not impossible to install properly sized orifice plates.
    - A method should be developed and put up for proposal (For instance, how many operators have chosen to use Option 1 and in which manner have they provided accurate data?)
    - Additionally, if emissions were measured from tanks
        - One would have to fit the thief hatch with a special apparatus for metering.

- Enardo Valves would have to be isolated to ensure gas would not leak. Enardo valves typically sit atop some as a secondary means of overpressure relief; to properly block this off requires a manlift. **It is unsafe to have personnel access via the valves by walking on tanks which would introduce the potential to fall through the roof of an unsuspected compromised tank and risk death.**
- Cost of such activities was not considered.

o We are asking for alternate means to demonstrate gas gradually released during well unloading such as a separator and mass flow meters which typically have a 1000:1 turndown ratio.

Commenter 0381: **EPA Should Reconsider the Proposed Revisions to Calculation Methods for Several Emission Sources.**

Liquids Unloading

Endeavor is generally supportive of greater direct measurement of emissions, but for liquids unloading, we urge EPA to reconsider the *requirement* that reporters use Calculation Method 1 (i.e., measured flow rates) at least once every three calendar years.[58] While we understand the appeal of using Calculation Method 1 to verify engineering estimates from other calculation methods, we believe that EPA has not fully considered the costs of requiring direct flow rate measurement; a reporter would not only need to install flow meters but also increase automation across its well sites to accommodate direct measurement, which will add additional costs. And as EPA notes, Calculation Methods 2 and 3 "rely on well-specific data, including well depth, tubing or casing diameter, and the flow line rate of gas, to calculate well-level emissions,"[59] meaning that the results are both site-specific and accurate as is. Reporters should have the flexibility to use the Calculation Method best suited for their operations, as currently provided for and proposed (including Method 1),[60] but Endeavor recommends removing the *requirement* to use Calculation Method 1 to verify the calculations from Methods 2 and 3.

Footnotes:

[58] 88 Fed. Reg. at 50,322.

[59] *Id*.

[60] *Id*. ("Therefore, the EPA is proposing to continue providing reporters the option to use Calculation Methods 2 and 3 to calculate emissions from liquids unloading.")

Commenter 0382: Well Venting for Liquids Unloading:

AIPRO opposes the proposed requirement to use Method 1 to calculate emissions from every well with liquids unloading at least once every three years. This requirement is overly burdensome and will not result in more accurate emissions estimates because adequate empirical data in the form of SCADA data and other real-time measurements is commonly available and can be used to determine more accurate vent rates using engineering calculations. As such, AIPRO suggests that EPA remove this proposed revision.

Commenter 0393: It is unclear what is meant every 3 consecutive calendar years. Testing could be done once every three consecutive calendar years.

Commenter 0397: **EPA should clarify that direct measurement of liquid unloading emissions may be used in reporting emissions in subsequent years.**

The Proposed Rule, under proposed 40 C.F.R. § 98.233(f), establishes three methods of calculating well venting for liquids unloading. See 88 Fed. Reg. at 50322-23. The rule requires direct measurement for liquid unloading utilizing Method 1 to be conducted every three years, with the option of using Methods 2 and 3—which use engineering estimates—in the years without direct measurement. EPA should ensure that the final rule allows an operator to use measurement data from Method 1 in subsequent years. EPA should allow an operator that uses direct measurement in the first year to use the data obtained from that first-year direct measurement in calculating emissions in subsequent years (i.e., years 2 and 3). This clarification would be consistent with EPA's other proposed revisions to Subpart W to allow the use of representative direct measurement as an accurate method of determining emissions.

Commenter 0399: *Liquids Unloading*

The proposal includes three options for calculating emissions from liquids unloading, one for using flow meters (Method 1) and one for engineering estimates (Methods 2 and 3), however, Methods 2 and 3 require the use of a flow meter as in Method 1 every three years to validate the emission factor used. This requirement would be needlessly burdensome and provide no additional accuracy over other, less burdensome options. Additionally, well unloading events are not always predictable and scheduled, so direct measurement may not always be available. Further, EPA should clarify that emission reporting for liquids unloading should be done on a well-by-well basis, not an hourly estimation. Liquids unloading events are rarely, if ever, uniform across an hourly time horizon, and tend to fluctuate significantly in rate. Instead, the emissions factors applied, and the requisite reporting, should be made based on each unloading event.

> **Recommendation:** EPA should remove the requirement that Method 2 and 3 calculations should be validated by direct measurement every three years, and instead allow for engineering calculations and operational data supported duration estimates.

Commenter 0402: Well Venting for Liquids Unloading

EPA should not require flow meter measurements of liquids unloading venting under Calculation Method 1 as it is technically and economically infeasible.

The proposed rule language that requires Calculation Method 1 every three years is unnecessary and burdensome and will not lead to more accurate reporting. EPA states in the preamble that this requirement will 'ensure that the engineering equations accurately and consistently represent the quantity of emissions from unloading event.' EPA must justify this additional burden and how potential differences between method results will be treated, as repeated validation of the methods will not lead to more accurate reporting. Further, EPA did not consider the Allen *et al* 2015 study that directly measured emissions from liquids unloading.[21]

Which wells will require and how often they require liquids unloading venting is not predictable or consistent. Liquids unloading or deliquification is the process of removing liquids build-up in a gas well. Not all deliquification techniques result in venting. Most wells in the US do not vent to the atmosphere. Managing well bore liquids build-up in gas wells is required to maintain production, avoid early abandonment of the wells, and maximize resource recovery. Liquids build up in the well when the velocity of the production string is not sufficient to push the liquids up the well bore. The deliquification approaches change as a well moves through its lifecycle, as shown in the figure below. Manually opening a well to atmosphere to reduce the back pressure on the liquids column results in most of the liquids unloading venting. When this is needed is variable and does not necessarily occur every 3 years.

Adding a flow meter will put back pressure on the well, restricting flow and preventing the well from unloading or making it more difficult. The purpose of liquids unloading is to relieve the back pressure on the well so that the well is able to push liquids, and a flow meter would prevent this from occurring. Anecdotal evidence from one operator that currently unloads gas wells in Colorado has trialed measurement on liquids unloading on twelve wells indicating this. The operator found results similar to the current GHGRP calculations. Additionally, the operator found that to use a meter, the gas must be routed through a knockout or other vessel that may have small piping between it and the meter. The constriction made the unloads take longer and reduced the effectiveness of the unloads. Of the twelve trial measurements, not a single well successfully unloaded itself.

….

Additionally, EPA does not require operators under NSPS OOOOb to install a flow meter for liquids unloading venting. NSPS OOOOb does not prescribe these flow meter requirements as necessary to achieve the zero-emission limit for liquids unloading, or for the recordkeeping/reporting requirements for these events, so it is unclear why this would be required under Subpart W.

Furthermore, a meter could be installed on a well that had liquids unloading venting in a previous year and never does again, or not be installed on a well that suddenly requires liquids unloading venting.

Industry should be allowed to continue to use the liquid unloading engineering estimates or other engineering process knowledge to estimate the duration and volume of emissions as measurement will not result in more accurate estimates.

Footnote:

[21] https://pubs.acs.org/doi/10.1021/es504016r.

Response 1: See Section III.H of the preamble to the final rule for the EPA's response to these comments.

Commenter: American Petroleum Institute et al. (Part 1 of 2)
Comment Number: EPA-HQ-OAR-2023-0234-0402
Page(s): 27

Comment 2: Well Venting for Liquids Unloading

Additional suggested revisions will improve the clarity of the requirements for reporters.

EPA should clarify that liquids unloading only applies to gas wells as was done in NSPS OOOOb. Oil wells typically require artificial lift to produce the liquids and do not vent gas.

Response 2: We acknowledge that the NSPS OOOOb rules refer specifically to gas wells in the context of liquids unloading. For example, the title of 40 CFR 60.5376b is "What GHG and VOC standards apply to gas well liquids unloadings operations at well affected facilities?" However, reporting under the GHGRP is intended to capture emissions from all unloadings at facilities meeting the reporting threshold. Although the commenter is correct that liquids buildup in the well bore and the unloading of those liquids typically occurs in gas wells, occasionally there are wells in oil sub-basins that require unloading. Between 2015 and 2022, reporters to the GHGRP reported around 33,000 unloading events from wells in oil sub-basins. During annual report verification, the EPA has notified some reporters that they have reported unloadings from oil sub-basins and further requested confirmation that these were actual unloading events. In their responses, reporters have asserted the data are correct. Therefore, we are not incorporating the suggested change and reporters with unloadings in oil sub-basins will continue to report those unloadings to the GHGRP.

Commenter: American Petroleum Institute et al. (Part 1 of 2)
Comment Number: EPA-HQ-OAR-2023-0234-0402
Page(s): 27

Comment 3: Well Venting for Liquids Unloading

Additional suggested revisions will improve the clarity of the requirements for reporters.

The Industry Trades support proposed revisions to add reporting requirements for liquids unloading events which vent directly to atmosphere or are routed to a control device, including whether the unloading event is automatic or manual, specific flow-line and tubing depth data, and the hours that wells are left open during unloading events. However, EPA should clarify that reporting for unloading events should only apply when the gas is vented directly to the atmosphere or routed to a control device. These additions will improve clarity for reporters and provide greater context for the reported emissions for EPA.

Response 3: See Section III.H of the preamble to the final rule for the EPA's response to these comments.

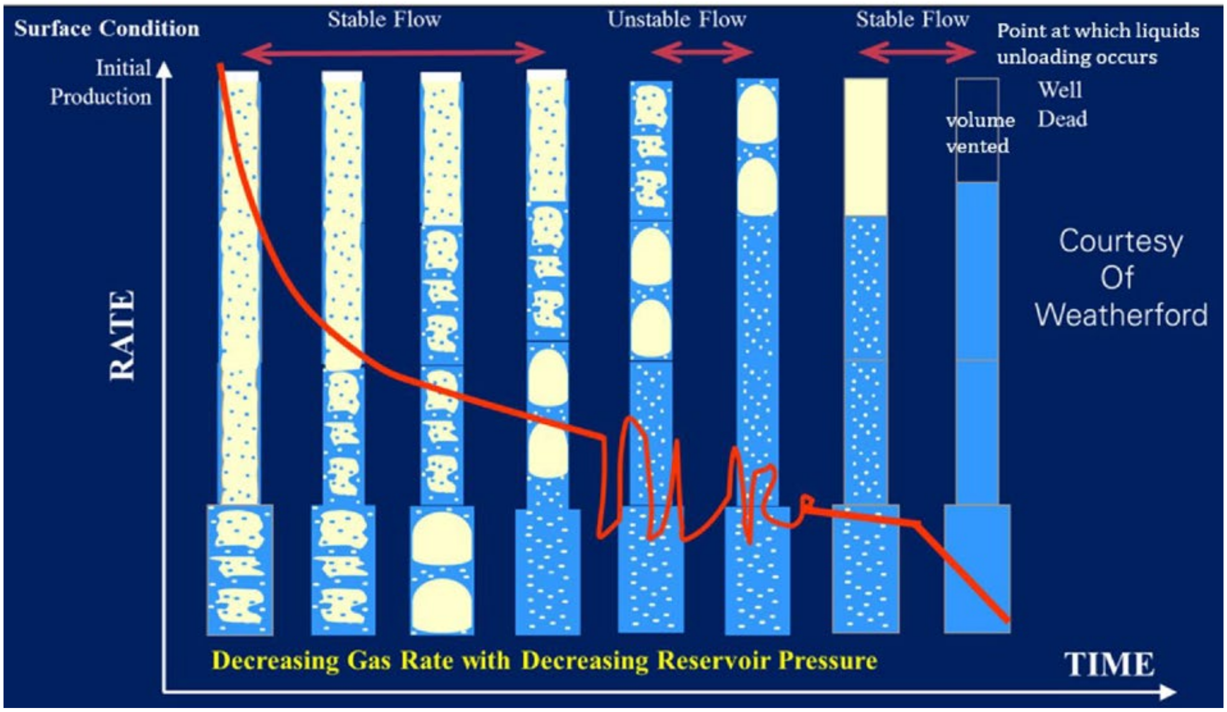
Commenter: American Petroleum Institute et al. (Part 1 of 2)
Comment Number: EPA-HQ-OAR-2023-0234-0402
Page(s): 27

Comment 4: Well Venting for Liquids Unloading

Additional suggested revisions will improve the clarity of the requirements for reporters.

Additionally, EPA should consider revising the definition of CDp in Equation W-8 to Idp (Internal Diameter) to allow the application of either tubing diameter if the well is equipped with tubing string and no plunger lift, or casing diameter if the well does not have tubing and plunger lift. It is common practice for operators to first install a tubing string to increase flow velocity and install a plunger lift later when the well undergoes production decline. The diameter that is used in the equation should be the diameter of the portion of the well that is vented, whether venting the casing, tubing, or both. EPA should also clarify that the depth is based only on the vertical depth for horizontal wells.

Furthermore, the volume should be able to account for the fluid column depth. EPA should allow companies to determine the depth to the top of the fluid and exclude the remaining volume from the venting volume estimate. The reason for liquids unloading is to remove the liquid column from the well. The volume of liquid should not be considered gas that is vented, and rather only the depth above the fluids should be used to quantify the vented gas, as shown by the 'volume vented' in the following diagram.



Response 4: See Section III.H of the preamble to the final rule for the EPA's response to these comments.

Commenter: Anonymous
Comment Number: EPA-HQ-OAR-2023-0234-0366
Page(s): 1

Commenter: Chesapeake Energy Corporation
Comment Number: EPA-HQ-OAR-2023-0234-0400
Page(s): 17

Comment 5: Commenter 0366: For liquids unloading, EPA says emissions should be calculated "when the well is unloaded to the atmosphere or a control device." EPA did not clarify what is considered a control device though. The preamble says, "when the well is unloaded to the atmosphere or to a control device" are the unloadings "that result in emissions of GHG to the atmosphere," which makes it sound like there are other unloadings where emissions aren't calculated. EPA should explain how "a control device" fits with the "routed to flares, combustion, or vapor recovery systems" phrase used for other sources.

Also, if a well is unloaded to a control device, EPA should explain what calculation method to use. Each method seems to only include unloadings to the atmosphere. Method 1 says "Calculate the total emissions from well venting to the atmosphere for liquids unloading using Equation W-7A of this section." Method 2 says "Calculate the total emissions for each well from manual and automated well venting to the atmosphere for liquids unloading without plunger lift assist using Equation W-8 of this section." Method 3 says "Calculate the total emissions for each sub-basin from well venting to the atmosphere for liquids unloading with plunger lift assist using Equation W-9 of this section.”

Commenter 0400: In addition, Chesapeake requests that EPA expand existing mechanisms for operators to utilize flaring to reduce reported emissions. Chesapeake requests that EPA include specific provisions for flaring for (1) liquids unloading and (2) crankcase venting:

- Liquids Unloading: EPA’s Proposed Rule does not provide a mechanism for operators to receive credit for flaring gas from liquids unloading. Chesapeake requests that EPA add the ability to reduce emissions from liquid unloading when a flare is utilized.

Response 5: See Section III.H of the preamble to the final rule for the EPA’s response to these comments.

Commenter: Endeavor Energy Resources, L.P.
Comment Number: EPA-HQ-OAR-2023-0234-0381
Page(s): 18

Commenter: CrownQuest Operating
Comment Number: EPA-HQ-OAR-2023-0234-0393
Page(s): 167

Comment 6: Commenter 0381: **EPA Should Reconsider the Proposed Revisions to Calculation Methods for Several Emission Sources.**

Liquids Unloading

EPA also proposes to divide liquids unloading across two sets of variables: (1) plunger versus non-plunger lift wells and (2) automated versus manual unloading. The additional data and information reporting requirements related to those variables will unnecessarily increase the complexity of reporting and the burdens on the reporters. And it is not clear to Endeavor the need for the additional data points, or how those data points will advance consistent, more accurate reporting of emissions data.

Commenter 0393: In regard to the Zaimes et al (2019) study referenced in the preamble, "This study is only speculating and did not evaluate the data. It should not be used for rule making."

Response 6: The EPA disagrees with the commenters that the proposed requirement to further differentiate unloadings by manual versus automated increases the reporting burden while providing minimal benefit. In response to the commenter that the Zaimes et. al. (2019) did not evaluate the data and should not be used for rulemaking, we note that the paper was published in a peer reviewed journal with supporting documentation. However, the EPA did not rely on data from Zaimes (2019) to develop proposed changes to calculation methods for liquids unloadings. Rather Zaimes (2019) was cited in the proposal preamble due to their suggestion that the type of unloading should be further differentiated between automated and manual unloadings to properly characterize emissions. As noted in the preamble to the proposed rule, the EPA agreed with this recommendation because there could be significant differences in the number and duration of unloadings and, hence, differences in emissions between manual and automated plunger lift unloadings and liquids unloading emissions. Correspondence with reporters via e-GGRT since subpart W reporting for the onshore production segment began in 2011 indicates potentially meaningful differences in the number of unloadings and emissions for manual versus automated non-plunger lift unloadings. In the final rule, the EPA is finalizing as proposed the requirement to report unloadings as plunger lift or non-lunger lift unloadings, and automated or manual unloadings.

10 Gas Well Completions and Workovers with Hydraulic Fracturing

Commenter: SLB
Comment Number: EPA-HQ-OAR-2023-0234-0196
Page(s): 1

Comment 1: This comment relates to the proposed rule within Title 40 / Chapter 1 / Subchapter C / Part 98 Subpart W / 98.233 Calculating GHG emissions/ paragraph G: *Well venting during completions and workovers with hydraulic fracturing*.

The feedback is related to the specific wording contained within this paragraph: "…If you elect to use Equation W-10B, you must use a recording flow meter installed on the vent line, downstream of a separator and ahead of a flare or vent, to measure the gas flowback."

Our comment is that this part of the rule should also consider measurement of vent or flare gas during completions and workovers with hydraulic fracturing to be performed upstream of any separation with multiphase flowmeters. The multiphase flow meter can measure oil, gas, water without the need of separation, simplifying the surface installation by reducing overall hardware as well vented emissions. Multiphase flowmeters are widely used in the industry and are a validated technology for production measurements upstream of a separator. In the US, multiphase flow meters are used for production measurement of oil, gas, water for permanent facilities, or on plug drill out and initial flowback of the wells. Specifically, API MPMS Chapter 20.3 governs the use and requirements of multiphase flow meters in oil and gas applications.

Consequently, in this applicable, a multiphase flowmeter installed upstream of a separator could theoretically replace a gas flow meter installed on the vent line/ flare line downstream of a separator, as the gas that is flowing thru the gas line towards the flare stack has been already measured by upstream flow meter.

In summary: The intent of this comment is for EPA to consider the use of multiphase flow meters, installed upstream of a separator, as an alternative method of gas measurement on vent line.

Links and references

- SLB Multiphase flowmeter details: https://www.slb.com/-/media/files/testing-services/productsheet/vx-spectra-tt-ps.ashx
- API MPMS Chapter 20.3: https://www .api.org/-/med ia/files/publications/whats%20new/20_3%20e1%20pa.pdf

Response 1: See Section III.I of the preamble to the final rule for the EPA's response to comments regarding using multiphase flow meters for completions and workovers with hydraulic fracturing.

Commenter: Marcellus Shale Coalition (MSC)
Comment Number: EPA-HQ-OAR-2023-0234-0275
Page(s): 18

Commenter: American Exploration and Production Council
Comment Number: EPA-HQ-OAR-2023-0234-0295
Page(s): 25

Commenter: The Petroleum Alliance of Oklahoma
Comment Number: EPA-HQ-OAR-2023-0234-0398
Page(s): 13

Comment 2: Commenter 0275: Update the correlation method to use choke flow equations demonstrated to be more predictive than the current method.

The MSC suggests that the U.S. EPA review how the choke flow calculation in eq W-11 compares to a Gilbert-type equation and evaluate the use of a Gilbert-type equation for emissions reporting. The Gilbert-type equation uses empirically derived data from measured flowbacks to estimate emissions from non-measured flowbacks in the same sub-basin category. The equation is available in the API Compendium https://www.api.org/-/media/files/policy/esg/ghg/2021-api-ghg-compendium-110921.pdf and also available in several project reports showing increased accuracy compared to the choke flow equation.

Commenter 0295: **Flowbacks**

Update the correlation method to use choke flow equations demonstrated to be more predictive than the current method

AXPC requests EPA to update the proposed choke flow calculation in eq W-11 to a Gilbert-type equation The Gilbert-type equation uses empirically derived data from measured flowbacks to estimate emissions from non-measured flowbacks in the same sub-basin category. The equation is available in the API Compendium[8] and also available in several project reports showing increased accuracy compared to the proposed choke flow equation.

Footnote:

[8] https://www.api.org/~/media/files/policy/esg/ghg/2021-api-ghg-compendium-110921.pdf}

Commenter 0398: Well Completions

EPA is proposing to retain equations W–10A and W–10B, but is proposing to remove the option in 40 CFR 98.233(g)(1) for reporters to use Calculation Method 2, the Choke Flow equation, when using equation W–10A. EPA requests comment on whether it should retain this equation.

EPA provides no rationale as to why it is proposing to remove this calculation other than its not used that often. However, there is an apparent need as reporters used this calculation method on

385 well completions or workovers. As previously stated, EPA should allow operators the flexibility to choose the methodologies that best fit their situation to report emissions.

Action Requested: We request EPA retain the Choke Flow equation.

Response 2: See Section III.I of the preamble to the final rule for the EPA's response to comments regarding the choke flow equation for completions and workovers with hydraulic fracturing.

Commenter: Marcellus Shale Coalition (MSC)
Comment Number: EPA-HQ-OAR-2023-0234-0275
Page(s): 15

Commenter: American Exploration and Production Council
Comment Number: EPA-HQ-OAR-2023-0234-0295
Page(s): 21

Commenter: Chesapeake Energy Corporation
Comment Number: EPA-HQ-OAR-2023-0234-0400
Page(s): 15-16, 19-20, 20-27

Comment 3: Commenter 0275: Well Completions and Workovers with Hydraulic Fracturing

The U.S. EPA should review the well completions and workovers with hydraulic fracturing (referred to here as flowbacks) emissions source and implement improvements based on publicly available data describing flowback emissions.

The proposed methodology can be improved to increase reporting accuracy. The current estimation method was developed during the original Subpart W rulemaking. Below is a pro/con analysis of the equations in the proposed regulation text:

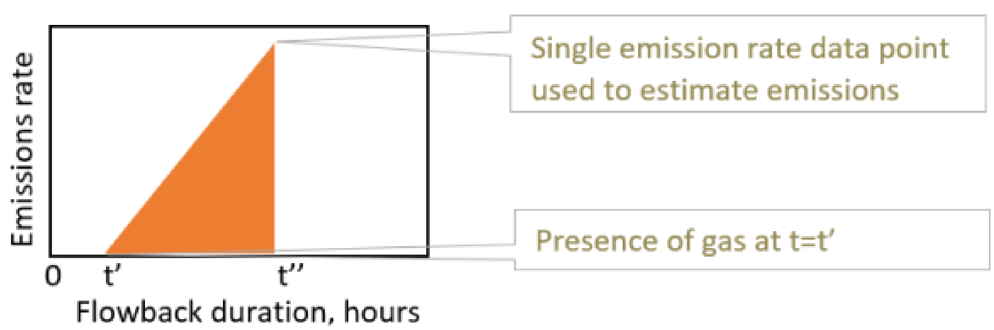
Pros of existing method	**Cons of existing method**
Assumptions are stated in Technical Support Document.	Emissions during initial period are based on assumptions rather than empirically derived. One key assumption is that emissions in the initial period increase linearly from zero to the initial rate of the separation period, but empirical data shows a different relationship based on observed presence or absence of gas and/or gas solubility in produced water.
Characterizes emissions in two flow periods, initial and sufficient gas flow.	Assumed emission during the initial period are not representative of actual emissions

Flared volumes can be represented separately from vented	No mechanism to demonstrate reduced emissions during the initial flow period, and these emissions can be the most significant contributor to this emissions source based on required assumptions.
The sufficient gas flow period can be adequately characterized through use of meters, average 30-day production rates, and gas destination data.	No mechanism to use existing empirically derived data to improve representativeness of the initial period's calculated result.
Includes provisions for wells without flowback metering, namely a choke flow correlation.	Choke flow correlation demonstrated to be a poor predictor of emissions compared to other choke flow equations supported by a data-driven review previously presented to the U.S. EPA.

The U.S. EPA should incorporate the below options for flowback emissions estimations so that the pros of the existing method are retained and the cons addressed. Consider the below graphic showing flowback duration on the x-axis and emissions rate on the y-axis. The x-axis is labeled with the time gas is first detected, t', and with the end of the initial period, t''. This graphic represents the proposed method for determining emissions during the initial period in the case where the duration is contiguous from t' to t''.

Example flowback plot for initial period.

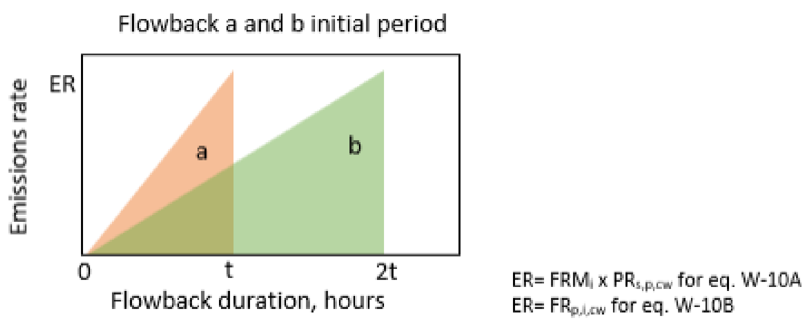
Figure A-1: Example Flowback Plot for Initial Period Using Interpolation Method



The graphic illustrates how the proposed method can be improved by incorporating existing empirically derived information. The proposed linear interpolation is a simplifying assumption to address the technical challenges or infeasibilities of using a flow measurement device during the initial period, but the assumption introduces significant inaccuracy into the calculated emissions. The initial period's emissions are modeled based on the spot rate when the gas separator first operates; however, this rate doesn't characterize emissions of the initial period. The spot rate is a presumed conservatively high upper bound for the initial period, but the spot rate represents gas that does not exist for the initial period and is not real or representative for the initial period. Although time on the x-axis is convenient to measure, initial period emissions are not a function of time and are instead a function of liquids throughput which is typically available data for the initial period.

As an example of how the proposed linear interpolation assumption yields non-representative emissions estimates, consider two flowbacks, a and b, with the same data except that the initial period is doubled between a and b:

Figure A-2: Comparison of Example Flowbacks Using Interpolation Method



Flowback duration, hours

In this example, flowback a and b are the same and in the field, except that flowback b has double the duration and half liquid rate as a so that cumulative volumes of a and b are equal. Flowbacks a and b have the same real emissions quantity in the field. However, for GHG reporting, emissions are unrealistically doubled between flowback a and b because of the required structure of equations W-10A or W-10B:

Emissions a = $t \div 2 \times ER$
Emissions b = $2t \div 2 \times ER$

The flowbacks have different calculated emissions estimates even though the initial spot rate, produced water volume, and other parameters are the same and would emit the same quantities in reality. This demonstrates that the existing methodology does not accurately characterize initial period emissions because the spot rate measurement and the cumulative duration are not a representative mathematical model for this situation.

The spot rate is a measurement of a condition that doesn't exist in the initial stage and is a mathematical discontinuity on the graph. The duration is readily measured but is not proportional to emissions in the initial period as the proposed equation assumes. Based on the proposed calculation methods, a reporter has limited ability to report emissions reductions during the initial flowback period. Liquids produced during the initial period may not be sent to a closed loop system due to low pressure. As a result, emissions over-estimated by the proposed methodology have a zero percent control factor and are potentially larger than emissions during the separation period, which results in an unrealistic annual emissions report and leads to incorrect conclusions for GHG policymaking.

One possible emerging or future emission management option may include routing low pressure emissions from a closed top tank to a destruction device. The current method, in addition to mischaracterizing emissions quantities, provides limited ability to report reduced emissions as the variables are limited in number and are poorly correlated to actual emissions. For example, reporters can only reasonably take measures to control the time, spot rate, and nitrogen injected parameters of a flowback job so that these parameters do not overestimate actual emissions. This undesired outcome has no material emissions reduction benefits and potentially incentivizes undesired behavior of controlling variables in an equation rather than controlling real emissions. Improving the proposed method so that it better represents the real initial period emissions avoids this undesired outcome and ensures that initial period emissions are determined using parameters that directly affect the real emissions quantity.

There are potentially other methods to represent initial period emissions that can be used to improve emissions estimation accuracy. These include: 1) emissions from the initial period can potentially be measured with new technologies such as closed top produced water tanks; and 2) emissions from the initial period can also be well-defined using data-based thermodynamic flash calculations that are acceptable for other Subpart W emissions sources such as storage tanks. The MSC suggest that the U.S. EPA improve the flowback reporting methodologies to improve emission estimates and has provided details on the two data-driven adjustments to the methodology that will improve emissions accuracy for flowback initial periods.

<u>Update equations W-10A and B estimation methodology to allow use of water throughput and flash factors during the initial period</u>.

Below is an example of this modification for equation W-10A. The equation replaces the proposed initial period term with liquid volume data and flash factors. This modification increases the representativeness of the method and eliminates the drawback of using unrealistic simplifying assumptions.

$$E_{s,n} = \sum_{p=1}^{CW} [T_{p,s,cw} \times \; FRM_s \times PR_{s,p,cw} - EnF_{s,p,cw} + \left[Vw_{p,i,cw} \times EFw_{p,i,cw} + \left[Vo_{p,i,cw} \times EFo_{p,i,cw}\right]\right]]$$

Where

Vwp,i,cw = Cumulative volume of produced water, in barrels, produced from the period of time when gas is first detected until sufficient quantities of gas are present to enable separation, for each completion or workover, cw, and for each well, p, during the reporting year. This may include non-contiguous periods of routing to open tanks/pits but does not include periods when the well ceases to produce fluids to the surface.

EFwp,i,cw = Emission factor for volumetric natural gas emissions released by produced water in standard cubic feet per barrel produced water. Calculate natural gas emissions from using operating conditions in the gas-liquid separator. Calculate flashing emissions with a software program, such as AspenTech HYSYS®, that uses the Peng-Robinson equation of state, models flashing emissions, and speciates CH_4 and CO_2 emissions that will result when the produced water from the separator equipment attains atmospheric pressure. The following parameters must be determined for typical operating conditions for the well completion or workover by engineering estimate and process knowledge based on best available data, and must be used at a minimum to characterize emissions from produced water during the initial flowback period:

(i) Wellhead equipment temperature.

(ii) Wellhead equipment pressure.

(iii) Ambient air temperature.

(iv) Ambient air pressure.

$V_{op,i,cw}$ = Cumulative volume of produced oil, in barrels measured at the atmospheric storage point, produced from the period of time when gas is first detected until sufficient quantities of gas are present to enable separation, for each completion or workover, cw, and for each well, p, during the reporting year. This may include non-contiguous periods of routing to open tanks/pits but does not include periods when the well ceases to produce fluids to the surface.

$EF_{op,i,cw}$ = Emission factor for volumetric natural gas emissions released by produced oil in standard cubic feet per barrel oil. Calculate natural gas emissions from using operating conditions in the gas-liquid separator. Calculate flashing emissions with a software program, such as AspenTech HYSYS® or API 4697 E&P Tank, that uses the Peng-Robinson equation of state, models flashing emissions, and speciates CH_4 and CO_2 emissions that will result when the produced oil from the separator equipment attains atmospheric pressure. The following parameters must be determined for typical operating conditions for the well completion or workover by engineering estimate and process knowledge based on best available data, and must be used at a minimum to characterize emissions from produced water during the initial flowback period:

(i) Wellhead equipment temperature.

(ii) Wellhead equipment pressure.

(iii) Sales oil or stabilized oil API gravity.

iv) Sales oil or stabilized oil production rate.

(v) Ambient air temperature.

(vi) Ambient air pressure.

(vii) Wellhead equipment oil composition and Reid vapor pressure. If this data is not available, determine these parameters by using one of the methods described in paragraphs (j)(1)(vii)(A) through (C) of this section.

(A) If wellhead equipment oil composition and Reid vapor pressure default data are provided with the software program, select the default values that most closely match your wellhead equipment pressure first, and API gravity secondarily.

(B) If wellhead equipment oil composition and Reid vapor pressure data are available through your previous analysis, select the latest available analysis that is representative of produced crude oil or condensate from the sub-basin category for onshore petroleum and natural gas production or from the county for onshore petroleum and natural gas gathering and boosting.

(C) Analyze a representative sample of wellhead equipment oil in each sub-basin category for onshore petroleum and natural gas production or each county for onshore petroleum and natural gas gathering and boosting for oil composition and Reid vapor pressure using an appropriate standard method published by a consensus-based standards organization.

This improved equation can be implemented as an additional option so that reporters have flexibility to use the proposed equation as currently characterized by the EPA's cost burden analysis and technical support documents, or to use the improved equation that uses data-driven outcomes to increase representativeness.

<u>Update the W-10A and B estimation methodology to allow for use of gas measurement from a closed loop process, such as enclosed frac tanks.</u>

Below is an example of this modification for equation W-10A. The equation replaces the proposed initial period term with average measured rate and duration of the measurement. This modification increases the representativeness of the method and eliminates the drawback of using unrealistic simplifying assumptions.

$$E_{s,n} = \sum_{p=1}^{CW} [T_{p,s,cw} \times FRM_s \times PR_{s,p,cw} - EnF_{s,p,cw} + [T_{p,i,cw} \times FR_{i,p,cw}]]$$

Where

$FR_{i,p,cw}$ = Average gas flow rate during the initial period in standard cubic feet per hour of each well, p, and completion or workover, cw, measured using a recording flow meter (digital or analog) on the vent line to measure the flowback, for the duration of the period of time when insufficient quantities of gas are present to enable separation at facility or line pressure, of the completion or workover according to methods set forth in § 98.234(b).

This type of calculation is appropriate to employ in a circumstance where the initial period's throughput can be routed to a closed top tank and to a low-pressure gas measurement device.

Commenter 0295: **Flowbacks**

EPA's proposed emission estimation methods included in the Proposal for flowbacks are based on oversimplistic assumptions rather than opportunities for empirically derived modeling, which is potentially restrictive of future efforts to reduce or eliminate emissions during completions operations. The proposed methodology can be improved to increase reporting accuracy, incorporate empirical data, and incentivize emission reductions.

Consider Figure 1 showing flowback duration on the x-axis and emissions rate on the y-axis. The x-axis is labeled with the time gas is first detected, t', and with the end of the initial period, t''. Figure 1 represents the Proposal's method for determining emissions during the initial period in the case where the duration is contiguous from t' to t''. Flowback duration is shown on the x-axis and emissions rate is shown on the y-axis. The x-axis is labeled with the time gas is first detected, t', and with the end of the initial period, t''.

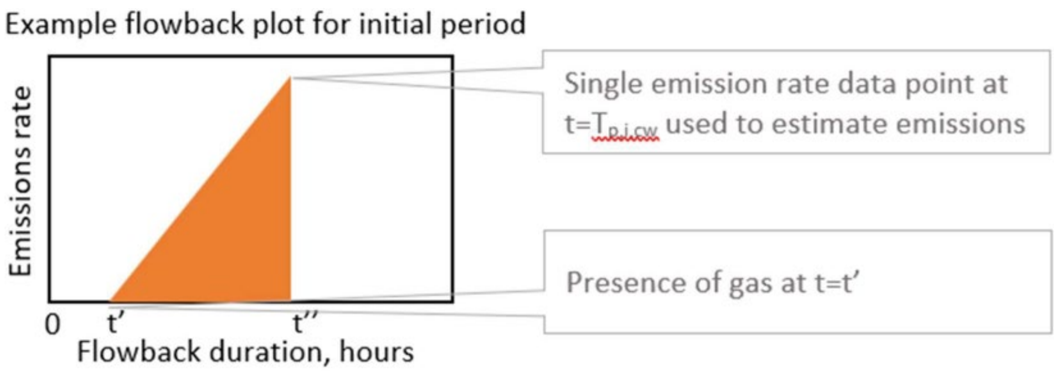


Figure 1: Graphic depiction of the Proposal's method of calculating flowback emissions, graph of emission rate by flowback duration, hours

The proposed linear interpolation is a simplifying assumption to address the technical challenges and/or infeasibilities of using a flow measurement device during the initial period, but the assumption introduces significant inaccuracy into calculated emissions. The initial period's emissions are modeled based on the spot rate when the gas separator first operates, however, this rate is not a good indicator of emissions during this initial period. The spot rate is a highly conservative upper bound for the initial period, but the spot rate overestimates the presence of gas in the initial period. Although time on the x-axis is convenient to measure, initial period emissions are not a function of time and are instead a function of liquids throughput which is typically available data for the initial period.

As an example of how the proposed linear interpolation assumption yields non-representative emissions estimates, consider two flowbacks, a and b, in Figure 2:

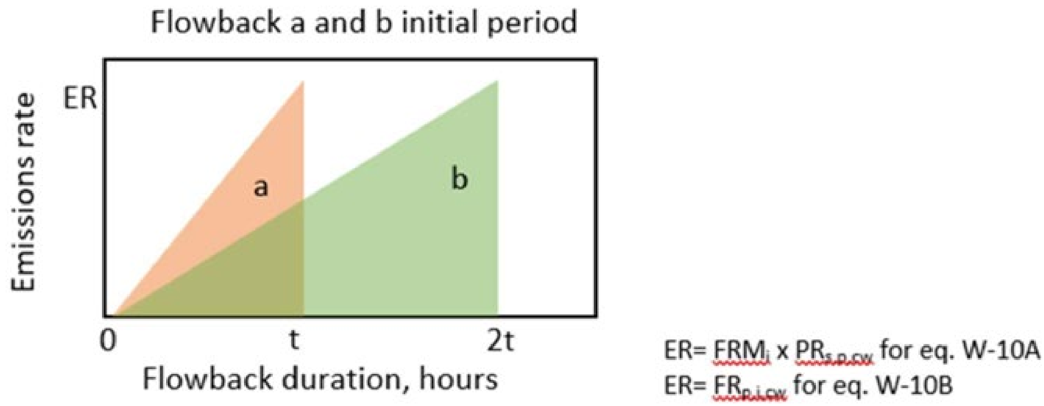


Figure 2: A graphic depiction of two flowback events that have equivalent emissions in the field, yet yield completely different calculated emissions when using the Proposal's calculation methodology

In this example, flowback a and b are equivalent in the field, except that Flowback b has double the duration and half the liquid rate of flowback a so that cumulative volumes of a and b are equal. Flowbacks a and b have the same real emissions quantity in the field. However, by using the Proposal's method of calculating flowback emissions, we find that Flowback b's emissions are unrealistically two times higher than Flowback a. This can be observed mathematically in equations W-10A or W-10B below:

$Emissions_a = t \div 2 \times ER$
$Emissions_b = 2t \div 2 \times ER$

This demonstrates that the existing methodology does not accurately estimate initial period emissions because the spot rate measurement and the cumulative duration are not a representative mathematical model for this situation. The spot rate is a measurement of a condition that doesn't exist in the initial stage and is a mathematical discontinuity on the graph. The duration is readily measured but is not proportional to emissions in the initial period as the proposed equation assumes.

Furthermore, based on the proposed linear calculation methods, an operator would have limited ability to claim emissions reductions during the initial flowback period. Using an equation to estimate emissions based on arbitrary parameters could lead to unproductive behaviors in the field.

For example, a company may focus its resources to closely control the time, spot rate, and nitrogen injected during a flowback job so that these parameters do not overestimate actual missions when those resources could have been better focused on controlling actual emissions.

AXPC recommends that emissions from flowbacks are calculated using well-defined, data-based thermodynamic flash calculations. These calculations are acceptable for other Subpart W emissions sources such as storage tanks and are also acceptable under the air permitting and compliance programs currently in effect under the Clean Air Act's authority. These equations are included in the following sections.

<u>Update equations W-10A and B estimation methodology to allow use of water throughput and flash factors during the initial period.</u>

Below is an example of this modification for equation W-10A. The equation replaces the proposed initial period term with liquid volume data and flash factors. This modification increases the representativeness of the method and eliminates the drawback of using unrealistic simplifying assumptions.

$$E_{s,n} = \sum_{p=1}^{CW} [T_{p,s,cw} \times \; FRM_s \times PR_{s,p,cw} - EnF_{s,p,cw} + \left[Vw_{p,i,cw} \times EFw_{p,i,cw} + \left[Vo_{p,i,cw} \times EFo_{p,i,cw}\right]\right]]$$

Where

$Vw_{p,i,cw}$ = Cumulative volume of produced water, in barrels, produced from the period of time when gas is first detected until sufficient quantities of gas are present to enable separation, for each completion or workover, cw, and for each well, p, during the reporting year. This may include non-contiguous periods of routing to open tanks/pits but does not include periods when the well ceases to produce fluids to the surface.

$EFw_{p,i,cw}$ = Emission factor for volumetric natural gas emissions released by produced water in standard cubic feet per barrel produced water. Calculate natural gas emissions from using operating conditions in the gas-liquid separator. Calculate flashing emissions with a software program, such as AspenTech HYSYS®, that uses the Peng-Robinson equation of state, models flashing emissions, and speciates CH_4 and CO_2 emissions that will result when the produced water from the separator equipment attains atmospheric pressure. The following parameters must be determined for typical operating conditions for the well completion or workover by engineering estimate and process knowledge based on best available data, and must be used at a minimum to characterize emissions from produced water during the initial flowback period:

(i) Wellhead equipment temperature.

(ii) Wellhead equipment pressure.

(iii) Ambient air temperature.

(iv) Ambient air pressure.

$V_{op,i,cw}$ = Cumulative volume of produced oil, in barrels measured at the atmospheric storage point, produced from the period of time when gas is first detected until sufficient quantities of gas are present to enable separation, for each completion or workover, cw, and for each well, p, during the reporting year. This may include non-contiguous periods of routing to open tanks/pits but does not include periods when the well ceases to produce fluids to the surface.

$EF_{op,i,cw}$ = Emission factor for volumetric natural gas emissions released by produced water in standard cubic feet per barrel oil. Calculate natural gas emissions from using operating conditions in the gas-liquid separator. Calculate flashing emissions with a software program, such as AspenTech HYSYS® or API 4697 E&P Tank, that uses the Peng-Robinson equation of state, models flashing emissions, and speciates CH_4 and CO_2 emissions that will result when the produced oil from the separator equipment attains atmospheric pressure. The following parameters must be determined for typical operating conditions for the well completion or workover by engineering estimate and process knowledge based on best available data, and must be used at a minimum to characterize emissions from produced water during the initial flowback period:

(i) Wellhead equipment temperature.

(ii) Wellhead equipment pressure.

(iii) Sales oil or stabilized oil API gravity.

iv) Sales oil or stabilized oil production rate.

(v) Ambient air temperature.

(vi) Ambient air pressure.

(vii) Wellhead equipment oil composition and Reid vapor pressure. If this data is not available, determine these parameters by using one of the methods described in paragraphs (j)(1)(vii)(A) through (C) of this section.

(A) If wellhead equipment oil composition and Reid vapor pressure default data are provided with the software program, select the default values that most closely match your wellhead equipment pressure first, and API gravity secondarily.

(B) If wellhead equipment oil composition and Reid vapor pressure data are available through your previous analysis, select the latest available analysis that is representative of produced crude oil or condensate from the sub-basin category for onshore petroleum and natural gas production or from the county for onshore petroleum and natural gas gathering and boosting.

(C) Analyze a representative sample of wellhead equipment oil in each sub-basin category for onshore petroleum and natural gas production or each county for onshore petroleum and natural gas gathering and boosting for oil composition and

Reid vapor pressure using an appropriate standard method published by a consensus-based standards organization.

The improved equation uses thermodynamic calculations and data elements previously vetted and approved by EPA for GHG reporting, and flash calculations are also a best practice for characterizing emissions in air permitting programs. AXPC requests that this improved equation can be a secondary calculation option so that reporters have flexibility to use the proposed equations W-10A and W-10B for simplicity or to use the improved equation that uses data-driven outcomes to increase representativeness.

Update the W-10A and B estimation methodology to allow for use of gas measurement from a closed loop process, such as enclosed frac tanks

Routing the initial period's gas through a closed loop processes, like enclosed frac tanks or closed top tank, and to a low-pressure gas measurement device is a viable option for emission reduction in the field. The following equation models this practice. The equation replaces the proposed initial period term with average measured rate and duration of the measurement. This modification increases the representativeness of the method and eliminates the drawback of using unrealistic simplifying assumption

$$E_{s,n} = \sum_{p=1}^{CW} [T_{p,s,cw} \times FRM_s \times PR_{s,p,cw} - EnF_{s,p,cw} + [T_{p,i,cw} \times FR_{i,p,cw}]]$$

Where

FRi,p,cw = Average gas flow rate during the initial period in standard cubic feet per hour of each well, p, and completion or workover, cw, measured using a recording flow meter (digital or analog) on the vent line to measure the flowback, for the duration of the period of time when insufficient quantities of gas are present to enable separation at facility or line pressure, of the completion or workover according to methods set forth in § 98.234(b).

AXPC requests that EPA consider adding this equation to the acceptable calculation methodologies for flowbacks.

Commenter 0400: **EPA should update the calculation methods for well completions and hydraulic fracturing to incorporate available data.**

Under the existing Subpart W regulations, operators currently calculate emissions from gas well completions and workovers with hydraulic fracturing using use equation W-10A or W-10B.[56] EPA's Proposed Rule retains these equations, but would remove the option for operators using the W-10A equation to use a "choke flow" calculation, which uses measured gas pressure differential across well choke to estimate gas flow rate. [57]

Chesapeake encourages EPA to develop an updated calculation method for well completions and workovers with hydraulic fracturing (referred to here as "flowbacks") based on a holistic review of available data on flowback emissions. EPA's current methodology is based on assumptions rather than empirical data, and in several cases, the assumptions are not representative of actual emissions, to the detriment of reporting accuracy. Chesapeake is attaching a Technical Appendix discussing these issues and proposed revisions more fully.

Chesapeake strongly encourages EPA to adopt the following data-driven adjustments to the methodology to improve emissions accuracy for the initial flowback period:

- First, EPA should include equations to incorporate use of water throughput and flash factors during the initial period.
- Second, EPA should allow for the use of gas measurements from a closed loop process (e.g., enclosed frac tanks).

As explained in further detail at Appendix A, these revisions would make the calculations more representative of actual emissions during flowback, avoid relying on assumptions, and increase reporting accuracy. In addition, these revisions would be more consistent with Congress' directive in CAA Section 136(h), which directs EPA to revise Subpart W regulations to incorporate empirical data where possible.

Footnotes:

[56] 88 Fed. Reg. 50,282, 50,323 (Aug. 1, 2023).

[57] Id.

…

TECHNICAL APPENDIX

<u>Well Completions and Workovers with Hydraulic Fracturing</u>

As noted in Chesapeake's comments *supra*, EPA should revise the existing methodology for well completions and workovers with hydraulic fracturing (referred to here as *flowbacks*) in order to improve reporting accuracy. EPA's Proposed Rule fails to update the existing methodology to incorporate improvements based on publicly available data describing flowback emissions.

The basis for the existing flowback emissions methodology was initially developed during the original Subpart W rulemaking in 2010,[64] with the current equations updated during subsequent rulemaking amendments in 2011 and 2012.[65] Below is a pro/con analysis of the existing equations:

Pros of existing method	Cons of existing method
Assumptions are stated in Technical Support Document for 2011 updates.[66]	Emissions during initial period are based on assumptions rather than empirically derived. One key assumption is that emissions in the initial period increase linearly from zero to the initial rate of the separation period, but empirical data shows a different relationship based on observed presence or absence of gas and/or gas solubility in produced water.
Characterizes emissions in two flow periods, initial and sufficient gas flow.	Assumed emission during the initial period are not always representative of actual emissions.
Flared volumes can be represented separately from vented	No mechanism to demonstrate reduced emissions during the initial flow period, which may be the most significant contributor to this emissions source due to the required assumptions.
The sufficient gas flow period can be adequately characterized through use of meters, average 30-day production rates, and gas destination data.	No mechanism to use existing empirically derived data to improve representativeness of the initial period's calculated result. New technology implementations can enable use of meters during the initial period.

Chesapeake strongly encourages EPA to revise its Proposed Rule to address the following considerations for flowback emissions estimations in order to retain the benefits of the existing methodology while also addressing existing limitations—

…

EPA should not rely on linear interpolation to estimate emissions during the initial period:

The Proposed Rule relies on linear interpretation to estimate emissions during the initial period, as illustrated by Figure A-1:

Figure A-1: Example Flowback Plot for Initial Period Using Interpolation Method

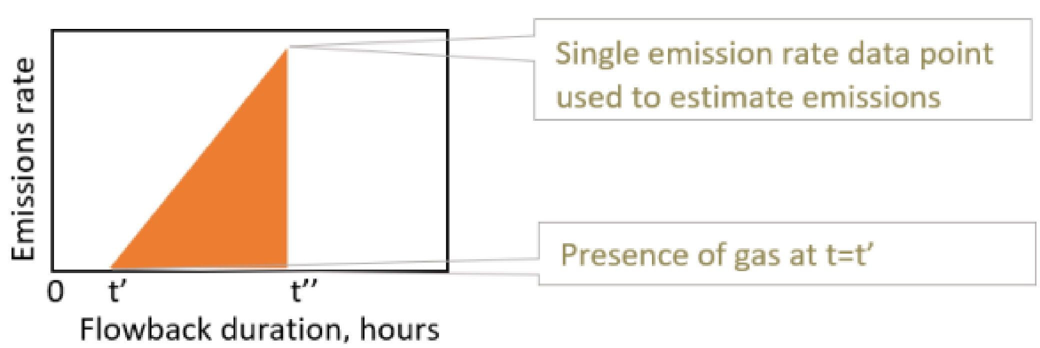


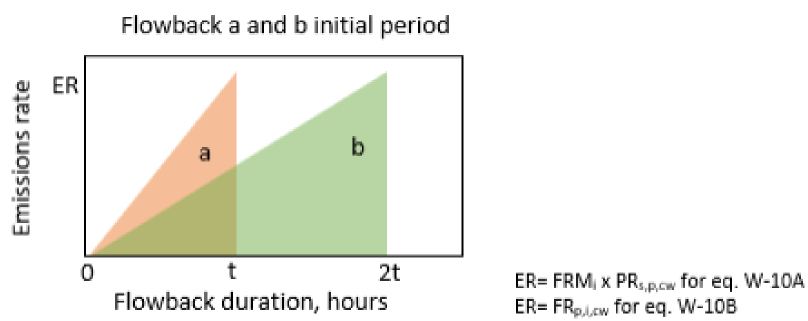
Figure A-1 shows flowback duration on the x-axis and emissions rate on the y-axis. The x-axis is labeled with the time gas is first detected, t’, and with the end of the initial period, t’’. This graphic represents EPA’s existing method for determining emissions during the initial period in the case where the duration is contiguous from t’ to t’’.

EPA uses linear interpolation as a simplifying assumption to address the technical challenges or infeasibilities of using a flow measurement device during the initial period. However, this assumption introduces significant inaccuracy into the calculated emissions. The initial period’s emissions are modeled based on the spot rate when the gas separator first operates, but this rate is not representative of emissions during the initial period. The spot rate is a presumed conservatively high upper bound for the initial period, but the spot rate represents gas that does not exist for the initial period and is not real or representative for the initial period. Although time on the x-axis is convenient to measure, initial period emissions are not a function of time and are instead a function of liquids throughput which is typically available data for the initial period.

The following example illustrates the disconnect between linear interpolation assumptions and actual emissions during the initial period:

Consider two flowbacks, a and b, with the same data except that the initial period is doubled between a and b:

Figure A-2: Comparison of Example Flowbacks Using Interpolation Method



In this example, flowbacks a and b are the same in the field, except that flowback b has double the duration and half liquid rate as a so that cumulative volumes of a and b are equal. Flowbacks a and b have the same real emissions quantity in the field. However, for GHG reporting, emissions are unrealistically doubled between flowback a and b because of the required structure of equations W-10A or W-10B:

Emissions a = t ÷ 2 × ER
Emissions b = 2t ÷ 2 × ER

The flowbacks have different calculated emissions estimates even though the initial spot rate, produced water volume, and other parameters are the same and would emit the same quantities in reality.

As illustrated by this example, the existing methodology does not accurately characterize initial period emissions because the spot rate measurement and the cumulative duration are not a representative mathematical model for the emissions. The spot rate is a measurement of a condition that doesn't exist in the initial stage and is a mathematical discontinuity on the graph. The duration is readily measured but is not proportional to emissions in the initial period as the proposed equation assumes.

This disconnect between emissions estimates under this method and actual emissions significantly impacts reporting accuracy. *First*, this method mischaracterizes emissions quantities, leading to inaccurate reporting. *Second,* this method limits operators' ability to demonstrate emissions reductions during the initial flowback period since the equation doesn't represent actual operations. Third, the existing methodology incentivizes monitoring and control of parameters than do not affect emissions and therefore disincentivizes innovation and emissions reduction. Under the existing method, operators must consider the time, spot rate, and nitrogen injected parameters of a flowback job in order to avoid reporting inaccuracies, which can divert resources from actual emissions reduction efforts directed at throughput, capture, and controls.

By revising this methodology, EPA has the opportunity to incorporate possible emerging or future emission management options such as routing low pressure emissions from a closed top tank to a destruction device. Although capture of emissions from the initial period may not be widely practicable or cost-effective currently, this is an emerging or future technology implementation that should be considered since it replaces assumptions with a method to use empirically derived emissions estimates. Liquids produced during the initial period historically may not be sent to a closed loop system due to low pressure. As a result, emissions overestimated by the proposed methodology always have a zero percent control factor. Initial period emissions as reported are potentially larger than emissions during the separation period, which results in an unrealistic annual emissions report and leads to incorrect conclusions for GHG policymaking. Improving the proposed method so that it better represents the real initial period emissions avoids this undesired outcome and ensures that initial period emissions are determined using parameters that directly affect the real emissions quantity.

EPA should revise the existing methodology to increase accuracy of emissions estimates for this initial period. Rather than rely on a time-based linear interpolation, EPA should incorporate data more representative of the initial period emissions:

(1) Emissions from the initial period can also be well-defined using data-based thermodynamic flash calculations that are acceptable for other Subpart W emissions sources such as storage tanks and also acceptable under the air permitting and compliance programs currently in effect under the Clean Air Act.

(2) Emissions from the initial period can potentially be measured with new technologies such as closed top produced water tanks.

<u>Update equations W-10A and B estimation methodology to allow use of water throughput and flash factors during the initial period.</u>

Below is an example of this modification for equation W-10A. The equation replaces the proposed initial period term with liquid volume data and flash factors. This modification increases the representativeness of the method and eliminates the drawback of using unrealistic simplifying assumptions.

$$E_{s,n} = \sum_{p=1}^{CW} [T_{p,s,cw} \times FRM_s \times PR_{s,p,cw} - EnF_{s,p,cw} + \left[Vw_{p,i,cw} \times EFw_{p,i,cw} + \left[Vo_{p,i,cw} \times EFo_{p,i,cw}\right]\right]]$$

Where:

$Vw_{p,i,cw}$ = Cumulative volume of produced water, in barrels, produced from the period of time when gas is first detected until sufficient quantities of gas are present to enable separation, for each completion or workover, cw, and for each well, p, during the reporting year. This may include non-contiguous periods of routing to open tanks/pits but does not include periods when the well ceases to produce fluids to the surface.

$EFw_{p,i,cw}$ = Emission factor for volumetric natural gas emissions released by produced water in standard cubic feet per barrel produced water. Calculate natural gas emissions from using operating conditions in the gas-liquid separator. Calculate flashing emissions with a software program, such as AspenTech HYSYS®, that uses the Peng-Robinson equation of state, models flashing emissions, and speciates CH4 and CO2 emissions that will result when the produced water from the separator equipment attains atmospheric pressure. The following parameters must be determined for typical operating conditions for the well completion or workover by engineering estimate and process knowledge based on best available data, and must be used at a minimum to characterize emissions from produced water during the initial flowback period:

(i) Wellhead equipment temperature.

(ii) Wellhead equipment pressure.

(iii) Ambient air temperature.

(iv) Ambient air pressure.

$Vo_{p,i,cw}$ = Cumulative volume of produced oil, in barrels measured at the atmospheric storage point, produced from the period of time when gas is first detected until sufficient quantities of gas are present to enable separation, for each completion or workover, cw, and for each well, p, during the reporting year. This may include non-contiguous periods of routing to open tanks/pits but does not include periods when the well ceases to produce fluids to the surface.

$EFo_{p,i,cw}$ = Emission factor for volumetric natural gas emissions released by produced water in standard cubic feet per barrel oil. Calculate natural gas emissions from using operating conditions in the gas-liquid separator. Calculate flashing emissions with a software program, such as AspenTech HYSYS® or API 4697 E&P Tank, which uses the Peng-Robinson equation of state, models flashing emissions, and speciates CH4 and CO2 emissions that will result when the produced oil from the separator equipment attains atmospheric pressure. The following parameters must be determined for typical operating conditions for the well completion or workover by engineering estimate and process knowledge based on best available data, and must be used at a minimum to characterize emissions from produced water during the initial flowback period:

(i) Wellhead equipment temperature.

(ii) Wellhead equipment pressure.

(iii) Sales oil or stabilized oil API gravity.

(iv) Sales oil or stabilized oil production rate.

(v) Ambient air temperature.

(vi) Ambient air pressure.

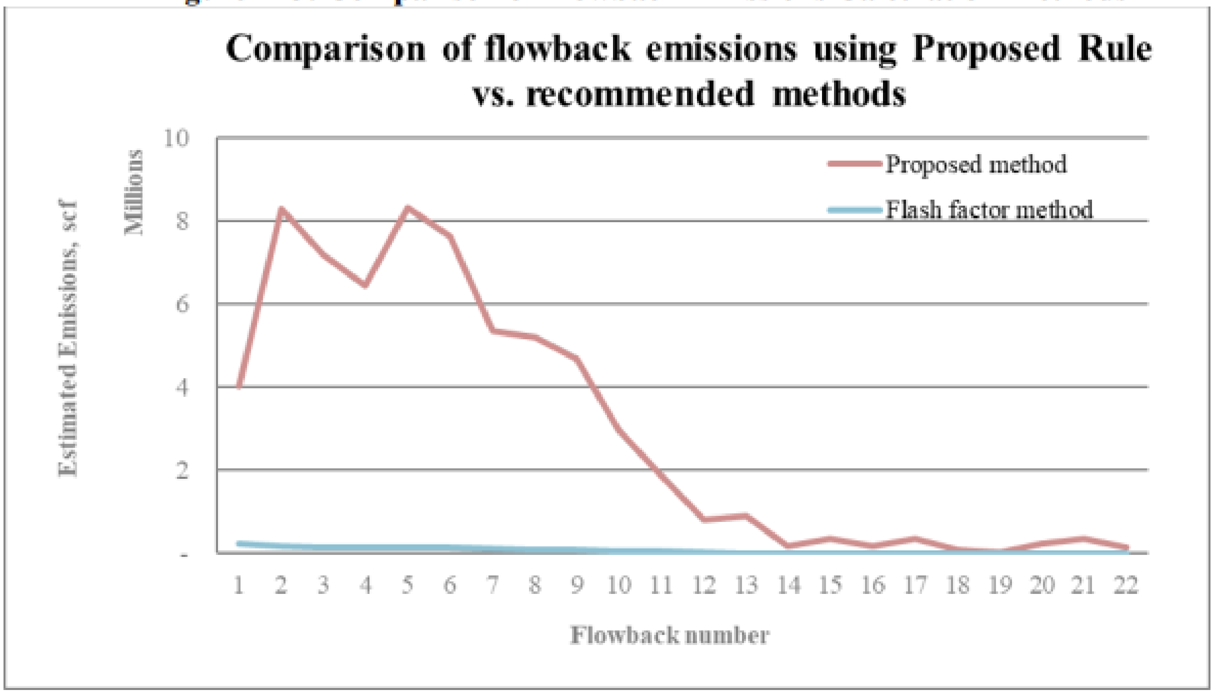
(vii) Wellhead equipment oil composition and Reid vapor pressure. If this data is not available, determine these parameters by using one of the methods described in paragraphs (j)(1)(vii)(A) through (C) of this section.

> (A) If wellhead equipment oil composition and Reid vapor pressure default data are provided with the software program, select the default values that most closely match your wellhead equipment pressure first, and API gravity secondarily.
>
> (B) If wellhead equipment oil composition and Reid vapor pressure data are available through your previous analysis, select the latest available analysis that is representative of produced crude oil or condensate from the sub-basin category for onshore petroleum and natural gas production or from the county for onshore petroleum and natural gas gathering and boosting.
>
> (C) Analyze a representative sample of wellhead equipment oil in each sub-basin category for onshore petroleum and natural gas production or each county for onshore petroleum and natural gas gathering and boosting for oil composition and Reid vapor pressure using an appropriate standard method published by a consensus-based standards organization.

This improved equation can be implemented as an additional option so that reporters have flexibility to use the proposed equation as currently characterized by the EPA’s cost burden analysis and technical support documents, or to use the improved equation that uses data-driven outcomes to increase representativeness. The improved equation uses thermodynamic calculations and data elements previously vetted and approved by EPA for GHG reporting, and flash calculations are also a best practice for characterizing emissions in air permitting programs.

Figure A-3 below illustrates the differences in estimated flowback emissions between the method in the Proposed Rule and the recommended method outlined by Chesapeake above, using sample data for flowbacks:

Figure A-3: Comparison of Flowback Emissions Calculation Methods



As Figure A-3 illustrates, there is significant disagreement between the methods to model actual emissions from the flowback initial period.

These differences are further analyzed in Chart A-4. Using the sample data, the orange columns calculate $E_{s,n}$ based on the Proposed Rule's simplifying linear interpolation assumption under equation W-10A. The green columns calculate $E_{s,n}$ based on Chesapeake's recommended method using a thermodynamic process simulation model with data inputs from the producing wells, including produced water throughput and an empirically derived flash factor for produced water at natural gas wellhead pressure. The sample data has zero emissions from the separation period for each of the 22 flowbacks, so all emissions are from the initial period when insufficient gas exists to operate a separator. These methods produce an average disagreement of **4536%**, which significantly impacts the accuracy of reported emissions during the initial period and is unreasonably high to characterize any assumed multiphase flow.

Chart A-4: Calculation of Flowback Emissions During Initial Period Using Sample Data

	Flowba	Tp,s hrs	FRMs (scf/hr) / (scf/hr) Use Eq. W-12A	PRs,p scf/hr	EnFs,p scf	Tp,i hrs	FRMi (scf/hr) / (scf/hr)	Es,n scf	Cumulative water bbls during initial period	produced water emission factor, scf gas per bbl produced water	Es,n scf	% difference
	1	0	0.269	410,559	0	73	0.269	4,027,275	16,970	13.4	227,398	1671%
	2	0	0.269	664,378	0	93	0.269	8,302,536	11,957	13.4	160,224	5082%
	3	0	0.269	575,311	0	93	0.269	7,189,484	11,782	13.4	157,879	4454%
	4	0	0.269	1,019,620	0	47	0.269	6,439,451	11,738	13.4	157,289	3994%
	5	0	0.269	1,166,844	0	53	0.269	8,310,004	11,497	13.4	154,060	5294%
	6	0	0.269	1,156,991	0	49	0.269	7,617,960	10,380	13.4	139,092	5377%
	7	0	0.269	595,655	0	67	0.269	5,362,680	8,098	13.4	108,513	4842%
	8	0	0.269	606,164	0	64	0.269	5,212,938	7,090	13.4	95,006	5387%
	9	0	0.267	531,755	0	66	0.267	4,687,370	6,329	13.4	84,809	5427%
	10	0	0.267	514,768	0	43	0.267	2,956,339	3,825	13.4	51,255	5668%
	11	0	0.269	632,254	0	22	0.269	1,869,075	3,192	13.4	42,773	4270%
	12	0	0.184	1,524,236	0	6	0.180	821,330	669	13.4	8,965	9062%
	13	0	0.173	1,474,187	0	7	0.173	890,385	398	13.4	5,333	16595%
	14	0	0.269	624,650	0	2	0.269	167,872	380	13.4	5,092	3197%
	15	0	0.267	1,381,259	0	2	0.267	368,960	290	13.4	3,886	9395%
	16	0	0.269	608,866	0	2	0.269	163,631	248	13.4	3,323	4824%
	17	0	0.269	1,320,555	0	2	0.269	354,894	210	13.4	2,814	12512%
	18	0	0.184	399,180	0	2	0.180	71,699	187	13.4	2,506	2761%
	19	0	0.184	358,430	0	1	0.180	32,190	122	13.4	1,635	1869%
	20	0	0.184	1,331,451	0	2	0.180	239,149	118	13.4	1,581	15025%
	21	0	0.269	544,644	0	5	0.269	365,927	75	13.4	1,005	36311%
	22	0	0.269	1,013,187	0	1	0.269	136,145	30	13.4	402	33767%
Total								65,587,297			1,414,839	4536%

Chart A-4 indicates a significant disagreement between the methods to model actual emissions from the flowback initial period. EPA's Proposed Rule relies on a simplifying linear interpolation assumption. This simplifying assumption may have been more representative preOOOOa, because the initial period term is insignificant compared to the total estimated emissions. However, after OOOOa, which requires operators to avoid or control emissions in the separation period of flowback, the initial period now represents 100% or near-100% of the estimated emissions.

Chart A-4 also illustrates that emissions from the flash factor method proposed by Chesapeake are proportional to cumulative water volume rather than duration. This corresponds to expected data trends during the initial period and is more representative of actual emissions. As Chart A-4 demonstrates, longer initial period durations tend to increase the magnitude of the emissions overestimate through use of a linear interpolation calculation. Therefore, the initial spot rate is not an appropriate data point to characterize the initial flowback period's emissions rate when initial period emissions are the majority of flowback emissions.

<u>Update the W-10A and B estimation methodology to allow for use of gas measurement from a closed loop process, such as enclosed frac tanks.</u>

Below is an example of this modification for equation W-10A. The equation replaces the proposed initial period term with average measured rate and duration of the measurement. This modification increases the representativeness of the method and eliminates the drawback of using unrealistic simplifying assumptions.

$$E_{s,n} = \sum_{p=1}^{CW} [T_{p,s,cw} \times FRM_s \times PR_{s,p,cw} - EnF_{s,p,cw} + [T_{p,i,cw} \times FR_{i,p,cw}]]$$

$FR_{i,p,cw}$ = Average gas flow rate during the initial period in standard cubic feet per hour of each well, p, and completion or workover, cw, measured using a recording flow meter (digital or analog) on the vent line to measure the flowback, for the duration of the period of time when insufficient quantities of gas are present to enable separation at facility or line pressure, of the completion or workover according to methods set forth in § 98.234(b).

This type of calculation is appropriate to employ in a circumstance where the initial period's throughput can be routed

Footnotes:

[64] Mandatory Reporting of Greenhouse Gases: Petroleum and Natural Gas Systems, 75 Fed. Reg. 74,458, 74,471 (Nov. 30, 2010).

[65] 76 Fed. Reg. 80,554, 80,561 (Dec. 23, 2011); 77 Fed. Reg. 51,477, 51,483 (Aug. 24, 2012).

[66] See Imegwu Memorandum Appendix D, EPA-HQ-OAR-2011-0512-0015 (Aug. 17, 2011), https://www.regulations.gov/document/EPA-HQ-OAR-2011-0512-0015.

Response 3: The EPA thanks the commenter for their suggestions, but the recommended changes to the calculation requirements for completions and workovers with hydraulic fracturing are outside the scope of this rulemaking. The only amendments proposed to equations W-10A and W-10B were related to the reporting of emissions from gas venting during well completions or workovers by well instead of by sub-basin and well type combination. The EPA did not propose amendments or request comments on potential new methodologies or changes to the existing calculation methodologies other than the potential removal of the choke flow equation. (see Section III.I of the preamble to the final rule). As noted elsewhere in this section, we are finalizing the rule with the option of using measurements from a multiphase flow meter during the initial flowback period.

Although the EPA considers the comments to be out of scope, we provide the following to respond to the commenters' concerns and suggestions without reopening the relevant provisions.

The commenters raised concerns about the lack of empirical data in calculating emissions from completion and workovers with hydraulic fracturing with the primary focus on calculation of emissions during the initial flowback period. They also expressed concern about the potential to overreport emissions when flowback during the initial period is routed to a closed loop system.

The commenters recommend two options for improving the calculation methods and submitted calculation methods for these options. Specifically, they recommend the use of thermodynamic flash calculations and also suggest that emissions can potentially be measured from low pressure closed top water tanks.

The EPA notes that the amount of time used to determine emissions for the initial flowback period in equations W-10A and W-10B is the cumulative amount of time of flowback to open tanks/pits. Therefore, the time that gas flowback is routed to a closed loop system rather than vented should be considered when determining total time of flowback multiplied by gas flow rate. For example, if flow is directed immediately to a closed loop system and no gas is vented or flared this would result in zero emissions during the initial flowback period.

We disagree with the comments concerning the lack of empirical data in calculating emissions from well completions and workovers with hydraulic fracturing. The equations in 40 CFR 98.233(g) that are used to calculate emissions from these sources are based on measured data at the well. Specifically, reporters are required to measure the gas flow rate of flowback from hydraulically fractured wells at the beginning of the period when the flow can be directed to a separator. The flow rate is then measured through the separation stage to production. Even when the engineering equations W-11A and W-11B are used to calculate a flow rate, the equations rely on well-specific data.

The EPA acknowledges that equations W-10A and W-10B calculate emissions during the initial flowback period using the average flow rate based on a point measurement of the flow rate taken at the initiation of separation. The equations then assume the average flow rate during the initial flowback stage is one half of the flow rate at the beginning of separation. The methodology was developed because of the difficulty in measuring gas flow rates where high velocity multiphase flow of water, produced fluids, gas, sand and injectants make it difficult to measure gas flow during this initial flowback stage.

The commenters are correct that in some cases there is a possibility that the equations may overestimate or underestimate emissions during the initial flowback stage. It is the EPA's objective for the GHGRP, and in particular for subpart W consistent with CAA section 136(h), that emissions data be as accurate as possible. Consistent with this approach, throughout subpart W we are finalizing requirements to use measured data or include use of measured data as an option for calculating emissions. While we believe the existing calculation methods provide a reasonable approximation of average gas flow through the initial flowback period, we are finalizing the rule to allow use of multiphase flow meters during the initial pre-separation stage as an option to measure gas flow rates through the full initial flowback period. We believe this should address the commenters' concerns regarding measurement of emissions during the initial flowback period. The commenters' suggestion that the methodology for low pressure tanks could potentially offer a measurement alternative suggests that the methodology requires additional study before proposal and acceptance as an alternative to current W-10A and W-10B. With regard to thermodynamic flash calculations, the EPA did not receive sufficient information to evaluate and incorporate this approach into the final rule. The EPA appreciates the submissions of the proposed methodologies by the commenters, but believes further research and analysis are necessary to better understand and assess the appropriateness of the methodologies for calculating emissions from hydraulically fractured completions and workovers. As we implement the new requirements in this final rule in the future, we intend to continue to assess alternatives for determining gas flow rates and flow volumes during the pre-separation stage.

11 Blowdown Vent Stacks

11.1 General Comments

Commenter: American Petroleum Institute et al. (Part 1 of 2)
Comment Number: EPA-HQ-OAR-2023-0234-0402
Page(s): 28

Comment 1: Blowdowns

Streamline blowdown reporting to reduce the burden without affecting accuracy.

EPA is proposing to require site-level details regarding blowdowns. The Industry Trades recommend streamlining this source category by allowing reporters to aggregate events by type at each facility. Aggregating events by type would avoid line-by-line reporting per event and greatly reduce the complexity of reporting for the source category, without impacting data quality or transparency. For example, EPA should allow blowdown emissions to be reported by site, but aggregated by activity (i.e., all blowdown types would be reported in aggregate rather than line-by-line for each blowdown event).

For mid-field pipeline blowdowns not associated with a given well pad or gathering station, reporting a site could be challenging. The Industry Trades recommend allowing these types of blowdown events to be aggregated by county (without segment ID), which is consistent with other pipeline reporting under the current rules for Pipeline and Hazardous Materials Safety Administration (PHMSA).

Response 1: See Section III.J of the preamble to the final rule for the EPA's response to this comment.

Commenter: Wyoming Department of Environmental Quality (WDEQ)
Comment Number: EPA-HQ-OAR-2023-0234-0388
Page(s): 7

Comment 2: WDEQ respectfully requests that EPA allows for flexibility in its emissions calculation methodologies.

Additionally, with regards to reporting pertaining to blowdowns at wells, WDEQ requests that EPA affords flexibility and strong consideration of emergency blowdown events. It is WDEQ's understanding that the applied methods for conducting well blowdowns are not conducive to direct measurements and undertaking such measurements in practice would be very difficult. Furthermore, there are certain unscheduled emergency events that could be nearly impossible to perform direct measurements for given their unpredictable nature. In these instances, WDEQ again encourages the consideration of reporting flexibilities.

While WDEQ recognizes EPA's commitment to obtaining highly specific emissions data through direct measurements and supports including direct measurements as an option, WDEQ encourages EPA to evaluate and thoroughly consider comments it receives pertaining to the technical difficulty of conducting such measurements.

Response 2: As proposed, the final rule allows the use of engineering estimates based on best available information to determine the temperature and pressure of emergency blowdown events at onshore petroleum and natural gas production facilities.

Commenter: Kirk Frost
Comment Number: EPA-HQ-OAR-2023-0234-0389
Page(s): 4

Commenter: Kirk Frost
Comment Number: EPA-HQ-OAR-2023-0234-0414
Page(s): 1

Comment 3: Commenter 0389: The docket solicits input regarding timeframe for reporting after an event has occurred such as a blowdown. Currently in New Jersey, my understanding is that it is an annual report and nothing is required more immediate from the annual report. I strongly encourage EPA to make it a mandatory report within 3 months from the event and for all planned and unplanned events that exceed 1 ton of methane.

I requested all the blowdown reports for a specific compressor station (CS-325) in New Jersey from 2000 to 2020. First, there were several years where the own/operator (Tennessee Gas Pipeline) did not provide a blowdown report. Second, there was only one (1) year where they did provide a blowdown report because that one year the blowdown exceeded 2,000 pounds of VOC emissions. The one blowdown was claimed to occur on 6/10/2004 where a blowdown event emitted 2,263 pounds of VOC emissions. Based off of the weight percentages natural gas composition that TGP provided to FERC, the amount of methane can be calculated as 572.419 tons of methane released in that one blowdown event. The blowdown event lasted 8 hours according to the report TGP submitted. In 2005, TGP reported total methane emissions of 0.640 ton. For all other years that were reported, TGP stated no reportable events that exceeded 2,000 pounds of VOCs.

Imagine, all of the facilities within the natural gas supply chain that perform regular venting and less frequent blow down events where none of this methane emissions are included in the annual emissions report. This includes electric compressor stations and any M&R facility where venting occurs. EIA stopped quantifying and identifying all of the compressor station locations after it exceeded 1,400 compressor stations (EIA informed me in writing that they stopped).

Commenter 0414:

Improving the accuracy of methane emissions is critical. Especially, since natural gas projects continue aggressively expanding the natural gas supply chain in the US.

I support EPA to tackle the super emitters, but I also want EPA to close all loop holes that enable facility owners/operators to avoid reporting all methane emissions from the owner's/operator's facility. With the 2,000 VOC blow down loophole:
1. facility owner/operator does not have to report any blow down that emits 2,000 pounds of VOCs or less.
2. The facility owner/operator does not have to report methane emissions that were released during the blow down.
3. Even with reportable blow downs (those exceeding 2,000 pounds of VOCs released, those events do not have to report the methane released during that event.

Hence, no methane reporting from any blow down or even venting is ever included in the annual estimates. One blow down event that emits 2,000 pounds of VOCs also emits more than 500 tons of methane. While EPA might be tackling 50 super emitters, there are thousands of facilities that are release more than 200 tons of methane every year and hundreds of facilities that are releasing more than 1,000 tons of methane every year. But none of those facilities are actually reporting those emissions.

Response 3: The EPA thanks the commenter for their feedback, but these recommendations are out of scope for this rulemaking. Regarding the commenter's suggestion to require incident reporting within three months, this would be beyond the scope of the GHGRP, as it is an annual emissions reporting program, not an incident reporting program. Regarding the commenter's reference to a VOC loophole, the GHGRP does not have any such exceptions or allowances for GHG emissions. Further, VOC is not considered when reporters are determining applicability to the GHGRP and it is not reported under the GHGRP.

Commenter: GPA Midstream Association
Comment Number: EPA-HQ-OAR-2023-0234-0299
Page(s): 82

Comment 4: Appendix A

Table of changes GPA supports as proposed.

Subpart	Citation	Change
…		
W	98.233(i)	Blowdowns: Remove exclusion of desiccant dehydrator blowdown venting before reloading.

Response 4: This comment was included as an attachment to the commenter’s letter, but it is a comment on the 2022 GHGRP Proposal and is not relevant to the 2023 Subpart W Proposal or this final rule.

11.2 Reporting Equipment and Event Type Categories

Commenter: Williams Companies, Inc.
Comment Number: EPA-HQ-OAR-2023-0234-0394
Page(s): 14

Comment 1: Blowdown Vents

Williams supports the following updates in the Proposed Rule regarding reporting equipment categories for pipelines, blowdown equipment types, blowdown temperature and pressure.

- Revising the description of "facility piping" and "pipeline venting" blowdown categories, with respect to onshore petroleum and natural gas gathering and boosting.
- Removing the reference to "distribution" pipelines from the "facility piping" and "pipeline venting" categories.

Response 1: The EPA acknowledges the commenter's support of the proposed revisions. The EPA is finalizing these amendments as proposed.

Commenter: GPA Midstream Association
Comment Number: EPA-HQ-OAR-2023-0234-0299
Page(s): 82

Comment 2: Proposed Change: EPA is revising the descriptions of "facility piping" and "pipeline venting" in attempt to reduce confusion about categorizing pipeline blowdowns.

> **Comment**: Removing the "distribution pipelines" terminology from the description of "pipeline venting" is an appropriate change. However, as EPA notes, because of the expansive definition of "facility" for G&B, most blowdowns associated with pipelines in that industry segment will be categorized as "facility piping" except for occasional blowdowns involving pipelines that span basins, which would be categorized as "pipeline venting." GPA requests that EPA consider whether having two separate definitions for pipeline blowdowns really serves its informational needs, especially since the two categories are rendered meaningless within G&B (and therefore, the two categories cannot be equated between processing and G&B). If EPA can obtain the information it requires with only one category for all pipeline blowdowns, then it should do so.

Response 2: This commenter submitted this comment on the 2022 Subpart W Proposal and the EPA considered it when developing the 2023 Subpart W Proposal. The EPA considers this comment to have been addressed by the proposed additional clarifications to the "facility piping" and "pipeline venting" categories in the 2023 Subpart W Proposal, which are finalized as proposed.

Commenter: Kirk Frost
Comment Number: EPA-HQ-OAR-2023-0234-0389
Page(s): 3

Comment 3: All of the transmission pipeline owners/operators claim they have central monitors that alert when blowdowns or other events occur. I am sure that the systems used log these events to data log files. These log files always include a timestamp and additional information to help the owner/operator know which facility, what unit and type of event. The log file can also help determine duration. Any systems administrator would validate this logging behavior and if pipeline companies are using centralized systems that receive alerts from all the remote facilities, then these systems will have those data logfiles. Writing scripts or using tools to monitor these logfiles is a very inexpensive cost-effective approach that many companies use to monitor their products, systems and security. In fact, it is an industry standard. I am sure the natural gas owner operators are no different.

Response 3: The EPA thanks the commenter for their feedback.

11.3 Blowdown Equipment Types

Commenter: Williams Companies, Inc.
Comment Number: EPA-HQ-OAR-2023-0234-0394
Page(s): 14, 15

Comment 1: Blowdown Vents

Williams supports the following updates in the Proposed Rule regarding reporting equipment categories for pipelines, blowdown equipment types, blowdown temperature and pressure.

…

- Moving the listing of blowdown event types to a new 40 CFR § 98.233(i)(2)(iv) to provide clear information regarding applicable requirements for each industry segment.

Response 1: The EPA acknowledges the commenter's support of the proposed revisions. The EPA is finalizing these amendments as proposed.

11.4 Blowdown Temperature and Pressure

Commenter: GPA Midstream Association
Comment Number: EPA-HQ-OAR-2023-0234-0299
Page(s): 36-37, 82-83, 105

Comment 1: "Best available information" should be allowed for determining the pressure and temperature of any blowdown.

EPA is proposing to allow and clarify use of engineering estimates based on best available information to determine the temperature and pressure of an emergency blowdown.[92] GPA supports this change, but we also request that the language "best available information" be applied to all blowdowns—not just emergency blowdowns. Operators do not always have a temperature or pressure gauge at the blowdown source, nor is it reasonable to expect operators to install such gauges. It is also not appropriate to request an "engineering estimate" for a simple matter of determining a reasonable estimate of the gas temperature and pressure. "Best available information" is a broad term that requires operators to use their best data, which is an appropriate standard for this requirement. GPA suggests the following changes to the proposed regulatory text:

98.233(i)(2)(i)
Ta = Temperature at actual conditions in the unique physical volume (°F)~~. For emergency blowdowns at onshore petroleum and natural gas production, onshore petroleum and natural gas gathering and boosting facilities, onshore natural gas transmission pipeline facilities, and natural gas distribution facilities, engineering estimates~~ based on best available information may be used to determine the temperature.
Pa = Absolute pressure at actual conditions in the unique physical volume (psia)~~. For emergency blowdowns at onshore petroleum and natural gas production, onshore petroleum and natural gas gathering and boosting facilities, onshore natural gas transmission pipeline facilities, and natural gas distribution facilities, engineering estimates~~ based on best available information may be used to determine the pressure.
Ta,p = Temperature at actual conditions in the unique physical volume (°F) for each blowdown "p"~~. For emergency blowdowns at onshore petroleum and natural gas production, onshore petroleum and natural gas gathering and boosting facilities, onshore natural gas transmission pipeline facilities, and natural gas distribution facilities, engineering estimates based on~~ best available information may be used to determine the temperature.
Pa,b,p = Absolute pressure at actual conditions in the unique physical volume (psia) at the beginning of the blowdown "p"~~. For emergency blowdowns at onshore petroleum and natural gas production, onshore petroleum and natural gas gathering and boosting facilities, onshore natural gas transmission pipeline facilities, and natural gas distribution facilities, engineering estimates~~ based on best available information~~ may be used to determine the pressure at the beginning of the blowdown~~.
Pa,e,p = Absolute pressure at actual conditions in the unique physical volume (psia) at the end of the blowdown "p"~~; 0 if blowdown volume is purged using non-GHG gases. For emergency blowdowns at onshore petroleum and natural gas production, onshore petroleum and natural gas gathering and boosting facilities, onshore natural gas transmission pipeline facilities, and natural gas distribution facilities, engineering estimates~~ based on best available information~~ may be used to determine the pressure at the end of the blowdown~~. You may assume 0 if blowdown volume is purged using non-GHG gases.

…

Proposed Change: EPA is proposing to allow and clarify use of engineering estimates based on best available information to determine the temperature and pressure of an emergency blowdown.

Comment: GPA supports this change, but we also request that the language "best available information" be applied to all blowdowns. Operators do not always have a temperature or pressure gauge at the blowdown source, nor is it reasonable to expect operators to install such gauges upon a blowdown. It is also not appropriate to request an "engineering estimate" for a simple matter of determining a reasonable estimate of the gas temperature and pressure. "Best available information" is a broad term that requires operators to use their best data, which is an appropriate standard for this requirement.

Suggested text:

98.233(i)(2)(i)

Ta = Temperature at actual conditions in the unique physical volume (°F)~~. For emergency blowdowns at onshore petroleum and natural gas gathering and boosting facilities and onshore natural gas transmission pipeline facilities, engineering estimates~~ based on best available information ~~may be used to determine the temperature~~.

Pa = Absolute pressure at actual conditions in the unique physical volume (psia)~~. For emergency blowdowns at onshore petroleum and natural gas gathering and boosting facilities and onshore natural gas transmission pipeline facilities, engineering estimates~~ based on best available information ~~may be used to determine the pressure~~.

Ta,p = Temperature at actual conditions in the unique physical volume (°F) for each blowdown "p"~~. For emergency blowdowns at onshore petroleum and natural gas gathering and boosting facilities and onshore natural gas transmission pipeline facilities, engineering estimates based on~~ best available information ~~may be used to determine the temperature~~.

Pa,b,p = Absolute pressure at actual conditions in the unique physical volume (psia) at the beginning of the blowdown "p~~". For emergency blowdowns at onshore petroleum and natural gas gathering and boosting facilities and onshore natural gas transmission pipeline facilities, engineering estimates~~ based on best available information ~~may be used to determine the pressure at the beginning of the blowdown~~.

Pa,e,p = Absolute pressure at actual conditions in the unique physical volume (psia) at the end of the blowdown "p"; 0 if blowdown volume is purged using non-GHG gases~~. For emergency blowdowns at onshore petroleum and natural gas gathering and boosting facilities and onshore natural gas transmission pipeline facilities, engineering estimates~~ based on best available information ~~may be used to determine the pressure at the end of the blowdown~~.

…

Appendix A

Table of changes GPA supports as proposed.

Subpart	Citation	Change
…		
W	98.233(i)(2)(i) Equation W-14A Equation W-14B	Blowdowns: Allow engineering estimates based on best available data to determine temperature and pressure of emergency blowdowns for Onshore Natural Gas Transmission Pipeline and Onshore Petroleum and Natural Gas Gathering and Boosting

Footnote:

[92] 88 Fed. Reg. at 50,302, 50,325.

Response 1: The EPA is finalizing the pressure and temperature term descriptions as they were proposed in the 2023 Subpart W Proposal. The EPA is not be removing the language "engineering estimates based on best available information" because this would be inconsistent with the rest of the rule. The EPA considers expanding the use of engineering estimates rather than measurements to blowdowns other than emergency blowdowns to be contrary to the directives in CAA section 136(h), including ensuring accuracy in total emissions reported. The EPA notes that facilities in the onshore petroleum and natural gas gathering and boosting industry segment have been successfully reporting emissions from blowdown vent stacks only using engineering estimates for emergency blowdowns since reporting year 2016.

Commenter: CrownQuest Operating
Comment Number: EPA-HQ-OAR-2023-0234-0393
Page(s): 86

Commenter: Williams Companies, Inc.
Comment Number: EPA-HQ-OAR-2023-0234-0394
Page(s): 14, 15

Comment 2: Commenter 0393: Agree with this proposal. as it is the most safe and practical in these types of situations. Almost all estimates are going to be based off engineering estimates.

Commenter 0394: **Blowdown Vents**

Williams supports the following updates in the Proposed Rule regarding reporting equipment categories for pipelines, blowdown equipment types, blowdown temperature and pressure.

…

- Permitting best engineering estimates for emergency blowdown volumes (temperature and pressure) for onshore natural gas transmission pipelines and natural gas gathering and boosting.

Response 2: The EPA acknowledges the commenters' support of the proposed revisions. The EPA is finalizing these amendments as proposed.

12 Atmospheric Storage Tanks

12.1 Open Thief Hatches

Commenter: American Exploration and Production Council
Comment Number: EPA-HQ-OAR-2023-0234-0295
Page(s): 17

Commenter: GPA Midstream Association
Comment Number: EPA-HQ-OAR-2023-0234-0299
Page(s): 38

Comment 1: Commenter 0295: **Tanks**

AXPC has comments on several aspects of the proposed changes to Subpart W related to storage tanks. These comments are further outlined below.

Open Thief Hatches

AXPC recognizes EPA's desire to quantify emissions resulting from open thief hatches to account for periods when tank emissions are not fully captured, recovered, or routed to a control device. First of all, EPA needs to define an "open or not properly seated thief hatch" to reflect the emissions scenario that EPA is trying to capture. The Proposal requires the use of thief hatch sensors and visual inspections to detect periods when thief hatches are open or not properly seated.

As such AXPC proposes the following definition:

> "a thief hatch is open or not properly seated if it is fully or partially open such there is a visible gap between the hatch cover and the hatch portal." It is critical to define the circumstances EPA is seeking to identify in order to determine the proper monitoring techniques.

…

If EPA chooses not to define an open or improperly seated thief hatch as provided above, EPA should clarify that leaks which can only be identified through use of an OGI camera do not meet the definition of an "open or not properly seated thief hatch," nor do they meet the leak definition exemption of "thief hatches or other openings on a storage vessel" in 98.232(c)(21)(i) for two reasons. First, it is technically unsupportable to assume a small, wisping, leak only seen through an OGI camera would require an operator to assume 0% capture efficiency when its commonly known most of the storage tank vapors remain in the tank, are captured, or are routed to a control device. Second, leaks such as the example provided (i.e., wisping) would not be identified with the current technology suggested by EPA: thief hatch sensor or visual inspection monitoring methods.

Commenter 0299: **An open or not properly seated thief hatch should be defined.**

EPA needs to define an open or not properly seated thief hatch, so that it can be consistently applied. GPA proposes the following definition: *"A thief hatch is open or not properly seated if it is fully or partially open such there is a visible gap between the hatch cover and the hatch portal."* If EPA chooses not to define an open or not properly seated thief hatch as provided above, EPA needs to clarify that leaks that can only be identified through use of an OGI camera or similar detection technology do not meet the definition of an open or not properly seated thief hatch. This definition also aligns with the EPA's proposed inspection techniques for thief hatches (98.233(j)(7)).

Response 1: See Section III.K.1 of the preamble to the final rule for the response to this comment.

Commenter: Independent Petroleum Association of New Mexico (IPANM)
Comment Number: EPA-HQ-OAR-2023-0234-0337
Page(s): 5

Commenter: Endeavor Energy Resources, L.P.
Comment Number: EPA-HQ-OAR-2023-0234-0381
Page(s): 15

Commenter: Range Resources Corporation
Comment Number: EPA-HQ-OAR-2023-0234-0397
Page(s): 8

Commenter: American Petroleum Institute et al. (Part 1 of 2)
Comment Number: EPA-HQ-OAR-2023-0234-0402
Page(s): 9, 29-30

Commenter: Encino Energy (EAP Ohio, LLC)
Comment Number: EPA-HQ-OAR-2023-0234-0408
Page(s): 4

Comment 2: Commenter 0337: **40 CFR § 98.233(j) Tanks**

EPA is proposing to revise existing § 98.233(j) to require reporters to assume that no emissions are captured by the control device (0 percent capture efficiency) when the thief hatch on a tank is open or not properly seated. Assuming a 0 percent capture efficiency would result in an overestimation of emissions; some vapors will continue to be captured by a control device even when a thief hatch is either open or not properly seated.

Commenter 0381: **EPA Should Reconsider the Proposed Revisions to Calculation Methods for Several Emission Sources.**

Atmospheric Storage Tanks

…

Additionally, EPA's underlying assertion that no emissions are captured by a tank's control device while a thief hatch is open or not properly seated is simply not accurate. Even if a thief hatch is open or not properly seated, the tank's emissions control device is still operational and capturing at least some portion of the emissions. EPA's assumption that no emissions are captured thus inaccurately overstates the actual emissions from an open thief hatch, which runs contrary to the IRA's mandate. While it may be more difficult to ascertain the exact portion of emissions captured from an open thief hatch on a controlled tank (as compared to a blanket assumption of "no capture"), that does not relieve EPA of its statutory requirement to ensure accurate emissions data collection. To the extent the Agency retains reporting requirements for atmospheric storage tanks in the final rule, EPA should determine and incorporate an appropriate factor in the proposed emissions calculations for thief hatches to account for control devices, even if such devices are operating at a reduced capture efficiency due to the open hatch.

Commenter 0397: EPA's proposal for storage tank thief hatch reporting will undoubtedly result in inaccurate overreporting of emissions.

The Proposed Rule states that "[d]uring periods when a thief hatch is open or not properly seated and emissions from the tank are routed to a vapor recovery system or a flare, assume the capture efficiency of the vapor recovery system or a flare is 0 percent." 88 Fed. Reg. at 50396 (to be codified at 40 C.F.R. § 98.233(j)(4)(C)). In addition, the proposal provides that operators are required to calculate emissions from thief hatches using this assumption. 88 Fed. Reg. at 50396 (to be codified at 40 C.F.R. § 98.233(j)(7)).

The proposed assumption that a thief hatch, under certain conditions, is capturing zero emissions will often be inaccurate and misrepresent the actual capture of emissions. For example, if a thief hatch is mis-seated or has a faulty gasket, but is largely containing emissions, there will still be a capture of emissions that are routed to control (i.e., vapor recovery). These types of emissions would be detected through OGI, could be quantified and reported as a leak in any event. In the final rule, EPA should make revisions to clarify that minor issues with a thief hatch do not require a reporting of zero emissions capture.

Commenter 0402: **EPA's assumption that improperly seated thief hatches result in a zero percent control efficiency for controlled tanks is overly conservative and not considered in the TSD. Further, EPA's proposed method to calculate the duration of open thief hatches over-estimates emissions from this source**. The Industry Trades propose that EPA use a bifurcated approach for thief hatches that accounts for when they are fully open or improperly seated, which would have lower expected emissions.

…

Storage Tanks

Thief Hatches

EPA should allow improperly seated thief hatches to be treated as an "other" component under equipment leaks. The proposed capture efficiency of zero percent for storage tanks

with an improperly seated thief hatch is inaccurate and would significantly overestimate emissions.

EPA has proposed a 100 percent reduction in VRU capture efficiency and flare destruction efficiency for both hydrocarbon and produced water storage tanks with open and improperly seated thief hatches. This proposed reduction in capture efficiency is inaccurate and would significantly overestimate methane emissions. The Industry Trades propose a bifurcated approach to reporting emissions from thief hatches where improperly seated thief hatches would be treated as a fugitive emission reported under equipment leaks, and open thief hatches would result in a zero percent capture efficiency for control devices.

Thief hatches are safety devices that relieve positive and negative pressure in atmospheric storage tanks to prevent structural damage. Thief hatches accomplish this by using weights or springs that allow the thief hatch valve to open at given pressure and vacuum settings. The thief hatch valve then reseats after the tank pressure or vacuum has dissipated. Thief hatch valves are designed to seat with minimal leakage under their pressure setting. For example, Enardo 660s, a common thief hatch in the upstream oil and gas industry, conforms to API 2000 Venting Atmospheric and Low-Pressure Storage Tanks Standard to not leak more than 5 SCFH at 75-90% of the thief hatch valve's pressure setpoint. Many of Enardo's valves can achieve smaller leak rates at 90% of the pressure setpoint. LaMot's L12 series thief hatches, another common type found at upstream oil and gas facilities, will not leak more than 1 SCFH at 90% of the pressure setpoint. These leak rates are a fraction of the gas produced in tanks. For example, the reduction in capture efficiency ranges from 0.5% to 2.5% given these leak rates for tanks with a relatively small throughput of 100 bbl./day and average GOR of 48 scfs/bbl given the above leak rates. Improperly seated thief hatches are technically closed but leak around the seat due to either grime on the valve gasket or an inadequate seal, similar to valves that leak into open-ended lines. Improperly seated thief hatches do not result in a zero percent capture efficiency because they are still able to maintain positive pressure on the tanks, allowing gases to be routed to the control device. The leakage from an improperly seated thief hatch is significantly lower than from a partially open thief hatch.

EPA's proposal to assume zero percent capture efficiency from improperly seated thief hatches that are leaking as opposed to venting gas will grossly overstate methane emissions. Instead, the Industry Trades propose that improperly seated thief hatches be considered and reported as a fugitive emissions component (under the "other" fugitive component category).

A zero percent capture efficiency as proposed by EPA would be used for thief hatches that are observed above their setpoint using pressure transmitters and confirmed open or found open during inspections. The Industry Trades believe that this bifurcated approach of accounting for improperly seated thief hatches as equipment leaks, and assuming open thief hatches result in a zero percent capture efficiency would be a more accurate representation of emissions from thief hatches.

<u>Commenter 0408</u>: Small tank leaks which cannot be detected by the proposed tank hatch sensors, will not result in a capture efficiency of zero and may not impact or reduce capture efficiency at all.

Response 2: See Section III.K.1 of the preamble to the final rule for the response to this comment.

Commenter: Nevada Nanotech Systems
Comment Number: EPA-HQ-OAR-2023-0234-0238
Page(s): 1-4

Commenter: Endeavor Energy Resources, L.P.
Comment Number: EPA-HQ-OAR-2023-0234-0381
Page(s): 15

Commenter: American Petroleum Institute et al. (Part 1 of 2)
Comment Number: EPA-HQ-OAR-2023-0234-0402
Page(s): 30

Commenter: LongPath Technologies, Inc.
Comment Number: EPA-HQ-OAR-2023-0234-0410
Page(s): 4-5

Commenter: Environmental Defense Fund, et al.
Comment Number: EPA-HQ-OAR-2023-0234-0413
Page(s): 51-52

Comment 3: Commenter 0238: Regarding Section K, Atmospheric Storage Tanks, Subsection 1, Open Thief Hatches, a request for comment on alternative methodologies for quantifying the time that a thief hatch is left open or not properly seated in lieu of a required visual inspection, we have the following comments:

- MethaneTrack™ has proven to be effective at providing rapid notification of thief hatch failures, including both human error such as an open or unlatched thief hatch, and mechanical failures such as broken springs and faulty seals. This has been demonstrated in the industry at operating upstream oil and gas tank batteries.
- MethaneTrack™ is FM Class 1, Div 1 and is safe to be installed in flammable gases. This allows for rapid leak notification, precise localization, and accurate quantification.
- Since MethaneTrack™ can quickly detect an open thief hatch, we are able to accurately log the start time and duration a thief hatch is left open in our software.
- MethaneTrack™ provides operators with actionable information so they can quickly close or repair a thief hatch, reducing overall emissions from atmospheric storage tanks.
- We have enclosed a brochure further describing MethaneTrack's™ thief hatch capabilities.

{Commenter submitted brochure highlighting the MethaneTrack system at a customer site.}

Commenter 0381: **EPA Should Reconsider the Proposed Revisions to Calculation Methods for Several Emission Sources.**

Atmospheric Storage Tanks

…

Endeavor also seeks clarity as to whether aerial surveys (or similar top-down monitoring systems) constitute "visual inspections"; if not, Endeavor strongly urges their inclusion, as aerial surveys have a proven track record for emissions detection and provide necessary flexibility for reporters in the onstream oil and natural gas production sector.

Commenter 0402: Storage Tanks

Thief Hatches

EPA should allow other monitoring options to detect open thief hatches besides thief hatch sensors and visual inspections as visual inspections create significant safety concerns. The start date for an open thief hatch should be based on best available monitoring data.

…

Similarly, EPA should expand the visual inspections to allow other monitoring techniques (audio and olfactory in addition to visual, OGI, and alternative screening technology) due to potential safety issues with a strictly visual inspection of thief hatches. Since thief hatches are located on the top of the tanks, a visual inspection may require personnel to climb to the top of the tanks with potential vapor exposure (e.g., H_2S). Therefore, more remote monitoring techniques should be allowed to monitor for open thief hatches on controlled tanks.

Commenter 0410: On page 50326, the EPA seeks comment on the use of alternative technologies for quantifying the time that a thief hatch has been left open or not properly seated. Long Path has a strong track record of correctly identifying and notifying operators of improperly seated or open thief hatches. Alternative technologies that can provide case study data of this type of capability should be approved for this and all other emission source types: for example, reduced capture efficiency, stuck dump valves, malfunctioning pressure relief devices, and so on.

Commenter 0413: *Methods for determining the duration of time a thief hatch is open or not properly closed*

…

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 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.

Footnote:

[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-announcesclean-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-andcompressor-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.

Response 3: We did not propose and are not finalizing an option for reporters to use site-level monitoring data from remote sensing technologies to report emission volumes identified in follow-up ground surveys (*i.e.*, use of aerial monitoring in lieu of visual inspections to determine whether a thief hatch is open). A visual inspection must be able to identify if a thief hatch is open. Per the finalized 40 CFR 98.233(j)(4)(i)(C), a thief hatch is open if it is fully or partially open such there is a visible gap between the hatch cover and the hatch portal. EPA did not propose a remote-sensing monitoring technology option for open thief hatches due to concerns that the variable emissions from atmospheric storage tank flashing would not be accurately captured. While we are not finalizing site-level monitoring from remote sensing at this time, we are undertaking research on and exploring options for using remote sensing for this purpose and may consider these changes in a future rulemaking.

Commenter: American Exploration and Production Council
Comment Number: EPA-HQ-OAR-2023-0234-0295
Page(s): 17

Commenter: GPA Midstream Association
Comment Number: EPA-HQ-OAR-2023-0234-0299
Page(s): 38-39

Commenter: Range Resources Corporation
Comment Number: EPA-HQ-OAR-2023-0234-0397
Page(s): 8

Commenter: American Petroleum Institute et al. (Part 1 of 2)
Comment Number: EPA-HQ-OAR-2023-0234-0402
Page(s): 30

Commenter: Encino Energy (EAP Ohio, LLC)
Comment Number: EPA-HQ-OAR-2023-0234-0408
Page(s): 4

Comment 4: Commenter 0295: **Tanks**

AXPC has comments on several aspects of the proposed changes to Subpart W related to storage tanks. These comments are further outlined below.

Open Thief Hatches

…

However, other mechanisms may be used to accomplish the same objective, and in some cases be a more effective, reliable and safe manner to detect open or improperly seated hatches, such as the use of pressure sensor transmitters or combustor temperature indicators. For example, if a thief hatch is open or not properly seated, as defined above, the tanks will not build up pressure and the temperature of the combustor will drop substantially due to the loss of waste gas escaping from the hatch. In fact, many operators already employ these indicators to assist with determining open or unseated thief hatches. The requirement for additional sensors or technologies would result in additional cost burden on operators without the benefit that EPA is assuming.

AXPC recommends that EPA consider revising the rule language to allow the use of pressure sensor transmitters or combustor temperature sensors and/or a combination as an alternative, equivalent means of incorporating empirical data in the monitoring for open thief hatches. Without a sensor, the Proposal would require that the operator calculate emissions as if the thief hatch had been open since the preceding visual inspection. While conservative, it will not be an accurate accounting of emissions and would be better remedied through the allowance of pressure sensors or combustor temperature indicators when available. …

<u>Commenter 0299</u>: **Tank pressure sensors should be allowed to determine if a thief hatch is open.**

GPA notes that tank pressure sensors should be acceptable to determine if tank thief hatches are open or not properly seated. On controlled tanks, these sensors will register (for example) between 0.8 and 8 pounds of pressure. A pressure indication outside of this range would indicate an issue with the thief hatch. Pressure indication could in fact be more accurate than a visual inspection in the case of a not properly seated thief hatch. Allowing pressure sensor data will improve the accuracy of reported emissions, incorporate empirical data, and not force operators to assume thief hatch emissions were occurring when monitored data clearly indicates they were not. GPA suggests the following changes to the proposed regulatory text to capture this concept:

98.233(j)(7) Thief hatches. If a thief hatch sensor is operating on a controlled atmospheric pressure storage tank, you must use data obtained from the thief hatch sensor to determine periods when the thief hatch is open or not properly seated. An applicable operating thief hatch sensor must be capable of transmitting and logging data whenever a thief hatch is open or not properly seated, as well as when the thief hatch is subsequently closed. <u>If a tank pressure sensor is operating on a controlled atmospheric pressure storage tank, you must use data obtained from the pressure sensor to determine periods when the thief hatch is open or not properly seated. An applicable operating pressure sensor must be capable of transmitting and logging tank pressure data.</u> If a<u>n applicable</u> thief hatch sensor <u>or tank pressure sensor</u> is not <u>present or</u> operating, you must perform a visual inspection of each thief hatch on a controlled atmospheric pressure storage tank in accordance with paragraph (j)(7)(i) through (iii) of this section.

GPA further notes that “thief hatch sensor” is an appropriate term that can accommodate many technologies used to detect thief hatch emissions, including tank vibration/acoustic sensors.

<u>Commenter 0397</u>: **Thief hatch emissions can be accurately measured using tank pressure monitors.**

EPA should clarify that tank pressure monitoring systems (e.g., pressure transmitter using SCADA) are an acceptable method of determining whether a thief hatch is open or not properly seated in addition to visual monitoring or thief hatch sensors. Operators will be able to improve the accuracy of their reporting of emissions from thief hatches if they are permitted to use tank pressure monitoring systems to evaluate when emissions are occurring.

<u>Commenter 0402</u>: Storage Tanks

Thief Hatches

EPA should allow other monitoring options to detect open thief hatches besides thief hatch sensors and visual inspections as visual inspections create significant safety concerns. The start date for an open thief hatch should be based on best available monitoring data.

EPA proposes thief hatch sensors or visual inspections as the monitoring options for detecting open thief hatches on controlled storage tanks. The Industry Trades recommend that EPA allows

Tank Emission Monitoring Systems (TEMS) or other parametric monitoring in addition to thief hatch sensors. For example, many companies utilize a pressure transmitter or similar device to determine if a thief hatch is venting as they are more accurate.

Commenter 0408: EPA is requesting comment on the prevalence of pressure monitoring systems on atmospheric storage tanks, how pressure monitoring systems can be used to identify and determine the duration of periods of reduced capture efficiency due to open pressure relief devices […]. EPA is proposing in 40 CFR 98.233(j)(7) to require either the use of a thief hatch sensor or visual inspection of the tank to monitor the thief hatch.

EAP Ohio, LLC has broadly installed pressure transducers which are effective indicators of hatch/pressure relief device positions, in combination with temperature, on many oil tanks.

EAP Ohio, LLC adds that combustor temperature drops are also indicators of hatch/pressure relief device positions and could stand by themselves as an option for indicating reduced capture efficiency.

…

EAP Ohio, LLC requests provisions in the rule to utilize pressure transducer and temperature data either together or separately as indicators of decreased capture efficiency start and end times in addition to visual inspections or the thief hatch sensor.

Response 4: See Section III.K.1 of the preamble to the final rule for the response to this comment.

Commenter: American Exploration and Production Council
Comment Number: EPA-HQ-OAR-2023-0234-0295
Page(s): 17

Commenter: CrownQuest Operating
Comment Number: EPA-HQ-OAR-2023-0234-0393
Page(s): 178

Commenter: Western Energy Alliance
Comment Number: EPA-HQ-OAR-2023-0234-0399
Page(s): 14

Commenter: American Petroleum Institute et al. (Part 1 of 2)
Comment Number: EPA-HQ-OAR-2023-0234-0402
Page(s): 30-31

Commenter: Environmental Defense Fund, et al.
Comment Number: EPA-HQ-OAR-2023-0234-0413
Page(s): 50-52

Comment 5: Commenter 0295: **Tanks**

AXPC has comments on several aspects of the proposed changes to Subpart W related to storage tanks. These comments are further outlined below.

Open Thief Hatches

… Lastly, for those operators who elect not to utilize pressure sensors or temperature indicators, AXPC requests that the EPA clarify that the preceding visual inspection or leak monitoring event would be sufficient to determine the start time of thief hatch vent period.

Commenter 0393: EPA is proposing that an open thief hatch without a sensor is said to be open since the last inspection. We disagree with this and recommend that EPA allows operators to assume the thief hath has been open since the last credible inspection (routine lease manager site visit/operator inspection) and not only based on the last required annual thief hatch inspection.

Commenter 0399: Further, EPA's proposal that a thief hatch should be assumed open since the last annual thief hatch inspection without a thief hatch sensor, is without merit. Thief hatches may be opened for a variety of activities and maintenance at the facility, and a thief hatch inspection is hardly the only activity that would identify that one was open unintentionally. Instead, operators should be permitted to provide data to identify the last routine inspection of the facility or tank battery in lieu of the date of the last thief hatch inspection to identify an assumed timeline for the hatch having been left open.

> **Recommendation:** EPA should … allow for a more reasonable determination of leak duration based on site visits.

Commenter 0402: Storage Tanks

Thief Hatches

…

EPA is proposing that an open thief hatch without a thief hatch sensor is to be considered open since the last required inspection, which is proposed at least annually or more frequently if subject to AVO surveys under NSPS OOOOb or EG OOOOc. The Industry Trades recommend that EPA allow an operator to assume the thief hatch has been open since the last credible inspection (e.g., routine operator inspection) and not solely based on the last required thief hatch inspection. Proposed NSPS OOOOb and EG OOOOc (and earlier versions of the NSPS) do not require thief hatch sensors but instead require routine inspections of closed vent systems and covers for applicable storage vessels in addition to routine site surveys of fugitive emissions components. These inspections and additional monitoring would offer more frequent opportunities for operators to identify open thief hatches on a routine basis.

Commenter 0413:Methods for determining the duration of time a thief hatch is open or not properly closed

…

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

Response 5: The EPA is finalizing open thief hatch visual inspection requirements as proposed in 40 CFR 98.233(j)(7)(ii), which is consistent with leak survey requirements in 40 CFR 98.233(q). We expect that a significant portion of subpart W facilities with atmospheric storage tanks will be subject to the audio, visual, and olfactory (AVO) inspection frequencies for storage tank covers in NSPS OOOOb or EG OOOOc and, thus, the thief hatch inspection requirements detailed in 40 CFR 98.233(j)(7)(i). Additionally, a significant portion of subpart W facilities will be subject to the monthly NSPS OOOOa AVO inspections for storage tank covers, which they may use to estimate open thief hatch periods. For the remaining subpart W facilities not subject to NSPS OOOOa, OOOOb or EG OOOOc, it is expected that reporters will likely perform annual leak detection surveys to meet other federal, state, or internal monitoring requirements, which could also include a visual inspection of thief hatches on atmospheric storage tanks. Further, reporters are allowed under the final rule and may prefer to undertake more frequent surveys because such an approach would shorten the assumed open thief hatch duration used for calculating controlled emissions in situations with open thief hatches. The EPA considers this approach consistent with the directives Congress specified in CAA section 136(h), as it ensures that reporting is based on empirical data and accurately reflects total methane emissions while also allowing reporters to submit appropriate empirical emissions data. The EPA recognizes that the option for reporters to submit additional empirical data for a given facility may lead to reporters taking additional voluntary actions for subpart W reporting, including for the purpose of demonstrating the extent to which a charge under CAA section 136(c) is owed. To the extent this approach "incentivizes" additional actions by the reporter, the EPA considers this to be inherent in the directives Congress gave the EPA in CAA section 136(h).

Commenter: GPA Midstream Association
Comment Number: EPA-HQ-OAR-2023-0234-0299
Page(s): 38

Commenter: Endeavor Energy Resources, L.P.
Comment Number: EPA-HQ-OAR-2023-0234-0381
Page(s): 15

Commenter: CrownQuest Operating
Comment Number: EPA-HQ-OAR-2023-0234-0393
Page(s): 181

Commenter: Williams Companies, Inc.
Comment Number: EPA-HQ-OAR-2023-0234-0394
Page(s): 10

Commenter: The Petroleum Alliance of Oklahoma
Comment Number: EPA-HQ-OAR-2023-0234-0398
Page(s): 14

Commenter: Environmental Defense Fund, et al.
Comment Number: EPA-HQ-OAR-2023-0234-0413
Page(s): 52-53

Comment 6: Commenter 0299 **Reporters must be able to account for cessation of thief hatch emissions.**

EPA proposes assuming zero percent capture efficiency if a thief hatch is found open or not properly seated, and if one visual inspection is performed per year, that emissions calculations are performed assuming that the thief hatch was open for the entire calendar year. [94]

For gas-liquid separator dump valve malfunctions, however, EPA has proposed that if a dump valve is fixed following the visual inspection, the time period for which the dump valve was stuck open will end upon repair. To maintain consistency and to increase the accuracy of reported emissions, GPA proposes the inclusion of a similar provision for thief hatches. When an open or not properly seated thief hatch is closed, re-seated, and/or repaired after detection in the annual visual inspection, the reporter should be allowed to document the repair/closure and the time period for which the thief hatch was open or not properly seated should end upon closure/re-seating/repair. This also aligns with the Inflation Reduction Act directive to allow reporters to incorporate empirical data. Mandating the assumption of ongoing emissions even after the emissions are resolved contradicts the IRA's directive to use empirical data and is arbitrary and capricious.

Footnote:

[94] *Id*.

Commenter 0381: **EPA Should Reconsider the Proposed Revisions to Calculation Methods for Several Emission Sources.**

Atmospheric Storage Tanks

In the Subpart W Proposal, EPA expresses concern about current reporting of emissions from atmospheric storage tanks, and more specifically from thief hatches that are open or not properly seated.[48] EPA proposes to require reporting of the number of controlled atmospheric tanks with open thief hatches within the reporting years and the total volume of gas vented through those open thief hatches.[49] For purposes of calculating emissions from open thief hatches, EPA would require reporters to assume that no emissions are captured by the control device when the thief hatch is open or not properly seated, and that for calculating the time period that emissions were vented, reporters either use a thief hatch sensor or visual inspection.[50] If taking the latter approach, reporters identifying an open thief hatch would assume that the hatch had remained open from the time of the immediately preceding inspection—or the beginning of the calendar year if the inspection identifying the open thief hatch was the first inspection of the calendar year.[51]

While some reporters use thief hatch sensors, this is far from a uniform practice across the Onshore Production reporting segment, as many reporters rely principally or in part on visual inspections, usually conducted several times or once a week and generally not less than monthly, depending on the type of tank and well. Endeavor thus supports the ability to choose between the two methods (i.e., sensors or visual inspections) for determining the duration for when a thief hatch has been opened. That said, for visual inspections, Endeavor recommends a much shorter default period that recognizes the frequent inspections that occur within our industry. A default period of 30 days or less would more accurately reflect the likely emissions from an open thief hatch, and therefore better align with the IRA's requirements.

…

While some reporters use thief hatch sensors, this is far from a uniform practice across the Onshore Production reporting segment, as many reporters rely principally or in part on visual inspections, usually conducted several times or once a week and generally not less than monthly, depending on the type of tank and well. … At the very least, EPA should include a provision allowing a reporter to demonstrate that a thief hatch had been closed or properly reseated between the inspection identifying it as closed and the subsequent inspection identifying it as open. While such closure may not have been documented during a formal inspection, there may be other on-site documentation or records showing the opened/closed status of the thief hatch; in those cases, reporters should not need to assume the thief hatch was open during the entire duration between inspections. Such a provision would help ensure that emissions data is more accurately reported, in line with the IRA, and help prevent undue methane charges.

Footnotes:

[48] *Id*. at 50,326–27.

[49] *Id*. at 50,326.

[50] *Id.*

[51] *Id.*

Commenter 0393: The ask for the operator to assume that a thief hatch has been open for an entire calendar year is farfetched. With current LDAR OGI surveys and voluntary internal flyovers we catch the majority if not all open thief hatches and address them within a matter of hours.

Commenter 0394: **Start and End Dates for Open Thief Hatches and Stuck-Open Dump Valves**

Williams supports the Proposed Rule as currently written regarding the start date of an open thief hatch being the beginning of the reporting year, or the date of the inspection that the thief hatch was first observed to be open (whichever is latest). Williams seeks clarification that when the thief hatch is closed or repaired, the time period for which the reduced capture efficiency to a control device ends is the date of closure or repair.

Commenter 0398: EPA proposes that if one visual inspection of a tank is conducted in the calendar year and a thief hatch is identified as open or not properly seated, the reporter would be required to assume that the thief hatch had been open for the entire calendar year (or if multiple visual inspections are conducted in a calendar year, reporters are to assume that the thief hatch was open since the preceding visual inspection). EPA is proposing this same requirement for dump valves.

EPA's methodology assumes the worst-case scenario in all situations which may not be the case, leading to significant overestimations of emissions.

Action Requested: We request EPA consider a more reasonable emission estimation approach e.g., average the emissions since the last survey.

Commenter 0413: *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 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.

Response 6: We have previously received comments and performed analyses of various options regarding leak duration as it applies to the calculation method in 40 CFR 98.233(q). These analyses considered how to account for the use of multiple surveys which could include re-monitoring after repair. As a result of these analyses, in the 2016 final rule amendments, the EPA clarified our intent that a leak detected in the first or any intermediate survey is not considered to continue leaking past the date of that specific equipment leak survey. For the last survey conducted in the calendar year, the leak is assumed to continue until the end of the year. We maintain the same conclusions regarding the time variable for open thief hatch duration as we did for leak durations in the 2016 final rule. This approach to leak surveys, and in this case surveys to identify open thief hatches when continuous monitoring data are not available, provides the most accurate means to estimate leak duration when leaks are routinely repaired while still limiting all durations to a specific calendar year, which is appropriate and consistent with CAA section 136(h). With regard to the commenter's assertion that the EPA's approach to leak duration may overestimate emissions, although this may be the case for an individual thief hatch identified as open during an inspection, we maintain that the final approach results in an accurate quantification of emissions from all open thief hatches in part due to the fact that a certain percentage of thief hatches will open after the last inspection conducted by facilities in the calendar year without those emissions being quantified and reported by the facility. Therefore, the EPA is finalizing the leak duration periods as proposed and is not amending the requirements to reflect a shorter default period. We also note that the final rule requires visual inspections be conducted annually at a minimum; inspections may be conducted more frequently, which would result in shorter thief hatch opening durations being assumed.

For a comprehensive review of our previous analyses and response to comments on the amendments in the 2016 final rule, please refer to the ''Response to Public Comments on Greenhouse Gas Reporting Rule: Leak Detection Methodology Revisions and Confidentiality Determinations for Petroleum and Natural Gas Systems'' (Docket Item No. EPA–HQ–OAR–2015–0764-0067) and ''Greenhouse Gas Reporting Rule: Technical Support for Leak Detection Methodology Revisions and Confidentiality Determinations for Petroleum and Natural Gas Systems Final Rule'' (Docket Item No. EPA–HQ–OAR–2015–0764-0066).

Commenter: American Petroleum Institute et al. (Part 1 of 2)
Comment Number: EPA-HQ-OAR-2023-0234-0402
Page(s): 30

Comment 7: Commenter 0402: Storage Tanks

Thief Hatches

…

Thief hatch sensors do periodically malfunction and may falsely indicate an open thief hatch. As such, EPA should allow reporters to exclude thief hatch sensor malfunction periods and instead use best available monitoring data (e.g., TEMS, other parametric monitoring, last inspection) when determining the time that the thief hatch was open in calculating and reporting storage tank emissions.

Response 7: See Section III.K.1 of the preamble to the final rule for the EPA's response to this comment.

Commenter: CrownQuest Operating
Comment Number: EPA-HQ-OAR-2023-0234-0393
Page(s): 184

Commenter: Environmental Defense Fund, et al.
Comment Number: EPA-HQ-OAR-2023-0234-0413
Page(s): 49-52

Comment 8: Commenter 0393: Tanks are atmospheric vessels which have very low tolerances, older tanks may be impractical to retrofit.

Commenter 0413: 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 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.

…

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 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.

Footnotes:

[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.

Response 8: The EPA in finalizing the language in 40 CFR 98.233(j)(7) as proposed, which states that if a thief hatch sensor is operating on a controlled atmospheric storage tank, then reporters must use data obtained from the thief hatch sensor to determine periods when the thief hatch is open or not properly seated. Further, in the final rule, the EPA is allowing operational pressure sensors on atmospheric storage tanks to be used to determine periods when the thief hatch is open per 40 CFR 98.233(j)(7). We believe visual inspections in conjunction with clarifications to when thief hatches should be considered open will result in sufficiently accurate estimates of open thief hatch emissions. Therefore, we are not finalizing requirements for the use of thief hatch sensors or pressure monitors for tanks that do not already have this equipment in place.

Commenter: The Petroleum Alliance of Oklahoma
Comment Number: EPA-HQ-OAR-2023-0234-0398
Page(s): 14

Commenter: American Petroleum Institute et al. (Part 1 of 2)
Comment Number: EPA-HQ-OAR-2023-0234-0402
Page(s): 31

Commenter: Environmental Defense Fund, et al.
Comment Number: EPA-HQ-OAR-2023-0234-0413
Page(s): 52-53

Comment 9: Commenter 0398:

EPA requests comments on expanding the start date of an open thief hatch prior to the beginning of the reporting year. In this scenario, if the reporter can identify the start date and it spans reporting years, then that reporter would have to report the vented tank emissions from an open thief hatch that occurred in each reporting year and, if necessary, revise reports for the previous reporting year.

This is an unnecessary paperwork exercise (especially if it is a minor emission in one or both reporting years), provides no environmental benefit and takes away the reporter's focus to address other priority emission issues.

Action Requested: EPA should allow the operator to limit reporting of these types of emissions to the beginning of the calendar year it was identified.

Commenter 0402: Storage Tanks

Thief Hatches

Emissions from an open thief hatch should be reported for the year in which it was discovered.

EPA is also seeking comment on expanding the start date of the open thief hatch prior to the beginning of the reporting year. The Industry Trades suggest that the reporting for an open thief hatch be limited to the calendar year in which the open thief hatch is discovered. If the thief hatch is open over a period that started prior to the start of the reporting year, then the total duration should be reported in the year in which it was discovered to avoid re-submittal of prior year reports. To expand on this point, the Industry Trades propose that any episodic GHG emissions be reported solely in the reporting year in which it was discovered.

Commenter 0413: *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 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.

…

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.

Response 9: The EPA is finalizing that open thief hatch durations be restricted to the calendar year of reporting as proposed in 40 CR 98.233(j)(7). This is consistent with leak duration assumptions in 40 CFR 98.233(q) for leak detection surveys and, as also explained in the proposal, the EPA determined that this methodology provides an accurate quantification of emissions and is consistent with the timeframe required for subpart W annual reports. Additional details on why this duration assumption is appropriate for open thief hatches is provided in the response to Comment 6 of this section

Commenter: Marcellus Shale Coalition (MSC)
Comment Number: EPA-HQ-OAR-2023-0234-0275
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Commenter: American Exploration and Production Council
Comment Number: EPA-HQ-OAR-2023-0234-0295
Page(s): 18

Commenter: GPA Midstream Association
Comment Number: EPA-HQ-OAR-2023-0234-0299
Page(s): 37

Commenter: CrownQuest Operating
Comment Number: EPA-HQ-OAR-2023-0234-0393
Page(s): 178

Commenter: Western Energy Alliance
Comment Number: EPA-HQ-OAR-2023-0234-0399
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Commenter: Encino Energy (EAP Ohio, LLC)
Comment Number: EPA-HQ-OAR-2023-0234-0408
Page(s): 4

Comment 10: Commenter 0275: Storage Tanks

The MSC seeks clarification on the intent of 0% vapor capture efficiency from thief hatches as proposed in paragraph 98.233(j)(4)(i) states:

> "For an atmospheric pressure storage tank that routes any emissions to a vapor recovery system or a flare, calculate vented emissions as specified in paragraphs (j)(4)(i)(A) through (E) of this section.
>
> (A) Calculate maximum potential vented emissions as specified in paragraph (j)(1), (2), or (3) of this section, and calculate an average hourly vented emissions rate by dividing the maximum potential vented emissions by the number of hours that the tank was in operation.
>
> (B) To calculate vented emissions during periods when the tank was not routing emissions to a vapor recovery system or a flare, multiply the average hourly vented emissions rate determined in paragraph (j)(4)(i)(A) of this section by the number of hours that the tank vented directly to the atmosphere. Determine the number of hours that the tank vented directly to atmosphere by subtracting the hours that the tank was connected to a vapor recovery system or flare (based on engineering estimate and best available data) from the total operating hours for the tank in the calendar year. If emissions are routed to a flare but the flare is unlit, calculate emissions in accordance with the

> methodology specified in paragraph (n) of this section and report emissions from the flare as specified in § 98.236(n).
>
> (C) During periods when a thief hatch is open or not properly seated and emissions from the tank are routed to a vapor recovery system or a flare, assume the capture efficiency of the vapor recovery system or a flare is 0 percent."

…

Additionally, rather than assuming that an open hatch results in a zero-percent control efficiency, there should be three categories for storage vessel emissions that are not being fully captured: open thief hatch, PSV, and leaking thief hatch. Due to the variability in configuration and type of tank hatch emissions, the MSC requests the ability to use engineering estimates and best available data to estimate the control efficiency more accurately during periods of open or improperly seated hatches.

<u>Commenter 0295</u>: **Tanks**

Capture Efficiency

AXPC agrees that storage tanks will have reduced capture efficiency during periods when thief hatches are open or are not properly reseated. However, AXPC believes that assuming 0% capture during each of those periods is overly conservative and does not represent actual emissions, especially when assuming a duration since the previous visual inspection (see comment 6.A). For example, in cases where there is an eight tank battery and only one tank's thief hatch is open, the other seven closed hatches would still partially function to capture some emissions. As another example, Industry works to maintain closed hatches when a vapor recovery unit is in use, however when a hatch unseats, the vapor recovery unit will continue to pull waste gas tank vapors into processes ensuring the recovery rate of the waste gas is not zero. Therefore, EPA's proposed calculation method of taking a vent rate multiplied by the opening duration is not the most accurate method to account for vented emissions during these events. AXPC recommends that EPA allow for the use of engineering estimates based on best available data to estimate the capture efficiency during periods when thief hatches are open or not properly seated.

Some examples of engineering estimates based on best available data may include information determined from pressure sensor transmitters, tank modeling, or combination thereof. Further supporting the benefits of allowing data from pressure sensors, isolating the time period when a thief hatch is open, can allow the operator to narrow the production throughputs through a tank battery to estimate a more exact capture efficiency based on throughputs rather than only on time. It is well known that an annual average production rate may not be the most accurate method in determining a singular event with open or not properly seated thief hatches. Since tank emissions are closely correlated in a linear fashion to throughput values, a capture efficiency based on engineering estimates and tank modeling in conjunction with pressure sensor data will result in a more accurate emissions profile from these events.

Commenter 0299: **EPA should not assume an open thief hatch has zero capture efficiency.**

EPA proposes that reporters must assume zero percent capture efficiency when thief hatches are found open or not properly seated.[93] EPA has not provided a justification for this assumption in the Preamble or Technical Support Document. If a tank is controlled with a vapor recovery unit ("VRU"), for example, the VRU does not run all the time. It turns on only when there is high enough pressure in the tank. If the vapors in the tank overwhelm the VRU, the tank thief hatch may open. This does not mean, however, that the VRU is no longer collecting any vapors. Depending on the pressures in the tanks and the pressures in the lines routing emissions to the associated control devices, in some situations, there may be some continued--though reduced--amount of capture. Therefore, GPA proposes that EPA allow engineering estimates of capture efficiencies to be used in situations where there are available data to make those estimates.

Footnote:

[93] Id. at 50,326.

Commenter 0393: EPA has proposed that both oil and produced water storage tanks with an open thief hatch must use VRU capture efficiency or flare of 0%. This has the potential to drastically overestimate methane emissions. The storage tank can hold sufficient pressure for the combustor and/or VRU to operate, then it is only partially leaking, and the capture efficiency can be estimated. The 0% would greatly overestimate the methane emissions vented to the atmosphere through the thief hatch. Some thief hatches are meant to "breathe" as it is their proper function. These devices open to relieve excess pressure and reseat when the overpressure (or unpressurized) is gone. The EPA should allow the use of engineering estimates to use the appropriate capture efficiency. This will depend on the extent to which the hatch is open, essentially an estimated capture efficiency greater than 0% when the hatch is partially open.

Commenter 0399: *Storage Tanks*

First, as proposed, the rule requires a drop in efficiency of Vapor Recovery Units (VRUs) and destruction efficiency of flares to zero for storage tanks in the absence of evidence that the resulting efficiency would be that low. Tank emissions monitoring systems (TEMS) or other parametric monitoring should be allowed in addition to thief hatch sensors. The destruction efficiency of flares and capture efficiency of VRUs is variable, even in situations where a thief hatch has been left open, or when a thief hatch seal has been compromised. EPA should allow for the use of engineering estimates and monitoring technologies to determine the actual capture efficiency of the equipment in place should there be an unintended event or malfunction within the thief hatch system.

…

> **Recommendation:** EPA should allow for the use of engineering estimates and monitoring technologies to determine actual capture and destruction efficiencies for flares and VRUs where thief hatches are open.

Commenter 0408: EAP Ohio, LLC disagrees with the proposed 0 percent capture efficiency when the hatches/pressure relief device are unseated/open.

- Although capture efficiency can be reduced severely in some circumstances, EAP Ohio, LLC has found the capture efficiency is not zero. Tank batteries can have several tanks in line with the combustor and one hatch open in the system does not mean all tanks fail to send vapors to the combustor

…

EAP Ohio, LLC asks EPA to ensure available data can be used to determine destruction efficiency in times when the hatch/pressure relief position fails to contain all tank vapors in addition to having the option of a non-zero default capture efficiency assumption.

Response 10: We are finalizing revisions to 40 CFR 98.233(j)(4)(i)(C) as proposed to require facilities to assume that no emissions are captured by the control device (0 percent capture efficiency) when the thief hatch on a tank is open. The EPA disagrees that engineering estimates using best available data could produce an accurate determination of control efficiencies during periods when the thief hatch is open. Commenters did not provide examples of the methodologies that could be used to determine capture efficiency while a thief hatch is open. While methodologies may be used to determine when a thief hatch is open, at this time the EPA has not found any verified studies or literature for determining capture efficiencies during these periods. The EPA intends to consider any future studies on this subject in future rulemaking amendments.

Commenter: Marcellus Shale Coalition (MSC)
Comment Number: EPA-HQ-OAR-2023-0234-0275
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Commenter: American Petroleum Institute et al. (Part 1 of 2)
Comment Number: EPA-HQ-OAR-2023-0234-0402
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Comment 11: Commenter 0275: Storage Tanks

…

The basis of emissions determined in accordance with paragraph (j)(1), (2), or (3) is total upstream separator, non-separator, or well throughput (which may feed multiple tanks). Due to the imprecise nature of the references to “the tank” throughout paragraph (j) in discussion related to determining an hourly emission rate and determining times when “the tank” vapors are uncaptured, it is difficult to understand the intent of these requirements. The U.S. EPA should clarify whether the assumption is that all separator, non-separator, or well vapors involved when routed to atmospheric conditions would be considered uncontrolled where one tank thief hatch (out of many in a battery) is found to be open or not properly seated.

Commenter 0402: Storage Tanks

Thief Hatches

EPA should allow engineering estimates of the open thief hatch volumetric flow for tank batteries with a common vent line.

For many tank batteries, vent lines for multiple tanks are combined in a common vent line header that is routed to a control device. If one thief hatch is found open, the entire tank battery should not be assumed to have open thief hatches with a resultant zero percent capture efficiency. The Industry Trades suggest that EPA allow for use of engineering estimates, e.g., modeled volumes, in this case to report the emissions from the tank battery's open thief hatch.

Response 11:

The EPA has not found any verified studies or literature for capture efficiencies for tank batteries with shared manifolds where one or more of the tanks have open thief hatches. The commenters did not provide additional details or studies for the EPA to evaluate that would require any further updates to the final rule. Therefore, we are finalizing revisions to 40 CFR 98.233(j)(4)(i)(C) as proposed to require facilities to assume that no emissions are captured by the control device (0 percent capture efficiency) when the thief hatch on a tank is open, including cases where a battery of tanks shares a common vent line header and a thief hatch on one or more of the tanks are open. The EPA intends to consider any future studies on this subject in future rulemaking amendments.

Commenter: Environmental Defense Fund, et al.
Comment Number: EPA-HQ-OAR-2023-0234-0413
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Comment 12: Commenter 0413: *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.

Response 12: The EPA disagrees that additional reporting data elements for atmospheric storage tanks with open thief hatches are necessary to provide more granularity on the data or to improve EPA's ability to understand individual event contributions to emissions. We are finalizing the reporting requirements of 40 CFR 98.236(j)(1)(x)(F) and 40 CFR 98.236(j)(1)(xv), 40 CFR 98.236(j)(2)(ii)(D) and (H), and 40 CFR 98.236(j)(2)(iii)(D) and (F) to collect the count of controlled atmospheric storage tanks with an open thief hatch and the total volume of gas vented through open thief hatches from controlled atmospheric storage tanks, respectively. This data will be collected for each facility, well-pad, or gathering and boosting site, which we determined will provide enough granularity a this time.

Commenter: GPA Midstream Association
Comment Number: EPA-HQ-OAR-2023-0234-0299
Page(s): 83-85

Commenter: CrownQuest Operating
Comment Number: EPA-HQ-OAR-2023-0234-0393
Page(s): 179

Commenter: The Petroleum Alliance of Oklahoma
Comment Number: EPA-HQ-OAR-2023-0234-0398
Page(s): 13-14

Comment 13: Commenter 0299: **Proposed Change**: EPA is proposing several changes that are likely to result in the double-counting of emissions through open or unseated thief hatches. EPA is also proposing that tank thief hatch emissions be quantified and reported. EPA claims this adds no reporter burden.

> **Comment**: EPA must revise its proposal to eliminate the potential for double counting of tank thief hatch emissions. As proposed, these emissions may be counted under tanks, equipment leak population counts, and equipment leak surveys. As explained below, tank thief hatch emissions should be accounted for under the equipment leak emission sources only. This aligns with EPA's definition of fugitive emissions in NSPS OOOOa.[25]
>
> To elaborate on the three areas the same emissions would be counted we have provided the following additional information:
>
>> First, EPA states that if "a reporter sees emissions from a thief hatch or other opening on a controlled atmospheric storage tank during an equipment leak survey conducted using OGI, the reporter should consider that information as part of the 'best available data' used to calculate emissions from that storage tank."[26] EPA says the amount emitted must be quantified and reported and then used to adjust the reported emissions from the tank.

> Second, for leaks by population count, EPA is proposing a population emission factor in Table W-1A (Default Whole Gas Emission Factors for Onshore Petroleum and Natural Gas Production Facilities and Onshore Petroleum and Natural Gas Gathering and Boosting Facilities) of 0.85 scf/hour per storage vessel. The proposed emission factor of 0.85 scf/equipment was derived from data that included thief hatch emissions (as noted in S-5, of the Supplementary Information for Methane Emissions from Gathering Compressor Station in U.S., Zimmerle et al., upon which the proposed emission factors were based). If this factor is finalized, then thief hatch emissions will already be accounted for under equipment leaks by population count.
>
> Third, for equipment leak surveys, in Tables W-1E (Default Whole Gas Leaker Emission Factors for Onshore Petroleum and Natural Gas Production and Onshore Petroleum and Natural Gas Gathering and Boosting) and W-2A (Default Total Hydrocarbon Leaker Emission Factors for Onshore Natural Gas Processing), EPA includes a component type labeled "Other." A leak from a tank thief hatch is generally accounted for under this "Other" category.

Emissions from an open or unseated thief hatch are difficult to quantify. Additionally, collecting and rolling up this kind of "exception data" is very burdensome in a GHG reporting program. Reporters already spend a substantial amount of time collecting and verifying data on stuck dump valves. Because quantifying these emissions and collecting this data are not easy, EPA should continue to account for these emissions under the leak categories and remove requirements specifying that unseated or open thief hatches should result in an adjustment to tank emissions. EPA should also remove the requirement to report volume of gas vented through open or unseated thief hatches. Without an involved "research project" this number will likely be an approximation, and EPA will not get the quality of data it needs to "quantify the impact of open thief hatches." It would be appropriate for EPA to clarify that open or unseated thief hatches detected while conducting a leak survey should be categorized as "Other."

We agree that it may not be appropriate to assume 100% recovery or control of emissions from tanks that have a vapor recovery unit ("VRU") or are routed to flare. Most permit applications will include a capture/control percentage for VRUs or flares, and we propose adding language to clarify that permitted capture/control percentages should be considered an "engineering estimate based on best available data."

Finally, in section 10.2 of the "Assessment of Burden" document, EPA claims that these "clarifying edits" to 98.233(j)(4) and (5) related to open thief hatches for atmospheric storage tanks impose no additional burden on reporters. As described above, this is an incorrect assumption.

Suggested text:

98.233(j)(4)(i) Using engineering estimates based on best available data<u>*, which includes permitted capture/control percentages,*</u> *determine the portion of the total emissions* *estimated in paragraphs (j)(1) through (3) of this section that is recovered using a vapor recovery system. You must take into account periods with reduced capture efficiency of the vapor recovery system (e.g., when the vapor recovery system is not operating ~~a thief hatch is open or not properly seated)~~ when calculating emissions recovered.*

98.233(j)(5)(i)(A) If unrecovered emissions from the storage tank are calculated in accordance with paragraph (j)(4) of this section, then determine the volume of the unrecovered emissions routed to flares based on best available data. If no emissions from the storage tank are routed to vapor recovery, then use the storage tank emissions volume as determined in paragraphs (j)(1) through (3) of this section, except that you must also adjust this total volume of emissions downward by the estimated portion of the total volume that is not routed to the flare (e.g., when the flare is bypassed ~~or when a thief hatch is open or not properly seated~~). Estimate the volume of the emissions not routed to flares based on best available data, which includes permitted capture/control percentages.

~~98.236(j)(1)(xiii) For the atmospheric tanks at your facility identified in paragraph (j)(1)(x)(D) of this section, the total volume of gas vented through open or unseated thief hatches, in scf, during periods while the tanks were also routing emissions to vapor recovery systems and/or flares.~~

Footnote:

[25] 40 C.F.R. § 60.5430a ("Fugitive emissions component means any component that has the potential to emit fugitive emissions of VOC at a well site or compressor station, including valves, connectors, pressure relief devices, open-ended lines, flanges, covers and closed vent systems not subject to § 60.5411 or § 60.5411a, thief hatches or other openings on a controlled storage vessel not subject to § 60.5395 or § 60.5395a, compressors, instruments, and meters. Devices that vent as part of normal operations, such as natural gas-driven pneumatic controllers or natural gas-driven pumps, are not fugitive emissions components, insofar as the natural gas discharged from the device's vent is not considered a fugitive emission. Emissions originating from other than the device's vent, such as the thief hatch on a controlled storage vessel, would be considered fugitive emissions.").

[26] 87 Fed. Reg. at 36,968.

Commenter 0393: this assumption is misleading. EPA has data of thousands of tanks; EPA should use its own LDAR surveys of which it has millions to evaluate if this is an actual issue rather than its vague notions on tank hatches.

Commenter 0398: EPA proposes several new requirements for storage tanks in the Proposed Rule and states there is no double counting of reported emissions via reporting of emissions from open or unseated thief hatches, tank leak surveys, emissions from tank identified as other large release events, reduced capture efficiencies, or dump valve emissions.

However, EPA fails to clearly and concisely explain how double counting of emissions will not occur.

Action Requested: We request EPA clarify how double counting of emissions for storage tanks will not occur as a result of multiple proposed requirements for storage tanks.

Response 13: The EPA has previously confirmed that there is no potential for double counting thief hatches in the methodologies provided in 40 CFR 98.233(q) and 40 CFR 98.233(r), and we have also confirmed that there is no potential for double counting thief hatches based on the proposed and final revisions to 40 CFR 98.236(j), (q) and (r). When determining leaks by population count per 40 CFR 98.233(r), the EPA is finalizing major equipment emission factors in existing Table W-1A (proposed Table W-1) that were developed using Rutherford *et al.* (2021). Population emission factors are presented by major equipment, which includes tanks – leaks; however, the major equipment indicating venting emissions (*e.g.*, tanks – unintentional vents) were not included. For equipment leak surveys per 40 CFR 98.233(q), existing Table W-1E (proposed Table W-2) references 40 CFR 98.232(c)(21) and (j)(10) for onshore petroleum and natural gas production and onshore petroleum and natural gas gathering and boosting, respectively. These provisions, which describe the list of components to be surveyed for equipment leaks, specifically state that thief hatches or other openings on a storage vessel should not be considered an "other component." As such, we confirm that the proposed thief hatch emissions reporting requirements in 40 CFR 98.236(j) would not overlap with the equipment leak emission reporting requirements in 40 CFR 98.236(q) and (r).

The EPA disagrees that reporters should be able to use permitted capture/control efficiencies to approximate the emissions that are vented when a thief hatch is open. Permitted capture/control efficiencies are typically representative of emissions reductions that can be achieved when a control is functioning as expected, which would not be the case when a control is being bypassed due to an open thief hatch. The commenter has not provided supporting documentation that states otherwise (i.e., that thief hatch openings are routinely considered when determining capture/control efficiencies within a permit). The EPA was not able to identify any studies where capture efficiencies during periods of an open thief hatch on an atmospheric storage tank were quantified. Therefore, we are maintaining the assumption of zero percent capture during these periods in an effort to avoid potential overestimation of the capture efficiency determined by an engineering estimate.

Comments regarding burden estimates for atmospheric storage tanks are addressed in section 25 of this document.

Commenter: Range Resources Corporation
Comment Number: EPA-HQ-OAR-2023-0234-0397
Page(s): 8

Comment 14: Commenter 0397: EPA's proposal for storage tank thief hatch reporting will undoubtedly result in inaccurate overreporting of emissions.

…

At the very least, EPA must clarify that its proposed assumption for thief hatch emissions is not an accurate reflection of actual emissions, particularly given the potential enforcement implications. Not all issues with a thief hatch will give rise to noncompliance. For example, a gasket that naturally deteriorates (more than what it typically would have in the way of reduced efficacy) does not necessarily arise to noncompliance. Additionally, a thief hatch that properly opens to accommodate safety requirements does not necessarily give rise to noncompliance. As currently structured, however, the Proposed Rule would require operators to self-report noncompliance when there may be no noncompliance. Thus, EPA should be mindful that operators that report inaccurate emissions based on assumptions in EPA's subpart W regulations—but which do not reflect actual emissions—should not be cause for finding noncompliance. Further, reports of emissions from thief hatches under subpart W should not necessarily impact a well site's closed vent system certification.

Response 14:

The proposed rule does not require "operators to self-report noncompliance when there may be no noncompliance." Noncompliance of subpart W of 40 CFR 98 is a violation that includes failure to report GHG emissions, failure to collect data needed to calculate GHG emissions, failure to continuously monitor and test as required, failure to retain records to verify GHG emission and failure to calculate GHG emissions following methodologies specified in this section. The EPA has provided detailed methodologies and individual facilities can contact the GHGRP help desk with questions about subpart W emission calculations. The methodologies are regularly updated by rulemaking to reflect the most current research to ensure the most accurate emissions are reported. The EPA has assessed that the methodologies for atmospheric pressure tanks are all supported by peer-reviewed studies and represent the best approach for calculating accurate emissions. The commenter did not provide any additional data or peer-reviewed studies for the EPA to address their concerns that warrant any further updates to the methodologies provided for atmospheric pressure storage tanks. We also note that in the final rule, the EPA has specified that a thief hatch is open if it is fully or partially open such that there is a visible gap between the hatch cover and the hatch portal.

Commenter: Anonymous
Comment Number: EPA-HQ-OAR-2023-0234-0237
Page(s): 1

Commenter: Encino Environmental Services
Comment Number: EPA-HQ-OAR-2023-0234-0364
Page(s): 5

Commenter: Environmental Defense Fund, et al.
Comment Number: EPA-HQ-OAR-2023-0234-0413
Page(s): 50

Comment 15: Commenter 0237: Finally, I feel that providing clear methods for reporting emissions from open thief hatches on tanks is vitally important to creating a thorough inventory of greenhouse gas emissions from the oil and gas industry. I support EPA's proposal to track open thief hatches through visual inspection.

Commenter 0364: ***Atmospheric storage tanks – Open thief hatches***

Encino understands that this proposed rule intends to address the apparent issue of not accurately accounting for emissions attributed to open thief hatches installed on atmospheric storage tanks. Encino agrees with the EPA with requiring visual inspections or sensors monitoring thief hatches. This in in line with current product development associated with more durable and smart thief hatch devices. For example, Encino's Enviromech composite thief hatch provides a more durable and smarter thief hatch.

Encino believes that this practice will help with the waste minimization efforts and will aid in minimizing underestimation of emissions attributed to atmospheric tanks.

Commenter 0413: *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).

Footnote:

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

Response 15: The EPA acknowledges the commenters' support of the proposed revisions. See Section III.K.1 of the preamble to the final rule for more information on the finalized amendments for open thief hatches.

Commenter: GPA Midstream Association
Comment Number: EPA-HQ-OAR-2023-0234-0299
Page(s): 83

Comment 16: Commenter 0299: **Proposed Change**: EPA is proposing to require reporting of the number of controlled tanks with open or unseated thief hatches within the reporting year.

> **Comment**: This requirement should be removed. Tracking and reporting open/unseated thief hatches is not currently required for many older tanks that are not subject to NSPS OOOO/OOOOa. Adding this requirement would greatly expand the number of tanks and facilities that would, in effect, need to comply with the OOOO/OOOOa leak tracking provisions and would create a significant additional burden on reporters. Additionally, for tanks that are subject to OOOO/OOOOa, this data element would be duplicative of the requirements of that rule, and as such, this data element would unnecessarily increase the burden of reporting by requiring the same information in multiple federal reports.
>
> **Suggested text**: ~~*98.236(j)(1)(x)(D) The number of atmospheric tanks in paragraph (j)(1)(x)(C) of this section that had an open or unseated thief hatch at some point during the year while the tank was also routing emissions to a vapor recovery system and/or a flare.*~~

Response 16: We are finalizing the reporting requirements in 40 CFR 98.236(j)(1)(x)(F) as proposed, which requires facilities to report the count of atmospheric pressure storage tanks that had an open thief hatch at some point during the year while the storage tank was also routing emissions to a vapor recovery system and/or a flare. In 40 CFR 98.233(j)(4), we are requiring that facilities reduce their control efficiency on atmospheric tanks during times that a thief hatch is open. Further, the EPA is finalizing the addition of 40 CFR 98.233(j)(7), which will require facilities to monitor thief hatch openings on controlled atmospheric tanks. With this information, facilities should have an accurate count of controlled atmospheric storage tanks with an open thief hatch, which is needed in order to comply with the requirements in 40 CFR 98.233(j)(4) and (7) and accurately estimate emissions from controlled atmospheric storage tanks, consistent with 136(h).

Regarding burden, costs related to the annual inspection of thief hatches were estimated at proposal and at final. In the EPA's final amendments cost analysis, the combined costs are $7.5 million total per year for the Onshore Petroleum and Natural Gas Production, Onshore Petroleum and Natural Gas Gathering and Boosting, and Onshore Natural Gas Processing industry segments.

12.2 Malfunctioning Dump Valves

Commenter: EnerVest Operating, LLC
Comment Number: EPA-HQ-OAR-2023-0234-0229
Page(s): 4

Commenter: GPA Midstream Association
Comment Number: EPA-HQ-OAR-2023-0234-0299
Page(s): 39

Commenter: MiQ
Comment Number: EPA-HQ-OAR-2023-0234-0392
Page(s): 11

Commenter: Range Resources Corporation
Comment Number: EPA-HQ-OAR-2023-0234-0397
Page(s): 9

Commenter: Chesapeake Energy Corporation
Comment Number: EPA-HQ-OAR-2023-0234-0400
Page(s): 17-18

Commenter: American Petroleum Institute et al. (Part 1 of 2)
Comment Number: EPA-HQ-OAR-2023-0234-0402
Page(s): 32

Commenter: Environmental Defense Fund, et al.
Comment Number: EPA-HQ-OAR-2023-0234-0413
Page(s): 54

Comment 1:

Commenter 0229: Malfunctioning Dump Valves

- The proposal states, in part "formalize the requirement to perform routine visual inspections of separator dump valves to determine if the valve is stuck in an open position, thus allowing gas carry- through to the controlled tank(s)."
- Many wells are on SCADA systems where trends detect a deviation or production drop.
- We propose that where SCADA or similar measurement systems are in place, the time a valve is malfunctioning could be determined with accounting or field personnel software.

Commenter 0299: **Inspection for stuck dump valves must extend beyond visual assessments alone.**

EPA proposes mandated visual inspections of gas-liquid separator dump valves on uncontrolled tanks.[95] EPA should allow alternative inspection methods, such as utilizing OGI cameras or advanced technology to detect excessive tank emissions. Another effective approach to identify stuck dump valves involves auditory inspections of the tank, particularly in cases where tanks are designed with submerged fill—a stuck dump valve allowing gas flow into the tank produces noticeable "bubbling" sounds. Relying solely on visual inspections of the dump valves themselves may not always reveal underlying issues. Broadening the spectrum of inspection options empowers reporters to encompass all relevant empirical data accurately. Accordingly, GPA proposes the following changes to the regulatory text:

98.233(j)(5)(i) You must perform an ~~visual~~ inspection ~~of each gas-liquid separator liquid dump valve~~ to determine if the gas-liquid separator dump valve is stuck in an open or partially open position, in accordance with paragraph (j)(5)(i)(A) and (B) of this section.
98.233(j)(5)(i)(A) ~~Visual inspections~~ Inspections must be conducted at least once in a calendar year.

Footnote:

[95] Id. at 50,327.

Commenter 0392: 98.233(j)(5)(i)(B): If stuck gas-liquid separator liquid dump valve is identified, the dump valve must be counted as being open since the beginning of the calendar year, or from the previous visual inspection that did not identify the dump valve as being stuck in the open position in the same calendar year. If the dump valve is fixed following visual inspection, the time period for which the dump valve was stuck open will end upon being repaired. If a stuck dump valve is identified and not repaired, the time period for which the dump valve was stuck open must be counted as having occurred through the rest of the calendar year.

MiQ Comments: Through experience with audits of MiQ facilities, it is fairly common practice amongst operators of high-pressure gas-liquid separators that wells will be shut-in or alarms requiring immediate response due to the separator reaching low liquid level, which will happen if a dump valve is stuck open. In some other cases, operators will also monitor the density of the fluid going to the tank and alarms on low density will trigger follow up to inspect for a malfunctioning dump valve. These best practices have been commonly verified amongst the vast majority of MiQ-certified operators on high-pressure gas-liquid separators. We cannot confirm if process parameters are also monitored on low-pressure gas-liquid separators. We suggest that EPA consider including the monitoring of process parameters as a method to both 1) identify a dump valve malfunction, and 2) estimate the amount of time the dump valve was stuck open resulting in emissions. We suggest that, if this is implemented, that EPA include reporting requirements of operators to list separators in which process parameters are used as the primary method to identify and estimate the duration of dump valve malfunctions.

Commenter 0397: **Revisions are needed to ensure that emissions from dump valves are accurately reported.**

The Proposed Rule requires visual inspection of dump valves at least once per year, in accordance with proposed 40 C.F.R. § 98.233(j)(5)(i). See 88 Fed. Reg. at 50237. EPA's new proposal requiring visual inspections would lead to unnecessary expenditures and a diversion of resources. Instead, operators should have the option to use process monitoring data to determine event occurrence and, if necessary, the duration of the event. The process data includes fluid density and pressure. If the gas in a dump valve is escaping, then the density and pressure will go down. Operators have sufficient process information to identify dump valves that have become stuck or that are malfunctioning, therefore, visual inspections are unnecessary. Indeed, utilizing process data will result in more accurate reporting because operators will be able to detect and quantify emissions more accurately. Process data is also evaluated more regularly than annually, which results in a more accurate assessment of malfunctioning dump valves.

Commenter 0400: **Stuck Dump Valves**

EPA's Proposed Rule requires operators to estimate emissions resulting from malfunctioning dump valves, based on part on the total time the dump valve did not close properly in the calendar year. [60] As proposed, operators would be required to visually inspect gas-liquid separators each year to determine if a liquid dump valve is stuck in an open or partially open position, and estimate emissions based on the assumption that the dump valve had been stuck open since the preceding visual inspection. [61] Operators could only base the total time a dump valve was on this visual inspection.[62]

Chesapeake strongly encourages EPA to allow operators to utilize other company records to estimate the duration of the stuck dump valve more accurately. Such records could include the following:

- Automation data that indicates when a stuck dump valve event began. As one example, operators could evaluate the liquid level in a separator—in severe cases, a stuck valve can be identified based on this level. In addition, operators could evaluate the production or gas sales rate prior to the observed stuck dump valve. A defined decline in production rate is a strong indicator of the start time for a stuck valve.
- Records of the facility being shut in and not producing. Regardless of the total time a valve is stuck, a stuck dump valve will not generate emissions during periods of shut in. Operators should be permitted to take these conditions into account in estimating emissions from a stuck dump valve.

Ensuring that reported emissions are accurate is consistent with both the goals of CAA Section 136(h) and EPA's rulemaking goals. Thus, EPA should extend to other source categories the use of company records in the determination of an emission event duration rather than defaulting to a specified duration as proposed.

Footnotes:

[60] Id. at 50,327.

[61] See id.

[62] See id.

Commenter 0402: Storage Tanks

Gas-liquid Separator Liquid Dump Valves

The start date for a stuck separator dump valve should be based on best available monitoring data.

Like the above comment on open thief hatch monitoring, EPA should allow the start date for a stuck gas-liquid separator liquid dump valve to be based on the best monitoring data available (TEMS, other parametric monitoring, alternative screening technology, routine operator inspections, etc.) rather than solely the date of the last required annual visual dump valve inspection. This flexibility will allow operators to calculate storage tank emissions more accurately.

Commenter 0413: *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.

Response 1: See Section III.K.2 of the preamble to the final rule for the response to these comments.

Commenter: CrownQuest Operating
Comment Number: EPA-HQ-OAR-2023-0234-0393
Page(s): 185

Commenter: Range Resources Corporation
Comment Number: EPA-HQ-OAR-2023-0234-0397
Page(s): 9

Comment 2:

Commenter 0393: This is a routine day-to-day operation for field personnel and does not need to be a requirement from the EPA. Open dump valves upset normal operations of a facility and will be dealt with for reasons other than gas carry-through if not immediately.

Commenter 0397: **Revisions are needed to ensure that emissions from dump valves are accurately reported.**

…

Moreover, the parameters that are required to be observed and recorded during visual inspections are unclear. Dump valves may become stuck for a short period of time and often self-resolve. In fact, it is uncommon to find a stuck dump valve that has been stuck for more than a day. Consequently, if a visual observation identifies a stuck dump valve, it would be inaccurate to report that the dump valve has been malfunctioning for a year.

Response 2: The EPA is finalizing the stuck dump valve duration requirements in 40 CFR 98.233(j)(5)(i)(B) for stuck dump valves identified during audio, visual, and olfactory inspections as proposed. These requirements are consistent with the stuck dump valve duration determinations for condensate storage tanks in 40 CFR 98.233(k). Further, as discussed in our response to comment 1 in Section 17.7 of this document, we have previously received comments and performed analyses of various options regarding leak duration as it applies to the calculation method in 40 CFR 98.233(q). These analyses considered how to account for the use of multiple surveys which could include re-monitoring after repair. As a result of these analyses, in the 2016 final rule amendments, the EPA clarified our intent that a leak detected in the first or any intermediate survey is not considered to continue leaking past the date of that specific equipment leak survey. For the last survey conducted in the calendar year, the leak is assumed to continue until the end of the year. Furthermore, our analysis also indicated that the option to determine leak duration based on remonitoring after repair was likely to underestimate leak emissions whereas the current methodology based on survey dates provided an accurate quantification of leak emissions. We maintain the same conclusions regarding the time variable for stuck dump valve duration as we did for leak durations in the 2016 final rule. Further, reporters are allowed under the final rule and may prefer to undertake more frequent surveys because such an approach would shorten the assumed stuck dump valve duration used for calculating controlled emissions in situations with stuck dump valves. With regard to the commenter's assertion that stuck dump valves often self-resolve, this would mean that certain stuck dump valves will not be identified during surveys (if they become stuck after an inspection and self-resolve before a subsequent inspection) and, therefore, associated emissions would not be quantified. This would be an argument for more conservative estimates of leak duration for those dump valves that are identified as being stuck during inspections rather than less conservative estimates.

For a comprehensive review of our previous analyses and response to comments on the amendments in the 2016 final rule, please refer to the ''Response to Public Comments on Greenhouse Gas Reporting Rule: Leak Detection Methodology Revisions and Confidentiality Determinations for Petroleum and Natural Gas Systems'' (Docket Item No. EPA–HQ–OAR–2015–0764-0067) and ''Greenhouse Gas Reporting Rule: Technical Support for Leak Detection Methodology Revisions and Confidentiality Determinations for Petroleum and Natural Gas Systems Final Rule'' (Docket Item No. EPA–HQ–OAR–2015–0764-0066).

Commenter: Marcellus Shale Coalition (MSC)
Comment Number: EPA-HQ-OAR-2023-0234-0275
Page(s): 9

Comment 3: Stuck Dump Valves

The regulation is not clear on where excess emissions resulting from stuck dump valves should be reported. The MSC recommends that these emissions be included with the source where it is emitted to the atmosphere. An example would be controlled or uncontrolled tank emissions.

Response 3:

The EPA has finalized provisions to report stuck dump valve emissions in section 98.236(j)(3). If any gas-liquid separator dump valve did not properly close during the calendar year, you must report the information specified in 40 CFR 98.236(j)(3)(i) through (v) for each well-pad site (for onshore production), gathering and boosting site (for onshore petroleum and natural gas gathering and boosting), or facility (for all other applicable industry segments) by liquid type.

Commenter: Williams Companies, Inc.
Comment Number: EPA-HQ-OAR-2023-0234-0394
Page(s): 10

Commenter: Environmental Defense Fund, et al.
Comment Number: EPA-HQ-OAR-2023-0234-0413
Page(s): 53-54

Comment 4: <u>Commenter 0394</u>: **Start and End Dates for Open Thief Hatches and Stuck-Open Dump Valves**

…

Williams supports the Proposed Rule as currently written regarding the start date of a stuck open dump valve being the beginning of the reporting year, or the date of the inspection that the dump valve was first observed to be stuck-open (whichever is latest). Williams agrees that the time period for which the reduced capture efficiency to a control device ends is the date of repair of the stuck open dump valve.

<u>Commenter 0413</u>: <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).

Response 4: The EPA acknowledges the commenters' support of the proposed revisions. The EPA is finalizing these amendments as proposed.

12.3 Applicability and Selection of Appropriate Calculation Methodologies for Atmospheric Storage Tanks

Commenter: GPA Midstream Association
Comment Number: EPA-HQ-OAR-2023-0234-0299
Page(s): 17

Commenter: Environmental Defense Fund, et al.
Comment Number: EPA-HQ-OAR-2023-0234-0413
Page(s): 54

Comment 1: Commenter 0299: The following is a list of substantive proposed changes that GPA expressly supports.

…

- Allowing Calculation Method 1 (process simulation) for produced water tanks and for storage tanks with throughputs less than 10 barrels per day [98.233(j)];

Commenter 0413: *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.

Response 1: The EPA acknowledges the commenters' support of the proposed revisions. The EPA is finalizing these amendments as proposed.

Commenter: Environmental Defense Fund, et al.
Comment Number: EPA-HQ-OAR-2023-0234-0413
Page(s): 54-55

Comment 2: *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.

Response 2: The EPA acknowledges the commenter's support of the proposed revisions. The EPA is finalizing these amendments as proposed.

Commenter: GPA Midstream Association
Comment Number: EPA-HQ-OAR-2023-0234-0299
Page(s): 41

Comment 3: EPA should not require inclusion of models run for "internal review", and reconsider or clarify requirements to use simulations for compliance and reporting.

Very similar language exists in both the *dehydrator vents* section [98.233(e)] and the *hydrocarbon liquids and produced water storage tanks* section [98.233(j)]. GPA has the same concerns for this section as those detailed in Comments 36 and 37.

Process simulations run for "internal review" should not be mandatory consider (see Comment 36), and GPA requests that EPA reconsider the necessity of the requirement to use the same simulations for compliance and reporting given the additional complexities and potential confusion around implementation (see Comment 37). However, if this provision is included in the final rule, GPA suggests the following regulatory text:

98.233(j) If you are required to or elect to use the method in paragraph (j)(1) of this section for compliance with federal or state regulations, air permit requirements, or annual inventory reporting for the current reporting year, you must use the results of ~~the model~~ this method to determine annual CH_4 and, if applicable, CO_2 emissions.

Response 3: See Section III.K.3 of the preamble to the final rule for the EPA's response to this comment.

12.4 Controlled Atmospheric Storage Tanks

Commenter: GPA Midstream Association
Comment Number: EPA-HQ-OAR-2023-0234-0299
Page(s): 41-42

Comment 1: EPA should remove the requirement to "Calculate maximum potential vented emissions."

Similar language also exists between the *dehydrator vents* section [98.233(e)] and the Hydrocarbon liquids and produced water storage tanks section [98.233(j)] concerning "maximum potential vented emissions." GPA has the same concerns in this section as those detailed in Comment 38.

As mentioned previously, assuming worst-case conditions would be required to determine a maximum potential case, which does not reflect actual operations. This does not further the EPA's goal of accurately determining emissions.

To address these issues, GPA suggests the following changes be made to the proposed regulatory text:

98.233(j)(4)(i)(A) Calculate ~~maximum potential~~ vented emissions as specified in paragraph (j)(1), (2), or (3) of this section, and calculate an average hourly vented emissions rate by dividing the ~~maximum potential~~ calculated vented emissions by the number of hours that the tank was in operation.

Response 1:

EPA's intent is for reporters to calculate vented emissions prior to the use of any control device. To clarify the intent, the EPA removed the phrase "maximum potential" from the final text of 40 CFR 98.233(j)(4)(i)(A).

12.5 Calculation Methods 1 and 2 for Atmospheric Storage Tanks

Commenter: Independent Petroleum Association of New Mexico (IPANM)
Comment Number: EPA-HQ-OAR-2023-0234-0337
Page(s): 4

Commenter: Texas Commission on Environmental Quality (TCEQ)
Comment Number: EPA-HQ-OAR-2023-0234-0349
Page(s): 2-3

Commenter: American Petroleum Institute et al. (Part 1 of 2)
Comment Number: EPA-HQ-OAR-2023-0234-0402
Page(s): 32

Commenter: Environmental Defense Fund, et al.
Comment Number: EPA-HQ-OAR-2023-0234-0413
Page(s): 55-56

Comment 1: Commenter 0337: **40 CFR § 98.233(j) Tanks**

Rather than requiring the use of software for calculating flash emissions for atmospheric storage tanks under § 98.233(j), we support adding laboratory measurement of the GOR from a pressurized liquid sample as a new emission calculation methodology. Flash analytical data is already available in some fields and is used in permitting as well.

Commenter 0349: **The proposed use of laboratory measurement of gas-to-oil ratio (GOR) from a pressurized liquid sample is an appropriate calculation methodology under 40 CFR §98.233(j) for determining atmospheric storage tank flash emissions for GHGs.**

The GOR method relies on a pressurized liquid sample to determine flash gas emissions from a facility, with resulting laboratory data that includes concentrations of various constituents within the vapor stream, including the GHG pollutants, methane (CH_4) and carbon dioxide (CO_2), in addition to VOC emissions. Emission estimation methods for determining VOC flashing emissions from storage tanks have been evaluated through comparison of estimated results that included modeled emissions to directly measured VOC flash emissions. The evaluation revealed that the GOR method had a strong correlation to measured values for sites measuring below 200 tons per year of VOC[1] (This correlation can be logically expanded to include GHG emissions present in the laboratory data.)

Many oil and gas sites in Texas currently include the GOR method, which is used, in conjunction with AP-42 Chapter 7 methodology for working and breathing emissions, to determine storage tank emissions. These emissions estimates are used to establish potential to emit (PTE) as part of air permitting of VOC emissions in Texas and TCEQ supports the continued use for emissions representations.

[1]https://www.epa.gov/sites/default/files/2017-06/documents/06nesvacil.pdf

Commenter 0402: Storage Tanks

Addressing EPA's Request for Comments

Industry Trades recommend adding GOR analyses as an allowable calculation methodology.

EPA is seeking comments on whether adding a laboratory measurement of the GOR from a pressurized liquid sample is an appropriate calculation methodology for atmospheric storage tanks. The Industry Trades are supportive of adding this GOR method to calculate emissions from storage tanks and emphasize that these samples do not need to be taken on a site-by-site basis to be representative.

Commenter 0413: 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 nonhydrocarbon 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.

Response 1:

The calculation methods provided in subpart W were selected to minimize burden on industry while maintaining the necessary quality and consistency of data. The EPA has decided to not add the use of laboratory measurement of GOR from pressurized samples to calculate emissions from atmospheric storage tank emissions, 40 CFR 98.2333(j). This method was not proposed and the quantity of scientific data at this time supporting its addition was not substantial enough to justify its addition in the current rulemaking for these purposes. The EPA understands that this method is currently approved for air permitting of VOC emission in various states (e.g., Texas) and is also incorrectly being used for some emission reporting under 40 CFR 98.233(j). To clarify an apparent misuse of GOR discovered during verification activities, EPA would like to emphasize that GOR is not allowed to calculate emissions because it does not meet the requirements of Calculation Method 1 (as the emissions are not calculated using a modeling software) or Calculation Method 2 (as the emissions are not calculated assuming that all the CH4 and CO2 in solution at separator temperature and pressure is emitted). .As more studies and data become available, the EPA intends to consider them in future rulemaking efforts.

Commenter: American Exploration and Production Council
Comment Number: EPA-HQ-OAR-2023-0234-0295
Page(s): 19

Commenter: GPA Midstream Association
Comment Number: EPA-HQ-OAR-2023-0234-0299
Page(s): 40-41

Commenter: CrownQuest Operating
Comment Number: EPA-HQ-OAR-2023-0234-0393
Page(s): 193, 195, 196

Commenter: Williams Companies, Inc.
Comment Number: EPA-HQ-OAR-2023-0234-0394
Page(s): 9

Commenter: Range Resources Corporation
Comment Number: EPA-HQ-OAR-2023-0234-0397
Page(s): 8-9

Commenter: Encino Energy (EAP Ohio, LLC)
Comment Number: EPA-HQ-OAR-2023-0234-0408
Page(s): 5, 6

Comment 2: Commenter 0295: **Tanks**

Site-specific Gas Analysis Gas Oil Ratio (GOR) Sampling

EPA is proposing to remove the provisions of 40 CFR 98.233(j)(2)(ii) and (iii) that allowed for representative compositions to be used for tanks receiving liquids directly from wells or non-separator equipment. AXPC requests that EPA continue to allow the use of representative analysis until a site-specific sample has been collected at the discretion of the operator. The use of a representative analysis should not result in falsely lowered emissions and is expected to be sufficient for the needs of the EPA.

Commenter 0299: **GPA requests clarification on measurement frequency expectations.**

EPA is proposing to require the use of measured input parameters to model tank emissions calculated using Method 1, including measurement of separator temperature and pressure, hydrocarbon liquid production rate, API gravity, Reid Vapor Pressure, and composition. EPA states that these parameters must be obtained by measurement "reflective of representative operating conditions over the time period covered by the simulation." [97] GPA requests clarification on whether EPA intends for these parameters to be measured annually. If that is EPA's intention, GPA requests a five-year measurement time frame in which measurements are gathered every five years due to the high level of burden that the measurement and sampling requirements impose, particularly in light of the relatively small amount of emissions that atmospheric pressure storage tanks represent as a source category.

Many of these parameters for tanks are not regularly directly measured and sharply increasing the number of tanks and separators requiring this level of measurement will result in a significant increase in data management burden and cost because reporters must pull regular samples and send to them to laboratories for analysis. It can also be difficult to obtain liquid samples because the liquids must be collected prior to flashing, so this usually involves collecting liquids at the separator. There are not always liquids present in the separator to sample, especially if the separator has recently dumped to the tank. It is also unclear whether the third-party laboratories that many reporters use will be able to accommodate the increase in sampling. Additionally, in some cases, reporters may need to purchase and install appropriate sampling ports and measurement devices in order capture this information, further increasing the costs associated with gathering data for an emissions source that represents only a small fraction of the reporter's overall greenhouse gas emissions.

Footnote:

[97] *Id*. at 50,329.

Commenter 0393: We ask that the ability to obtain representative samples across operating areas remain in the rule. We have obtained dozens of site-specific samples spanning multiple counties. The differences in separator pressure and separator GOR is negligible. Many of these projects have wells producing from the same zones with very similar characteristics. It would be misguided to not allow representative sampling in these calculations. The burden on the operator to obtain site specific samples vs the emissions benefit of doing so is just not there.

As stated, the burden to acquire these samples would be significant, but the accuracy increase would be negligible. Operators already have representative samples per area, these samples should more than suffice since the facilities will have the same formations being produced.

…

Obtaining direct lab measurement on a per facility basis annually would be extremely costly and the emissions reduction benefit would not be justified. As mentioned before, the dozens of representative samples that have been obtained are more than adequate because they are similar in pressure, GOR and formation type.

…

It is of our opinion that the EPA should understand the burden on operators to perform direct measurement on such many sites on an annual basis. With many basins if not all of them producing wells from the same formation(s) it is our recommendation that representative sampling should be a viable option with this segment of the rule.

Commenter 0394: **Input Modeling Parameters for Calculation Method 1**

For Calculation Method 1 (modeling method)[24], the EPA requires certain input modeling parameters "reflective of" the time period covered by the model, with a minimum of annual modeling. Williams seeks clarification regarding the required measurement frequency for the input modeling parameters in paragraphs (j)(1)(i) through (vii). For annual modeling, the EPA should allow measurements of separator / non-separator natural gas flow rate, temperature, and pressure to be collected annually, while allowing measurements of API gravity, Reid vapor pressure, and liquid composition data to be collected every 5 years since annual analysis of liquid samples would be burdensome due to difficulty of sample collection and analysis.

Footnote:

[24] Proposed Rule, 88 Fed. Reg. at 50,394-395.

Commenter 0397: **Flashing emissions simulations should be based on a set of parameters regardless of whether simulations are conducted periodically as long as operating conditions remain the same.**

Under the Proposed Rule, operators are required to calculate flashing emissions from storage tanks using an emissions simulation software program. 88 Fed. Reg. at 50394-95 (to be codified at 40 C.F.R. § 98.233(j)(1)). The simulation incorporates parameters that are developed using engineering estimates, process knowledge, and best available data. The Proposed Rule provides that parameters are to be measured to represent the operating conditions over the period of time covered by the simulation. The Proposed Rule also provides that an operator may conduct simulations periodically rather than only annually.

Conducting periodic simulations assists an operator in ensuring that it fully complies with the regulations in a timely manner and allows for any potential errors to be addressed in subsequent simulations. However, EPA seems to be proposing a disincentive to these periodic simulations by requiring an operator to perform field measurements to establish the parameters for the simulation every time that operator performs a simulation. In other words, it would be much more cost effective to perform a simulation once a year rather than periodically, even though periodic simulations would result in more accurate and timely information. EPA should clarify in the final rule that, even if an operator performs periodic simulations, it only needs to collect the parameters incorporated into that simulation once. EPA also might include an exception to that clarification where an operator has reason to know that certain parameters have changes since the last simulation, in which case the operator could be obligated to recollect only those parameters that have changed.

Commenter 0408: Calculation Methods 1 and 2 for Atmospheric Storage Tanks: EPA is proposing to require input parameters to include separator or non-separator equipment temperature and pressure, sales or stabilized hydrocarbon liquids API gravity, sales or stabilized hydrocarbon liquids production rate, and separator or non-separator equipment hydrocarbon liquids composition and Reid vapor pressure.

Currently, engineering estimate and process knowledge are used for the emission calculations. EAP Ohio, LLC requests that engineering estimate and process knowledge continue to be used for the calculations. In the engineering estimates and process knowledge, actual and historical site parameters are reflective of representative operating conditions over the period covered by the simulation are used for the determination of the estimates.

…

EPA is proposing to remove the provisions of 40 CFR 98.233(j)(2)(ii) and (iii) that allowed for representative compositions to be used for tanks receiving liquids directly from wells or non-separator equipment.

- Sampling at each facility is costly and takes a significant amount of time to complete.
- EAP Ohio, LLC has concerns about the ability to collect a sample at every location and run updated emissions analysis in time for implementation of the proposed rule.
- Operator experience shows individual location sampling would result in lowered projected emissions from facilities since representative analysis are typically conservative and from samples taken earlier in a comparable well pad's life when the material produced is expected to be more volatile (e.g. resulting in higher emissions than the material produced in an older facility).
- EAP Ohio, LLC requests that EPA continue to allow the use of representative analysis until a site-specific sample has been collected at the discretion of the operator. The use of a representative analysis should not result in falsely lowered emissions and is expected to be sufficient for the needs of the EPA

Response 2: See Section III.K.5 of the preamble to the final rule for the response to this comment.

Commenter: GPA Midstream Association
Comment Number: EPA-HQ-OAR-2023-0234-0299
Page(s): 40-41

Comment 3: GPA requests clarification on measurement frequency expectations.

…

Additionally, EPA should limit the requirement to measure API gravity and Reid Vapor Pressure as parameters for Calculation Method 1. Not all process simulation software requires these two parameters to run the model. In at least some robust process simulators (e.g., BR&E ProMax, AspenTech HYSYS), if a hydrocarbon liquids composition is provided for the tank feed (as is currently required), API gravity and Reid Vapor Pressure are not needed as inputs to the simulation as these can be calculated from the other input parameters. As a result, GPA suggests the following revisions to the proposed regulatory text:

98.233(j)(1)(iii) For atmospheric pressure storage tanks receiving hydrocarbon liquids, sales oil or stabilized hydrocarbon liquids API gravity (must be measured if required by the model).
98.233(j)(1)(vii) Well, separator, or non-separator equipment hydrocarbon liquids or produced water composition and Reid vapor pressure (must be measured if required by the model).

Response 3: See Section III.K.5 of the preamble to the final rule for the response to this comment.

Commenter: Williams Companies, Inc.
Comment Number: EPA-HQ-OAR-2023-0234-0394
Page(s): 9-10

Comment 4: Daily Throughput Calculations and Modeling Methodology for Calculation Method 1

The EPA's description of Calculation Method 1[25] lacks detail with regard to how modeling is to be conducted and how daily separator / non-separator throughput is to be calculated. Depending upon the Williams facility, between 5 and 60 separators and non-separators can deliver a produced combined water and hydrocarbon liquid to a tank battery through a common piping manifold. These sources of liquids can include slug catchers, inlet helical and baffle-type separators, compressor inlet and discharge bottle separators, stabilizers, dehydrator still vent condensate sumps, and rainwater from secondary containment sumps. Most of these individual separators and non-separators do not have liquid flow meters. For Calculation Method 1, Williams (and other midstream companies) selects a separator or non-separator that has a gas operating pressure and temperature representative of the facility. The daily volume of liquid throughput to the tank battery is conservatively used as the throughput across the selected representative separator or non-separator. Daily liquid volume throughput to the tank battery is calculated as the sum of the monthly measured volume of produced water and hydrocarbon liquid hauled from the tank battery, divided by the number of days in the month. Williams seeks clarification that utilizing this throughput method would be acceptable for purposes of inventorying GHG emissions.

Footnote:

[25] Id.

Response 4: The determination of the production rate used in Calculation 1 for facility-specific situations is not within the scope of this rulemaking. If the owner or operator would like assistance from the EPA regarding a facility-specific situation, that owner or operator should contact the GHGRP help desk.

Commenter: GPA Midstream Association
Comment Number: EPA-HQ-OAR-2023-0234-0299
Page(s): 85-86

Commenter: CrownQuest Operating
Comment Number: EPA-HQ-OAR-2023-0234-0393
Page(s): 198

Comment 5: Commenter 0299: **Proposed Change**: EPA is proposing to add the reporting element of flow-weighted average concentration (mole fraction) of CO_2 and CH_4 in flash gas from onshore production and onshore natural gas gathering and boosting storage tanks (calculated as the sum of all products of the concentration of CO_2/CH_4 in the flash gas for each storage tank times the throughput for that storage tank, divided by the sum of all throughputs from storage tanks).

> **Comment**: As proposed, this addition would create a significant additional burden on reporters over the current requirement to report the minimum and maximum CO_2 and CH_4 without providing EPA useful additional information. Calculating flow-weighted averages is time consuming and can be difficult to implement accurately in database software systems that are utilized by many reporters due to the way that multiple tables and data types often need to be cross referenced and brought together to calculate a flow-weighted average. GPA proposes that EPA instead modify this requirement to report to a straight average, rather than a flow-weighted average in order to reduce the complexity of complying with this requirement but still incorporates stream specific data.
>
> Additionally, GPA notes that as currently written the text describing the calculation of the flow-weighted average could be interpreted to use the tank liquid throughputs in the calculation of that average, rather than the total flash gas volume. GPA therefore suggests the changes below to clarify that the average should be calculated based on the volume of flash gas produced rather than the liquid throughput of the tanks.
>
> **Suggested text**:
>
> *98.236(j)(1)(vii) The ~~flow-weighted~~ average concentration (mole fraction) of CO_2 in flash gas from onshore production and onshore natural gas gathering and boosting storage tanks (calculated as the sum of all products of the concentration of CO_2 in the flash gas for each storage tank ~~times the throughput for that storage tank~~, divided by the sum of all flash gas emissions ~~throughputs~~ from storage tanks) ("X_{CO2}" in Equation W–20 of this subpart if the flash gas is routed to a flare).*

98.236(j)(1)(viii) The ~~flow-weighted~~ average concentration (mole fraction) of CH_4 in flash gas from onshore production and onshore natural gas gathering and boosting storage tanks (calculated as the sum of all products of the concentration of CH_4 in the flash gas for each storage tank ~~times the throughput for that storage tank~~, divided by the sum of all flash gas emissions ~~throughputs~~ from storage tanks) ("X_{CH4}" in Equation W–20 of this subpart if the flash gas is routed to a flare).

Commenter 0393: The EPA does not offer any data to support this claim. Industry would disagree with this claim as we feel we do a good job of this already.

Response 5:

As the EPA stated in the preamble for the proposed rule, under 40 CFR 98.236(j)(1)(vii) and (viii), reporters with atmospheric storage tank emissions calculated using Calculation Method 1 or Calculation Method 2 were required to provide the minimum and maximum concentrations (mole fractions) of CO_2 and CH_4 in the tank flash gas. Reporting of emissions and activity data for atmospheric storage tanks is aggregated at the sub-basin or county level under the current regulations, and the minimum and maximum flash gas concentrations were expected to provide the EPA with a broad characterization of the often-significant number of tanks reported for each sub-basin or county. However, through correspondence with reporters via e-GGRT, the EPA has found that the minimum and maximum flash gas concentrations do not accurately represent the majority of atmospheric storage tanks within the reported sub-basins and counties. The EPA found that concentrations can vary significantly across a sub-basin and throughout the reporting year, which made the relationship between emissions and concentration difficult to relate. Further, reporting of the extreme low concentrations and high concentrations found in tank flash gas was not indicative of the typical concentrations found in the atmospheric storage tanks within the sub-basin.

Thus, the EPA is finalizing as proposed the revisions to these two reporting requirements to report the flow-weighted average concentration (mole fraction) of CO_2 and CH_4 in the flash gas, rather than the minimum and maximum values for reporters that used Calculation Method 1 of § 98.233(j) to calculate GHG emissions for atmospheric pressure storage tanks receiving hydrocarbon liquids. These values are calculated as the sum of all products of the concentration of CO2 or CH4 in the flash gas for each storage tank times the total quantity of flash gas for that storage tank, divided by the sum of all flash gas emissions from storage tanks. However, in response to another comment received (see Comment 9 of this section), the EPA is not finalizing the revisions to these two reporting requirements for reporters that used Calculation Method 2 of § 98.233(j) to calculate GHG emissions for atmospheric pressure storage tanks receiving hydrocarbon liquids. (Note that this comment was on the 2022 proposal and that the 2023 proposal incorporated the commenter's request that the divisor of the flow-weighted average be the sum of all flash gas emissions from storage tanks).

Commenter: GPA Midstream Association
Comment Number: EPA-HQ-OAR-2023-0234-0299
Page(s): 17

Commenter: CrownQuest Operating
Comment Number: EPA-HQ-OAR-2023-0234-0393
Page(s): 193

Comment 6: Commenter 0299: The following is a list of substantive proposed changes that GPA expressly supports.

…

- Including ProMax as an example software program for calculating emissions from … atmospheric tanks [98.233(j)];

Commenter 0393: Agree with the ability of the operator to use various software's to calculate tank emissions, namely ProMax.

Response 6: The EPA acknowledges the commenters' support of the proposed revisions. The EPA is finalizing these amendments as proposed.

Commenter: Encino Energy (EAP Ohio, LLC)
Comment Number: EPA-HQ-OAR-2023-0234-0408
Page(s): 5-6

Comment 7: EPA recommends software for determining tank emissions in the proposed Subpart W rule to include BRE (Bryan Research & Engineering) ProMax®.

- While acceptable on many facilities, ProMax® is not a dynamic model and can only reflect emissions from a facility in what is a heartbeat of time of a specific location extrapolated over a year.
- ProMax® does not consider facility controls in place which limit emissions from the tank battery. For example, in facilities in which Tank Emission Management Systems have been installed, a valve is used to stop the follow of production to the tanks when the pressure in the battery is too high, also, there is a waste gas valve on the combustor which actuates to burn down waste gas before the battery would leak from over pressuring. Should tank pressure increase and fail to be controlled, site specific alarms immediately notify the operator and allow action before leaks occur and document if leaks did occur.
- EAP Ohio, LLC has broadly installed Tank Emission Management systems and has so far been unable to reflect the action of the combustor waste gas valve or production valves in the emission modeling software. ProMax® simulations continue to reflect steady state flow without the protective and environmentally friendly systems which have been installed.

- EAP Ohio, LLC believes that ProMax® overestimates emissions from tank batteries where Tank Emission Management Systems have been installed and requests the EPA not require the use of such software and exempt sites with Tank Emission Management systems from the requirement to calculate process emissions from the tank battery and instead only report those emissions from infrequent fugitive releases using engineering estimates in relations to tank high pressure alarms exceeding the leak point or fugitive leaks.

Response 7: The EPA is finalizing the revisions to 40 CFR 98.233(j) to add Promax as an example software for atmospheric storage tank modeling as proposed. Reporters have the option to use any software option to complete modeling under Calculation Method 1 that uses the Peng-Robinson equation of state, models flashing emissions, and speciates CH_4 and CO_2 emissions that will result when the hydrocarbon liquids or produced water from the well, separator, or non-separator equipment enters an atmospheric pressure storage tank. The commenter is not limited to the use of Promax to calculate emissions with Calculation Method 1 if they feel emissions are not well represented by the modeling software. Further, if preferred, reporters may use Calculation Method 2 or Calculation Method 3 instead of Calculation Method 1 to calculate emissions from atmospheric storage tanks.

Commenter: Colorado Department of Public Health and Environment (CDPHE)
Comment Number: EPA-HQ-OAR-2023-0234-0373
Page(s): 3

Comment 8: For storage tank emissions (98.233(j)), E&P Tank v3.0 is cited as an acceptable model for emissions from hydrocarbon liquid storage tanks (see e.g., Preamble 50289, 50304, and proposed 98.233(j)(1)), However, E&P Tank v3.0 software is no longer available for new licenses and is not a practical solution for new users. Indeed, footnote 47 states E&P Tank v3.0 is "formerly available". We presume EPA retains the references to E&P Tank v3.0 in Subpart W in order to signify its continued approval for use by existing users, but we would suggest EPA consider sunsetting or curtailing its use in the future. Increasingly as time goes on, agencies, observers, and the public may have difficulty in verifying emissions calculations using E&P Tank v3.0 if it is not available to new users…

Response 8: The EPA is finalizing the revisions to 40 CFR 98.233(j) to add Promax as an example software for atmospheric storage tank modeling as proposed. At this time, we are maintaining that E&P Tanks may be used as an applicable software option for atmospheric storage tank modeling and are not finalizing revisions to remove the reference. However, the EPA may consider removing references to E&P Tanks in future rulemakings.

Commenter: Anonymous
Comment Number: EPA-HQ-OAR-2023-0234-0237
Page(s): 1

Comment 9: I also agree with the decision to allow facilities with wells sending oil directly to tanks without separation to use modeling (method 1) or calculation (method 2) for determining their emissions. However, EPA stated that they are "proposing conforming edits within 40 CFR 98.233(j)(1) and (2) and 40 CFR 98.236(j)(1) to refer to parameters and requirements for wells flowing directly to atmospheric storage tanks." I note that one additional edit is required to 236(j)(1)(vii) and (viii); these requirements to report flash gas CO2 and CH4 concentrations seem to be specific to method 1. For method 2, companies must assume the CO2 and CH4 in solution from the oil sent to tanks is all emitted to atmosphere, so technically the concentrations of CO2 and CH4 in the flash gas are not known. Does EPA intend for the concentrations in solution be reported for method 2? If so, the data element should be adjusted to say this.

Response 9: See Section III.K of the preamble to the final rule for the EPA's response to this comment.

Commenter: GPA Midstream Association
Comment Number: EPA-HQ-OAR-2023-0234-0299
Page(s): 105

Comment 10: Appendix A

Table of changes GPA supports as proposed.

Subpart	Citation	Change
…		
W	98.233(j)(1)(x)(A) 98.233(j)(1)(x)(B) 98.233(j)(1)(x)(C)	Tanks: Clarify/simplify reporting of the count of tanks

Response 10: The EPA acknowledges the commenter's support of the proposed revisions. The EPA is finalizing these amendments as proposed.

12.6 Calculation Method 3 for Atmospheric Storage Tanks

Commenter: Environmental Defense Fund, et al.
Comment Number: EPA-HQ-OAR-2023-0234-0413
Page(s): 54

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

…

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.

Response 1: The EPA has evaluated this request and does not agree that Calculation Method 3 is inappropriate for atmospheric storage tanks with an average annual daily throughput less than 10 barrels per day. As detailed in the memo "Equipment Threshold for Tanks" in the rulemaking docket EPA-HQ-OAR-2009-0923, the EPA determined that setting an equipment threshold of 10 barrels per day of separator throughput, such that any tank connected to a separator below the equipment threshold use a simple emissions factor approach, would result in significant reduction in burden without significantly compromising emissions data reporting quality. Further, the commenter did not provide an alternative source for an emission factor representative of low throughput atmospheric storage tanks.

12.7 General Atmospheric Tanks Comments

Commenter: Williams Companies, Inc.
Comment Number: EPA-HQ-OAR-2023-0234-0394
Page(s): 10

Comment 1: Storage Tanks with Methane Blankets

At some tank batteries storing condensate and / or produced water, methane blankets are used to ensure that the vapor headspace in the tank battery is above the UEL. The EPA does not account for this type of equipment in the Proposed Rule. The EPA should account for and advise reporters on how GHG emissions from these tank batteries should be accounted for in Subpart W.

Response 1: The requirements in 40 CFR 98.233(j) are for reporters to estimate and report flashing emissions from atmospheric pressure storage tanks. As it does not appear that emissions from the use of a methane blanket in an applicable tank would meet the typical definition of "flashing emissions," the EPA is not finalizing any amendments to the rule to account for emissions from methane blankets at this time but may consider revisions in future rulemakings.

Commenter: American Petroleum Institute et al. (Part 1 of 2)
Comment Number: EPA-HQ-OAR-2023-0234-0402
Page(s): 31-32

Comment 2: Storage Tanks

Atmospheric Storage Tank Exclusions

The Industry Trades recommend that emergency use storage tanks and process tanks not be subject to reporting.

The Industry Trades also recommend that EPA specify that some tanks are not subject to reporting under this program. Some facilities contain tanks which are used only rarely for off spec oil and should be excluded from the definition of storage vessel. These process vessels are rated significantly higher than atmospheric and do not have similar venting risks as atmospheric storage tanks. The expected GHG emissions from these emergency use storage tanks would be minimal. At the state level, emergency use tanks are exempt from control requirements from state and local regulations because state agencies such as California's Air Resources Board (CARB) or San Joaquin Valley Air Pollution Control Board (SJVAPCD) have recognized that these tanks are used in rare and extreme situations for the safety of people and nearby infrastructure. [24,25]

Likewise, process tanks like those that recirculate liquids for processing should also be excluded. Storage tank regulations, including proposed NSPS OOOOb and EG OOOOc, have historically excluded process vessels or tanks. In short, any tank which is not expressly used as a primary storage vessel for hydrocarbon liquids and produced water (if included as proposed) in the normal operation of a production or gathering and boosting facility should be excluded. Therefore, the Industry Trades offer the following redline of the proposed definition of atmospheric pressure storage tank:

Atmospheric pressure storage tank means a vessel ~~(excluding sumps)~~ operating at atmospheric pressure that is designed to contain an accumulation of crude oil, condensate, intermediate hydrocarbon liquids, or produced water and that is constructed entirely of nonearthen materials (e.g., wood, concrete, steel, plastic) that provide structural support. Atmospheric pressure storage tanks include both fixed roof tanks and floating roof tanks. Floating roof tanks include tanks with either an internal floating roof or an external floating roof. For the purposes of this subpart, the following are not considered atmospheric pressure storage tanks:

- *Sumps;*
- *Process vessels such as surge control vessels, bottoms receivers or knockout vessels; and*
- *Vessels that only receive crude oil, condensate, intermediate hydrocarbon liquids, or produced water due to an unforeseeable failure or malfunction of operating equipment that is necessary to prevent or control an unsafe situation and contains the crude oil, condensate, or produced water for 45 days or less per calendar year.*

Footnotes:

[24] CARB O&G Regulation, 17 CCR 95668(a)(2)(E): Separators, tanks, and sumps that have contained crude oil, condensate, or produced water for 45 calendar days or fewer per calendar year provided that the owner or operator maintains, and can make available at the request of the ARB Executive Officer, a record of the number of days per year in which the separators, tanks, or sumps have contained liquid.

[25] The SJVAPCD has defined an emergency in some permits as: an unforeseeable failure or malfunction of operating equipment that: (1) is not due to neglect or disregard of air pollution laws or rules; (2) is not intentional or the result of negligence; (3) is not due to improper maintenance; and (4) is necessary to prevent or control an unsafe situation.

Response 2: The EPA disagrees that emergency use storage tanks and process tanks should not be subject to reporting. Given the description provided by the commenter of these tanks, it appears that emergency use storage tanks and process tanks would receive little throughput and thus qualify to use Calculation Method 3 to calculate emissions using an emission factor. Thus, the EPA does not expect the burden of reporting to be significant for these tanks. Further, the commenter did not provide details on expected emissions from these tanks in order to quantify their emission impacts. The EPA is finalizing the definition of "atmospheric pressure storage tank" in 40 CFR 98.238 as proposed.

Commenter: Public Hearing Transcript
Comment Number: EPA-HQ-OAR-2023-0234-0224
Page(s): 24 (Joan Brown), 26 (Bill Midcap), 30 (Marlene Perrotte)

Commenter: Anonymous
Comment Number: EPA-HQ-OAR-2023-0234-0237
Page(s): 1

Comment 3: Commenter 0224: Farmers and ranchers know all too well that equipment breaks down. EPA is proposing multiple changes that would require operators to report higher emissions when they discover malfunctioning equipment such as open hatches or stuck dump valves and Rocky supports these changes because Subpart W currently does not accurately account for these emissions from equipment failures.

…

In our work, we have immersion retreat experiences with people of faith in the Permian, and we experience on the ground with some of those community members this malfunctions of thief hatches and other equipment so these issues need to be addressed and they can be with optical gas imaging in these facilities, the technology is available.

…

I also support EPA's proposal to address equipment malfunctions. These multiple changes would require operators to report higher emissions when they discover malfunctioning equipment, such as open thief hatches or stuck dump valves.

Commenter 0237: I am writing to provide my support for the proposed amendments to 233(j) and 236(j), atmospheric tanks. Specifically, I support the flexibility that is being proposed for calculating emissions from tanks. EPA's proposal to allow companies with low-throughput tanks to model their emissions (rather than relying on emission factors that are likely significantly underestimating emissions) will improve the accuracy of tanks emissions that are reported.

Response 3: The EPA acknowledges the commenters' support of the proposed revisions. The EPA is finalizing these amendments as proposed.

13 Transmission Storage Tank Vent Emissions

Commenter: GPA Midstream Association
Comment Number: EPA-HQ-OAR-2023-0234-0299
Page(s): 41

Commenter: Williams Companies, Inc.
Comment Number: EPA-HQ-OAR-2023-0234-0394
Page(s): 15

Comment 1: Commenter 0299: **The proposed names for the tank source categories are confusing.**

EPA proposes to rename the "transmission storage tank" source category to "condensate storage tanks" and then apply this term only to transmission and underground storage facilities.[98] Unfortunately, this nomenclature is confusing and lacks transparency because many gathering and boosting, and gas processing facilities also have tanks that collect condensate that are commonly referred to as "condensate tanks." To address this issue, GPA recommends renaming these emission sources "Transmission and underground storage tanks" and "Onshore production, onshore natural gas processing, and onshore petroleum and natural gas gathering and boosting storage tanks." Another possible solution is to combine the two sections on tanks into one.

Footnote:

[98] *Id*. at 50,301-02.

Commenter 0394: Storage Tanks in Transmission & Underground Natural Gas Storage Segments

Williams supports the differentiation between storage tanks in the Transmission Compression and Underground Natural Storage Segments, and Hydrocarbon Liquid and Produced Water Storage Tanks in the Gathering & Boosting and Processing Segments. As proposed, Williams supports retaining the existing emissions calculation methodology for storage tanks at transmission compressor stations and expanding its application to storage tanks at underground natural gas storage facilities.

Williams, however, believes the new name of "Condensate Storage Tanks" for tanks in the transmission compression and underground natural gas storage segments may cause confusion. Condensate occurs in multiple industry segments (including gathering and boosting, and processing). Consequently, some reporters may incorrectly infer that Condensate Storage Tanks includes tanks that store condensate at gathering compressor stations and processing plants. The EPA should rename "Transmission Storage Tanks" to "Transmission and Underground Natural Gas Storage Tanks" for tanks located in these respective segments.

Response 1: After consideration of the comments, the EPA has decided to finalize the names of the "condensate storage tanks" and "hydrocarbon liquids and produced water storage tanks" emission source types as proposed. We do not believe that the name "condensate storage tanks" will cause confusion for gas processing facilities and gathering and boosting facilities because 40 CFR 98.232(e) and (f) clearly indicate that this emission source type is subject to reporting by only transmission compression facilities and underground natural gas storage facilities. The first sentence in 40 CFR 98.233(k) also indicates that the calculation methodology applies only to these two industry segments. Additionally, we note that with this final rule, all other emission source type names are based on the type of equipment or activity rather than the applicable industry segment. As noted in Section III.S.1 of the preamble to the final rule, we have also changed the emissions source type name for combustion equipment to remove the names of industry segments.

We also decided to not incorporate the suggestion from one commenter to combine the requirements for condensate storage tanks with the requirements for hydrocarbon liquids and produced water storage tanks because it is not clear how the commenter envisions implementing this suggestion, and any such change could have unintended consequences that we did not provide an opportunity for comment on in the proposal.

14 Associated Gas Venting and Flaring

Commenter: Environmental Defense Fund, et al.
Comment Number: EPA-HQ-OAR-2023-0234-0413
Page(s): 56-57

Comment 1: 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 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]

Footnotes

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

[97] 88 Fed. Reg. 50332 (Aug. 1 2023).

[98] Id.

[99] See, e.g., Festa-Bianchet et al., Methane 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/wpcontent/uploads/2015/04/21094438/CATF_Pub_PuttingOuttheFire.pdf.

[101] Id.

Response 1: See Section III.M.2 of the preamble to the final rule for the EPA's response to this comment.

Commenter: Taxpayers for Common Sense (TCS)
Comment Number: EPA-HQ-OAR-2023-0234-0351
Page(s): 4

Comment 2: *Gas Emitted Through Venting and Flaring*

Routine venting and flaring in the oil and gas sector represents an egregious waste of a valuable natural resource and contributes to the taxpayer costs of climate change. On federal lands, flaring is the primary source of natural gas lost by drilling operators, accounting for 82 percent of reported lost gas over the last decade.[9] TCS supports efforts to more accurately measure and report the amount of gas lost through these practices.

For venting, the proposed rule would require reporters to use direct measurements to calculate the volume of vented gas if a continuous flow measurement device is already in use, as opposed to estimating the amount of vented gas using equation W–18. This proposal will provide more precise data on emissions from venting practices and is unlikely to impose additional burdens on reporters, given that it applies only if a continuous flow measurement device is already in use.

Footnote:

[9] TCS, "Gas Giveaways II," Aug 30, 2022. https://www.taxpayer.net/energy-natural-resources/gas-giveaways-ii-methane-wasteon-federal-lands-is-business-as-usual/

Response 2: The EPA acknowledges the commenter's support for the proposed calculation methods for associated gas venting and flaring.

Commenter: Endeavor Energy Resources, L.P.
Comment Number: EPA-HQ-OAR-2023-0234-0381
Page(s): 18

Commenter: The Petroleum Alliance of Oklahoma
Comment Number: EPA-HQ-OAR-2023-0234-0398
Page(s): 14-15

Comment 3: Commenter 0381: General & equation W-18

EPA Should Reconsider the Proposed Revisions to Calculation Methods for Several Emission Sources.

Associated Gas Venting and Flaring

Endeavor supports EPA's proposal to use continuous flow measurement as an *alternative* to Equation W-18 to calculate emission from associated gas and venting.[61] As noted throughout these comments, flexibility is key for many owners and operators and reflects the diversity in resources available to an owner or operator and the location and nature of its assets.

Footnote:

[61] *Id*. at 50,332.

Commenter 0398: General & equation W-18

Subpart W currently requires reporters to calculate annual emissions from associated gas venting and flaring using equation W–18, which uses the GOR, volume of oil produced, and volume of associated gas sent to sales to calculate the volume of gas vented. Associated gas venting emissions are then calculated using the results of equation W–18 and the gas composition determined using 40 CFR 98.233(u), and associated gas flaring emissions are calculated by applying the calculation method of flare stacks in 40 CFR 98.233(n) to the associated natural gas volume and gas composition determined for the associated gas stream routed to the flare. For associated gas venting emissions, EPA is proposing provisions in 40 CFR 98.233(m)(3) to specify that if the reporter measures the flow to a vent using a continuous flow measurement device, the reporter must use the measured flow volumes to calculate the volume of gas vented rather than using equation W–18.

Reporters are familiar with the current reporting requirements, and it may be challenging to accurately measure extremely low volumes or variable volumes of gas.

Action Requested: We request EPA allow reporters the option to continue to use the current calculation methodology using equation W-18.

Response 3: See Section III.M of the preamble to the final rule for the EPA's response to this comment.

Commenter: Environmental Defense Fund, et al.
Comment Number: EPA-HQ-OAR-2023-0234-0413
Page(s): 56-57

Comment 4: GOR

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.

Footnotes:

[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://lawslois.justice.gc.ca/eng/regulations/SOR-2018-66/FullText.html.

[103] Id.

Response 4: The EPA disagrees with the suggestion to place a limit or cap on the volume of vented gas that can be calculated using equation W-18. In situations where it is not possible to measure the flow rate, such an approach could result in an over-reliance on substitute data procedures and, potentially, lower accuracy of reported data relative to using equation W-18. Moreover, the commenter does not propose a specific cap and has not provided any data or analyses that support this recommendation. Regarding the reliability of GOR and equation W-18, as discussed in Section III.M.2 of the preamble to the final rule, we believe that while measured data is preferable, the use of the GOR equation will result in reasonably accurate estimates of emissions. Furthermore, the disaggregated reporting and clarification of how oil production and gas sales data are determined will support greater confidence in reported GOR values when measurement of flow rates is not possible. EPA will continue to assess this method of estimating emissions from associated gas venting and flaring and may consider further updates in a future rulemaking.

We also acknowledge that GOR values can vary over time and this is a natural function of oil and gas production and the reason an average GOR value is reported when using equation W-18. While not including a methodology for determination of GOR in the final rule, the EPA agrees with the commenter that the final rule should make clear that the reporter must determine a GOR value for each well with associated gas venting and flaring specific to the reporting year and has added language to this effect in 40 CFR 98.233(m). The EPA thanks the commenter for their suggestion of using the Canadian regulations and standards to establish requirements for determination of GOR (last amended January 1, 2023; see Section 24, Determination of gas-to-oil ratio at https://laws-lois.justice.gc.ca/eng/regulations/SOR-2018-66/page-2.html#h-858738). However, inclusion of such requirements in 40 CFR 98.233(m), whether similar to the Canadian regulations or uniquely defined, is outside the scope of this rulemaking as the EPA did not propose or request comment on requirements for GOR determination. We may consider such updates to requirements for GOR determination in future rulemakings.

Commenter: Environmental Defense Fund, et al.
Comment Number: EPA-HQ-OAR-2023-0234-0413
Page(s): 56-57

Comment 5: Source name

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."

Response 5: The EPA disagrees with the commenter because 40 CFR 98.233(m) still includes the requirements to calculate emissions from venting and flaring associated gas, but just directs reporters that flare associated gas to calculate emissions under the flare stacks source, 40 CFR 98.233(n).

Commenter: Taxpayers for Common Sense (TCS)
Comment Number: EPA-HQ-OAR-2023-0234-0351
Page(s): 4

Commenter: CrownQuest Operating
Comment Number: EPA-HQ-OAR-2023-0234-0393
Page(s): 214

Commenter: American Petroleum Institute et al. (Part 1 of 2)
Comment Number: EPA-HQ-OAR-2023-0234-0402
Page(s): 32

Commenter: Environmental Defense Fund, et al.
Comment Number: EPA-HQ-OAR-2023-0234-0413
Page(s): 57-58

Comment 6: Commenter 0351: *Gas Emitted Through Venting and Flaring*

TCS also supports the EPA's efforts to gather additional data on venting and flaring practices that could educate the public. This could include data elements used as inputs for equation W–18 for emission calculation, such as the Gas-Oil Ratio (GOR), volume of oil produced, and volume of gas sent to sales for wells with associated gas venting or flaring. This information should be collected even when reporters use real data from a continuous flow measurement device, provided the EPA believes such data would be beneficial to the public.

Commenter 0393: Reporting W-18 data elements

Also, EPA is seeking comment on whether to continue requiring reporting of GOR, produced oil volume, gas sales volume, etc. We are in support of no longer requiring this. In general, we support streamlining the data reporting process, especially when the reported elements are not used to calculate emissions.

Commenter 0402: Reporting W-18 data elements

Associated Gas Venting and Flaring

EPA is seeking comment on whether to continue to require reporting of GOR, produced oil volume, gas to sales volume, etc. The Industry Trades are in support of no longer requiring these reporting elements, unless required by the WEC. In general, the Industry Trades support efforts to streamline the data reporting process, particularly when the reported elements are not used to calculate emissions.

Commenter 0413: Reporting W-18 data elements

Associated gas venting reporting

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.

Response 6: See Section III.M of the preamble to the final rule for the EPA's response to comments regarding Associated Gas Venting and Flaring.

Commenter: CrownQuest Operating
Comment Number: EPA-HQ-OAR-2023-0234-0393
Page(s): 206

Commenter: American Petroleum Institute et al. (Part 1 of 2)
Comment Number: EPA-HQ-OAR-2023-0234-0402
Page(s): 32

Comment 7: Commenter 0393: Disaggregated reporting

"40 CFR 98.236(m)(7)(i) currently requires the reporter to provide the total number of wells and a list of well IDs in the sub-basin for wells that vented associated gas emissions. As noted in section III.D of this preamble, however, the EPA is proposing that reporters begin reporting information for this emission source by well rather than at the sub-basin level. Therefore, we are proposing to remove this reporting requirement. The well ID would be reported for each vented well under proposed 40 CFR 98.236(m)(1) and the total number of wells reported at the sub-basin level is no longer necessary, because we are proposing to require reporting at the well level for associated gas venting rather than the sub-basin level."

This is unclear as to what is not being reported. EPA needs to clarify on reporting and at what level it is appropriate.

Commenter 0402: Disaggregated reporting

Associated Gas Venting and Flaring

EPA is proposing to require reporting of associated gas venting and flaring on a site-by-site basis. The Industry Trades recommend that EPA keep emissions and associated data rolled up to the basin-level (or county-level, as required by other regulatory programs, such as PHMSA).

Response 7: Regarding disaggregation of reporting associated gas venting and flaring emissions at the well level in contrast to current reporting requirements which are at the sub-basin level, the EPA, as further discussed in Section III.D of the preamble, is finalizing the proposed requirement to report emissions and other data elements at the well level rather than at the sub-basin level. As noted in our response to more general comments concerning disaggregated reporting in the onshore production segment and onshore gathering and boosting segment, the aggregation of data currently collected for these industry segments "can present challenges in the process of emissions verification, with corresponding potential impacts on data quality, and it also limits data transparency." The directive under CAA section 136(h) to ensure that reporting under subpart W accurately reflects total methane emissions is inexorably linked to verification of reported data. Absent a robust system of emissions verification, the EPA cannot ensure the accuracy of reported data. As such, the proposed amendments to improve the quality and verification of subpart W data are supportive of the directive of CAA section 136(h). Further, as discussed in section II.C of the preamble to the proposed rule, beyond consistency with the directives in CAA section 136(h), the data collected under subpart W is used to support a range of policies and initiatives including but not limited to "provisions involving research, evaluating and setting standards, endangerment determinations, or informing EPA non-regulatory programs."

In response to the commenter's request for additional clarity regarding the reporting of well IDs, the EPA proposed amendments to 40 CFR 98.236(m) that would require the reporter to report the well ID number for each well with flared or vented associated gas. This requirement is in 40 CFR 98.236(m)(1), which replaces the previous requirement in this rule citation to report the sub-basin ID and a list of well IDs. Under 98.236(m)(2) and (m)(3), the reporter must also report whether the well was subject to venting or flaring. These requirements remain unchanged from the previous rule.

In the existing rule, 40 CFR 98.236(m)(7)(i) requires the reporter to report the total number of wells for which associated gas was vented directly to the atmosphere without flaring and a list of their well ID numbers. We proposed to remove this requirement in the proposed rulemaking, and we are finalizing this removal in the final rulemaking because the data element is no longer necessary due to the new requirement to report the well ID for each associated gas well in 40 CFR 98.233(m)(1).

Commenter: CrownQuest Operating
Comment Number: EPA-HQ-OAR-2023-0234-0393
Page(s): 205

Comment 8: Bleeding pressure off well

It is unclear if the EPA is asking to measure the amount of gas vented when bleeding pressure off a well. If so, this would not be practical as it would require many operational units to add flow measurement devices for many day-to-day operations that scarcely ever vent, possibly only a couple times a year. This is completely impractical.

If understanding this correctly, it would require every pulling unit in the basin to add a flow meter, and composition analyzer. They would be required to record and track this data daily and report to the operator. If not the service company, the burden would fall on the operators. Operating companies do not have the manpower to have a representative on location every morning to measure this data.

Response 8: See Section III.M of the preamble to the final rule for the EPA's response to comments regarding Associated Gas Venting and Flaring.

15 Flare Stack Emissions

15.1 General/Overview of Flare Emission Calculation and Monitoring Requirements

Commenter: Permian Basin Petroleum Association (PBPA)
Comment Number: EPA-HQ-OAR-2023-0234-0346
Page(s): 6-7

Comment 1: Operations and Facilities Vary Between Upstream, Midstream, and Downstream Oil and Gas Sectors and Should Not Be Treated the Same

The Proposed Rule treats certain equipment used in upstream, midstream, and downstream sectors the same despite the fact that they are used very differently within each sector of the oil and gas industry. While administratively efficient, the one-size-fits-all approach does not result in gathering empirical data because it ignores the differences in the purpose and operation of equipment used in multiple sectors.

For example, flares often operate at low pressures when used in upstream operations, whereas flares are operated at high pressures for downstream uses. Despite these different operations, the monitoring requirements in the Proposed Rule make no distinction between flares used in the upstream and downstream sectors.

Response 1: While the EPA recognizes that there are operational differences in how flares are used across the overall oil and natural gas industry, the basics of proper flare operation needed to ensure methane reduction are consistent regardless of the industry segment. For example, the commenter pointed out that some flares operate at low pressure and some at high pressure. Regardless of the pressure of the flare, proper operation is dependent on the same basic factors – velocity, flow rate, heat content, and perhaps most importantly, the presence of a pilot flame. Other than the general comment, the commenter did not provide any specific instances to support their claim that the proposed monitoring requirements would not be appropriate under certain operating scenarios. In addition, the EPA points out that the proposed monitoring requirements associated with Tier 2 (which are used for inputs in the calculation methodology for subpart W) are in alignment with NSPS OOOOb, which applies across the same spectrum of types of facilities. In conclusion, no changes were made in the final rule as a result of consideration of this comment.

Commenter: Permian Basin Petroleum Association (PBPA)
Comment Number: EPA-HQ-OAR-2023-0234-0346
Page(s): 8, 12-15

Comment 2: Flare Requirements in the Proposed Rule are Inconsistent with OOOOb and OOOOc

While the Proposed Rule specifically states that Amendments to Subpart W will reference the final version of the method(s) in the NSPS OOOOb and presumptive standards proposed in EG

OOOOc, the Proposed Rule also contains glaring inconsistencies with those same proposed rules.

The most obvious example of the differences between the various proposals relates to flare requirements. In addition to inconsistencies with OOOOb and OOOOc, the Proposed Rule is also inconsistent with the NESHAP requirements for Petroleum Refineries, which the Proposed Rule requires operators to comply with in order to claim 98% DRE. Included in Attachment A is a summary of the inconsistencies among these three existing or proposed rules specifically related to flare requirements.

…

Attachment A

Comparison of Flare Monitoring Requirements in OOOOb/c, GHGRP, and Refinery NESHAP

Requirement	OOOOb/c (allows claiming 95% DRE per 40 CFR 98 W)	GHGRP 40 CFR W (required for all flares, regardless of DRE Tier)	40 CFR 63.670-671 (allows claiming 98% DRE per 40 CFR 98 W)
Continuous parameter monitoring to determine gas flow to the flare	"…continuous parameter monitoring system to determine the flow of gas sent to the flare or combustor, except as noted below for pressure-assisted devices. Alternatively, the owner or operator may conduct an initial engineering assessment of the sources vented to the flare to demonstrate that, based on the maximum pressure of these sources, the maximum possible gas flow rate would not exceed the allowed maximum flare tip velocity in 40 CFR 60.18 or the maximum design flow rate of the enclosed combustor."	"…for all flares, regardless of the tier discussed above, we are proposing to require at least continuous parameter monitoring to determine gas flow to the flare. Specifically, the proposed revisions to 40 CFR 98.233(n)(1) specify that the flow rate determination must be based on direct measurement using a flow meter if one is present, or if a flow meter is not available, it must be based on indirect calculation of flow using continuous parameter monitoring…"	"Flare vent gas, steam assist and air assist flow rate monitoring. The owner or operator shall install, operate, calibrate, and maintain a monitoring system capable of continuously measuring, calculating, and recording the volumetric flow rate in the flare header or headers that feed the flare as well as any flare supplemental gas used…" Mass flow monitors may be used for determining volumetric flow rate of flare vent gas provided the molecular weight of the flare vent gas is determined using compositional analysis…so that the mass flow rate can be converted to volumetric flow at standard conditions... Continuous pressure/temperature monitoring system(s) and appropriate engineering calculations may be used in lieu of a continuous volumetric flow monitoring system provided the molecular weight of the gas is known. The owner or operator shall determine Vtip on a 15-minute block average basis according to the following requirements… (1) use design and engineering principles to determine the unobstructed cross sectional area of the flare tip. (2) determine the cumulative volumetric flow of flare vent gas for each 15-minute block average period using the data from the continuous flow monitoring system required…"
Continuous parameter monitoring for the presence of pilot flame or combustion flame	"...all flares and enclosed combustion devices to have a continuous pilot flame and install a continuous parameter monitoring system capable of continuously (at least once every 5 minutes) monitoring for the presence of a pilot or combustion flame."	"…for all flares, regardless of the tier discussed previously in this section, we are proposing in 40 CFR 98.233(n)(2) to require either continuous monitoring (proposed 40 CFR 98.233(n)(2)(i)) or visual inspection at least once per month (proposed 40 CFR 98.233(n)(2)(ii))…"	"…continuously monitor the presence of the pilot flame(s) using a device (including, but not limited to, a thermocouple, ultraviolet beam sensor, or infrared sensor) capable of detecting that the pilot flame(s) is present." "…each flare with a pilot flame present at all times when regulated material is routed to the flare."

Requirement	OOOOb/c (allows claiming 95% DRE per 40 CFR 98 W)	GHGRP 40 CFR W (required for all flares, regardless of DRE Tier)	40 CFR 63.670-671 (allows claiming 98% DRE per 40 CFR 98 W)
Visible Emissions Flare Monitoring	"…require inspections to monitor for visible emissions using section 11 of EPA Method 22 of appendix A-7 of part 60 (EPA Method 22). The observation period for the EPA Method 22 inspection would be 15 minutes. Visible emissions longer than 1 minute during the 15-minute period would be a deviation of the standard. This is consistent with similar requirements in NSPS OOOOa. The EPA is proposing that these inspections would occur monthly, and at other times as requested by the Administrator."	N/A (the only visual monitoring is the option of monthly visual inspection of pilot flame or combustion flame noted above)	"…conduct an initial visible emissions demonstration using an observation period of 2 hours using Method 22 at 40 CFR part 60, appendix A-7. The initial visible emissions demonstration should be conducted the first time regulated materials are routed to the flare. "…no visible emissions, except for periods not to exceed a total of 5 minutes during any 2 consecutive hours, when regulated material is routed to the flare and the flare vent gas flow rate is less than the smokeless design capacity of the flare." "Subsequent visible emissions observations must be conducted using either…: (1) At least once per day for each day … conduct visible emissions observations using an observation period of 5 minutes using Method 22 at 40 CFR part 60, appendix A-7…" OR (2) "Use a video surveillance camera to continuously record…images of the flare flame…"
Gas Composition	N/A (other than the requirement to continuously monitor or complete initial assessment/demonstration of net heating value below)	"The proposed options are to use a continuous gas composition analyzer or to take samples for compositional analysis at least once each quarter in which the flare operated. If a continuous gas analyzer is used, then the measured data would be required to be used to calculate flared emissions."	"**Flare vent gas composition monitoring.** The owner or operator shall determine the concentration of individual components in the flare vent gas using either… (1)… a monitoring system capable of continuously measuring (*i.e.*, at least once every 15-minutes)" OR (2)"… a grab sampling system capable of collecting [samples] at least once every eight hours."

Requirement	OOOOb/c (allows claiming 95% DRE per 40 CFR 98 W)	GHGRP 40 CFR W (required for all flares, regardless of DRE Tier)	40 CFR 63.670-671 (allows claiming 98% DRE per 40 CFR 98 W)
Heating Value	"…Owners and operators would install a continuous parameter monitoring system … to continuously determine the net heating value of the gas sent to the flare or combustor. Alternatively, the owner or operator could conduct an initial assessment to demonstrate that the net heating value of the vent gas sent to the flare or combustor consistently exceeds the required minimum net heating value in 40 CFR 60.18 or the minimum net heating value proposed for pressure-assisted flares." "For pressure-assisted devices, the EPA is proposing to include special provisions in NSPS OOOOb/EG OOOOc, which include a minimum net heating value (NHV) of the gas sent to the flare/combustor of **800** British thermal units per standard cubic feet (Btu/scf)…" "…net heating value of the gas being combusted being 7.45 MJ/scm (**200** Btu/scf) or greater if the flare is nonassisted." [40 CFR 60.18(c)(3)(ii)]	"…require all reporters to use either a flare-specific HHV or individual flared gas stream-specific HHVs in the calculation…require the use of a flare-specific HHV when composition of the inlet gas to the flare is measured or when flow-weighted concentrations of the inlet gas are calculated from measured flow and composition of each of the streams routed to the flare."	"Except as provided in paragraphs (j)(5) and (6) of this section, the owner or operator shall install, operate, calibrate, and maintain a calorimeter capable of continuously measuring, calculating, and recording NHVvg at standard conditions… (5) Direct compositional or net heating value monitoring is not required for purchased ("pipeline quality") natural gas streams. The net heating value of purchased natural gas streams may be determined using annual or more frequent grab sampling at any one representative location. Alternatively, the net heating value of any purchased natural gas stream can be assumed to be **920** Btu/scf. (6) Direct compositional or net heating value monitoring is not required for gas streams that have been demonstrated to have consistent composition (or a fixed minimum net heating value)… "Dilution operating limits for flares with perimeter assist air. Except as provided in paragraph (f)(1) of this section, for each flare actively receiving perimeter assist air, the owner or operator shall operate the flare to maintain the net heating value **dilution** parameter (NHVdil) at or above **22** British thermal units per square foot (Btu/ft 2) determined on a 15-minute block…" For nonassisted flares: "**Combustion zone operating limits.** For each flare, the owner or operator shall operate the flare to maintain the net heating value of flare combustion zone gas (NHVcz) at or above **270** British thermal units per standard cubic feet (Btu/scf) determined on a 15-minute block period basis…"

Response 2: The commenter's analysis is flawed, as the comparisons do not recognize the differences in the purposes of the various programs' requirements. All the flare monitoring requirements in NSPS OOOOb, EG OOOOc, and NESHAP CC serve the purpose of ensuring that the flare is operating properly and achieving the required destruction efficiency under those programs. The requirements cross-referenced under this rulemaking are important in the subpart W context related to the use of the flare efficiency tiers under the calculation methodologies in 40 CFR 98.233(n)(1) of the final rule. For example, in order to utilize a methane destruction efficiency of 95% for the purpose of calculating and quantifying emissions under the subpart W calculation methodology, the subpart W flare Tier 2 incorporates and requires that a source follow the NSPS OOOOb flare monitoring requirements related to flare tip velocity, flow rate, and heat content.

The purpose of subpart W is to quantify the emissions, which is not required by NSPS OOOOb, EG OOOOc, or NESHAP CC. This requires that additional data be obtained to enable this quantification and ensure that the calculated emissions are based on empirical data and are accurate.

The best example of how the commenter mixed the purposes in the creation of their table is the row entitled “Continuous parameter monitoring to determine gas flow to the flare.” The NSPS OOOOb requirements summarized are related to a requirement that flares maintain an exit velocity less than the specified level for the type of flare. This is important because exceeding the velocity limit can cause the flare to lift off the tip and flame out (i.e., a flame out leaves the flare unlit, which results in no emissions control). The important aspect of this requirement under the NSPS is to remain below the limit. The commenter also failed to include the requirements for flow rate monitoring under NSPS OOOOb to ensure that the flow rate remains above the minimum value needed for proper combustion. However, for subpart W, where the purpose is to estimate the emissions, the actual volume of gas routed to the flare is needed to calculate emissions. Therefore, it is not enough to simply ensure that the flow rate is below a maximum level (or above a minimum); the actual volume of gas must be determined.

In conclusion, the commenter’s table does not accurately compare the flare monitoring requirements appropriately. While several changes were made in the final rule related to the flare monitoring requirements after consideration of comments (see section III.N of the final rule preamble), none were made in direct response to this comment.

Commenter: American Exploration and Production Council
Comment Number: EPA-HQ-OAR-2023-0234-0295
Page(s): 3

Commenter: Enerplus Resources (USA) Corporation
Comment Number: EPA-HQ-OAR-2023-0234-0342
Page(s): 1

Commenter: Ovintiv Inc.
Comment Number: EPA-HQ-OAR-2023-0234-0350
Page(s): 1-2

Commenter: Marathon Oil Company
Comment Number: EPA-HQ-OAR-2023-0234-0378
Page(s): 2-3

Commenter: American Petroleum Institute et al. (Part 1 of 2)
Comment Number: EPA-HQ-OAR-2023-0234-0402
Page(s): 38

Comment 3: Commenter 0295: **Flares**

AXPC is concerned that EPA's proposed changes with respect to flares will impose costly monitoring requirements without improved reporting accuracy and introduce complexity in calculation methodologies. The Proposal introduces discrepancies between Subpart W, various state permitting practices, and other federal requirements. Further, the Proposal's limitation on the ability for operators to be able to use empirical data to demonstrate a higher performing flare destruction efficiency runs counter to Congress's directive in the IRA and intent to incentivize accelerated emission reductions; in contrast, flare provisions of the Proposal inadvertently disincentivize improved emission performance in this space. We discuss these significant concerns regarding proposed changes to flares separately in the subsections below.

Commenter 0342: Flares

EPA's proposed changes with respect to flares will impose additional costly monitoring requirements without providing improved accuracy and introduce complexity in calculation methodologies due to discrepancies between Subpart W and various state permitting practices and federal requirements.

Commenter 0350: Flares

EPA's proposed changes with respect to flares will impose additional costly monitoring requirements without providing improved accuracy and introduce complexity in calculation methodologies due to discrepancies between Subpart W and various state permitting practices and federal requirements. The monitoring requirements will increase company spending on emissions monitoring without associated improved emissions reduction benefit.

…

Commenter 0378: Flare monitoring requirements must be changed to avoid costly monitoring requirements without improved accuracy.

The Subpart W revisions relating to "flares" will impose additional costly monitoring requirements without providing improved accuracy and introduce complexity in calculation methodologies, providing no emissions reduction benefit for this added cost and complexity, largely due to discrepancies between the Subpart W revisions and state permitting requirements. Subpart W revisions should be amended to allow operators to use empirical data and credible information to estimate GHG emissions wherever such data is available, rather than relying on inaccurate monitoring requirements that introduce unnecessary complexities to calculation methodologies.

…

Commenter 0402: Flares

EPA's proposed changes with respect to flares will impose additional costly monitoring requirements without providing improved accuracy and introduce complexity in calculation methodologies due to discrepancies between Subpart W and various state permitting practices and federal requirements.

…

Response 3: Regarding comments on the monitoring requirements to demonstrate that the tier 1 and tier 2 flare efficiencies are being achieved, for use in the subpart W calculation methodology, see the specific comments in Section 15.2.3 of this document and see the EPA's responses to these comments in Section III.N.1 of the preamble to the final rule. Regarding comments on the proposed monitoring requirements for flow, gas composition, and presence of pilot flame, see the specific comments in Sections 15.2.4, 15.2.5, and 15.2.6 of this document and see the EPA's response to these comments in Section III.N.1 of the preamble to the final rule.

Commenter: The Petroleum Alliance of Oklahoma
Comment Number: EPA-HQ-OAR-2023-0234-0398
Page(s): 15

Comment 4: EPA is proposing to remove existing 40 CFR 98.233(m)(5) and instead direct reporters to 40 CFR 98.233(n) to calculate emissions from associated gas flaring. The EPA is also proposing to remove 40 CFR 98.236(m)(8), as flared emissions would be reported under 40 CFR 98.236(n).

Operators are familiar with these calculation methodologies and have processes and procedures established to report emissions using these methodologies.

Action Requested: We request EPA continue to allow reporters to use calculation methodologies provided 40 CFR 98.233(m)(5) and 40 CFR 98.236(m)(8) to report emissions.

Response 4: 40 CFR 98.233(m)(5)(i) in the current rule specifies that flow and composition of associated gas routed to flares is to be determined according to the methodology in 40 CFR 98.233(m)(1) through (4). As discussed in responses to comments in sections 15.2.4 and 15.2.6 of this document, the same methodology has been added as options in 40 CFR 98.233(n)(3) and (4) of the final rule that the owner or operator may elect to use for calculating flow and composition of individual associated gas streams routed to flares.

40 CFR 98.233(m)(5)(ii) in the current rule specifies that the calculation methodology of flare stacks in 40 CFR 98.233(n) of the current rule is to be used to calculate flared associated gas emissions. The final rule contains the same equations as the current rule for calculating flared emissions, but the procedures for determining the flare efficiency and the fraction of gas sent to an unlit flare have been changed. See Section III.N.1 of the preamble to the proposed rule and Section III.N.1 of the preamble to the final rule for discussions of why procedures for determining these input parameters have been changed for the final rule.

40 CFR 98.236(m)(8) of the current rule requires owners and operators to report the total count of wells flaring associated gas emissions and the total flared associated gas emissions per sub-basin. In 40 CFR 98.236(n) of the final rule, reporting of all flare data for onshore production facilities is per well-pad. See section 5.1 of this document and Section III.D of the preamble to the final rule for additional information regarding reporting at the site level rather than the sub-basin level.

Commenter: CrownQuest Operating
Comment Number: EPA-HQ-OAR-2023-0234-0393
Page(s): 214

Comment 5: We are concerned there could be confusion in accounting for pilot, purge and sweep gas under "Flares" in paragraph N. Associated gas flaring is accounted for here, we recommend that engineering estimates be allowed for pilot, purge and sweep gas in the "Flares" section.

Response 5: The commenter did not explain why accounting for emissions from combustion of pilot, purge and sweep gas as flare stack emissions could be confusing. Accounting for these streams when calculating flared emissions is not a change from the current rule. Emissions from combustion of these streams must be accounted for as flare stack emissions under the current rule because current 40 CFR 98.233(n)(1) requires flow to be measured or estimated for "all of the flare gas," and current 40 CFR 98.233(n)(2) requires gas compositions to be determined for "each stream of hydrocarbons going to the flare." By explicitly stating in the final rule that emissions from combustion of pilot, purge and sweep gas must be included in the total emissions from a flare, we believe the final rule is clarifying the requirements, thereby reducing rather than creating confusion.

Regarding the commenter's recommendation that engineering estimates be allowed for pilot, purge, and sweep gas, 40 CFR 98.233(n)(3) and (4) of the final rule specify revised procedures to determine flow and composition of these streams. We inadvertently neglected to specify procedures for determining flow and composition of pilot gas in the proposed rule. In 40 CFR 98.233(n)(3), the final rule specifies that pilot gas flow is to be determined using engineering calculations based on best available data and company records. Similarly, in 40 CFR 98.233(n)(4), the final rule specifies that composition of pilot gas must be determined by engineering calculation based on process knowledge and best available data.

If a reporter determines emissions for individual streams routed to the flare (instead of measuring characteristics of the total stream at the inlet to the flare), then 40 CFR 98.233(n)(3)(ii) of the final rule specifies that flow of streams such as purge and sweep gas are to be determined using either a continuous parameter monitoring system, as proposed, or by using engineering calculations based on process knowledge, company records, and best available data. This is consistent with flow determination methods in the current rule for such streams. See specific comments regarding the proposed flow measurement requirements in Comment 2 of Section 15.2.4 of this document and see the EPA's responses to these comments in Section III.N.1 of the preamble to the final rule.

The proposed rule (40 CFR 98.233(n)(3)(iii) and (iv) as proposed) would have required annual sampling of purge and sweep gas. In the final rule, annual sampling is an option. In 40 CFR 98.233(n)(4)(iii)(B), the final rule also includes an option derived from the current rule for determining composition from hydrocarbon product streams such as methane, ethane, propane, butane, pentane-plus or mixed light hydrocarbons. If a purge gas or sweep gas stream can be classified as a hydrocarbon product stream, then the owner or operator may use a representative composition of the stream determined based on process knowledge and best available data. Otherwise, composition of purge gas and sweep gas at an onshore production facility must either be measured using a continuous gas composition analyzer or annual sampling of produced gas in accordance with 40 CFR 98.233(n)(4)(iii)(B) of the final rule. See Section III.N.1 of the preamble to the final rule for a discussion of the requirement to conduct annual samples.

Commenter: Western Energy Alliance
Comment Number: EPA-HQ-OAR-2023-0234-0399
Page(s): 3

Comment 6: *The Proposed Rule Conflict with the Proposed OOOOb and OOOOc Standards*

First, the revised GHG Subpart W reporting rule would add significant requirements to flare monitoring standards over and above those that are proposed in the NSPS (OOOOb) and existing source Emission Guideline (OOOOc) standard revisions. Gas composition monitoring is included in the proposed revised Subpart W, but not in the NSPS or existing source standards in OOOOb/c. The revised Subpart W rule would also accelerate the schedule for all flare monitoring standards ahead of OOOOc, because the revised Subpart W is effective January 1, 2025, and the state-by-state implementation of OOOOc will not be effective for several years after that. Using the revised Subpart W reporting rule to incorporate flare monitoring standards from a NEHSAP standard (40 CFR 63 Subpart CC), for a different industry sector, petroleum refineries, as a requirement to claim a flare DRE of 98% at production facilities regulated under OOOOb/c NSPS/existing source standards is not appropriate.

Response 6: The purpose of incorporating certain requirements of NSPS OOOOb and NESHAP CC is to provide a mechanism to ensure that flares are operating properly and achieving the reductions being used in the selected methodology under subpart W when calculating emissions. While the commenter is correct regarding the schedule for state plans developed in accordance with subpart OOOOc, this is not relevant for the purposes (calculating and reporting accurate emissions based on empirical data) that we are incorporating these certain requirements under subpart W in the separate GHGRP program. It is important that the efficiencies utilized under the selected calculation methodology after January 1, 2025 are representative of the actual reductions being achieved irrespective of whether a source is subject to a OOOOc state plan. The EPA also points out that subpart W does not require all sources to utilize the Tier 1 efficiencies (and meet the certain incorporated requirements from NESHAP CC) or Tier 2 efficiencies (and meet the certain incorporated requirements from NSPS OOOOb). Reporters can elect to utilize the calculation methodology with Tier 3 efficiencies and associated requirements, thus not using a calculation methodology that incorporates certain requirements from either NESHAP CC or NSPS OOOOb.

With regard to the incorporation of NESHAP CC requirements, the proper operation of a flare is not sector dependent. Thus, EPA maintains the more intensive flare monitoring requirements are appropriate to ensure that reporting using the calculation methodology with 98% reduction accurately reflects the emissions from that source.

Finally, after consideration of public comments related to composition monitoring, we are not finalizing this proposed requirement and are instead finalizing requirements that are comparable to requirements for calculating composition in the current rule (see Section III.N.1 of the final rule preamble).

Commenter: GPA Midstream Association
Comment Number: EPA-HQ-OAR-2023-0234-0299
Page(s): 42

Comment 7: EPA cannot establish flare compliance requirements in Subpart W, and the requirements for flare stack reporting must be simplified.

As discussed above in Comment 6, the GHGRP is an informational program. As EPA noted when it promulgated the program, "[t]he rule does not require control of greenhouse gases, rather it requires only that sources above certain threshold levels monitor and report emissions."[99] The revisions to Subpart W cannot be the driver on control of air pollutant emissions. Rather, other provisions of the CAA such as section 111 and 112, are available for this purpose.

Unfortunately, in the proposal, EPA indirectly imposes flare monitoring requirements that go vastly above-and-beyond current requirements for petroleum and natural gas systems operators. This is wholly inappropriate for a reporting rule. If EPA believes current regulations should require additional monitoring for flares in the oil and gas source category, then it should address this directly by revising the specific regulations for emission controls and not indirectly through an emissions inventory reporting rulemaking.

Response 7: The GHGRP is an emissions reporting program. However, the commenter's inference that subpart W is being used to control or reduce emissions is entirely incorrect. Subpart W does not require any reduction in emissions, only that the level of emissions be reported and that the provisions ensure that the reporting be based on empirical data and reflect accurate total emissions from the facility. Given the evidence that, left unmonitored, flares in the oil and natural gas segment are not performing properly[9], it is necessary to include requirements to ensure that emission reductions used in emission calculations are accurate (i.e., being achieved). The incorporation of certain flare monitoring provisions from CAA section 111 and 112 regulations as subpart W requirements under our calculation methodologies is intended for this purpose. Further, no source is required to utilize Tier 1 or Tier 2, thus subpart W does not require reporters to follow the corresponding flare monitoring provisions.

[9] Permian Methane Analysis Project (PermianMAP) reporting the results of 4 Environmental Defense Fund (EDF) surveys of over a thousand flare stacks from February to November 2020. See https://www.permianmap.org/flaring-emissions.

Commenter: GPA Midstream Association
Comment Number: EPA-HQ-OAR-2023-0234-0299
Page(s): 44-45

Comment 8: EPA should not specify monitoring technology to allow flexibility for new technology development.

EPA should incorporate direct or parametric monitoring data into calculations only when the data are available. EPA should also eliminate references to specific types of equipment. This approach ensures flexibility for emerging technology and accommodates changes in regulatory language in other rules without necessitating revisions to Subpart W.

Response 8: Based on the subsequent paragraph in the commenter's letter, it appears the statement regarding parametric monitoring in this comment is referring to the proposed requirement to use a continuous parameter monitoring system to determine flared gas flow. See the commenter's specific comment regarding proposed flow monitoring requirements in Comment 3 in section 15.2.4 of this document, see other similar comments regarding the proposed flow monitoring requirements in Comment 1 in Section 15.2.4 of this document, and see the EPA's response to these comments in Section III.N.1 of the preamble to the final rule.

Based on subsequent comments in the commenter's letter, it appears the request in this comment to eliminate references to specific types of equipment refers to the proposed requirements for the presence of a pilot flame. See the commenter's specific comments in Comment 1 in Section 15.2.5 of this document regarding their assertion that newer, remote visual inspection technology for determining the presence of a flame must be allowed in the rule and see the EPA's response to this and related comments in Section III.N.1 of the preamble to the final rule.

Commenter: American Petroleum Institute et al. (Part 1 of 2)
Comment Number: EPA-HQ-OAR-2023-0234-0402
Page(s): 32-33

Comment 9: Flares

It is critical to the Industry Trades that the GHGRP does not directly include monitoring, measuring and sampling requirements for flares in order to avoid conflicting or duplicative requirements. Instead, the GHGRP should refer to data available through other applicable federal air quality regulatory programs. The Industry Trades request that EPA should ensure consistency across programs. This will help ensure that the requirements in the GHGRP are fully harmonized with any potential requirements under other federal air quality programs.

The Industry Trades support more accurate approaches for destruction efficiency for estimating flare emissions; however, the **tiers as proposed should be amended** (specific comments below). Further, while it is sensible to allow for the use of available empirical data and appropriate to define multiple estimation methods based on different types of available information, **monitoring requirements that are repeated in Subpart W rather than referencing the applicable regulation, especially those that exceed NSPS OOOOb and EG OOOOc requirements, which are defined in those rules, should not be included in Subpart W**. Further, flare estimating methods should be appropriate to the equipment and designs deployed within the segment (e.g., small, mostly unassisted, distributed flares) rather than arbitrarily under a rubric designed for a specific compliance assurance matter from a very different set of facilities and designs (refining and chemical manufacturing). …

With the Industry Trade's recommendations, the Industry Trades generally support EPA's focus on pilot flame monitoring as unlit flares can be large sources of methane emissions from flares. However, the proposed rule's requirements to continuously measure or monitor flow volumes, as well as use continuous gas analyzers or pull quarterly samples for gas compositions would result in little benefit to accuracy while posing significant costs and safety risks. Further, the Industry Trades disagree with EPA's proposed three-tier destruction efficiency (see Comment under Section 3.8.4 below).

Response 9: For the EPA's responses to specific comments from this commenter and other commenters on proposed destruction efficiency requirements see Section 15.2.3 of this document and Section III.N.1 of the preamble to the final rule. For the EPA's responses to specific comments from this commenter and other commenters on proposed flow monitoring requirements, see Section 15.2.4 of this document and Section III.N.1 of the preamble to the final rule. For the EPA's responses to specific comments from this commenter and other commenters on proposed monitoring requirements for the presence of pilot flame, see Section 15.2.5 of this document and Section III.N.1 of the preamble to the final rule. For the EPA's responses to specific comments from this commenter and other commenters on proposed gas composition monitoring requirements, see Section 15.2.6 of this document and Section III.N.1 of the preamble to the final rule.

Commenter: American Petroleum Institute et al. (Part 1 of 2)
Comment Number: EPA-HQ-OAR-2023-0234-0402
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Comment 10: Flares

Completion Combustion Devices Should not be Subject to Proposed 98.233(n)

Requirements for completion combustion devices used during completions with hydraulic fracturing should not be required to have the same monitoring provisions as flares under 98.233(n).

For completions with hydraulic fracturing in 98.233(g), EPA has proposed operators to follow the requirements listed in 98.233(n), which include extensive monitoring requirements. Under existing air quality regulations and proposed NSPS OOOOb, combustion of emissions that cannot be routed to sales, such as for wildcat or delineation wells, are combusted using a completion combustion device. This equipment has a separate definition and compliance assurance requirements from typical control devices based under NSPS due to the temporary use of these devices during a completion event. The proposed requirements under 98.233(n) are inappropriate and EPA should, at a minimum, have appropriate provisions that allow engineering estimates for completion combustion events. Completion combustion devices must be equipped with a reliable continuous pilot flame under NSPS.

Response 10: Under NSPS OOOOb, the only requirement that applies to a completion combustion device is that it be equipped with a continuous pilot flame. Under subpart W, a completion combustion device meets the definition of flare. Since it is not a flare under NSPS OOOOb, it would never be subject to NSPS OOOOb, but since it is a flare under subpart W, the owner or operator could elect to implement the procedures for flares in NSPS OOOOb (as specified in 40 CFR 98.233(n)(1)(ii) of the final rule) in order to use the tier 2 efficiencies. Otherwise, the owner or operator must comply with tier 3. No monitoring requirements are specified in subpart W for demonstrating that the tier 3 efficiencies are achieved, but flow and composition are required in order to calculate flared emissions from the completion. The proposed rule would have required continuous flow monitoring of such streams. However, as discussed in a response to comments in Section III.N.1 of the preamble to the final rule, continuous flow monitoring as proposed is specified as one option in the final rule, and another option added to 40 CFR 98.233(n)(3)(ii)(B)(*3*) in the final rule specifies that flow from completions with hydraulic fracturing also may be determined using the engineering calculation method in 40 CFR 98.233(g) of the final rule. Similarly, the proposed rule would have required that composition of flared streams from completions be determined using either a continuous gas composition analyzer or quarterly sampling and analysis. As discussed in a response to another comment in Section III.N.1 of the preamble to the final rule, the proposed quarterly sampling and analysis option has been changed to annual sampling and analysis in the final rule. Additionally, under the proposed rule, the sampling and analysis option would have applied separately to each stream, including emission streams from completions, but 40 CFR 98.233(n)(4)(iii)(B)(*5*) of the final rule cross-references 40 CFR 98.233(u)(2)(i) so that composition of emission streams from completions may be based on the composition of produced gas.

Commenter: Environmental Defense Fund, et al.
Comment Number: EPA-HQ-OAR-2023-0234-0413
Page(s): 62

Comment 11: 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 CH_4 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.

Footnotes

[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-permiandata.s3.amazonaws.com/videos/Flaring_August_2021/S6M_0330 mp4. Examples of large methane emissions from central tank battery, available at: https://edf-permiandata.s3.amazonaws.com/videos/Flaring_December_21/S8R_0480.mp4.

Response 11: We agree with the commenter that it is possible that emissions from a flare may be reported as an other large release event in cases where the flare is lit and the combustion efficiency is significantly lower than the default and results in calculated emissions greater than 100 kg/hr greater than would be calculated under 40 CFR 98.233(n). As noted in section III.B.1 of the preamble, the final requirements related to assessing incremental emission differences for the purpose of determining whether the event is an other large release event applies to flares, as proposed. We note, however, that we expect that large emission events due to unlit flares will still be reported under flares, as the finalized calculation methodologies are expected to appropriately account for unlit flares.

Commenter: American Petroleum Institute et al. (Part 1 of 2)
Comment Number: EPA-HQ-OAR-2023-0234-0402
Page(s): 6

Comment 12: We urge EPA to seek true alignment and harmonization with other federal regulatory requirements, particularly the NSPS OOOOb and EG OOOOc "Methane Rules" and the GHGRP itself. Below are a few examples that are articulated in our comments:

…

- Flare requirements should not extend beyond 60.18 "General control device and work practice requirements" and the Methane Rules.

Response 12: See Section III.N of the preamble to the final rule for our response to this comment.

Commenter: American Petroleum Institute et al. (Part 1 of 2)
Comment Number: EPA-HQ-OAR-2023-0234-0402
Page(s): 8

Comment 13: EPA should avoid any potential double-counting of emissions across source types. The Industry Trades have identified specific areas with the potential for double-counting. Since it is expected that the GHGRP will be used to determine associated fees within a methane-fee environment, the Industry Trades are extremely concerned about any source and methodology which could result in double counting emissions, and therefore, double fees. Categories that are particularly susceptible to potential double counting are other large release events and unlit flares; and even between flares and unlit flares, where the proposed Tier 3 destruction efficiency for flares includes unlit flares.

Response 13: With respect to double counting between flares and other large release events, see Section III.B of the preamble to the final rule for our response to this comment. With respect to the commenter's assertion that the Tier 3 destruction efficiency for flares includes unlit flares, see Section III.N of the preamble to the final rule for our response to this comment.

Commenter: American Petroleum Institute et al. (Part 1 of 2)
Comment Number: EPA-HQ-OAR-2023-0234-0402
Page(s): 8

Comment 14: EPA's tiered approach to flare "combustion efficiency" is flawed and is not supported by the data cited by EPA in the Technical Support Document. The Industry Trades are concerned that EPA proposes to override decades of precedent on oil and gas flare monitoring and operation established in federal and state regulations, permits, manufacturer guarantees, and performance tests based on the results of just one limited study. As such, the Industry Trades are requesting EPA to allow performance test data for flare methane destruction efficiency, rather than inappropriate National Emission Standards for Hazardous Air Pollutants (NESHAP) requirements, as aligned with EPA's intent to incorporate empirical data. Further and importantly, the Industry Trades have provided additional data to supplement its position that flare "combustion efficiency" should be a minimum of 95%, or arguably even higher based on data from 132 flares tested in the Permian and Bakken. Please refer to Section 3.8.4.4.

Response 14: See Section III.N.1 of the preamble to the final rule for our response to this comment.

Commenter: Endeavor Energy Resources, L.P.
Comment Number: EPA-HQ-OAR-2023-0234-0381
Page(s): 14

Comment 15: EPA Should Reconsider the Proposed Revisions to Calculation Methods for Several Emission Sources.

Flare Stack Emissions

Although Endeavor supports EPA's approach for greater flexibility, such as with respect to gas composition, Endeavor has serious concerns about EPA's proposed regulations for flare stack emissions. Specifically, EPA proposes a three-tier approach to flare efficiency and new requirements for continuous monitoring for gas flow and pilot flames, neither of which is supported by EPA's record and both of which will likely result in inaccurate reporting. Endeavor's concerns and recommendations are described below.

Response 15: See Section III.N.1 of the preamble to the final rule for our response to this comment.

Commenter: Permian Basin Petroleum Association (PBPA)
Comment Number: EPA-HQ-OAR-2023-0234-0346
Page(s): 4

Comment 16: Flares

…

Furthermore, EPA is also proposing that the Tier 2 DRE of 95% can be used if the operator is in compliance with the yet to be finalized OOOOb. This Proposed Rule's continuous flow monitoring requirement also effectively accelerates the requirements of presumptive standards proposed in EG OOOOc, which will not be formally adopted by states for several years. As discussed in more detail below, it is not appropriate to base portions of this rule on compliance with another yet to be finalized rule, especially considering that the OOOOb/c rules could be entangled in litigation for years. The EPA should have a clear picture of what the final OOOOb/c standards will be before it proposes additional rules that incorporate those standards.

Response 16: The EPA Administrator signed the final NSPS OOOOb regulation and the subpart OOOOc Emission Guideline on November 30, 2023. This rule and guideline have subsequently been published in the Federal Register. Therefore, in the development of this final rule, the EPA closely monitored the potential changes to NSPS OOOOb and was fully aware of that final rule when considering public comments and finalizing the subpart W amendments.

The EPA also notes the distinction between commenter's assertion (subpart W requiring "compliance" with NSPS OOOOb) and this rulemaking incorporating specific provisions under a subpart W calculation methodology that are to be followed to use that method in order to ensure that the emissions calculated are accurate (i.e., a flare is operating properly so as to achieve 95% reduction in methane emissions being used where Tier 2 is applied in the calculation methodology). Failure to use the Tier 2 method does not constitute a subpart W violation of any kind and whether the facility is "in compliance" with the NSPS as determined under that separate program is not relevant to the subpart W program. Rather, if an owner or operator is using the Tier 2 method but fails to conform with the subpart W Tier 2 requirements that cross reference certain specific NSPS OOOOb requirements for 15 days, it simply means that the owner or operator must use the Tier 3 method for calculations until such time as the Tier 2 method requirements are being followed again.

Commenter: Independent Petroleum Association of New Mexico (IPANM)
Comment Number: EPA-HQ-OAR-2023-0234-0337
Page(s): 5-6

Comment 17: 40 CFR § 98.233(n) Flares

…

Current calculation methods in Subpart W for streams that can be routed to flare, such as storage tanks, glycol dehydrators, associated gas, completions and workovers etc., already provide for empirical data to be used to calculate the emissions from these streams that are covered under other source types. Those methods provide the empirical data to satisfy the requirement for flares in CAA § 136(h).

Response 17: See Section III.N.1 of the preamble to the final rule for our response to this comment.

Commenter: GPA Midstream Association
Comment Number: EPA-HQ-OAR-2023-0234-0299
Page(s): 17, 105

Comment 18: The following is a list of substantive proposed changes that GPA expressly supports.

…

- Allowing flared emissions from acid gas removal units (“AGRUs”), nitrogen vents, and glycol dehydrators to be reported under the flare source category [98.233(d), (e)];

…

Appendix A

Table of changes GPA supports as proposed.

Subpart	Citation	Change
…		
W	98.238	Flare Stacks: Revising definition of *Flare Stack Emissions*
W	98.236(n)(1)(xi)	Flare Stacks: Clarification that flare stack CO2 emissions should exclude CO2 emissions reported under Acid Gas Removal Units.

Response 18: The EPA acknowledges the commenter’s support for the proposed revisions. We note that the table under the heading “Appendix A” was included as an attachment to the commenter’s letter, but it is a comment on the 2022 GHGRP Proposal. The comment in the last

row of the table are not relevant to this final rule. The commenter also submitted comments on the 2023 Subpart W Proposal related to this issue, included earlier in this comment.

Commenter: GPA Midstream Association
Comment Number: EPA-HQ-OAR-2023-0234-0299
Page(s): 86, 90

Comment 19: EPA should move away from dissecting flare emissions source-by-source and thereby introducing enormous complexity in data collection, calculation, reporting and the rule text itself. As a general matter, most facilities do not have meters on every individual source that can be routed to a flare and determining exact volumes or compositions for any individual source is often a rough estimate at best. EPA seems to be on an investigatory quest to understand the nature of flare emissions at a fine grain, and even if it was possible to do so with data routinely available at facilities (which we argue, it is not), imposing the detailed and prescriptive requirements to collect this information in an annual reporting program applicable to the vast majority of flares in oil and gas is beyond burdensome and is wholly unnecessary to determine greenhouse gas emissions from flares.

…

RFC: For flared sources, EPA requests comment on whether proposed changes to describe the applicable procedures for calculating flared emissions for each source type separately rather than trying to generally describe a single set of consolidated procedures makes the rule easier for reporters to understand.

> **Comment**: Per our previous comments, we do not support reporting requirements to parse out flare emission data, and the procedures for calculating flare emissions are overly prescriptive.

Response 19: See Section III.N.1 of the preamble to the final rule for our response to this comment.

15.2 Calculation Methodology for Total Emissions from a Flare

15.2.1 Alternative Measurement/Monitoring Methods to Determine Emissions

Commenter: Chevron
Comment Number: EPA-HQ-OAR-2023-0234-0232
Page(s): 5,6,7

Comment 1: Flare – Combustion Efficiency Reporting

The proposed rule specifies a tiered combustion efficiency (CE) value for flares which includes extensive monitoring requirements for Tier 1 (CE=98%) and Tier 2 (CE=95%). The default CE for flares is proposed at 92%. While EPA's stated intention is to ensure more accurate reporting of flare CEs, the proposed tiers and monitoring methodology are not the most effective means of correctly monitoring and reporting flare combustion efficiencies. Other, more direct, monitoring technologies such as flyover surveys or multi-spectral cameras can be used for periodic flare combustion efficiency monitoring. Advanced technologies such as aerial surveys can provide a more comprehensive overview of flare emissions, especially for unlit flares or those with lower combustion efficiencies, particularly when combined with parametric and operational data from each site.

…

Aerial surveys using the appropriate monitoring technology can be an effective tool in observing emissions from flares. When combined with the use of parametric data, this can be a more effective approach to monitoring flares than the current proposed tiered approach. For instance, gas volumetric rates to flares may be well understood through design parameters or measurements, and sufficiently large such that appropriate monitoring technologies will be able to detect methane emissions from flares with CEs either above or below 98%. Because of this, advanced technologies would be effective in identifying less efficient flares, especially within the set of flares operating at high rates and high frequency.

…

Response 1: We acknowledge the commenter's support for aerial surveys in observing emissions from flares. As discussed in Section II.B of the preamble to the final rule, this final rule does not include general provisions that incorporate the use of advanced measurement approaches for sources at this time and instead specifically allows its use in certain appropriate cases, including for large release events. However, the Agency recognizes that these technologies, and approaches for using these technologies for long-term quantification of emissions from oil and natural gas operations, are evolving rapidly. In advance of future rulemaking, the EPA may consider these technologies in a future rulemaking.

Commenter: GPA Midstream Association
Comment Number: EPA-HQ-OAR-2023-0234-0299
Page(s): 46

Comment 2: EPA should allow data from advanced technologies.

EPA is highly prescriptive in the current and proposed emissions calculation methodologies, which does not readily accommodate new technology. New technologies continue to be developed, and EPA should develop a process that allows proven technology to be used to determine emissions. Vendors should have an approval process through EPA, and once the technology is approved, it should be available for use in determining emissions under the GHGRP.

Response 2: Specific with regard to the measurement of flare efficiencies, the final rule includes the provision to allow owners and operators to utilize an alternative test method that has been approved under 40 CFR 60.5412b(d) of NSPS OOOOb. This can be used to establish efficiencies different from the final rule's specified Tier efficiencies. This is one instance of how the final rule accommodates new technologies.

15.2.2 Enclosed Combustion Devices and Thermal Oxidizers

Commenter: Marcellus Shale Coalition (MSC)
Comment Number: EPA-HQ-OAR-2023-0234-0275
Page(s): 12-14

Commenter: American Exploration and Production Council
Comment Number: EPA-HQ-OAR-2023-0234-0295
Page(s): 8

Commenter: GPA Midstream Association
Comment Number: EPA-HQ-OAR-2023-0234-0299
Page(s): 43

Commenter: Pioneer Natural Resources USA, Inc.
Comment Number: EPA-HQ-OAR-2023-0234-0385
Page(s): 9

Commenter: Williams Companies, Inc.
Comment Number: EPA-HQ-OAR-2023-0234-0394
Page(s): 7-8

Comment 1:

<u>Commenter 0275</u>: <u>Flares</u>

The MSC requests clarification on U.S. EPA's definition of flares. The regulatory discussion attached to the GHGRP could be interpreted in a way that all thermal control devices could be considered flares. This would include open flame flares, sonic flares, enclosed combustors, NSPS OOOO and OOOOa 95% certified units, and high efficiency thermal oxidizers. Many of these units meet NSPS or NESHAP requirements, have manufacturer guarantees up to 99.9% control, and/or operate under federally enforceable permit requirements which align with a specified control efficiency.

…

There are numerous conflicting definitions of "flare" throughout Part 60, 63, and Part 98 which leads to ambiguity and inconsistency. The definition should be consistent with NSPS and NESHAP requirements, including NSPS OOOO, OOOOa and OOOOb, and NESHAP HH. To provide context, a list of definitions is provided below.

MACT CC: 63.641: Flare means a combustion device lacking an enclosed combustion chamber that uses an uncontrolled volume of ambient air to burn gases. For the purposes of this rule, the definition of flare includes, but is not necessarily limited to, air-assisted flares, steam-assisted flares and non-assisted flares.

NSPS OOOOb: 60.5430b: Flare means a thermal oxidation system using an open (without enclosure) flame. Completion combustion devices as defined in this section are not considered flares.

Subpart W: 98.238: Flare means a combustion device, whether at ground level or elevated, that uses an open or closed flame to combust waste gas without heat recovery.

Subpart C: §98.6: means a combustion device, whether at ground level or elevated, that uses an open flame to burn combustible gases with combustion air provided by **uncontrolled ambient air around the flame**.

The preamble to the proposed Subpart W rule includes classification of flares as:

- open ground-level flare,

- enclosed ground-level flare

- open elevated flare, or

- enclosed elevated flare.

The U.S. EPA's classifications listed above are broken down in section 3.2 Chapter 1 of the U.S. EPA Air Pollution Control Cost Manual: Chapter 1 - Flares (epa.gov). This document specifically states under "Other Flare Type Designations" that:

"Enclosed ground flares have burner heads enclosed inside a shell that is internally insulated or shielded. This shell reduces noise, luminosity, and heat radiation and provides wind protection, which makes enclosed ground flares less susceptible to poor performance that can occur from open-flame flares during high winds. (…) A primary difference between an enclosed ground flare and a combustor is that an enclosed ground flare does not have a direct method to control the volume of air introduced in the combustion zone beyond the fixed stack height (i.e., no direct air supply or louvers to limit air supply within the flare enclosure)"

It can be inferred from the paragraph above, that "enclosed" flares do not include enclosed combustors. Enclosed in the context of flares refer to shrouds or shields that offer some protection of the flame but fundamentally, an uncontrolled volume of ambient air is used for combustion.

Therefore, EPA's proposed reporting rule leaves no valid option to report enclosed combustion devices or direct fire thermal oxidizers without waste heat recovery even though these are defined as flares. These technologies use methods to introduce air into a fully enclosed combustion chamber such as forced draft, induced draft, or natural draft. Therefore, it is recommended that more clarity be given on the definitions of these proposed classifications to maintain quality of reported data and if the EPA's intent is to include enclosed combustors and thermal oxidizers as "enclosed flares". However, it would be better to completely differentiate flares from enclosed combustion devices and thermal oxidizers as described below.

Because enclosed combustors do not meet the definition of MACT CC, and are not intended to be regulated by MACT CC, it is unclear if these devices can meet the requirements of MACT CC and thus it is unclear whether there is any circumstance where 98% combustion efficiency can be claimed. In addition, alternative "Tiers" of combustion efficiency or use of manufacturer rated destruction removal efficiency (DRE) or performance test values for enclosed combustion devices or direct-fire thermal oxidizers should be allowed where the owner and operator can demonstrate that the manufacturer's recommendations are followed, similar to the provisions listed in proposed NSPS OOOOb, §60.5417b(d)(1)(i).

Finally, the study cited by the U.S. EPA to derive a 92 percent combustion efficiency (Plant et al. 2022) did not include enclosed combustors, therefore, this data is not relevant to these technologies. Overall, a key distinction needs to be made between these flares and enclosed combustion devices. The simplest distinction is present in Part 63: **Flare means a combustion device lacking an enclosed combustion chamber that uses an uncontrolled volume of ambient air to burn gases. This is similar to the intent of Subpart C as well not to include these device types.**

Flares that are enclosed by a shroud or shield but are fundamentally still "flares", based on a common understanding of what a flare is, should be reported under NSPS Subpart W paragraph (n) for flare stacks. Enclosed combustors and thermal oxidizers (regardless of waste heat recovery) should be reported under 98.233(z) (or other separate section) and allowed to use the specific manufacturer combustion efficiency, performance test data, or empirically derived estimates of combustion efficiency relevant to the technology.

…

Commenter 0295: **Flares**

Contextual Clarification

AXPC believes it is important to include a fundamental clarification. Historically, the term "flare" has been defined in Subpart W as a "combustion device, whether at ground level or elevated, that uses an open or closed flame to combust waste gases without energy recovery." It is important for EPA to understand that there are fundamental differences in the operation of a traditional open-flame flare as compared to other combustion driven control devices, such as an enclosed combustion device (ECD), which has an enclosed flame. These other control devices are growing in field use, for example, in Colorado, the Colorado Department of Public Health and Environment (CDPHE) does not allow the use of open-flame flares, requiring ECDs in nearly all circumstances. This is important to recognize as the EPA's Proposal is now more granular in establishing monitoring requirements and attempting to apply uniform destruction efficiencies to all control devices, flares and ECDs, that are inherently different. At a minimum, AXPC requests that ECDs be evaluated differently than open-flamed flares with regard to a default destruction efficiency. If a default destruction efficiency is employed in the final rule, we request that there be a separate carve out for ECDs since they operate at a much higher destruction efficiency than 92% over the life of the unit.

Commenter 0299: The Plant et al. study also only observed open flares. EPA must also allow additional methodologies for other types of combustion control devices reported under the flare source category. Enclosed flares and vapor combustors are also reported under the flare source category but operate with different design parameters than a standard flare that must be taken into account when accounting for destruction efficiency and monitoring. Separate DREs must be considered for these devices, and Subpart W should defer to the permit or state requirement, OEM data, and/or performance tests for the DRE for these devices.

Commenter 0385: **The Flare DRE Defaults Are Not Accurate and EPA Does Not Allow Direct Measurement**

…

The 92% DRE proposed is based on data which includes traditional open-flamed flares and the Enclosed Combustion Devices ("ECDs"). Open-flamed flares have a shorter operating life, have less control or air intake and are more heavily influenced by wind. Data in the EPA referenced research study, Plant, G., et al. 2022, from which the EPA concluded a 92% destruction efficiency, shows ECDs have a destruction efficiency of 90 to 99.9% over the life of the ECDs which is higher than the 92% proposed. Therefore, if a default destruction efficiency must be used, Pioneer recommends the ECDs be evaluated differently than open-flamed flares with regard to a default destruction efficiency since they will be operating at a much higher destruction efficiency over the life of the unit than 92%. If the manufacturer's destruction efficiency cannot be used for the emission calculations, 95% should be allowed due to the data present in Plant, G., et al. 2022.

Commenter 0394: **DREs for Control Devices Other than Flares**

In the spirit of meeting the EPA's goal of treating flares and combustion devices other than flares consistently, Williams recommends that Subpart W refer to DREs in existing federal and state regulations, facility operating permits, manufacturer's performance tests, and field performance tests, for facilities where thermal oxidizers, enclosed combustors, and condensers are used as emissions controls. These emissions control devices function differently than flares, have distinct DREs, and should therefore be calculated and reported separately from flares in Subpart W. Based on Williams' current operating permits, thermal oxidizers are commonly permitted for 99% DRE and enclosed combustors are often permitted for DRE = 95%.

Response 1: The EPA recognizes the differences between open flares, enclosed combustors, incinerators, and other types of combustion devices. The EPA also acknowledges that subpart W defines flares in a comprehensive manner that is not necessarily completely consistent with terminology used in other federal and state regulations, permits, and elsewhere. However, the provisions in the final rule, particularly those related to the default efficiencies associated with the Tiers in 40 CFR 98.233(n)(1), distinguish between the different types of control devices. This is inherent within the subpart W provisions cross references to the requirements in NESHAP CC and NSPS OOOOb. For example, in the final rule amendments 40 CFR 98.233(n)(1)(ii), which includes the Tier 2 requirements, 40 CFR 98.233(n)(1)(ii)(A) cites the NSPS OOOOb requirements related to enclosed combustors, while 40 CFR 98.233(n)(1)(ii)(B) cites the NSPS OOOOb requirements related to open flares. Similarly, the Tier 1 requirements in 40 CFR 98.233(n)(1)(i) of the final rule cite the performance testing and monitoring requirements for non-flare combustion devices in 40 CFR 63.645 and 40 CFR 63.644, respectively, of NESHAP CC that owners and operators would implement to demonstrate compliance with the Tier 1 destruction efficiency of 98 percent. Thus, we disagree with the comment that enclosed combustion devices were not intended to be used as a control device under NESHAP CC or that the flare provisions in 40 CFR 98.233(n) do not adequately consider enclosed combustion devices that are considered flares under subpart W but may not be considered flares under NESHAP CC.

Regarding the comment that subpart W should defer to permit or state requirements or to manufacturer data, see Section III.N.1 of the preamble to the final rule for the EPA's response to this comment for all flares as defined in subpart W.

Regarding the comments that subpart W should specify different default efficiencies for enclosed combustion devices than for open flares, we note that we do not have data to demonstrate there is a difference and the commenters have not provided data to support their position. Commenter 0395 did cite a range of destruction efficiencies from the 2022 Plant, et al study, but as Commenter 0299 correctly noted, those data are for open flares, so these data cannot be used to support a separate default destruction efficiency for enclosed combustion devices.

15.2.3 Default Combustion Efficiency

Commenter: Permian Basin Petroleum Association (PBPA)
Comment Number: EPA-HQ-OAR-2023-0234-0346
Page(s): 4-5

Commenter: Pioneer Natural Resources USA, Inc.
Comment Number: EPA-HQ-OAR-2023-0234-0385
Page(s): 9

Commenter: Providence Photonics, LLC
Comment Number: EPA-HQ-OAR-2023-0234-0370
Page(s): 2,5,6-9

Commenter: Range Resources Corporation
Comment Number: EPA-HQ-OAR-2023-0234-0397
Page(s): 9-10

Commenter: Range Resources Corporation
Comment Number: EPA-HQ-OAR-2023-0234-0397
Page(s): 10

Commenter: American Exploration and Production Council
Comment Number: EPA-HQ-OAR-2023-0234-0295
Page(s): 5

Commenter: North Dakota Petroleum Council (NDPC)
Comment Number: EPA-HQ-OAR-2023-0234-0417
Page(s): 6-7

Commenter: North Dakota Petroleum Council (NDPC)
Comment Number: EPA-HQ-OAR-2023-0234-0417
Page(s): 7

Commenter: Encino Energy (EAP Ohio, LLC)
Comment Number: EPA-HQ-OAR-2023-0234-0408
Page(s): 4-5

Commenter: Encino Energy (EAP Ohio, LLC)
Comment Number: EPA-HQ-OAR-2023-0234-0408
Page(s): 4,5

Commenter: Encino Energy (EAP Ohio, LLC)
Comment Number: EPA-HQ-OAR-2023-0234-0408
Page(s): 4,5

Commenter: Baker Hughes
Comment Number: EPA-HQ-OAR-2023-0234-0383
Page(s): 2-3

Commenter: Interstate Natural Gas Association of America (INGAA)
Comment Number: EPA-HQ-OAR-2023-0234-0387
Page(s): 16-17

Commenter: CrownQuest Operating
Comment Number: EPA-HQ-OAR-2023-0234-0393
Page(s): 212

Commenter: GPA Midstream Association
Comment Number: EPA-HQ-OAR-2023-0234-0299
Page(s): 43-44

Commenter: GPA Midstream Association
Comment Number: EPA-HQ-OAR-2023-0234-0299
Page(s): 46-47

Commenter: American Petroleum Institute et al. (Part 1 of 2)
Comment Number: EPA-HQ-OAR-2023-0234-0402
Page(s): 43-44

Commenter: Pioneer Natural Resources USA, Inc.
Comment Number: EPA-HQ-OAR-2023-0234-0385
Page(s): 3-4

Commenter: Enerplus Resources (USA) Corporation
Comment Number: EPA-HQ-OAR-2023-0234-0342
Page(s): 2-3

Commenter: Ovintiv Inc.
Comment Number: EPA-HQ-OAR-2023-0234-0350
Page(s): 2

Commenter: American Exploration and Production Council
Comment Number: EPA-HQ-OAR-2023-0234-0295
Page(s): 33

Commenter: Marcellus Shale Coalition (MSC)
Comment Number: EPA-HQ-OAR-2023-0234-0275
Page(s): 15

Commenter: Williams Companies, Inc.
Comment Number: EPA-HQ-OAR-2023-0234-0394
Page(s): 6

Commenter: Williams Companies, Inc.
Comment Number: EPA-HQ-OAR-2023-0234-0394
Page(s): 7

Commenter: North Dakota Petroleum Council (NDPC)
Comment Number: EPA-HQ-OAR-2023-0234-0417
Page(s): 5

Commenter: Ascent Resources, LLC
Comment Number: EPA-HQ-OAR-2023-0234-0339
Page(s): 1-2

Commenter: GPA Midstream Association
Comment Number: EPA-HQ-OAR-2023-0234-0299
Page(s): 46

Commenter: Marathon Oil Company
Comment Number: EPA-HQ-OAR-2023-0234-0378
Page(s): 2-3

Commenter: Western Energy Alliance
Comment Number: EPA-HQ-OAR-2023-0234-0399
Page(s): 3

Comment 1:

Commenter 0275:

Flares

…

5. Combustion efficiencies defined by the rule must be consistent with existing regulations as well as requirements under federal and state operating permits. Prescribed efficiencies must also take into consideration manufacturer guarantees.

Commenter 0295:

XVII. EPA's Proposal conflicts in key aspects with the text and purpose of new CAA § 136.

…

Third, although Congress was unequivocal in its direction that EPA revise Subpart W so that reporting thereunder, and calculation of the MERP charge, "are based on empirical data" and allow for the submission thereof, in key respects the Proposal *prevents* reporting from being based on empirical data. The most glaring example of this is the treatment of default flare combustion efficiency assumptions, see 88 Fed. Reg. at 50,334. The current default assumed efficiency is 98 percent. EPA proposes to lower this to 92 percent, which can be raised to 95 percent only if certain monitoring measures are conducted. But even if an owner can empirically demonstrate an efficiency of above 95 percent, no empirical demonstration of that fact is allowed. Adoption of provisions derived from the refinery standards under Section 112 may allow use of a 98 percent factor. But the adoption of those provisions in this rulemaking is inappropriate, as discussed above—and, in any event, this would *still* not allow empirical demonstration of efficiency higher than that. This shifts the policy in the precise opposite direction from that which Congress directed.

The adoption of the refinery Section 112 provision, in addition to its other flaws discussed above, is also a particularly clear example of the Proposal's not only not furthering Congress's direction to allow for submission of empirical data, but in fact running directly counter to that direction. EPA specifically does *not* incorporate the aspect of the refinery provision which allows for empirical submissions. *See* 88 Fed. Reg. at 50,398/3 ("The alternative means of emissions limitation specified in § 63.670(r) of this chapter do not apply for the purposes of this paragraph [governing flare efficiency calculation]."). This subsection (r) of the refinery provision, which EPA is *not* adopting here, is what governs a demonstration of efficiency "based on a performance evaluation" involving parametric monitoring. If EPA were following Congress's direction to ensure that operators can submit empirical data, the Agency would be *adding* such provisions, not *removing* them, from its source material. Doing exactly the opposite confirms that EPA is not acting in conformity with Congress's intent.

Commenter 0295:

I. Flares

A. Flare DRE

3. Recommendations

AXPC requests that the EPA remove the tiered control efficiency approach (DRE of 92%, 95%, or 98% based on additional monitoring practices) for flares from the final Subpart W rule and allow operators to claim the control efficiency that is most appropriate and justifiable by making reference either to:

A) a manufacturer's guarantee plus monitored operational data demonstrating the flare is operating within the manufacturers' specifications; or

B) an applicable regulatory requirement to which the flare is subject.

AXPC's request will allow for more accurate reporting from the many different types of "flares" utilized in the field for a multitude of purposes, not just associated gas control. See Section I.F Contextual Clarification section below.

This is the most appropriate way for the EPA to implement Congress's direction to incorporate empirical data in emissions estimation and reporting.

Commenter 0299:

54. EPA must revise destruction efficiency tiers to be relevant to the natural gas industry.

EPA seems to have discarded, without explanation, multiple existing flare studies that have been integral to establishing destruction efficiency levels regularly utilized in criteria pollutant annual emissions inventories, best available control technology demonstrations for new source review ("NSR") permits, and compliance. This is arbitrary and capricious. EPA cannot overturn decades worth of precedent based on a single study—especially one that admits it "did not yield compelling explanatory relationships."[103]

Reporters should be allowed to rely on empirical data to overrule the proposed destruction efficiency tiers. For example, if a reporter has a manufacturer guarantee or test data that show a destruction efficiency above the presumed efficiency tiers, that higher level should be allowed to be used.

The proposed approach here forces inconsistent data reporting between Subpart W and other EPA programs such as emissions inventory reporting, excess emissions reports, and permit compliance. For example, midstream operations (encompassing both processing and gathering and boosting stations) typically operate process flares at their sites. Process flares are often required to meet NSPS and NSR permitting requirements, which typically include a requirement to comply with 40 C.F.R. § 60.18, either directly under a NSPS or indirectly through NSR permit conditions. EPA should not dismiss the design or testing to demonstrate a minimum 98 percent DRE for flares operating according to the requirements of this regulation.

Footnote:

[103] *See, e.g., Butte County v. Hogen*, 613 F.3d 190, 194 (D.C. Cir. 2010) (noting "an agency cannot ignore evidence contradicting its position and 'must take into account whatever in the record fairly detracts from its weight'") (quoting *Universal Camera Corp. v. NLRB*, 340 U.S. 474, 487-88 (1951)).

Commenter 0299:

59. EPA should allow data from advanced technologies.

…

For example, GPA is aware of existing technology that remotely monitors and controls the combustion efficiency of a flare. EPA should provide an option for calculating the destruction efficiency of a flare that uses this type of monitoring technology. Existing and future technologies should be allowed to use the actual or calculated destruction efficiency from these advanced monitoring technologies for calculating emissions from flare stacks once the technology has been vetted through a regulatory agency. This will result in a co-benefit of more accurate reporting of emissions and decreased emissions with higher actual destruction efficiencies.

Commenter 0299:

61. EPA should allow at least 98 percent DRE for flares operating within 40 C.F.R. § 60.18 operating parameters.

The 95 percent emission reduction required under NSPS OOOOa (and proposed to be required under NSPS OOOOb and EG OOOOc) should not be a basis for determining flare destruction efficiency. The lower reduction in those regulations was designed to allow operators to use other control options beyond flare combustion devices. Instead, GPA believes a better option is that flares designed according to 40 C.F.R. § 60.18 and operated within design parameters should be given a default 98 percent destruction efficiency. This is consistent with NSR permit authorizations and annual emission inventory calculations for VOC emissions. There are numerous studies that show most flares generally achieve at least 98% DRE when operating within the parameters of 60.18. For flares that are not subject to 40 C.F.R. § 60.18, EPA should allow a minimum 98 percent DRE for flares operated within NSR permit compliance requirements.

Several states allow higher destruction efficiencies if the control device meets certain criteria. For example, North Dakota's High Efficiency Program allows manufacturers to submit testing data on the performance of their control devices within an operating range to establish higher destruction efficiencies.[108] The testing must be reviewed by the state agency, but once approved, an operator can submit a request to use the higher DRE (above 98 percent) for installation of an approved model at a site. EPA should allow these demonstrated higher destruction efficiencies in inventory calculations under the GHGRP.

Other control devices reported under the flare stack source type must be allowed. Pressure-assisted (sometimes called sonic velocity) flares do not meet the flare tip velocity limitations in 40 C.F.R. § 60.18 but have been demonstrated to meet high destruction efficiencies in testing such as for Alternative Means of Emission Limitation. Vapor combustors, enclosed flares, and some thermal oxidizers are also utilized by midstream operators to control emissions. As noted in Comment 53, separate DREs must be considered for these devices, and Subpart W should defer to the permit or state requirement, OEM data, and/or performance tests for the DRE for these devices.

Footnote:

[108] See North Dakota Department of Environmental Quality, High Efficiency Program, https://deq.nd.gov/AQ/oilgas/HighEffProgram.aspx.

Commenter 0339:

1. Flares

…

Ascent requests that the EPA remove the tiered control efficiency for flares from the final Subpart W rule and allow operators to claim the control efficiency that is most appropriate and justifiable by manufacturer's guarantee or applicable regulatory requirement that the flare is subject to.

Commenter 0342:

1. Flares

…

The monitoring requirements will increase company spending on emissions monitoring without associated improved emissions reduction benefit. Enerplus requests that the EPA remove the tiered control efficiency for flares from the final Subpart W rule and allow operators to claim the control efficiency that is most appropriate and justifiable by manufacturer's guarantee or applicable regulatory requirement that the flare is subject to.

…

Enerplus requests the EPA remove the tiered control efficiency for flares from the final Subpart W rule and allow operators to claim the control efficiency that is guaranteed … . This will allow for more accurate reporting and ensure operators still utilize the higher DRE control devices.

Commenter 0346:

1. Flares

In its Proposed Rule, EPA has identified three tiers of DRE for flares. Tier 1 has a default combustion efficiency of 98 percent if the flare is subject to monitoring consistent with the National Emission Standards for Hazardous Air Pollutants ("NESHAP") standards for Petroleum Refineries. Tier 2 has a default combustion efficiency of 95 percent if the operator complies with the monitoring specified in proposed OOOOb. Finally, the default combustion efficiency under Tier 3, which would apply if neither Tier 1 nor Tier 2 requirements are met, would be 92 percent.[3]

The Tier 3 default combustion efficiency of 92% is the same efficiency established under the proposal for natural gas destroyed/removed in an explosion or an open fire.[4] To equate the destruction/removal efficiency of a flare to an explosion or open flame solely because that flare is not monitored is completely arbitrary. Instead of limiting operators to using overly conservative destruction removal efficiency (comparable to an explosion or open fire), operators should have the flexibility to rely on the tested efficiency as an alternate methodology or demonstrate the accurate removal efficiency of the flare using various other options, such as sampling or modeling.

…

Finally, the Proposed Rule does not incorporate § 63.670(r) or allow for an alternative means of emissions limitation, which would appear to prevent the ability for production operators to determine that they have flares with 98% (or higher) DRE, based on actual operational data. Without the ability to claim actual DRE of 98% or higher based on operational and testing data, the lower DRE Tiers of 95% or 92% will result in over-reporting of emissions, contrary to EPA's intent for more accurate reporting. EPA should add an option to Tier 1 flare monitoring that allows for parametric monitoring to be used in determining destruction efficiency.

Footnotes:

[3] Proposed Rule at 50334.

[4] Proposed Rule at 50298.

Commenter 0350:

1. Flares

…

Ovintiv requests that the EPA remove the tiered control efficiency for flares from the final Subpart W rule and allow operators to claim the control efficiency that is most appropriate and justifiable by manufacturer's guarantee or applicable regulatory requirement that the flare is subject to.

<u>Commenter 0370</u>:

2.1 Flare Combustion Efficiency

Currently, Subpart W reporters use the default value of 0.98 (i.e., 98%) for flare combustion efficiency (η) in Eq. W-19 and W-20 to calculate methane and CO_2 emissions from the flare. The proposed 40 CFR 98.233(n)(4) will require the reporters to use a tiered approach to determine flare combustion efficiency η.

• Tier 1: η = 98 if a reporter monitors the flare as specified in §63.670 and §63.671, i.e., monitoring Combustion Zone Net Heating Value (NHVcz) or monitoring Net Heating Value Dilution Parameter (NHVdil) if flare actively receiving perimeter assist air].

• Tier 2: η = 95 if the reporter monitors the flare as specified in the proposed §60.5417b(d)(1)(viii), i.e., monitoring combustion zone temperature.

• Tier 3: η = 92 if the reporter does not use Tier 1 or Tier 2.

We have comments on multiple aspects of the proposed rule.

…

Values and Methods for Determining Flare CE and DE

For the convenience of description, we will use DE in this section of our comments to focus on methane emission calculations. The same approach applies to CE in CO_2 emission calculations.

The EPA proposes default DE values of 0.98, 0.95, and 0.92 for the proposed Tier 1, 2, and 3, respectively. For Tier 1, the value of 0.98 (i.e., 98% control efficiency) and the condition required to use this value (i.e., monitor the flare NHVcz or NHVdil) are derived from 40 CFR 63.670 & 671, which is already required for downstream sources in refineries subject to 40 CFR 63.670 & 671. It does not impose additional regulatory and cost burden for refineries. However, for upstream and mid-stream sources, implementing continuous NHVcz monitoring as specified in 40 CFR 63. 670 & 671 will be very costly. The EPA recognizes the high cost in its economic impact analysis for the refinery rule. Due to the high cost, the upstream and mid-stream sources will unlikely be able to use Tier 1 reporting, resulting in most facilities using the 95% or 92% DE values for reporting. We believe this will be a significant underestimation of flare control efficiency and overestimation of the methane emission – see more discussions on this subject later.

One solution to this problem is to allow GHGRP reporters in non-refinery sectors to use an alternative monitoring method that provides continuous monitoring of flare NHVcz and is economically feasible. A simplified Video Imaging Spectral Radiometry (VISR) method can be one of the alternative methods. The EPA has funded a test of such a method – see Exhibit 2 and Exhibit 3. The test has demonstrated accuracy and precision suitable for this GHG reporting program, especially for non-refinery flares.

…

The 3-tiered approach effectively put a cap of 98% on quantifying methane emissions. It is common knowledge that many flares have a DE considerably higher than 98. This has been demonstrated in the 2010 TCEQ study, the 2016 PERF study, and our field measurement of a large number of flares (see Exhibit 4). This also can be seen in Fig. 3 of Plant, et. al. (2022), where the observed CH_4 DRE exhibits lognormal distribution and the largest number of measured data points are in one of the 98, 99, and 100 bins. The reporters operating these high DE flares should be allowed to quantify emissions based on the high DE if they demonstrate, through actual measurement or monitoring, a DE higher than 98%. Capping the DE at 98% and not allowing a regulatory mechanism to accurately account for the higher DE and lower emissions would be contradictory to the CAA section 136 mandate this proposed rule is aimed to accomplish. To fully meet the CAA section 136 mandate for accurately reporting GHG emissions, the EPA should add a new tier to allow a regulatory mechanism for a higher flare efficiency if a GHGRP reporter opts to use it. Below we recommend two options for this new tier.

Option 1: Directly measure flare CE and DE

Under this option, a GHGRP reporter can directly measure flare CE and DE using a validated measurement method. The EPA can either designate acceptable methods based on its technical review or reference methods which have been vetted by other organizations for the same GHG reporting purpose. For example, the Oil and Gas Methane Partnership 2.0 (OGMP 2.0), a global organization formed by UN, EU, EDF, Climate & Clean Air Coalition, and most prominent oil and gas companies, has issued a "Technical Guidance Document – Flare Efficiency" (https://ogmpartnership.com/wpcontent/uploads/2023/02/Flare-efficiency-TGD-Approved-by-SG.pdf) identifying four methods for flare efficiency measurement: VISR, Passive Fourier Transform Infrared (PFTIR), Open-Path OP-FTIR, and Differential Absorption Lidar (DIAL). The International Association of Oil and Gas Producers (IOGP)- Ipieca-Oil and Gas Climate Initiative (OGCI) recently issued Report 661 (Recommended practices for methane emissions detection and quantification technologies - upstream | IOGP Publications library) and an accompanying online methane emission detection and quantification technology selection tool (Methane detection and quantification technology filtering tool | IOGP), and the VISR method (identified as "Mantis Flare Monitor") is recommended for quantifying flare methane emissions.

We recommend that the EPA consider revising the proposed rule to allow GHGRP reporters to directly measure DE, using either continuous monitoring or campaign-based approach. For continuous monitoring, EPA should establish the suitable technologies (e.g., the VISR method) and required measurement interval. For the campaign-based approach, EPA should establish the program guidelines, e.g., acceptable method (e.g., VISR, PFTIR, Open-path op-FTIR, and DIAL), the frequency and duration of the measurement, flare conditions during the measurement, etc. In both cases, if a GHGRP reporter participates in these direct measurement approaches they should be allowed to use the actual DE for reporting of methane emissions.

Option 2: Continuous monitoring of flare NHVcz and use of bracketed DE based on NHVcz

This option can be viewed as a natural extension of the proposed Tier 1. In Tier 1, the DE is deemed to be 98 if the monitored NHVcz is greater than 270 Btu/scf (or NHVdil > 22 Btu/sqft for flares with active perimeter air assist). The technical foundation of Tier 1 is illustrated in Figure 3. When NHVcz > 270 Btu/scf, data points on the right side of the red vertical line show that flare efficiency is generally above the green line and DE > 98%.

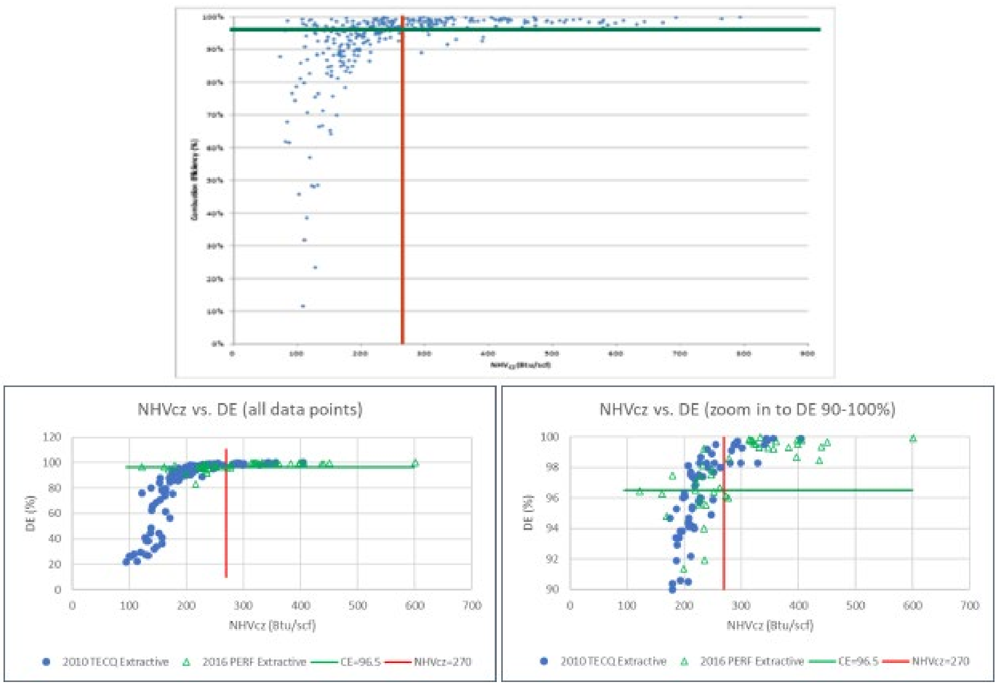

Figure 3. Flare control efficiency vs. NHVcz.

Top chart: EPA document “Parameters for Properly Designed and Operated Flares" (available in EPA-HQ-OAR-2010-0682-0191.dpf), Figure 3-13, the green line (CE=98%) and red line (NHVcz = 270 Btu/scf) added.

Bottom left chart: similar chart populated with data from the 2010 TCEQ flare study and 2016 PERF study. Data used to generate the chart can be found in Exhibit 1.

Bottom right chart: same as the bottom left chart but zoomed in to the DE range of 90-100%.

The proposed Tier 1 puts the flare NHVcz into two brackets: if NHVcz = 270 Btu/scf, flare DE =98%; if NHVcz < 270 Btu/scf, no instruction is given in the proposed rule on how to calculate the emission (see our earlier discussion on this issue). For Option 2, we would recommend that EPA expand the NHVcz brackets from two to four:

Bracket	If NHVcz (Btu/scf)	DE is deemed to be
1	> 330	99 %
2	> 270 and ≤ 330	98 %
3	> 230 and ≤ 270	95 %
4	≤ 230	92 %

Applying this method to the data from the 2010 TCEQ study and the 2016 PERF study, i.e., applying this method to the Bottom chart in Figure 3, the results are shown in Figure 4 below.

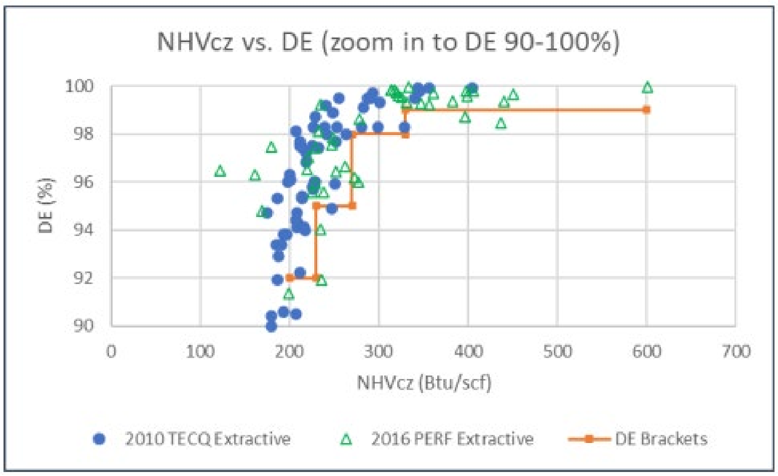

Figure 4. Recommended new NHVcz/flare DE brackets for Option 2 of the recommended new tier.

The above recommended Option 2 for a newly added tier follows the same principle as the already proposed Tier 1, with the same technical foundation as the proposed rule. It is both technically and economically feasible for some facility operators if they choose this option. It will have the following benefits:

• It cures the deficiency in the proposed Tier 1. If and when the monitored NHVcz drops below the threshold established in 40 CFR 63.670 (e.g., 270 Btu/scf), the emissions can still be calculated.

• It resolves the issue of the unreasonable cap on the flare DE at 98% with the proposed 3-tierd approach by providing a DE=99% bracket and making the emission reporting much more representative of the actual flare performance (see earlier discussions on lognormal distribution and not capturing the highest number of flares in the DE = 98-100% bins). This recommended Option 2 will produce more accurate GHG reporting as mandated by CAA section 136.

• The recommended Option 2 will give facility operators incentive to monitor and improve flare performance. By actively monitoring flare NHVcz and moving it to a higher bracket, the facility will have a higher flare DE, less GHG emissions, and lower methane fees when the fee regulations are promulgated.

Although the above discussions reference steam-assisted flares, it is our understanding that the NHVcz metric applies to all types of flares except the flare that actively receives perimeter air assist, in which case the NHVdil would apply instead. This is important because in the upstream and midstream, there are less steam-assisted flares. We would recommend that EPA explicitly clarify this in the final rule.

Commenter 0383:

The proposed rule discourages use of continuous monitoring of combustion efficiency. At proposed regulatory text 40 CFR 98.233(n)(4) EPA would establish three tiers of default flare combustion efficiency values based on the reporting entity's compliance with either §63.670 and §63.671 (Tier 1), or §60.5417b(d)(1)(viii) or §60.5417b(d)(1)(viii) (Tier 2). A default flare combustion efficiency (CE) value of 92% is proposed for cases where operators do not monitor the flare as specified in either of the previously referenced regulations (Tier 3).

The proposed rule does not consider circumstances where flare operators have installed flare combustion measurement or monitoring systems (CMMS) that provide accurate, continuous measurement of flare CE. Baker Hughes recommends that operators that have installed CMMS have the option to report flare efficiency measured by such systems in lieu of using default values to estimate CE. Further, EPA should clarify in the rule how continuous measurement of flare performance data should be reported (e.g., on a five-day moving average) and used.

An example of one such CMMS is Baker Hughes' flare.IQ solution which uses a parametric modeling method based on available CE measurement data and computational fluid dynamic data, analyzed by an artificial intelligence technique to generalize all the factors affecting CE of a flare system. These factors include crosswind speed and process conditions, such as flare flow rate, vent gas exit velocity (flare tip diameter), vent gas molecular weight, vent gas net heating value (NHV) or NHV in the combustion zone for assisted flares, gas composition (N_2, H_2 content) if available and assisted gas (steam or air) flow rate. These effects are generalized into a numerical model to calculate the CE. Destruction and removal efficiency (DRE) can then be derived from the calculated CE as they have shown to be in an approximate linear relationship.

Depending on the specific flare design of assisted media, three different CE models were developed for steam-assisted, air-assisted, and non-assisted (including pressure-assisted) flares. On a system level, one of the key features of this flare CE monitoring system is that it can be built around an ultrasonic flare flowmeter. Specifically, ultrasonic flare flowmeters are designed to measure flowrate based on ultrasound transit "time of flight" across the flow, where the flow and ultrasonic beam intercept at a fixed angle. Because sound wave travels faster along the flow and slower against the flow, the time difference between ultrasonic beam travel along the flow and against the flow is the transit time. Flare gas flowrate can be measured from the transit time.

In addition, from vent gas speed of sound, the average molecular weight (MW) can be derived using the virial equation of state. From the average MW, flare gas net heating value (NHV) can be determined providing concentrations of inert gases (noncombustible gases such as N2, CO2 etc.). With the measurement of flare gas flowrate, NHV and MW from ultrasound flowmeter, flare process key parameters affecting flare CE are available. With the addition of wind speed measurement, a complete flare CE monitoring system-including the flowmeter and an industrial computer loaded with the model can provide real-time measurement and continuous monitoring of flare CE and DRE.

Commenter 0378:

2. Flare monitoring requirements must be changed to avoid costly monitoring requirements without improved accuracy.

…

Further, EPA should remove the arbitrary tiered control efficiency scheme for flares from the final Subpart W rule and allow operators to claim the control efficiency that is most appropriate and justifiable by manufacturer's test data or regulatory requirement applicable to the specific flare. Providing an avenue that allows a reporter to use available technologies to measure and report company specific flare destruction efficiencies or a combination of technologies to demonstrate the reporter's flares operate within the parameters specified by the flare manufacturer when gases are routed to the flare would be effective in achieving the aims of the Subpart W revisions and would be far more efficient and feasible. We believe providing a technically feasible methodology to measure and report company specific performance meets the intent of the IRA and is a more credible basis on which to charge an emissions fee.

Commenter 0385:

5. The Flare DRE Defaults Are Not Accurate and EPA Does Not Allow Direct Measurement

The proposed rule requires that a default destruction rate efficiency ("DRE") of 92% be used, rather than the previously allowed 98%, unless additional monitoring requirements are followed. The EPA proposes that if a company would like to claim a DRE of 95%, compliance with the monitoring requirements of NSPS OOOOb would need to be followed. These requirements would include continuous measurements of pilot flame presence, net heating value, and flow rate that comply with NSPS OOOOb protocols. The EPA states that if a company would like to claim a DRE of 98%, compliance with the monitoring requirements of 40 CFR 63, Subpart CC (Refinery MACT) would need to be followed. These requirements would include daily observations, continuous measurements of flare tip velocity, net heating value, pilot flame presence, volumetric flow rate, and gas composition that comply with Subpart CC protocols.

While the premise that additional monitoring would allow an operator to claim a higher DRE is generally reasonable, Pioneer has serious concerns with the basis of the proposed default DRE of 92% as described in more detail below.

Pioneer requests that the EPA remove the tiered control efficiency for flares from the final Subpart W rule and allow operators to claim the control efficiency that is most appropriate and justifiable by manufacturer's guarantee or applicable regulatory requirement that tile flare is subject to.

…

<u>Commenter 0385</u>:

EPA's Proposal Conflicts in Key Aspects with the Text and Purpose of New Clean Air Act ("CAA") § 136

…

Second, although Congress was unequivocal in its direction that EPA revise Subpart W so that reporting thereunder, and calculation of the MERP charge, "are based on empirical data" and allow for the submission thereof, in key respects the Proposal *prevents* reporting from being based on empirical data. The most glaring example of this is the treatment of default flare combustion efficiency assumptions, *see* 88 Fed. Reg. at 50,334. The current default assumed efficiency is 98 percent. EPA proposes to lower this to 92 percent, which can be raised to 95 percent only if certain monitoring measures are conducted. But even if an owner can empirically demonstrate an efficiency of above 95 percent, no empirical demonstration (i.e. direct measurement) of that fact is allowed--which moves the policy in the precise opposite direction from what Congress directed.

<u>In these examples especially. EPA's underlying rationale or factual basis is unreasonable. Further, EPA is ignoring key aspects of the statutory scheme precisely when it would be most relevant, one of the hallmarks of arbitrary and capricious rulemaking.</u>

<u>Commenter 0387</u>:

Subpart W should not mandate default flare / combustion destruction efficiencies that differ from state or federal rules or permits, or other information such as manufacturer guarantees.

The Proposed Rule includes default destruction efficiency tiers (98%, 95% or 92%) based on aerial surveys conducted in the production sector that should not be mandated for T&S. For example, operators should be able to document an alternative as reflected in a permit or due to a federal or state regulation, or from a performance guarantee. Federal or state regulations or permits are better designed to address performance than mandated performance levels in a reporting regulation. A guarantee from a flare manufacturer is another example of support documentation that should be sufficient for estimating emissions.

The proposed three-tier approach for defining destruction efficiency (98%, 95% or 92%) is based on a study using airborne sampling from three gas production basins.[26] Similar to the discussion in Comment 4 on use of upstream data for other segments, EPA has not adequately justified applicability to T&S, and T&S operators should be able to document an alternative, such as a control efficiency document in a permit, emission limit, or from a federal or state regulation.

…

Information from existing permits or related federal or state regulations is more appropriate to address performance than mandated performance levels in Subpart W, as is a manufacturer guarantee. Flare monitoring and regulatory criteria have a long history and are mostly related to refinery and natural gas industry upstream applications, where process streams differ considerably from T&S. Burdensome Tier 1 (NESHAP CC) and Tier 2 continuous monitoring requirements are not typically required for T&S facilities. Thus, the DRE selection hierarchy results in a Tier 3 default requirement of 92%. This could result in differences in reported or permitted emissions as compared to methodologies previously used – e.g., for state reporting for facility permits. The mandatory default should not be required, especially for T&S sources. Rather than mandating default DREs based on the proposed tiers, T&S operators should be allowed to use an alternative based on other information, including facility permits and state regulations or reporting criteria as well as manufacturer guarantees.

Footnote:

[26] Plant, G., et al. 2022. ‘‘Inefficient and unlit natural gas flares both emit large quantities of methane.’’ Science, 377 (6614).

Commenter 0393:

The tiered system sounds good in practice but seems more pertinent that the EPA would allow flare manufacturer testing and provide an approved list of flares with >95% combustion efficiency. If this were the case, it would be clearer to the operators which flares to use, and likely reduce emissions.

Commenter 0394: Flares

…

Ascent requests that the EPA remove the tiered control efficiency for flares from the final Subpart W rule and allow operators to claim the control efficiency that is most appropriate and justifiable by manufacturer's guarantee or applicable regulatory requirement that the flare is subject to.

Commenter 0394: For flares not subject to federal NSPS and NESHAP regulations, Subpart W should reflect DRE percentages in state regulations and state operating permits to be used to inventory GHG emissions.

Commenter 0397: **There is a lack of congruity in the combustion control device emissions regulations that needs to be resolved.**

Under the Proposed Rule, operators are required to calculate carbon dioxide, methane, and nitrous oxide emissions from each flare stack. The Proposed Rule provides for a tiered approach under which an operator can report 98% (Tier 1), 95% (Tier 2), or 92% (Tier 3) efficiency depending on the protocols the operator follows.

The proposed Tier 2 regulations at 40 C.F.R. § 98.233(n)(4)(ii) require the use of flare monitoring standards in proposed subpart OOOOb in order to report 95% efficiency. Indeed, the subpart OOOOb regulations require that a control device reduces methane and volatile organic compound ("VOC") emissions by at least 95.0%. (To be codified at 40 C.F.R. § 60.5377b).

Under the proposed subpart OOOOb provisions, EPA allows for a combustion control device whose model has been manufacturer-tested to use certain continuous monitoring system requirements to establish compliance with the 95% efficiency standard. (Proposed OOOOb, to be codified at 40 C.F.R. § 60.5417b(d)(1)(vii)). Different continuous monitoring system requirements are required for combustion control devices that do not have a manufacturer testing certification. (Proposed 40 C.F.R. § 98.233(n)(4)(ii)). It is reasonable for EPA to allow an operator to use a manufacturer certification based on testing to establish that a combustion device is 95% efficient for the purpose of demonstrating compliance with operating standards.

However, in cross-referencing the subpart OOOOb regulations, EPA is excluding reference to those provisions that allow an operator to use a manufacturer certification of 95% efficiency for its GHG reporting obligation. This incongruity in the regulatory schemes is inexplicable and will inevitably lead to confusion and inconsistent reporting. It is unreasonable for EPA to allow an operator to claim a 95% efficiency based on a manufacturer's certification when establishing compliance with the applicable methane and VOC capture and destruction standards, but not when reporting such emissions.

<u>Commenter 0397</u>: Requiring reporting of a 92% efficiency for flares will result in inaccurate reporting and conflict with EPA's performance standards.

Another incongruity in the Proposed Rule is that while operators are required to obtain 95% efficiency in their combustion control devices, EPA proposes to establish a default GHG emission reporting standard of 92% efficiency under proposed 40 C.F.R. § 98.233(n)(4)(iii). See 88 Fed. Reg. at 50398. In other words, EPA is requiring operators to claim under one regulatory regime that they have achieved 95% efficiency but then report that they have 92% efficiency under another regime. EPA should resolve this incongruity, which may be aided by allowing an operator to use a manufacturer certification of 95% efficiency for subpart W reporting obligations.

<u>Commenter 0399</u>: *The Proposed Rule Conflict with the Proposed OOOOb and OOOOc Standards*

…

This is further challenging because, as proposed, Subpart W would not incorporate 63.670 (r) Alternative means of emissions limitation, which would appear to prevent the ability for production operators to determine that they have flares with 98% or higher DRE, based on operational data. EPA should allow control devices to report a DRE of 95% or higher through state-approved performance testing. For example, Colorado's Reg. 7 now has DRE standards for enclosed combustion devices (ECDs) at upstream and midstream facilities. The rule requires initial and subsequent (every five years) performance testing to demonstrate ECDs are meeting a minimum 95% DRE. Flowrate monitoring of waste gas to the ECD is required prior to testing and during testing. Testing protocols must be submitted and approved by CDPHE prior to testing. ECDs that fail testing require prompt reporting to CDPHE, corrective maintenance, and subsequent testing. State programs such as these should be sufficient for operators to claim DREs of 95% or higher. Without being able to claim actual DRE of 98% or higher based on operational and testing data and given that flare monitoring equipment is prohibitively expensive, operators will be forced to use the lower DRE Tiers of 95% or 92%. The use of the much less accurate DRE factor will artificially cause emission reporting numbers to increase in the absence of evidence that those factors represent actual field conditions. Such overestimation runs counter to the intent of the GHGRP and IRA's requirements about the use of empirical data, and could potentially steer policy decisions in a misleading direction.

Commenter 0402: Flares

Variable 'Combustion Efficiency' Based on Compliance and/or Monitoring

Tier 1 methods should allow an option to perform combustion efficiency testing or performance test data to validate a combustion efficiency assumption of 98% or greater. Tier 2 methods should provide a default combustion efficiency of 98%. The default factor in Tier 3 should be revised to a minimum of 95%.

EPA Should Allow Direct Measurement and Performance Testing for Flare Methane Destruction Efficiency

Direct measurement and performance testing by manufacturers or operators should be accepted as an optional demonstration of even greater destruction efficiency beyond 98%.

The Industry Trades request that EPA allow directly measured data, as well as NSPS performance testing by manufacturers or operators, as a more accurate approach to quantify an individual flare's methane destruction efficiency. Whether or not a flare is monitored pursuant to NESHAP CC or NSPS OOOOb has no actual bearing on the flare combustion efficiency values. Even if a flare meets the monitoring requirements of either rule, it does not necessarily follow that the actual flare combustion efficiency is at the respective values. For example, flow volume values may indicate flow exceeding minimum or maximum flows which is an indicator of potential suboptimal combustion efficiency. Additionally, if all monitored flare values are within performance standards, the flare combustion efficiency could be higher than the specified combustion efficiency for the specified tier. As is standard practice with GHG estimation methodologies, the timing and values of detections, measurements, and parametric data— not whether monitoring requirements are met--determine emission rates, such as flare combustion efficiency. Thus, the Industry Trades recommend that EPA supplement the tiered monitoring approach to flare combustion efficiency reporting to include directly measured data or NSPS performance testing by manufacturers or operators.

Some operators are deploying emergent technologies to directly measure combustion efficiency (or the closely related destruction efficiency) for flares, such as Providence Photonics Mantis and Mantis light (additional information regarding this technology is available in Annex D). Many operators, either through state or permit requirements, or voluntarily, conduct more traditional stack testing to assure high combustion efficiency of enclosed combustors, which also meet the definition of "flare" in Subpart W. Both of those testing methodologies provide the most accurate estimate of any particular flare and should be allowed as an option.

EPA should also allow for the use of the recently finalized "Other Test Method (OTM 52): *Method for Determination of Combustion Efficiency from Enclosed Combustion Devices Located at Oil and Gas Facilities*,"[36] using Portable Analyzers to determine destruction or combustion efficiency.

These approaches would further support technology development and allow for flexibility in using advanced and evolving technologies. For example, the Department of Energy is currently in year two of funding for the ARPA-E REMEDY program (REMEDY | arpa-e.energy.gov) that has a stated goal of developing technical solutions to achieve 99.5% methane conversion in flares. If technology development from this 3-year, $35 million research program is successful, the ability to use a higher flaring efficiency value in methane emissions reporting could help to drive greater adoption of new technologies in operations.

Footnote:

[36] https://www.epa.gov/system/files/documents/2023-09/otm-52_method-for-determination-of-combustion-efficiency-from-enclosed-combustors_clean_8_31_2023-004.pdf.

Commenter 0408:

EPA proposed a tiered approach to setting a default combustion efficiency that would provide higher defaults when supported by data from the reporter implementing certain flare monitoring procedures, in proposed 40 CFR 98.233(n)(4).

EAP Ohio, LLC advises the EPA that the additional costly monitoring, in addition to the destruction efficiency cap in each of the three-tiered approaches proposed, disincentives operators from purchasing quality devices with tested higher destruction efficiencies greater than 92, 95, or 98%.

Commenter 0408:

EPA proposed a tiered approach to setting a default combustion efficiency that would provide higher defaults when supported by data from the reporter implementing certain flare monitoring procedures, in proposed 40 CFR 98.233(n)(4).

EAP Ohio, LLC appreciates an opportunity to show a higher destruction efficiency than the 92% default proposed by EPA and requests EPA remove the tiered control efficiency for flares from the final Subpart W rule and allow operators to claim the control efficiency that is most appropriate and justifiable by manufacturer's guarantee.

Commenter 0408:

EPA proposed a tiered approach to setting a default combustion efficiency that would provide higher defaults when supported by data from the reporter implementing certain flare monitoring procedures, in proposed 40 CFR 98.233(n)(4).

…

EAP Ohio, LLC requests a pathway to utilize the manufacturer destruction efficiency, which is provided by purchased units in which EAP Ohio, LLC invested additional funding to ensure a device which achieves an environmentally friendly destruction threshold greater than 98%.

Commenter 0417:

EPA's proposed changes to flare efficiencies … introduce complexity in calculation methodologies due to discrepancies between Subpart W and various state permitting practices and federal requirements. …

Commenter 0417:

The proposed Tier 1 and 2 flare efficiencies and associated monitoring criteria are unnecessarily confining and do not allow for other recognized technologies, including technologies that EPA has itself used in enforcement and consent decrees with Title V sources, refineries, and chemical plants. For example, EPA funded the development of Providence Photonics' Video Imaging Spectral Radiometry (VISR)[1] and has contracted Providence to establish flare destruction efficiencies with the VISR technology for inspection and enforcement purposes as noted in multiple EPA documents and presented in detail in Docket ID No. EPA-HQ-OAR-2017-0357. [2]

NDPC member operators have also contracted with Providence to conduct VISR flare evaluations with good results overall while also indicating instances where improvements needed to be made. Prior to the development of VISR, the EPA also recognized and accepted Passive and Active Fourier Transform Infrared Spectroscopy (PFTIR and AFTIR) for evaluating flares in refineries and chemical plants as detailed in consent decrees, with notable examples including Marathon's Cattleburg refinery[3] and Flint Hills Port Arthur. [4] While PFTIR is more costly than VIFR, it offers another example in which EPA has accepted direct evaluation methodologies to establish flare DRE rather than the currently proposed tiers based on parameter monitoring that assert flares can only be assigned arbitrary DREs of 95 or 98 percent. Operators that invest in direct assessment technologies and use the data to make real world improvements in flare performance should be allowed to realize the benefits of improved flare performance in GHG reporting as well as reduce their Waste Emissions Charge accordingly. NDPC believes that any flare evaluation technology funded, utilized, or accepted by EPA for inspection and enforcement purposes and performed on a reasonable number of representative facilities under varying operating conditions should be allowed to establish operator-specific flare destruction efficiencies for GHG reporting without the need for additional monitoring of flare gas parameters, provided the flares are lit. To disallow such technologies would ignore the empirical evidence that the EPA has itself recognized in the Plant, et al study and aforementioned flare evaluation technologies, have the unintended consequences of disincentivizing continued efforts in flare optimization, shift focus toward intense and expensive data sets instead of actual flare performance, and unnecessarily inflate the Waste Emissions Charge.

Footnotes:

[1] https://cfpub.epa.gov/ncer_abstracts/index.cfm/fuseaction/display.abstractDetail/abstract_id/10420/report/F

[2] https://downloads.regulations.gov/EPA-HQ-OAR-2017-0357-0039/attachment_1.pdf

[3] https://www.justice.gov/sites/default/files/enrd/pages/attachments/2016/06/09/env_enforcement-2188119-v1- notice_of_lodging_and_lodged_cd.pdf

[4] https://www.epa.gov/sites/default/files/2014-03/documents/flinthills-cd_0.pdf

<u>Commenter 0417</u>:

NDPC requests that the EPA remove the arbitrary tiered control efficiencies for flares, allow for objective third party assessment technologies to establish flare efficiencies, and allow for DRE of greater than 98 percent to be evidenced if the empirical data supports it in cases where the technologies have been utilized by EPA in enforcement.

Response 1: See Section III.N.1 of the preamble to the final rule for the EPA's response to the recommended alternatives to determining efficiencies in this comment.

Regarding the comment that the tier 1 option in the proposal prevented facilities from using the alternative means of emission limitation in 40 CFR 63.670(r) to determine that they have flares with 98% or higher DRE, it appears the commenter has misinterpreted the purpose of the cited provisions. The procedures in 40 CFR 63.670(r) allow a refinery to request approval to use alternatives to the specified monitoring procedures in NESHAP CC to demonstrate compliance with the 98 percent destruction efficiency; it does not allow the facility to request approval of a destruction efficiency higher than 98 percent. Therefore, the final rule, like the proposal, does not cross reference 40 CFR 63.670(r).

One commenter noted that the 2010 TCEQ study, the 2016 PERF study, and field measurements conducted by the commenter have shown destruction efficiencies greater than 98 percent for many flares. We recognize that it is possible for flares to achieve greater than 98 percent destruction efficiency, but we have also determined that monitoring is needed to demonstrate that such efficiencies are achieved continuously. However, the studies cited by the commenter do not describe ongoing monitoring procedures that would be used to demonstrate that the efficiency obtained during the test is maintained continuously. As discussed in Section III.N.1 of the preamble to the final rule, the EPA is finalizing a provision that allows facilities to use efficiencies other than the default options if they request approval to use an alternative test method in accordance with 40 CFR 60.5412(d). The requests must show the achievable efficiency and include a description of monitoring procedures that will demonstrate the claimed efficiency will be met on a continuous basis.We are not finalizing an option based on the four NHVcz ranges suggested by commenter 0370 because it would represent a significant departure from the proposed approach and would effectively replace the existing tier 2 option. We intend to continue to assess the underlying data as well as the feasibility and performance of such an approach and may consider proposing an alternative related to the suggested approach in a future rulemaking.

Commenter: Enerplus Resources (USA) Corporation
Comment Number: EPA-HQ-OAR-2023-0234-0342
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Commenter: Pioneer Natural Resources USA, Inc.
Comment Number: EPA-HQ-OAR-2023-0234-0385
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Commenter: Williams Companies, Inc.
Comment Number: EPA-HQ-OAR-2023-0234-0394
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Commenter: American Exploration and Production Council
Comment Number: EPA-HQ-OAR-2023-0234-0295
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Commenter: The Petroleum Alliance of Oklahoma
Comment Number: EPA-HQ-OAR-2023-0234-0398
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Commenter: Encino Energy (EAP Ohio, LLC)
Comment Number: EPA-HQ-OAR-2023-0234-0408
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Commenter: GPA Midstream Association
Comment Number: EPA-HQ-OAR-2023-0234-0299
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Commenter: American Petroleum Institute et al. (Part 1 of 2)
Comment Number: EPA-HQ-OAR-2023-0234-0402
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Commenter: Permian Basin Petroleum Association (PBPA)
Comment Number: EPA-HQ-OAR-2023-0234-0346
Page(s): 4-5

Commenter: Range Resources Corporation
Comment Number: EPA-HQ-OAR-2023-0234-0397
Page(s): 10

Comment 2:

Commenter 0295:

I. Flares

A. Flare DRE

The Proposal would require that a default flare destruction efficiency (DRE) of 92% be used, rather than the previously allowed 98%, unless additional monitoring requirements are followed. If a company wishes to claim a DRE of 95%, that company will need to comply with the monitoring requirements of NSPS OOOOb, which have not been finalized. The OOOOb requirements may include continuous measurements of pilot flame presence, net heating value (NHV), and flow rate that comply with NSPS OOOOb's proposed protocols. The EPA states that if a company would like to claim a DRE of 98%, compliance with the monitoring requirements of 40 CFR 63, Subpart CC (Refinery MACT) would need to be followed. These Refinery MACT requirements would include daily observations, continuous measurements of flare tip velocity, NHV, pilot flame presence, volumetric flow rate, and gas composition that comply with Subpart CC protocols.

AXPC has serious concerns with the tiered control efficiency approach (DRE of 92%, 95%, or 98% based on additional monitoring practices) and the basis of the proposed default DRE of 92%, as described in more detail below.

1. Requiring Refinery MACT Compliance As a Prerequisite for Claiming 98% DRE Is Inappropriate

EPA imposing refinery requirements on the upstream oil and gas industry in order to claim the DRE (98%) that most manufacturers of flares claim they can meet or exceed under normal operating conditions is inappropriate. Upstream oil and gas operations are completely different from the processes performed and the multiple and variable waste streams controlled at a refinery. For example, the Refinery MACT requires NHV monitoring, which makes sense in a complicated system like a refinery that must manage for variable stream compositions. Whereas productions systems are simpler, the vast majority of applicable vent gas streams at oil and gas production sites are consistently above applicable minimum NHV limits and have little variability in composition. Particularly for upstream facilities, these vent gas streams are typically high in methane, ethane, and VOC content – typically 95+%, meaning the NHV of these streams is usually at or above 1,000 Btu/scf, and often much higher. The highest NHV low limit for an enclosed combustion device or flare is 800 Btu/scf,[1]which is significantly below the expected NHV for most vent gas streams and limited to pressure-assisted devices. Non-pressure assisted flares and ECDs are subject to minimum NHV limits of 200 – 300 Btu/scf, which is well below the typical NHV of an oil and gas vent stream. In addition, unlike a refinery, operators do not use inert gases, like nitrogen or others, that would reduce the inherently high NHV of a vent gas stream. Thus, there is little risk, and in many cases no risk, that vent gas streams will fall below the minimum NHV at any time, and certainly not great enough risk to warrant requiring NHV monitoring as a prerequisite for an operator claiming a DRE of 98%.

Second, the use of calorimeters to continuously monitor NHV in the upstream oil and gas sector is unproven. Production streams, though consistent in composition, are variable in flow rates. The variable nature of production rates results in low and/or intermittent vapor control streams. Current calorimeter technology cannot accurately measure the NHV of these low and/or intermittent streams consistently over time and across varying operating conditions. In these applications, calorimeters are unlikely to yield accurate or useful data. In addition to the technical and accuracy concerns, the Proposal will prompt thousands of calorimeter orders that will overwhelm calorimeter supply vendors, exacerbating what is already an ongoing supply chain crisis, as operators wait months or longer for order fulfillment.

If the EPA wishes to monitor the NHV of the gas, then annual or longer-duration testing of recovered gases may yield the same data quality without the installation of thousands of new calorimeters creating additional leak points and consequently more emissions.

Footnote:

[1] See proposed 40 CFR §§ 60.5412b(a)(1)(iv), 5412b(a)(3)(i) (proposed regulatory text for NSPS OOOOb), 5412c(a)(1)(iv), 5412c(a)(3)(i) (proposed regulatory text for EG OOOOc).}

Commenter 0299:

60. Refinery NESHAP Standards exceed necessary requirements for petroleum and natural gas sources.

Sources in the gathering and boosting and processing segments are not subject to the requirements in 40 C.F.R. Part 63, Subpart CC (NESHAP for Petroleum Refineries). Imposing monitoring for GHG emission reporting based on a regulation for refinery flares that midstream operators are not subject to is inappropriate and exceeds EPA's authority under the GHGRP, which, as EPA has stated, "does not require control of greenhouse gases, rather it requires only that sources above certain threshold levels monitor and report emissions."[107] As stated in Comment 6, EPA cannot require emissions reduction or control through the GHGRP. Gas streams directed to a refinery flare differ significantly from the gas streams routed to midstream flares, making the application of these regulatory requirements inappropriate and warranting their removal from the final rules because they are arbitrary and capricious.

Footnote:

[107] 74 Fed. Reg. at 56,260.

Commenter 0342:

1. Flares

…

The Proposal would require that a default flare DRE of 92% be used, rather than the previously allowed 98%, unless additional monitoring requirements are followed. The EPA proposes that if a company wishes to claim a DRE of 95%, that company will need to comply with the monitoring requirements of NSPS OOOOb. These requirements would include continuous measurements of pilot flame presence, net heating value (NHV), and flow rate that comply with NSPS OOOOb's proposed protocols. The EPA states that if a company would like to claim a DRE of 98%, compliance with the monitoring requirements of 40 CFR 63, Subpart CC (Refinery MACT) would need to be followed. These requirements would include daily observations, continuous measurements of flare tip velocity, NHV, pilot flame presence, volumetric flow rate, and gas composition that comply with Subpart CC protocols. Enerplus purchases engineered flares that consistently demonstrate a DRE of higher than 98%. If we are unable to claim a DRE higher than 95% through manufacturer-based guarantees, then the EPA may inadvertently disincentivize improved performance in this space.

To achieve the manufacture guaranteed 98%, Enerplus would have to follow refinery requirements despite oil and gas operations being completely different from those of a refinery. Enerplus' specific concerns with applying the Refinery MACT to the production segment are summarized below.

1a. NHV Monitoring The Refinery MACT requires NHV monitoring, which makes sense in a complicated system that has variable stream compositions, but applicable vent gas streams at oil and gas production sites are consistently above applicable minimum NHV limits and have little variability in composition. Particularly for Enerplus and other upstream facilities, these vent gas streams are typically high in methane, ethane, and VOC content, meaning the NHV of these streams is usually at or above 1,000 Btu/scf, and for Enerplus is typically at least 1400 Btu/scf. Thus, there is no risk, that vent gas streams will fall below the minimum NHV at any time, and certainly not great enough risk to warrant requiring NHV monitoring as a prerequisite for an operator claiming a DRE of 98%.

…

<u>Commenter 0346</u>:

1. Flares

…

In addition, requiring compliance with 40 CFR 63.670-671 Refinery NESHAPs CC regarding flare monitoring to claim 98% DRE for NSPS OOOOb and OOOOc EG would be a very burdensome option for production facilities. Simply put, the GHGRP shouldn't force upstream operators to comply with downstream standards in order to claim 98% DRE.

…

<u>Commenter 0385</u>:

5.a. Refinery MACT Compliance for 98% DRE is Unacceptable

Pioneer has significant concerns with EPA imposing refinery requirements on the oil and gas industry in order for them to claim the DRE. 98%, that most manufacturers of flares claim they can operate at under normal conditions. Upstream oil and gas operations are completely different from the processes performed and the multiple and variable waste streams controlled at a refinery. For example, the Refinery MACT requires net heating value monitoring, which makes sense in a complicated system that has variable stream compositions, but the vast majority of applicable vent gas streams at oil and gas sites are consistently above applicable minimum NHV limits. In addition, unlike a refinery, operators do not use inert gases that would reduce the inherently high NHV of a vent gas stream. Thus, there is little risk, and in many cases no risk, that vent gas streams will fall below the minimum NHV at any time, and certainly not great enough risk to warrant NHV monitoring in order to allow for an operator to claim a DRE of 98%.

Second, the use of calorimeters to continuously monitor net heating value in the upstream oil and gas sector is unproven. Production streams, though consistent in composition, are variable in flow rates. These flow rates are often low and/or intermittent vapor control streams. Current calorimeter technology cannot accurately measure the NHV of these low and/or intermittent streams consistently over time and across varying operating conditions. In these applications, calorimeters are unlikely to yield accurate or useful data. In addition to the technical concerns, the Proposal will prompt thousands of calorimeter orders that will overwhelm calorimeter supply vendors, resulting in a supply chain crisis, as operators wait months or longer for order fulfillment.

Commenter 0394: Removal of Reference to Refinery NESHAP Subpart CC

Gas streams routed to flares at natural gas gathering compressor stations and processing plants vary greatly in composition from gas streams routed to flares at refineries. As such, subjecting natural gas facilities to Refinery NESHAP Subpart CC performance requirements and DRE in Subpart W for Petroleum and Natural Gas Systems is inappropriate in a Subpart W GHG inventory rulemaking and should be deleted. If the EPA believes this sector should meet Refinery NESHAP Subpart CC, that change in regulatory standard must be done in a separate rulemaking where the agency and industry members can engage in a substantive dialogue on the validity of that approach.

Commenter 0397:

Comment #14: There is a lack of congruity in the combustion control device emissions regulations that needs to be resolved.

…

Finally, the proposed steps required to report 98% efficiency are excessively onerous and will not be achievable by many operators. These steps are extremely resource intensive and the costs would not justify using a 98% efficiency reporting threshold even though that may be the actual efficiency of the combustion device.

Commenter 0398:

EPA proposes to revise the default combustion efficiency for flares and establish a tiered approach to setting the default combustion efficiency that would provide higher defaults when supported by data from the reporter implementing certain flare monitoring procedures, in proposed 40 CFR 98.233(n)(4). For example, under Tier 1, a default combustion efficiency of 98 percent would be allowed where the reporter conducts flare monitoring consistent with the procedures specified in 40 CFR 63.670 and 40 CFR 63.671 of the National Emission Standards for Hazardous Air Pollutants from Petroleum Refineries.

This proposed requirement is meant for refineries and is excessive, unreasonable, inappropriate for other industry segments like production facilities, and will be of limited use. This requirement will not allow reporters that use production flares that can obtain the 98 percent destruction efficiency just because the reporter does not comply with the stringent requirements of 40 CFR 63.670 and 40 CFR 63.671. In those cases, emissions will be overestimated. Additionally, these rigid requirements will disincentivize operators from purchasing and utilizing flares that are capable of the 98 percent destruction efficiency.

Action Requested: We request the Proposed Rule align and incorporate by reference the flare requirements in EPA's NSPS OOOOb/c rules or at a minimum allow reporters to provide information (e.g., manufacturers data, performance test data or engineering studies) supporting its flares have 98 percent destruction capability.

Commenter 0402:

3.8 Flares

3.8.4 Variable 'Combustion Efficiency' Based on Compliance and/or Monitoring

Tier 1 methods should allow an option to perform combustion efficiency testing or performance test data to validate a combustion efficiency assumption of 98% or greater. Tier 2 methods should provide a default combustion efficiency of 98%. The default factor in Tier 3 should be revised to a minimum of 95%.

3.8.4.1 NESHAP CC Requirements Are Not Applicable to Subpart W Flares

The reference to and requirements from refinery NESHAP CC are not applicable for Tier 1 reporting under Subpart W.

EPA should remove any tier requirement related to NESHAP CC for refineries because the characteristics of the flare designs, operating conditions, and composition variability are not representative of, and in fact quite dissimilar from, petroleum and natural gas systems flares.

The Industry Trades believe the reference to NESHAP CC which applies to petroleum refineries is inappropriate. There are numerous ways in which refinery and chemical manufacturing flares and flare gas differ from that of upstream and midstream.

- Flare gas composition and flows span large ranges: Refinery flares receive flare gas of highly variable composition and of varying levels of heat content. Refinery flares can be dedicated to one or more related process units but are quite often very large and in service to many different process units, or even operate as a single interconnected system. Resultantly, the range of flows and composition to the flare is highly variable over a matter of hours. The heating value of the streams is typically much higher in upstream and midstream with the high-pressure gas being primarily natural gas and the gas from secondary separators, heater treaters and vapor recovery towers having a higher heating value greater than 2000 btu/scf. Except for the minority of wells that produce inert gases, where the composition of that production is known, flare gas streams are always highly combustible.
- Because refinery and petrochemical manufacturing flares combust gases with greater propensity to produce smoke (e.g., concentrations of olefins, diolefins, and aromatics) and thus are generally designed with an emphasis on smoke control, often including one or more steam addition systems, there is a documented risk of "over-steaming" for these flares. Less frequently, refinery and chemical manufacturing flares are air assisted, and even more rarely, unassisted. The reverse trend is true for upstream and midstream flares, where steam assist is the exception to the norm. Utilities to support steam assist are generally not available, upstream flares are less likely to need commensurate smoke suppression systems, and upstream and midstream flares are much smaller and dedicated units.
- While upstream operations are also actively seeking to reduce flaring, Refinery and chemical manufacturing flares also often have an obligation to flare gas minimization. Accordingly, any routine flaring that exceeds the flare gas recovery capacity of the facility results in flaring at extremely high turn-down conditions for the flare. High turn-down (<0.1% of flare capacity) at a steam-assisted flares presented the perfect storm for degraded combustion efficiency, which drove the enforcement initiative, subsequent ICR testing, and ultimately rulemaking to address this specific conditions. This condition does not exist in the up- and midstream segments

<u>Commenter 0408</u>:

EPA proposed a tiered approach to setting a default combustion efficiency that would provide higher defaults when supported by data from the reporter implementing certain flare monitoring procedures, in proposed 40 CFR 98.233(n)(4).

…

With the removal of the tiered control EPA should remove 40 CFR 63.670 as a requirement as listed in the Tier 1 destruction efficiency standards.

1. Production operations facilities do not have a continuous pilot because waste gas is not always vented to the combustor due to environmentally friendly processes which return waste gas to sales in the pipeline.
2. Combustor observations for two hours, required in 40 CFR 63.670, is onerous and is not necessary to ensure proposer combustion. Since there is not a continuous flow of waste gas to the combustor, the combustor may not be operating for the entire duration of the two-hour observation time.
3. EAP Ohio, LLC requests the EPA remove the tiered efficiency standards and offers assurance that that monthly Method 22 inspections would be sufficient substitute to the two-hour observations outlined in 40 CFR 63.670.

Response 2: The EPA is finalizing the Tier 1 requirements mostly as proposed, except that the final rule provides more specific cross-references to the applicable monitoring and related testing procedures in the refineries NESHAP and the final rule allows up to 15 consecutive days of nonconformance with the applicable parameters before the reporter would be required to switch to using the Tier 3 efficiencies within the calculation methodologies. After consideration of these comments and the comments in Comment 1 of this section requesting alternative methods for determining efficiencies, the EPA has added an option to the final rule that allows facilities to use efficiencies other than one of the defaults if they request and receive approval in accordance with 40 CFR 60.5412(d) to use an alternative test method that demonstrates a different efficiency and that includes monitoring an other procedures for demonstrating continuous compliance with that efficiency. See Section III.N.1 of the preamble to the final rule for the EPA's response to Comment 1 in this section.

We disagree with the comments asserting that calorimeters cannot accurately measure the NHV of low and/or intermittent streams consistently. In the response to similar comments on the Supplemental Proposal for NSPS OOOOb, we noted that the EPA does not have data to support the assertion that continuous sampling systems have technological issues with sampling low and intermittent streams.

We are not changing from proposal the incorporation of the NHV monitoring requirements under the subpart W calculation methodology at this time. We acknowledge that NSPS OOOOb provides alternative demonstrations to continuous monitoring for unassisted and pressure-assisted flares and enclosed combustion devices and those that use only perimeter assist air without steam assist or premix assist air. NSPS OOOOb also does not require NHV monitoring or the alternative demonstration when only associated gas is routed to the flare. We intend to continue to assess the appropriateness of including similar alternatives in the tier 1 requirements and may consider further updates in a future rulemaking.

We disagree with the comment that "monitoring for GHG emission reporting based on a regulation for refinery flares that midstream operators are not subject to is inappropriate and exceeds EPA's authority under the GHGRP" because neither the proposed nor the final rule requires compliance with the Refineries NESHAP. The Tier 1 calculation methodology is an option for subpart W purposes, which if selected by the reporter must be complied with to use that option. Furthermore, in incorporating and referencing certain NESHAP CC requirements, neither the proposed nor the final rule require control of GHG. Rather, we are specifying testing and monitoring requirements that must be met in order for facilities to be able to claim the tier 1 flare combustion and destruction efficiencies for purposes of calculating emissions under subpart W.

Commenter: Chevron
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Commenter: Marcellus Shale Coalition (MSC)
Comment Number: EPA-HQ-OAR-2023-0234-0275
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Commenter: American Exploration and Production Council
Comment Number: EPA-HQ-OAR-2023-0234-0295
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Commenter: GPA Midstream Association
Comment Number: EPA-HQ-OAR-2023-0234-0299
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Commenter: Enerplus Resources (USA) Corporation
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Commenter: Pioneer Natural Resources USA, Inc.
Comment Number: EPA-HQ-OAR-2023-0234-0385
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Commenter: CrownQuest Operating
Comment Number: EPA-HQ-OAR-2023-0234-0393
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Commenter: American Petroleum Institute et al. (Part 1 of 2)
Comment Number: EPA-HQ-OAR-2023-0234-0402
Page(s): 38, 39, 45

Comment 3:

Commenter 0232:

Flare – Combustion Efficiency Reporting

…

EPA has used a single study, Plant et al. (2022)[11], to develop the proposed tiers of flare CE reporting under Subpart W. Plant et al. used aerial flights to intercept airmasses downwind of flares to estimate flare CEs which is not a direct measurement of CEs. The CE of 92% is not supported by the data presented by the Plant et al. study. The study estimates flare CEs indirectly based on measurements of concentrations through downwind aerial transects and assumptions they made where direct measurements were unavailable. We have concerns about the use of this single study for the development of the tiered approach by EPA:

…

- Flare selection – Including unlit and flaming flares in the same dataset to estimate average CEs is not a correct representation of flare CEs. This approach adds further uncertainty to the interpretation of the results as the statistical spread of the collected data may result in a significant difference between the use of mean and median values derived from the measurements.

In addition, other studies (e.g., Caulton et al. 2014) have presented data that support 98% CE for most flares. Caulton et al. note that methane emissions from unlit flares may be a bigger contributor to overall observed flare emissions than flares with lower CEs. Unlit flares can be detected through surveys using advanced detection technology or the use of continuous flare pilot monitoring sensors.

Footnote:

[11] Plant, Genevieve, et al. "Inefficient and unlit natural gas flares both emit large quantities of methane." Science 377.6614 (2022): 1566-1571.

<u>Commenter 0275</u>:

<u>Flares</u>

…

An excerpt from Plant et al. 2022 states: "Assuming the flare characterization (DRE, unlit flare fraction) performed in this work is representative to all flares in the U.S., we estimates CH4 emission from the remaining U.S. flares by assuming a gas composition of 80% CH4, a total flare volumes equal to the difference between the VIIRS Skytruth national volume estimate (12.7 bcm (13)) and the flares within this work's study regions (see Fig.1). For a global estimate, we simply apply the mean observed effective efficiency (91.1%) to the global flared volume estimates from VIIRS, assuming an average methane gas content of 80%."

The purpose of the study was to estimate the effective combustion efficiency including unlit flare fraction on a large scale. It is not appropriate to apply this combustion efficiency to individual flares that are also required to estimate unlit flare time by monitoring for the presence of a pilot flame. This would result in duplication of emissions given that the 92% figure already accounts for unlit flare time and would not comport with the directive to ensure that the information submitted to the U.S. EPA "is based on empirical data, accurately reflects the total CH4 emissions (and waste emissions) from the applicable facilities, and allow owners and operators of applicable facilities to submit empirical emissions data, in a manner to be prescribed by the Administrator, to demonstrate the extent to which a charge is owed under CAA section 136."

In other words, empirical study data should be applied in a way that accounts for the nuances of how the data was collected and adjusts to the intended purpose to collect individual equipment information rather than large scale data. At a minimum, the U.S. EPA should further justify why including unlit flare time in the Tier 3 combustion efficiency is appropriate given that unlit flare time is also included in another variable in the calculations under §98.233(n).

Commenter 0295:

I. Flares

A. Flare DRE

2. Use of Plant et al. Study is Inappropriately Applied and Creates Bias

The Plant et al. study is stated as EPA's basis for the lower proposed flare DRE in this rulemaking. We identify several problems with EPA's application of this study as the basis for the lower DRE in the Proposal.

…

d. EPA's use of the study's average "total effective" DRE of 91.1% is not appropriate for inventory reporting because it accounts for unlit flares, which are reported separately in Subpart W. As noted below, AXPC supports use of operational knowledge and data, which is a straight forward way to ensure a flare is lit, when needed, and provides data to carve out the periods a flare was unlit, again, to be reported separately under other provisions in this rule. If unlit flares are not included, the study's "observed DRE" goes up to 95.2%, which is very different from when unlit flares are included. If the EPA continues to use the 92% DRE as the blanket for all flares, then it is inappropriate to include a separate category for unlit flares, though by taking this approach, EPA brings the proposed rule further away from Congress's directive to use empirical data.

…

In summary, the use of 92% as a default DRE based on this study is flawed since […] it accounts for unlit flares that are already required to be reported separately.

Commenter 0299:

62. GPA supports a zero DRE for instances when a flare is found to be unlit.

GPA agrees that unlit flares should be given a destruction efficiency of zero. Monitoring for flame presence is already a generally accepted practice for combustion control devices and would be an appropriate monitoring data record to require for reporting under this regulation, given that EPA accepts the additional monitoring options addressed in our other comments. This makes logical sense, but as such, it would be inappropriate for EPA to assume a default flare efficiency of 92 percent because it includes data collected from unlit flares (and therefore unlit flare emissions would be "double-counted.")

Commenter 0342:

1. Flares

…

Enerplus requests the EPA remove the tiered control efficiency for flares from the final Subpart W rule and … require facilities to report unlit flare emissions based on the proposed pilot flame monitoring. Revising the rule in this way would also avoid double-counting emissions assumed in the proposed 92% DRE as that emission factor was derived based on a study that included unlit and malfunctioning flares. This will allow for more accurate reporting and ensure operators still utilize the higher DRE control devices.

Commenter 0385:

5.b. Use of Plant et al. Study is Inappropriately Applied and Creates Bias

The Plant et al. study is stated as EPA's basis for the lower proposed flare DRE in this rulemaking, specifically stating in the rule preamble, "*Plant et al. conducted extensive testing in the Eagle Ford, Bakken, and Permian basins and found average combustion efficiencies ranging from less than 92 percent in the Bakken basin to slightly more than 97 percent in the Permian basin.*" [Footnote, there is an error in EPA's statement in the preamble. Flares in the Bakken basin showed an average DRE of 97% in the study, while the Permian flares showed an average DRE of 92%.] We see several issues with EPA's application of this study as the basis for the lower DRE in the proposal.

…

Secondly, it appears that EPA is using the average total flare effective DRE from the study results as the basis for the 92% assumption, which is not appropriate because it accounts for unlit flares. The study tested flares across several basins to estimate an average "observed DRE" of 95.2% across the study and an average "total effective DRE" of 91.1%. The study notes that the total effective DRE is calculated based on a combination of observed unlit flare statistics and DRE of lit flares (i.e., observed DRE). Given that EPA is proposing additional monitoring for the pilot flame as part of this proposal, the unlit flare durations would be known and the associated emissions from unlit flares are required to be reported separately under this rule. This is how unlit flares should be considered rather than including them into an average that will erroneously bring it down and significantly alter actual emissions reported from flare that are indeed lit and operating properly.

In summary. the use of 92% as a default DRE based on this study is flawed since the sample set […] accounts for unlit flares that are already required to be reported separately.

Commenter 0393:

EPA is proposing that reporters adjust the assumed combustion efficiency based on:

- tier 1: compliance with NESHAP CC 98%
- tier 2: compliance with NSPS OOOOb 95%
- tier 3: assume 92%

…

We disagree with the proposed tier 3 combustion efficiency as it is also not supported by the study mentioned above, also referenced in the EPA in the technical support document. This study shows that ~95% of combustion efficiency was the average across the basins, not counting unlit flares. " The average observed DRE across the three regions of study is 95.2% and the average total effective DRE accounting for unlit flares is 91.1%."

This efficiency proposal by the EPA includes unlit flares, so the unlit flare contribution would be double counted since they are reported separately. So, 95% combustion efficiency seems appropriate for Tier 3 as supported by the study, NOT the 92%.

Commenter 0402: Flares

Variable 'Combustion Efficiency' Based on Compliance and/or Monitoring

Tier 1 methods should allow an option to perform combustion efficiency testing or performance test data to validate a combustion efficiency assumption of 98% or greater. Tier 2 methods should provide a default combustion efficiency of 98%. The default factor in Tier 3 should be revised to a minimum of 95%.

Tier 3 Methane Destruction Efficiency Should be Revised to a Minimum of 95%

Destruction Efficiency of 95% Supported by Plant *et al* Study

The default proposed 'combustion efficiency' in Tier 3 reporting is based upon errant analysis in the Plant et al study and a more appropriate interpretation of those data would result in an overall methane destruction efficiency of >95% across upstream and gathering and boosting flares.

The Plant *et al* published study results state that 'the majority of flares function close to expected performance, with DRE values near 98%.' [37] The study concluded that approximately **95% methane destruction efficiency was the average across the basins in the study without accounting for unlit flares**. Since Subpart W already requires the monitoring of and segregation of periods where flares are unlit, it is not appropriate to *also* include that condition in an average destruction efficiency assumption. The average observed DRE across the three regions of study is 95.2% and the average total effective DRE after accounting for unlit flares is 91.1%.[38] The lower 'combustion efficiency' proposed by EPA is not aligned with the methane destruction efficiency findings from the Plant et al study, and represents the inclusion of unlit flares, **meaning that the unlit flare contribution would effectively be double counted since unlit flares are reported separately**. Therefore, 95% methane destruction efficiency would be more appropriate for Tier 3 as supported by the study referenced by EPA (rather than 92%). This 95% destruction efficiency would be aligned with NSPS OOOO and OOOOa control requirements; requiring a Tier 3 efficiency of 92% would not be aligned with other applicable requirements.

…

Footnotes:

[37] https://graham.umich.edu/media/files/F3UEL-Fugitive-Emissions-from-Flaring.pdf.

[38] Ibid.

Response 3: See Section III.N.1 of the preamble to the final rule for the EPA's response to this comment.

Commenter: Chevron
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Commenter: American Exploration and Production Council
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Commenter: GPA Midstream Association
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Commenter: GPA Midstream Association
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Commenter: Independent Petroleum Association of New Mexico (IPANM)
Comment Number: EPA-HQ-OAR-2023-0234-0337
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Commenter: Permian Basin Petroleum Association (PBPA)
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Comment 4:

Commenter 0232:

Flare – Combustion Efficiency Reporting

…

EPA has used a single study, Plant et al. (2022)[11], to develop the proposed tiers of flare CE reporting under Subpart W. Plant et al. used aerial flights to intercept airmasses downwind of flares to estimate flare CEs which is not a direct measurement of CEs. The CE of 92% is not supported by the data presented by the Plant et al. study. The study estimates flare CEs indirectly based on measurements of concentrations through downwind aerial transects and assumptions they made where direct measurements were unavailable. We have concerns about the use of this single study for the development of the tiered approach by EPA:

- Methodology – The method used by the Plant et al. was adapted from two previous flare plume measurement studies (Caulton et al., 2014[12] and Gvakharia et al., 2017[13]), but the new method of flare CE estimation is different from the previous studies (e.g., aircraft flight patterns and the methodology for the identification of the plumes). Plant et al.'s paper and the supplemental information do not discuss any validation for the method used nor provide any information on the QA/QC of the measurements and data processing. In addition, there is increased uncertainty associated with the reported CE values as part of the adapted use of aerial flux estimation methodology using a point sensor on the aircraft combined with modeling based on assumptions made by Plant et al., instead of the use of more direct multi-spectral cameras or flyovers using laserbased solutions.

…

In addition, other studies (e.g., Caulton et al. 2014) have presented data that support 98% CE for most flares. Caulton et al. note that methane emissions from unlit flares may be a bigger contributor to overall observed flare emissions than flares with lower CEs. Unlit flares can be detected through surveys using advanced detection technology or the use of continuous flare pilot monitoring sensors.

…

Footnotes:

[11] Plant, Genevieve, et al. "Inefficient and unlit natural gas flares both emit large quantities of methane." Science 377.6614 (2022): 1566-1571.

[12] Caulton, Dana R., et al. "Methane destruction efficiency of natural gas flares associated with shale formation wells." Environmental science & technology 48.16 (2014): 9548-9554.

[13] Gvakharia, Alexander, et al. "Methane, black carbon, and ethane emissions from natural gas flares in the Bakken Shale, North Dakota." Environmental Science & Technology 51.9 (2017): 5317-5325.

<u>Commenter 0295</u>:

I. Flares

A. Flare DRE

2. Use of Plant et al. Study is Inappropriately Applied and Creates Bias

The Plant et al. study is stated as EPA's basis for the lower proposed flare DRE in this rulemaking. We identify several problems with EPA's application of this study as the basis for the lower DRE in the Proposal.

a. The flares selected for the study will inherently produce biased results. The studied flares were not a randomly selected sample, but rather, they were selected based on specific criteria. One such criteria was that the flares studied must have had a recent (within the past 7 months) detection in Skytruth, VIIRS-based satellite data, which is only able to identify flares that meet certain heat signature or emission rate criteria based on spectral observations within certain spectral bands. This means the study selected for large, open-flame flares that already had a notable, recent emission event thus resulting in a skewed analysis of destruction efficiency.

b. The basins observed in the study are predominantly oil plays; therefore, observations are not representative of primarily gas producing plays which fundamentally operate differently because they control different sources (ex. Associated gas vs. Storage tank emissions).

c. The study did not observe ECDs. The VIIRS satellite would not be able to identify ECDs because the flame is enclosed and they are not traditionally used in oil plays. As such, they are absent from this study and their DRE capabilities are not at all reflected in the 92%. This issue reflects the fundamental problem with using the generic term "flare" in Subpart W, as described in Section I.F Contextual Clarification.

…

e. The purpose of the cited study wasn't to necessarily define a DRE for flares, but rather to estimate basin-wide, national and global methane emissions from flares. As such, EPA is inappropriately applying the 92% assumption for site level emissions reporting because there are too many assumptions baked into it, including unlit flares, as described above.

f. The study mischaracterizes flare performance stating that assuming 98% is not supported by real-world flare observations. Flares (and ECDs) have manufacturer guaranteed performance that should not be discredited. They perform reference method testing to ensure their equipment is meeting their stated destruction guarantees.

In summary, the use of 92% as a default DRE based on this study is flawed since the sample set is inherently biased, it is not representative of the general population of "flares" […].

Commenter 0299:

More extensive comments are provided in this letter, but to highlight our key areas of concern the following summary is provided:

…

- **Default Flare Destruction Removal Efficiency (“DRE”)** – EPA proposes to change the default flare DRE to 92 percent, which is a massive change from the current DRE of 98 percent and will result in severe hardship to reporters. This proposed change is based on only a single limited study that used remote sensing technology. These proposed changes ignore decades of EPA’s own research and other scientific evidence that justify a minimum 98 percent DRE. This proposed change would also create a paradox of compliance because other rules and permits allow much higher DREs.

Commenter 0299:

Moreover, it is inappropriate to revise destruction efficiencies in the proposed rule based on a single recent study, Plant et al., and discount all other previous flare studies conducted, many of them specifically to determine destruction efficiencies. EPA cannot set destruction efficiencies for an entire industry based on a single study using only remote sensing technology measurements.

Remote monitoring has a large degree of uncertainty in estimated actual emissions. Without site-level verification of the emission rates, it cannot be the sole determination of emission rates and destruction efficiency. Many companies have begun conducting evaluations of measurements from remote sensing technology versus site level measurements as remote sensing technology increases in use. While the information from the Plant et al. study can be useful from an overall emissions profile perspective, it cannot be the only data used to accurately calculate emissions from a single source since other nearby emitting sources can influence the site-level emission measurements.[100]

Although this study found that “[t]he majority of flares function close to expected performance, with DRE values near 98%,”[101] EPA is only allowing a source to take this level of emission reduction if a flare has additional, expensive monitoring that is not otherwise required by regulations applicable to the associated industry. Plant et al. does not evaluate individual flare sources to determine if they were even operating within their designed operating range. Therefore, GPA does not believe it is appropriate to develop industry-wide destruction efficiencies based on this study. Notably, Plant et al. states the following:

Investigations into possible drivers of reduced DRE, such as wind speed (measured at the aircraft), flare volume and temperature (VIIRS), and estimated well age and gas/oil ratio (37) did not yield compelling explanatory relationships, suggesting that the combination of our airborne sampling and these supplemental datasets cannot explain most of the observed flare CH4 DRE variability. Improving attribution to flare design, operation, and environmental conditions would require a different study strategy, likely with more information on individual flare infrastructure and operation.[102]

…

Footnotes:

[100] The American Petroleum Institute is submitting comments on additional technical issues involving the Plant et al. study, and GPA urges EPA to pay extra attention to those comments.

[101] Flaring and Fossil Fuels: Uncovering Emissions and Losses (F3UEL) Project, Graham Sustainability Institute, University of Michigan, "Fugitive Emissions from Flaring" (summarizing Plant et al.), https://graham.umich.edu/media/files/F3UEL-Fugitive-Emissions-from-Flaring.pdf.

[102] Plant, et. al., "Inefficient and Unlit Natural Gas Flares Both Emit Large Quantities of Methane," Science (Sept. 29, 2022) (internal citations omitted), https://www.science.org/doi/10.1126/science.abq0385#:~:text=We%20find%20that%20both%20unlit,%25%20con fidence%20interval)%20of%20methane.

Commenter 0337:

40 CFR § 98.233(n) Flares

EPA is proposing a tiered approach, as outlined in § 98.233(n)(3), to determine the destruction efficiency to meet the requirements of CAA § 136(h). In lieu of this approach, and until better scientific evidence can be established to support a reduction in default DRE, EPA should retain the 98% DRE in the current version of the rule.

The Plant, et al study, which is the basis of the default DRE of 92% in Tier 3, is based on flare observations and not sampling data consistent with the sampling requirements to determine DRE in current NSPS-OOOO or OOOOb, or in the proposed NSPS-OOOOb. As such, it does not provide sufficient evidence to render 98% DRE inaccurate or provide adequate evidence to support a default DRE of 92%. EPA also admits that this 92% value is based on the low end of the range of results, which is not a valid representation of the average. Furthermore, the Plant study actually supports the long held DRE value of 98%. See e.g. a summary of this study, "The majority of flares function close to expected performance, with DRE values near 98%. However, across all basins, a relatively modest number of poorly performing flares (with DRE values as low as 60%) were observed to cause a significant drop in average performance" (Plant, Genevieve et al. | DOI 10.1126/science.abq0385). EPA should retain the 98% DRE in the current rule.

…

Commenter 0346:

1. Flares

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While PBPA members are reluctant to rely on the findings of a single study as the basis for setting a default DRE of 92%, the Plant et al. study found that average combustion efficiencies were approximately 97 percent in the Bakken Basin to slightly more than 92 percent in the Permian Basin. This, in itself, illustrates PBPA's concern about EPA's implementation of a one-size-fits-all standard when there are obvious differences in operations and associated emissions across sites, basins, and industry sectors.

…

Commenter 0349:

Of additional concern is the change in default combustion efficiency for flares. TCEQ has conducted numerous flare studies over the past 40 years, the most recent of which continues to support a default combustion efficiency of 99 percent for waste stream contributions of one to three carbon atoms and 98 percent for waste stream contributions greater than three carbon atoms to be utilized for unassisted flares typically used at upstream oil and gas facilities meeting the criteria of both 40 CFR §§60.18 and 63.11. Requiring monitoring consistent with the procedures specified in 40 CFR §63.670 and 40 CFR §63.671 of the National Emission Standards for Hazardous Air Pollutants from Petroleum Refineries (40 CFR Part 63, Subpart CC) in order to demonstrate a combustion efficiency of 98 percent creates a significant regulatory burden for little benefit. The change also creates a disconnect between the representations typically made for criteria air pollutants (CAP) and GHGs. The default combustion efficiency of 98 percent has been well established for unassisted flares and commonly used for emission calculations for compliance demonstrations, PTE representations, and emissions inventories for decades. By changing the default combustion efficiency to 92% and only allowing additional combustion efficiency in response to additional monitoring that was previously not required conflicts with established control efficiencies in promulgated rules.

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Commenter 0370:

2.1 Flare Combustion Efficiency

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The proposed Tier 3 has a very low control efficiency, only 92%. It seems that this value is based on the research by Plant, et. al. (2022). Table 1 in Plant, et al. (2022) lists mean for observed flare DRE as 95.2% across three regions (96.5%, 97.3%, and 91.7% for Eagle Ford, Bakken, and Permian, respectively). When unlit flares are included, the mean is lowered to 91.1%. We are not sure if the proposed Tier 3 DE of 92% is based on the lowest in the three regions (91.7% for Permian) or the average of three regions but includes the unlit flares (i.e., 91.1%). If it is the former, the justification for the lowest value, instead of the average, is weak. In recent years, Providence Photonics has measured 567 flares (and 977 flare operating conditions) worldwide as of March 31, 2023. The CE and DE distributions of these measured flares can be seen in Exhibit

4. Comparing to Plant, et. al. (2022), significantly more flares are included in Exhibit 4 and the DE is noticeably higher.

If the value for Tier 3 is based on the average including the unlit flares, it would not be representative for an individual GHGRP reporter to use the value that is based on a basin-wide average taking into account the potential for unlit flares. An individual reporter may not have any unlit flares.

We would encourage EPA to consider the default value for Tier 3 based on a broader range of measured flares. Based on our field experience in measuring a large number of flares, the average DE is expected to be significantly greater than 92%.

…

Commenter 0381:

III. EPA Should Reconsider the Proposed Revisions to Calculation Methods for Several Emission Sources.

A. Flare Stack Emissions

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First, EPA arbitrarily proposes the following three-tier approach to default flare combustion efficiency:

- **Tier 1 (98% efficiency)**: The flare complies with flare monitoring procedures at National Emission Standards for Hazardous Air Pollutants ("NESHAP") Subpart CC.

- **Tier 2 (95%)**: The flare complies with the monitoring requirements at NSPS OOOOb.

- **Tier 3 (92%)**: The flare does not comply with either Tier 1 or Tier 2 requirements.[41]

While both NESHAP Subpart CC and NSPS OOOOb do in fact provide standards for flare efficiency, it is not clear to Endeavor *why* EPA has chosen to link flare efficiency for purposes of Subpart W strictly to those two separate regulatory regimes, which may not even be applicable to a particular facility. Flares, including the ones used by Endeavor, have manufacturer-tested efficiencies, generally 95% or above and quite often at least 98%. And flares are generally subject to state regulatory requirements for efficiency and maintenance that ensure a flare's stated efficiency is maintained. For instance, the Texas Commission on Environmental Quality's best available control technology ("BACT") requirements allow producers like Endeavor to use a stated 95% to 98% flare efficiency so long as certain design and operational requirements are met.[42] There is simply no reason for EPA to leverage Subpart W, which is intended as a procedural datagathering framework, to effectively layer *an additional* set of federal regulatory obligations (i.e., NESHAP, OOOOb) on top of owners and operators, in the process displacing those of state permitting authorities, at the risk of higher reported emissions and higher methane charges under the IRA if those additional obligations are not met.

Furthermore, it is not clear to Endeavor where EPA derived its proposed minimum flare efficiency of 92%. The only reference to that efficiency is a single study, Plant *et al*. (2022), that, according to EPA, found "average combustion efficiencies rang[ed] from less than 92 percent in the Bakken basin to slightly more than 97 percent in the Permian basin."[43] Yet EPA does not connect the dots as to why a single study finding a range of combustion efficiencies among various production basins justifies a generally applicable efficiency tied to the lowest observed value representing a single basin. There is no rational connection between that single study and the value EPA has chosen for the third, default tier of its efficiency hierarchy.[44] And such a decision will surely overestimate flare emissions, and thus fail to advance the IRA's mandate for accurate, empirical emissions data, as well as fail to meet the APA's standard that its decision be supported by the record.

Endeavor thus recommends that EPA retain the currently applicable 98% default combustion efficiency at 40 C.F.R. § 98.233(n)(3) and decline to finalize its proposed three-tier framework. If EPA does keep a tiered system, then operators should be able to rely on the manufacturer certified flare efficiency when determining their emissions calculations.

...

Footnotes:

[41] 88 Fed. Reg. at 50,334.

[42] *See* generally TCEQ, *Control Device Requirements Charts for Oil and Gas Handling and Production Facilities*, https://tinyurl.com/4r8ya7wd.

[43] 88 Fed. Reg. at 50,334 & n.91

[44] *See State Farm*, 463 U.S. at 43.

Commenter 0385:

5.b. Use of Plant et al. Study is Inappropriately Applied and Creates Bias

The Plant et al. study is stated as EPA's basis for the lower proposed flare DRE in this rulemaking, specifically stating in the rule preamble, "*Plant et al. conducted extensive testing in the Eagle Ford, Bakken, and Permian basins and found average combustion efficiencies ranging from less than 92 percent in the Bakken basin to slightly more than 97 percent in the Permian basin.*" [Footnote, there is an error in EPA's statement in the preamble. Flares in the Bakken basin showed an average DRE of 97% in the study, while the Permian flares showed an average

DRE of 92%.] We see several issues with EPA's application of this study as the basis for the lower DRE in the proposal.

Firstly, based on review of Plant et al.'s study, the flares selected for the study inherently will give bias results for multiple reasons. To begin, the studied flares weren't selected at random, but rather, they were selected based on specific criteria, one of which is if they had a recent (within the past 7 months) detection in Skytruth, VIIRS-based satellite data, that is only able to identify flares that meet certain heat signature or emission rate criteria based on spectral observations within certain spectral bands. Next, the sample set can't be applied nationwide because the basins observed are focused on associated gas flaring in predominantly oil plays; therefore, is not representative of primarily gas producing plays which operate completely differently. Finally, many operators use ECDs that would never be seen from the VIIRS satellite; therefore, would never be targeted in this study, nor are they traditionally used in oil plays, so their DRE capabilities are not reflected. All of these reasons invalidate the results of this study and render applying the conclusions to the nationwide population of flares and other similar control devices arbitrary and capricious.

…

In summary, the use of 92% as a default DRE based on this study is flawed since the sample set is not representative of the general population […].

<u>Commenter 0385</u>:

5.c. Additional concerns with 92% DRE

Moreover, the change in allowable DRE to a default of 92% is also inconsistent with many states' permitting and compliance guidelines. This inconsistency would cause discrepancies in reported emissions across the state and EPA GHG reporting programs. For example, the Texas Commission on Environmental Quality (TCEQ) policy allows up to 98% DRE to be claimed for flares at minor sources with no monitoring; and up to 99% for hydrocarbon molecules with three or fewer carbon atoms. The CDPHE allows facilities to claim a default of 95% DRE on ECDs. The Pennsylvania Department of Environmental Protection (PAEDP) also allows a minimum flare destruction efficiency of 95%. PADEP will accept flare DREs higher than 95% based on manufacturer specifications or stack testing data. Example testing reports can be found here
https://cimarron.com/quado-enclosed-combustors-should-you-claim-95-dre-or-99-dre/
https://www.cleanair.com/measuring-flare-destruction-efficiency-passive-ftir/
https://www.zeeco.com/resources/presentations/destruction-efficiency-of-air-assisted-flares

For the above reasons, we recommend that EPA retain the current flare default DRE of 98% and require facilities to report unlit flare emissions based on the proposed pilot flame monitoring. This is the most appropriate way for the EPA to reach the directive given by Congress in the IRA to incorporate empirical data in emissions estimation and reporting.

<u>Commenter 0387</u>:

Subpart W should not mandate default flare / combustion destruction efficiencies that differ from state or federal rules or permits, or other information such as manufacturer guarantees.

…

Alternatives to the defaults are warranted because there are questions about the cited top-down study, its conclusions regarding destruction and removal efficiency (DRE), and its application to downstream segments. For example, the study contains uncertainty in the alignment of the airborne dataset with the location of flares/wells and states that further work is required to access infrastructure details to obtain more accurate attribution of individual DRE values to factors pertaining to the flare design and operation. The Tier 3 default value is based on the low end of the range of empirical results observed in testing from 3 production basins; there is no indication that these processes and gas streams are representative of flare applications at T&S facilities. No additional justification for this lower value has been provided and further analysis of the DRE uncertainty (i.e., volumes of ±50%) is warranted. The default Tier 3 DRE value is poorly supported, based on aerial surveys with inherent measurement limitations, and appears to arbitrarily rely on low end destruction efficiencies from the dataset.

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Commenter 0393:

EPA is proposing that reporters adjust the assumed combustion efficiency based on:

- tier 1: compliance with NESHAP CC 98%
- tier 2: compliance with NSPS OOOOb 95%
- tier 3: assume 92%

We disagree with the proposed tier 2 combustion efficiency as it's not supported in the study (Planet et al). This study says, " the majority of flares function close to expected performance, with DRE values near 98%." This finding supports the monitoring requirements with NSDPS OOOOb

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Commenter 0394:

(1) Flare Destruction Removal Efficiencies (DRE) for Federally Regulated Flares

In 2010, the EPA published Subpart W in 40 CFR Part 98 for the express purpose of *inventorying* GHG emissions in the petroleum and natural gas sector.[13] EPA acknowledged that the data "will inform decisions about possible emissions reduction regulations in the petroleum and natural gas industry." Yet, the EPA's proposed incorporation of tiered flare destruction and removal efficiencies (i.e. the tiered default combustion efficiencies of 92%, 95%, and 98%) in the Proposed Rule essentially transforms an inventory rule into a performance and compliance regulation by introducing compliance requirements to flare standards that are beyond what the industry is currently subject.[14] This transformation is entirely inconsistent with the purpose and scope of Subpart W and should be corrected.

Because Subpart W is a GHG inventory rule, Subpart W should refer to the DRE associated with two existing federal air regulations governing flare operations– 40 CFR § 60.18(a)–(f)[15] and 40 CFR § 63.11 (a)–(b)[16]. Performance requirements in both General Provisions specify that flares be: (1) steam-assisted, air-assisted, or non-assisted; (2) operated at all times when emissions may be vented to them; (3) designed for and operated with no visible emissions, except for periods not to exceed a total of 5 minutes during any 2 consecutive hours; and (4) operated with the presence of a pilot flame at all times. To ensure flame sustainability and proper combustion, the General Provisions specify minimum heat content of the waste gas stream routed to the flare and maximum gas exit velocity at the flare tip.

The EPA has acknowledged that flares, when properly designed and operated in accordance with the General Provisions in 40 CFR § 60.18(a)-(f) and § 63.11(a)-(b), are expected to achieve a 98% minimum DRE. EPA reached this determination after reviewing multiple ground-based flare performance studies conducted by the Agency at flare testing facilities.[17] Williams contends that the EPA's DRE is more technically defensible than the average DRE recently published by Plant et al. for production flares that relied on aerial LiDAR survey data, which also appears to be the sole study the EPA relies upon in the Proposed Rule. Discarding or ignoring several prior studies without explanation to change flare efficiency standards in the midst of revising a GHG reporting rule is indefensible and inappropriate.

The EPA should update 40 CFR § 60.18 and 40 CFR § 63.11 to clearly indicate that compliance with these general flare provisions qualifies the owner / operator to use a 98% DRE for criteria pollutant emissions reporting and GHG inventory purposes. With this addition, Subpart W, along with NSPS and NESHAP regulations[18], would uniformly reference the same 98 % DRE for properly designed and operated industrial flares.

…

Footnotes:

[13] Mandatory Reporting of Greenhouse Gases: Petroleum and Natural Gas Systems, 75 Fed. Reg. 74,458, 74,460 (Nov. 30, 2010) (Congress authorized EPA to publish a rule to "require the mandatory reporting of greenhouse gas emissions above appropriate thresholds in all sectors of the economy of the United States. . . . These data will inform EPA's implementation of CAA section 103(g) regarding improvements in sector based nonregulatory strategies and technologies for preventing or reducing air pollutants, and inform policy on possible regulatory actions to address GHG emissions.").

[14] "Specifically, under Tier 1, a default combustion efficiency of 98 percent would be allowed where the reporter conducts flare monitoring consistent with the procedures specified in 40 CFR 63.670 and 40 CFR 63.671 of the National Emission Standards for Hazardous Air Pollutants

From Petroleum Refineries (40 CFR part 63, subpart CC).” Proposed Rule, 88 Fed. Reg. at 50,334.

[15] General Provisions Section of EPA’s New Source Performance Standards (NSPS) establishing specific performance standards for industrial flares.

[16] General Provisions of EPA’s National Emissions Standards for Hazardous Air Pollutants (NESHAP) establishing performance requirements for flares.

[17] See “Parameters for Properly Designed and Operated Flares”, USEPA Office of Air Quality Planning and Statistics, April 2012.

[18] Federal air regulations applicable to petroleum and natural gas facilities include: NSPS Subpart Kb, NSPS Subpart (KKK / VV), NSPS Subparts (OOOO / OOOOa / VVa), Proposed NSPS Subpart OOOOb/c, and NESHAP Subpart HH. Emission sources potentially requiring control are wet seal centrifugal compressors, storage tanks, glycol dehydrators, pressure relief valves, and pneumatic pumps in light liquid service. For emission sources controlled with flares, compliance with the General Provisions in 40 CFR Parts § 60.18 and § 63.11 for flares is required.

Commenter 0402: Flares

Variable ‘Combustion Efficiency’ Based on Compliance and/or Monitoring

Tier 1 methods should allow an option to perform combustion efficiency testing or performance test data to validate a combustion efficiency assumption of 98% or greater. Tier 2 methods should provide a default combustion efficiency of 98%. The default factor in Tier 3 should be revised to a minimum of 95%.

Tier 3 Methane Destruction Efficiency Should be Revised to a Minimum of 95%

Destruction Efficiency of 95% Supported by Plant *et al* Study

The default proposed ‘combustion efficiency’ in Tier 3 reporting is based upon errant analysis in the Plant et al study and a more appropriate interpretation of those data would result in an overall methane destruction efficiency of >95% across upstream and gathering and boosting flares.

…

Furthermore, in the Plant *et al* study, investigators did not have access to operational data, including flow information, for any of the observed flares. Resultantly, extrapolation of the observations to a regional emission factor inherently assumes that the set of flares observed well represented the population of flares in terms of size, design, and most importantly, flow rates. In the case of refinery and petrochemical plant flare combustion efficiency studies, it was found that flares most at risk for reduced combustion efficiency were those operating at high turndown (low flow) conditions. Low flows also result in reduced exit velocity, where higher exit velocities are more protective against cross-winds. Therefore, it is quite plausible that the majority of the flares encountered in the Plant et al study that were operating at reduced combustion efficiencies were flares at low flows. However, the authors applied the destruction efficiencies by count of flares to regional flare gas estimates from the Visible Infrared Imaging Radiometer Suite (VIIRS), which inherently incorporates an assumption that flare gas was evenly distributed among the observed flares and that flare turndown was not correlated to combustion efficiency degradation.

Validity of the Plant et al Study Data is Questionable

The validity of the Plant *et al* study data as the sole underlying basis for quantifying flare methane destruction efficiency is questionable.

There are several limitations of the Plant *et al* study, most of which are raised by the authors themselves within the study and quoted below. These limitations raise questions about the study validity as a basis for establishing a 3-tier combustion efficiency framework and a presumptive Tier 3 value of 92%. These include:

- The study design did not disclose how the flight-path test method (i.e., 'shifting racetrack' pattern) was validated, for example, using a well-characterized source of CO_2 and CH_4 or a test flare having known input flow rates, combustion characteristics, and dispersion behavior. Without documentation of method validation using a model source, peer reviewers were, and end-users are, unable to determine how the field sampling techniques were calibrated, and the appropriateness of the error correction / statistical treatment applied to the collected information to address test method-induced artifacts.
- There were no data presented on the vertical or horizontal dispersion effects or on the ability of the sampling technique to discern the presence of imperfect distribution of CH_4, CO_2 or other components within the sampled plumes. In fact, in the Supplementary Materials[39] the authors noted that (emphasis added), "In real-time, the concentration reading of CO_2 was monitored to look for an intercept (i.e., peak) of the ***relatively narrow flare combustion plume as the aircraft transected downwind. If an intercept was not identified on the first downwind pass, the flight team adjusted altitude, using the visual flare as a guide.***" This statement confirms that each sample event would likely have employed a unique flight path, introducing an inconsistency across individual runs in the dataset.
- The sampling scenario was challenging. As noted in the Supplementary Materials[40] , "In real-time, the concentration reading of CO_2 was monitored to look for an intercept (i.e., peak) of the relatively narrow flare combustion plume as the aircraft transected downwind." No information was available to readers to determine the parameters of each flight path. Using publicly available information for the aircraft and assuming a circular flight path, the estimated dwell time of the aircraft in the plume during each pass was likely extremely short. The Scientific Aviation Mooney aircraft have a cruise speed of 170 knots (or higher)[41] with stall speeds of 50- 60 knots[42,43] according to various sources. At a speed of 130 knots[44] in a 6500ft diameter circular flight pattern, and assuming a 10^o sample window (570ft), the dwell time in the sample window is less than 2.5 seconds.

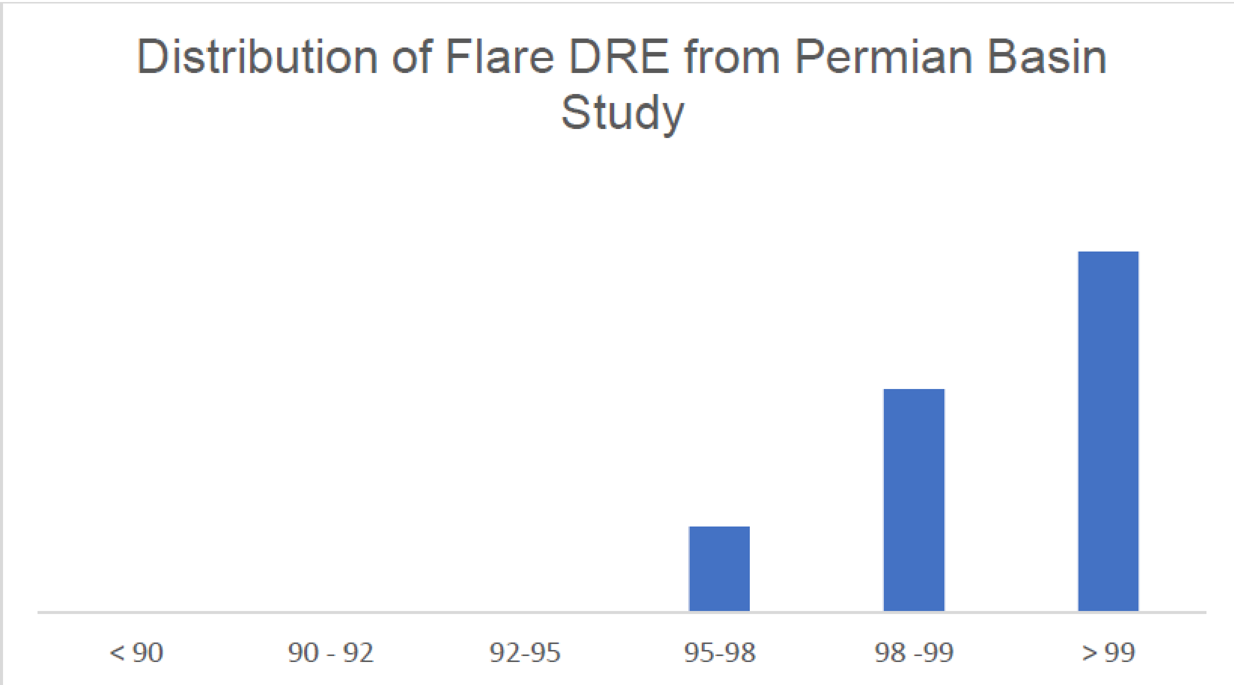
Even with a wide 22.5° sample window (1275 ft), the dwell time in the sample window is just 5.5 seconds. Higher air speeds would shorten the dwell times.

- The study acknowledged that the log-normal curve-fitting technique used likely leads to overweighting the importance of the outlying data, thus magnifying the influence of tails even though the authors noted that the median observed DRE values were close to 98%. Also, the authors could not explain the outlying, tail-defining observations collected (emphasis added), "Investigations into possible drivers of reduced DRE… did not yield compelling explanatory relationships, suggesting that the combination of our airborne sampling and these supplemental datasets ***cannot explain most of the observed flare CH4 DRE variability***." Also, the authors did not solicit input from operators about operating conditions that could explain the observed data. Given the influence of the low DRE datapoints, further scrutiny as to their validity and possible exclusion from the dataset should have been made.
- The Plant *et al* study did not provide information on the rate, duration and variability of the gas being flared at each location, nor what activity precipitated the flaring, such as: flowback from a single well, emergency operations during drilling or a workover, a lightning strike that shut down control systems, a gas compressor failure, malfunction of a tank or separator liquid level or other controller, on a well pad co-located with the flare or at a central gathering and boosting facility, upset at a gas treating unit co-located with the flare, shut-in of a downstream gas plant forcing gas to be flared from multiple upstream sources etc. Absent this information, it is impossible to determine what separated high-performing flares, from those that exhibited low DREs and whether the low-performing flares represent the effect of transient anomalies that cannot be assumed to be present basin-wide for extended periods of time.
- The use of "bootstrapping sampling" to extend to basin-scale the data from the limited sample set collected via aircraft sampling magnifies the weaknesses discussed above and should not be the basis for a regulatory change. The Plant *et al* study authors combined contributions of both observed" inefficient **performance (*i.e., CH4 DRE*) and the prevalence of unlit flares into a total effective DRE.**" This was done by randomly resampling (with replacement) the observed DRE distributions and applying those efficiencies to the population of flares seen in VIIRS within each basin. Essentially, this manipulation of the data multiplied the small observed dataset many times over. Then the authors ***inferred the uncertainty*** (emphasis added) of basin-average estimates to derive 95% confidence intervals. This approach does not support the use of the word "found" in the following statement made in the preamble: "Plant *et al.* … ***found*** average combustion efficiencies ranging from less than 92 percent in the Bakken basin to slightly more than 97 percent in the Permian basin."

Member-Provided Data Supports a Destruction Efficiency Well Over 95%

Additional flare destruction efficiency data provided by Industry Trade members indicate that all but two flares out of 132 tested achieve a destruction efficiency of over 95%, with the majority (nearly 90%) achieving a destruction efficiency greater than 98%.

In September 2023, API members conducted a flare study on 39 flares throughout the Permian Basin using Providence Photonics Mantis. Due to the limited timeframe in which to prepare comments, this study was limited to 39 flares; however, the study found that 85% of flares achieved a destruction efficiency greater than 98%. All flares achieved a destruction efficiency greater than 95%, as shown in the Figure below.



Other available member-provided destruction efficiency test data from the Bakken, which includes 92 individual flare measurements, and one measurement in the Permian, show that over 90% of the flares tested had a destruction efficiency of 98% or higher, and over 75% were higher than 99% destruction efficiency. All but two flares out of 92 tested had a destruction efficiency above 95% (i.e., 94.85% and 90.52 %, respectively). The table below summarizes the distribution of methane destruction efficiencies calculated from member-provided flare testing in both the Permian and Bakken basins:

Basin	Number of Flares Tested		Mean Flare Destruction Efficiency, %	Median Flare Destruction Efficiency, %
Permian	40		98.82	99.05
Bakken	92		99.27	99.69
Combined	132		99.14	99.50

As shown, the median flare destruction efficiency for the combined dataset of 132 flares tested from the Permian and Bakken was 99.5%. **These studies further reinforce that the Tier 3 destruction efficiency should be a minimum of 95%. Arguably, the Tier 3 destruction efficiency should be considerably higher than 95% based on the test data from members, as the data supports a destruction efficiency closer to 98%**. Please see Annex D for a summary of the test results.

Footnotes:

[Footnotes 39 through 44 were not provided in the comment letter.]

Commenter 0417:

The proposed Tier 3 default combustion efficiency of 92 percent regardless of reporting basin disregards much of the empirical data in the study referenced by EPA in support of it (Plant, G., et al. 2022. ‘‘Inefficient and unlit natural gas flares both emit large quantities of methane.’’), referred herein as “Plant, et al.” Page 14 of the study states: “*The average flare-based CH4 DRE for each basin is **97.6**%, 96.3%, and 89.2% for the **Bakken**, Eagle Ford, and Permian, respectively*.” (emphasis added). Thus, according to this study, it appears Bakken flare performance averaged 97.6 percent destruction and removal efficiency (DRE) in an unannounced third party study that even appears to have included unlit flares and with no assurance of flare gas monitoring that may or may not have been occurring at the time. This is not a surprise to NDPC, as its members have put considerable resources into improving flare reliability. The North Dakota Department of Environmental Quality (NDDEQ) has also contributed to the Bakken’s superior flare performance with its vigorous inspection programs and collaborative efforts with the industry. Proper acknowledgement of this work and the empirical data presented in the Plant, et al study would be to recognize better flare performance in the areas that have achieved it and incentivize continued improvement in emissions reductions. NDPC believes that if the referenced study contains enough empirical data for the EPA to propose lowering the default DRE from the currently accepted 98 percent to 92 percent, then the study also presents enough empirical data to 1) establish a default DRE of 97.6 percent for the Bakken without any additional monitoring of pilot status or inlet gas parameters and 2) remain at the current 98 percent when flares are evidenced to be lit. In support of this assertion, NDPC is including the results of a flare survey performed by Providence Photonics utilizing VISR technology, further discussed in a subsequent paragraph, on 264 flares at facilities operated by multiple Bakken operators. Data in the referenced flare survey shows the majority of flares to be operating at a DRE above 99 percent, well above the current default of 98 percent and the 98 percent default requested in this comment letter. Operators could then perform additional monitoring or direct flare assessment to evidence better flare efficiency if they desire.

Commenter 0417:

Regarding the Plant, et al study and proposed Tier 3 flare efficiency of 92 percent, EPA states in the preamble to this rulemaking that “*This value 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 United States (U.S.) in Plant et al. Our assessment is that this would be a reasonable combustion efficiency for Subpart W sources that are not monitoring as specified under Tier 1 or Tier 2 because the overall average in the empirical results likely included many facilities that would comply with those tiers and thus would be excluded from the calculation of the average for Tier 3 flares.*” However, NSPS OOOOb has not been finalized and therefore none of the facilities surveyed in the study could be assumed to have been monitoring flare gas parameters to comply with a requirement that did not exist at the time of the study. Further, none of those pre-OOOOb facilities would be required to monitor for OOOOb requirements going forward. In a similar manner, OOOOc is not yet finalized and will depend on state implementation programs that EPA has not yet seen. It is not valid for EPA to assume that other proposed rules will be finalized in a certain way to justify the proposed amendments to Subpart W.

Commenter 0417:

Arbitrary assignment of "*low end*" flare efficiencies to areas that have demonstrated superior flare performance in an EPA-recognized third party study is not supported by the empirical data presented in the Plant, et al. study. This arbitrary flare efficiency assignment does not benefit the environment, does not incentivize operators and states to continue pursuing feasible real-world flare improvements, and only serves to unnecessarily inflate the IRA Waste Emissions Charge.

Response 4: We disagree with the commenters that stated the data from the Plant et al. study is biased and not representative of the general population of flares. The commenters noted that the flares in the study were not selected at random but rather were selected based on specific criteria such as having a detection within the preceding 7 months in Skytruth, a satellite system that is able to identify flares that meet certain heat signature or emission rate criteria based on spectral observations within certain spectral bands. We are not aware of any studies that indicate a difference in efficiency between large flares and small flares. We also note that the satellite data represent a snapshot in time. Although a particular flare may have been operating poorly at the time of the study, that does not mean it always operates poorly. Similarly, a flare that was operating properly during the study does not necessarily always operate properly. As another commenter noted, it is plausible that some of the low efficiencies could have been due to high turndown or other reasons for low flow at the time of the study. Considering the high number of flares in the study, we expect that a snapshot at another point in time would provide similar overall results. The commenters also asserted that the Plant et al. study results are biased because they focused on associated gas flaring in predominately oil plays, which according to the commenters, is not representative of flaring in primarily gas plays. However, the commenters did not provide data to support their position that the type of source routing gas to the flare or that the characteristics of flared gas from an oil well versus a gas well affect the efficiency of the flare. The commenters also noted that the Plant et al. study did not include enclosed combustion devices because such combustion devices would not be detected by the satellite system; according to the commenters, enclosed combustion devices have higher efficiencies than open flares. We agree that it is likely that the study included few, if any, enclosed combustion devices. However, we note that the performance standards in both NSPS OOOOb and the refineries NESHAP are the same for both enclosed combustion devices and open flares and we are taking that same approach in this final rule for subpart W purposes. The final amendments also clarify that performance testing is part of the requirements for using the tier 1 or tier 2 efficiencies under the calculation methodology for subpart W. Reporters may use the tier 1 or tier 2 efficiencies instead of the tier 3 efficiency for their enclosed combustion device if their test meets or exceeds the applicable threshold and they conduct monitoring to maintain operating parameters within limits established during the test. Furthermore, in a change from proposal, the final amendments also allow reporters to request approval of alternative test methods according to § 60.5412b(d) that they demonstrate can meet efficiencies that differ from the tier efficiencies.

Commenter: GPA Midstream Association
Comment Number: EPA-HQ-OAR-2023-0234-0299
Page(s): 44

Commenter: Providence Photonics, LLC
Comment Number: EPA-HQ-OAR-2023-0234-0370
Page(s): 2-4

Commenter: Baker Hughes
Comment Number: EPA-HQ-OAR-2023-0234-0383
Page(s): 3-4

Commenter: Williams Companies, Inc.
Comment Number: EPA-HQ-OAR-2023-0234-0394
Page(s): 7

Comment 5:

Commenter 0299: **EPA seems to confuse "combustion efficiency" with "destruction efficiency."**

Throughout the preamble and the proposed regulatory text, EPA consistently used the term "combustion efficiency." However, EPA seems to confuse this term with "destruction efficiency." Combustion efficiency refers to complete combustion (i.e., the fraction of the hydrocarbon stream that is completely oxidized to CO_2) whereas destruction efficiency is the fraction of the hydrocarbon stream that is destroyed in the flare and includes the incomplete combustion to other compounds (such as CO). Emission calculations in Subpart W for methane emitted from a flare must be based on *destruction efficiency*, not combustion efficiency, to account for all methane oxidized whether to CO_2 or CO. It is also imperative for EPA to understand the distinction between these terms when evaluating studies and literature on the topic.

Commenter 0370: Flare Combustion Efficiency

…

Combustion Efficiency (CE) vs. Destruction Efficiency (DE)

Conventionally, CE is the fraction of the hydrocarbon fuel that has been oxidized to its ultimate combustion product, carbon dioxide (CO_2), whereas DE (also referred to as Destruction and Removal Efficiency, DRE) is the fraction of the hydrocarbon fuel that has been destroyed but may or may not be oxidized all the way to CO_2 [e.g., breaking into smaller molecules, forming a different molecule or radical, partially oxidized to elemental carbon (soot or smoke) or carbon monoxide (CO)]. In 40 CFR 63.670 (r), EPA effectively makes 96.5% CE equivalent to 98% DE. Research has shown the difference between CE and DE. In a comprehensive flare study commissioned by TCEQ in 2010, CE and DE were measured and reported separately (Allen & Torres, 2011). Similarly, CE and DE were measured and reported separately in a 2016 flare measurement test funded by the Petroleum Environmental Research Forum (PERF) and administered by John Zink Hamworthy (hereafter referred to as PERF study). The difference between DE and CE (DE-CE) in these tests is plotted in Figure 1 below. The data used to generate this chart is included in Exhibit 1.

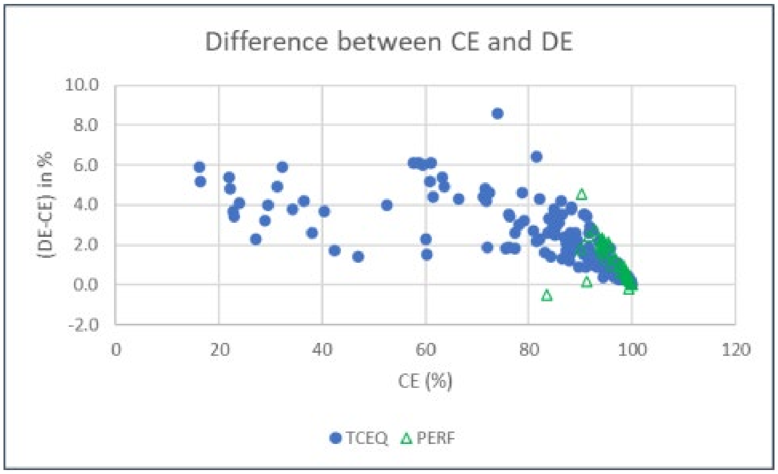


Figure 1. Difference between DE and CE at different CE levels based on the 2010 TCEQ flare study and 2016 PERF flare test. Both CE and DE were measured by extractive sampling method.

As shown in Figure 1, the difference is larger when the flare efficiency is lower because more incomplete combustion products (e.g., carbon soot, CO, etc.) are generated. As combustion efficiency approaches 100%, the difference between DE and CE becomes very small or negligible.

EPA recognizes the difference between CE and DE in other flare regulations (e.g., 40 CFR 63.670). Lumping CE and DE together as "combustion efficiency" η in Eq. W-19 and W-20 will be inconsistent with other EPA flare regulations and does not reflect the fact that there is a fraction of materials that are neither methane nor CO_2. As illustrated in Figure 1 above, this fraction can be significant relative to the fraction of unburned methane (in the same order of magnitude as methane slippage), especially when the "combustion efficiency" is as low as 92% in the Tier 3 scenario. The accurate method to calculate and report methane and CO_2 emissions is to use DE in lieu of η in Eq. W-19 for methane emission and use CE in lieu of η in Eq. W-20 for CO_2 emission.

According to the TCEQ and PERF flare studies, the CE and DE are well correlated – see Figure 2 (data used to generate this chart is included in Exhibit 1). One could use this correlation to measure CE and calculate DE or vice versa with high accuracy. The equation for such a conversion is slightly different depending on the range of data to be used to develop the equation. In our opinion, using a subset (e.g., the data points with CE between 50-100% as shown in the bottom chart of Figure 2) is more representative of the vast majority of the flares.

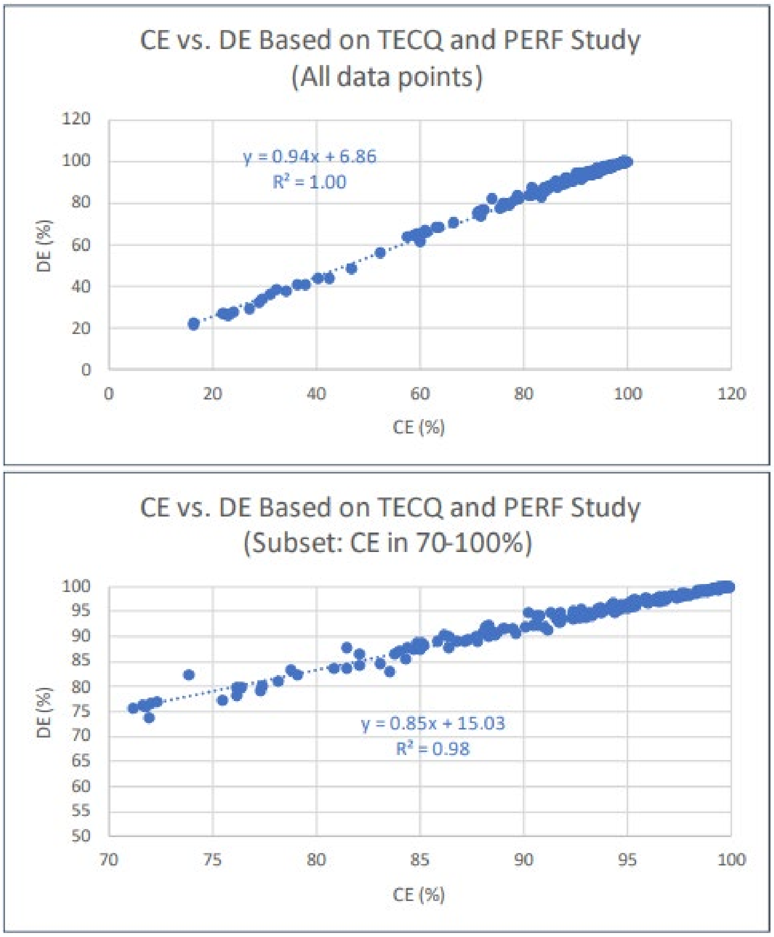


Figure 2. Correlation between CE and DE.

Top chart: all data points from 2010 TCEQ study and 2016 PERF study.

Bottom chart: a subset of data covering test conditions with CE in the range of 70-100%.

…

<u>Commenter 0383</u>: **The equations used to calculate CE and DRE should be clarified.**

At proposed regulatory text 40 CFR 98.233(n)(5), the EPA calculation of annual CH4 emissions from a flare stack in cubic feet at standard conditions (Es,CH4) is based on equation W-19:

$$E_{s,CH_4} = V_s * X_{CH_4} * [(1-\eta) * Z_L + Z_U] \quad \text{(Eq. W-19)}$$

In the equation η designates flare CE, expressed as fraction of gas combusted by a burning flare.

However, in the scientific literature from the U.S. and internationally, CE and DRE have clear yet different definitions. η in the equation W-19, is equivalent to the DRE in the literature, see for example the Texas Commission on Environmental Quality publication "TCEQ 2010 Flare Study Final Report"[2] and "Detailed Expressions and Methodologies for Measuring Flare Combustion Efficiency, Species Emission Rates, and Associated Uncertainties".[3] This inconsistency will lead to confusion as those familiar with flares calculate emissions from DRE, not from CE. Essentially, what the EPA defines as CE in the rule is DRE in the literature. The definitions of CE and DRE in TCEQ 2010 report are more common and widely accepted.

Baker Hughes recommends that EPA clarify the definitions of these terms to avoid confusion and promote consistency. We recommend adopt the TCEQ definitions of CE and DRE:

Combustion Efficiency (CE) = $$\left(\frac{CO_2(exhaust)}{CO_2(exhaust)+CO(exhaust)+\sum \text{hydrocarbons}(exhaust)}\right)\times 100$$

Destruction and Removal Efficiency (DRE) = $$\left(1-\frac{\text{propene}_{out}}{\text{propene}_{in}}\right)\times 100$$

Footnotes:

[2] "TCEQ 2010 Flare Study". Texas Commission on Environmental Quality PGA No. 582-8-862-45-FY09-04. August 1, 2011. Available at: https://downloads.regulations.gov/EPA-HQ-OAR-2012-0133-0047/attachment_32.pdf

[3] "Detailed Expressions and Methodologies for Measuring Flare Combustion Efficiency, Species Emission Rates, and Associated Uncertainties". Ind. Eng. Chem. Res. 2014, 53, 49, 19359–19369. 2014. Available at: https://pubs.acs.org/doi/10.1021/ie502914k

Commenter 0394: **DRE for Malfunctioning and Unlit Flares**

Williams questions the technical merit of the proposed combustion efficiency (CE) of 92% since the EPA failed to provide any supporting data in the rule's Technical Support Document. Assuming the EPA has sufficient and defensible data to support this CE, setting the value at 92% is still incorrect based on past EPA practices. If the EPA can justify a CE of 92 %, Williams suggests that CE be converted to a DRE of 93.5% (add 1.5% to CE to obtain DRE, as done by EPA[22]) to be consistent with other regulations which reference DRE and not CE. …

Footnote:

[22] See id. <21 See "Parameters for Properly Designed and Operated Flares", USEPA Office of Air Quality Planning and Statistics, April 2012.>

Response 5: See Section III.N.1 of the preamble to the final rule for the EPA's response to this comment.

Commenter: American Petroleum Institute et al. (Part 1 of 2)
Comment Number: EPA-HQ-OAR-2023-0234-0402
Page(s): 44

Comment 6: Flares

Variable 'Combustion Efficiency' Based on Compliance and/or Monitoring

Tier 1 methods should allow an option to perform combustion efficiency testing or performance test data to validate a combustion efficiency assumption of 98% or greater. Tier 2 methods should provide a default combustion efficiency of 98%. The default factor in Tier 3 should be revised to a minimum of 95%.

Requirements for Proposed Tier 2 Support 98% Methane Destruction Efficiency

The compliance assurance provisions in NSPS OOOOb and EG OOOOc, as proposed under Tier 2, are sufficient to ensure 98% methane destruction efficiency.

The underlying goals of the flare compliance assurance provisions in part 63 subpart CC flare requirements was to supplement the provisions in 60.18 to specifically protect against over steaming, especially in concert with lower heat content flare gas by transitioning the compliance point from heat content of flare gas to heat content reaching the combustion zone, which would account for inert gases introduced to the flare gas within the variable gas composition in manufacturing settings, and account for the impact of steam on the combustion zone. In the absence of those conditions, 60.18 provisions continue to provide a reasonable assurance of high combustion efficiency.

Further, a recent study on flare destruction and removal efficiency (DRE) conducted in the Permian Basin by members of the Industry Trades indicates that over 85% of flares have a destruction efficiency above 98% (refer to comment below in Section 3.8.4.4). Other available member-provided destruction efficiency test data from the Bakken, which includes 92 individual flare measurements, show that over 90% of the flares tested had a destruction efficiency of 98% or higher, and over 75% were higher than 99% destruction efficiency. These findings support a 98% combustion efficiency default for Tier 2, especially considering the enhanced monitoring requirements aligned with NSPS OOOOb rule requirements.

Response 6: We disagree with the commenter's conclusion that the default destruction efficiency for tier 2 should be 98 percent because this is inconsistent with the 95 percent efficiency that was determined to be achievable when complying with the testing, monitoring, and inspection requirements in NSPS OOOOb.

The final rule also includes a new option that allows facilities to request approval of an alternative test method. For approved alternative methods, a facility may use the efficiency that was demonstrated in the request for approval, provided the facility also implements any testing, monitoring, and inspections specified in the alternative method to demonstrate the efficiency is met. See Section III.N.1 of the preamble to the final rule for more information regarding this new option.

Commenter: Williams Companies, Inc.
Comment Number: EPA-HQ-OAR-2023-0234-0394
Page(s): 6-7

Comment 7: DRE for OOOOb/c Flares at Gathering Compressor Stations

The Proposed Rule sets a "default combustion efficiency of 95 percent that would be allowed if the reporter is required to or elects to comply with the monitoring specified in proposed 40 CFR §60.5417b(d)(1)(viii) of NSPS OOOOb."[19] Similar to what Williams shared in our comment letter dated February 13, 2023, submitted as part of the OOOOb/c proposed rulemaking, the EPA's OOOOb/c regulation should not require flares at gathering compressor stations to be subject to the flare performance standards in 40 CFR § 60.18 and 40 CFR § 63.11. The large number of flares at gathering compressor stations across the United States makes the installation of calorimeters, flow meters, and data recorders at every flare location impracticable. In addition, measurement of waste gas heat content and flow rate at natural gas compressor stations is unnecessary since these flares typically handle a limited number of waste streams with nominally low flow rates and NHVs consistently exceeding 1,000 Btu/scf.

The EPA should authorize facility owners to conduct routine visual inspections of compressor station flares using manual observations or video cameras to test for proper combustion. Visual confirmation of a properly operating flare at a compressor station can be determined by the presence of a luminous yellow flame, absence of smoking, absence of down drafting, and no lift-off of the flame from the flare tip. Photographs of properly operating flares with high destruction efficiencies have been published by both the Texas Commission on Environmental Quality and the EPA.[20,21] Routine visual inspections of flares at compressor stations are a practical and effective alternative to NHV and flowrate measurements and will achieve the goal of reducing VOC and methane emissions and visible (smoking) emissions from flares at compressor stations.

Finally, the EPA should authorize companies that are subject to OOOOb/c to use a 95% DRE when visual confirmation of a properly operating flare at a gathering compressor station is obtained. For purposes of clarity for the GHG inventory, the EPA should revise Subpart W to reference the 95% DRE in OOOOb/c for flares at gathering compressor stations.

Footnotes:

[19] Proposed Rule, 88 Fed. Reg. at 50,334.

[20] Visible flames on Industrial Flares, Why Flames May Be Visible More Frequently From Industrial Flares", Texas Commission on Environmental Quality, GI-419, (12/11).

[21] See "Parameters for Properly Designed and Operated Flares", USEPA Office of Air Quality Planning and Statistics, April 2012.

Response 7: The EPA disagrees with the commenter's suggestion that facilities should be allowed to use a 95 percent destruction efficiency for purposes of the subpart W calculation methodology when routine visual inspections of the flare show the presence of a luminous yellow flame, absence of smoking, absence of down drafting, and no lift-off of flame from the flare tip. The EPA has determined that the conditions specified in 40 CFR 60.18 together with the flare (and enclosed combustion device) testing, monitoring, and inspection requirements in NSPS OOOOb are needed to ensure a 95 percent destruction efficiency is accurate for calculating emissions for subpart W reporting. At this time the EPA has not developed or assessed a method based solely on visual inspections that can achieve this objective. The commenter also has not defined how the suggested routine inspections would be implemented, nor has the commenter demonstrated how the suggested inspections would achieve a 95 percent destruction efficiency.

Regarding the commenter's concern that installation of calorimeters, flow meters, and data recorders for every flare at gathering compressor stations to meet the proposed requirements is impracticable due to the large number of flares at such facilities, we note that many facilities electing to comply with tier 2 under subpart W will not need to install flow meters and calorimeters in order to claim the 95 percent destruction efficiency because NSPS OOOOb includes many alternatives to using flow meters and calorimeters. Some of these alternatives address emission streams that have low flow rates and/or consistently high heating values. Additionally, although the proposed subpart W amendments would have required the use of continuous parameter monitoring systems to generate flow rate data to use in calculating emissions, the final subpart W provides additional alternative methods for determining flow rates. See Section III.N.1 of the preamble to the final rule for additional information on alternative flow rate determination methods that are included in the final rule. The final rule, like the proposed rule, also does not require owners and operators to use calorimeters to determine HHV for use in calculating N_2O emissions from flares. Instead, 40 CFR 98.233(n)(8) specifies that HHV may be calculated based on gas composition, and 40 CFR 98.233(n)(4) specifies several alternative methods that may be used to determine composition.

Regarding the commenter's statement that routing visual inspections will achieve the goal of reducing VOC and methane emissions, we note that the purpose of these revisions to subpart W is for owners and operators to accurately report their actual emissions based on empirical data; the purpose of subpart W is not to reduce emissions.

Commenter: Providence Photonics, LLC
Comment Number: EPA-HQ-OAR-2023-0234-0370
Page(s): 5

Comment 8: Flare Combustion Efficiency

…

There is another issue with the proposed Tier 1. What DE will be used to quantify emissions if/when NHVcz < 270 Btu/scf? The referenced 40 CFR 63.670 & 671 regulation is a compliance/noncompliance binary determination. The proposed Subpart W is about quantifying emissions, not compliance/noncompliance determination. Whatever the NHVcz value is, there needs to be a DE assigned in order to calculate the emissions. The proposed rule does not account for this, and we propose a solution later in our comments.

…

Response 8: The final rule amendments include provisions that specify if a flare claiming the Tier 1 efficiency does not conform with all the specifically incorporated and referenced NESHAP CC testing and monitoring provisions for 15 consecutive days, the Tier 3 efficiencies must be used until such time that full conformance with the subpart W requirements for using that tier is achieved. Therefore, for the specific instance mentioned by the commenter, if the NHVcz value is less than 27 Btu/scf for one or more 1-minute blocks for 15 consecutive days, the owner or operator would be required to apply a 92 percent destruction efficiency and a 90.5 percent combustion efficiency until the NHVcz value rises above 270 Btu/scf. This same concept is included in the final rule amendments for sources utilizing the Tier 2 efficiencies.

Commenter: Providence Photonics, LLC
Comment Number: EPA-HQ-OAR-2023-0234-0370
Page(s): 5

Comment 9: Flare Combustion Efficiency

…

As for the proposed Tier 2, a GHGRP reporter has to use the DE value of 0.95 (i.e., 95% DE) if the reporter monitors the flare as specified in proposed §60.5417b(d)(1)(viii). The proposed regulation §60.5417b(d)(1)(viii) is about monitoring combustion zone temperature in a boiler or process heater. We don't understand how this requirement can be applied to a flare. Thermocouples are sometimes used in proximity to the flare as a method to ensure the pilot is lit, but in no case do these thermocouples provide the temperature inside the combustion zone. We also don't see the rational for the 95% control efficiency for this Tier 2.

…

Response 9: In the final amendments, the differences between the types of combustion devices is acknowledged and references to NSPS OOOOb are cited accordingly. Specifically, 40 CFR 98.233(n)(1)(ii)(A) is specific to enclosed combustors and the provisions of § 60.5412b(a)(1), 40 CFR 60.5413b(b), § 60.5415b(f), and § 60.5417b are cited. For open flares, which are addressed in 40 CFR 98.233(n)(1)(ii)(B), the NSPS OOOOb provisions cited are 40 CFR 60.5412b(a)(3), 60.5415b(f), and 60.5417b. In addition, 40 CFR 98.233(n)(1)(ii)(C) is for enclosed combustion devices tested by the manufacturer in accordance with 40 CFR 60.5413b(d) of NSPS OOOOb, and it references 40 CFR 60.5413b(b)(5)(iii) and (e), 60.5415b(f), and 60.5417b.

Commenter: Range Resources Corporation
Comment Number: EPA-HQ-OAR-2023-0234-0397
Page(s): 10

Comment 10: Requiring reporting of a 92% efficiency for flares will result in inaccurate reporting and conflict with EPA's performance standards.

…

Regardless, EPA should clarify that operators will not be found in violation of OOOOa and OOOOb simply because they chose to comply with the default reporting standard at proposed 40 C.F.R. § 98.233(n)(4)(iii) in subpart W.

Response 10: If an owner or operator is subject to NSPS OOOOb, then it is unclear to the EPA why such a facility would elect to use Tier 3 efficiencies, as compliance with the subpart W Tier 2 requirements would be met through compliance with the incorporated aspects of the NSPS OOOOb requirements. However, if they do, their election to use Tier 3 for subpart W purposes would not in itself constitute a violation of NSPS OOOOb.

If the source is subject to NSPS OOOOa, it is possible that would not constitute conformance with the NSPS OOOOb requirements cited in subpart W, as there are differences between NSPS OOOOa and OOOOb. However, the use of Tier 3 for subpart W has no impact on their compliance status under NSPS OOOOa.

Commenter: Taxpayers for Common Sense (TCS)
Comment Number: EPA-HQ-OAR-2023-0234-0351
Page(s): 4

Commenter: Environmental Defense Fund, et al.
Comment Number: EPA-HQ-OAR-2023-0234-0413
Page(s): 58-60

Comment 11:

Commenter 0351: *Gas Emitted Through Venting and Flaring*

For flaring, the proposed rule would assume a maximum combustion efficiency of 92 percent for flares that are not continuously monitored or in other cases where natural gas is combusted in an explosion or fire. This rate aligns with recent data that show natural gas flared in the U.S. combusts 91.1 percent of methane, as opposed to the previously held assumption that the combustion rate was closer to 98 percent. [10] The 92 percent maximum default combustion efficiency will more accurately calculate the amount of GHG emitted into the atmosphere during these release events. TCS believes the maximum assumed combustion efficiency should not be greater than the proposed rate of 92 percent. A higher assumed combustion efficiency would underestimate actual GHG emissions.

Footnote:

[10] Genevieve Plant et al., "Inefficient and unlit natural gas flares both emit large quantities of methane," Science, September 29, 2022. https://www.science.org/doi/10.1126/science.abq0385

Commenter 0413: 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 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 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.

…

Footnote

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

Response 11: The EPA acknowledges the commenters' support of the proposed tiered approach for default flare combustion efficiencies. The EPA is finalizing the general approach as proposed, but some details have changed for the final rule. First, in consideration of comments in comment 5 of this section and as discussed in Section III.N.1 of the preamble to the final rule, the proposed default combustion efficiencies have been redesignated as destruction efficiencies, and combustion efficiency values are specified that are 1.5 percent lower than the destruction efficiencies. Second, in consideration of comments in Comment 1 of this section, the EPA added an option in 40 CFR 98.233(n)(1)(iv) for reporters to request approval of an alternative test method in accordance with 40 CFR 60.5412b(d). For methods approved using this protocol, reporters will be able to use approved efficiencies that differ from the tiers. See Section III.N.1 of the preamble to the final rule for a discussion of this finalized option. Third, the EPA is finalizing changes to the specific language in 40 CFR 98.233(n)(1)(i) and (ii) to more clearly cross-reference the applicable procedures in NESHAP CC and NSPS OOOOb that must be implemented to claim the tier 1 and tier 2 efficiencies under the subpart W calculation methodology.

Commenter: Texas Commission on Environmental Quality (TCEQ)
Comment Number: EPA-HQ-OAR-2023-0234-0349
Page(s): 3,4

Comment 12: Of additional concern is the change in default combustion efficiency for flares.

…

Furthermore, by tying the GHGRP tier 2 flare combustion efficiency of 95% to compliance with requirements that are proposed and not included in a final rule creates unnecessary uncertainty. By proposing that a 92% combustion efficiency be utilized until 40 CFR Part 60, Subpart OOOOb (NSPS OOOOb) and/or 40 CFR Part 60, Subpart OOOOc (EG OOOOc) proposed rules are promulgated, EPA is effectively moving the assumed basis for long-established facilities. TCEQ recommends … outlining specific control monitoring requirements that will be required when determining combustion efficiency from flares if the proposed NSPS OOOOb and EG OOOOc are not finalized.

Response 12: NSPS OOOOb was finalized on March 8, 2024 (89 FR 16820), and the final subpart W is in alignment with the final NSPS OOOOb as applicable.

Commenter: Chevron
Comment Number: EPA-HQ-OAR-2023-0234-0232
Page(s): 5-6

Comment 13: Flare – Combustion Efficiency Reporting

…

Additionally, EPA should carefully consider the unintended consequences of the proposed changes to reported flare CEs on other state and federal permitting or reporting requirements.

…

Response 13: It is difficult to provide a comprehensive response because the commenter did not identify what types of unintended consequences the proposed flare efficiencies might cause. One possibility is that the commenter may be concerned that a facility could be considered out of compliance with an NSR permit if the state requires a higher flare combustion/destruction efficiency in the permit than what the facility is allowed to use under subpart W. The GHGRP is a separate and independent program. Thus, any methods and assumptions required for calculating emissions under subpart W that result in certain efficiencies being applied or emissions calculated for a facility or source that differ from other programs' requirements for that facility or source, such as permit conditions, are separate from the manner the facility or source is required to demonstrate compliance with requirements under other programs, such as compliance status under a permit.

Commenter: North Dakota Petroleum Council (NDPC)
Comment Number: EPA-HQ-OAR-2023-0234-0417
Page(s): 5

Comment 14: EPA's proposed changes to flare efficiencies impose additional and costly monitoring requirements without providing improved accuracy …. The monitoring requirements will increase company spending on emissions monitoring without associated improved emissions reduction benefit.

Response 14: As described in Section VI of the preamble of the final rule, the EPA has assessed the cost to comply with the final rule and has concluded as a result of that assessment that the costs of the final rule are reasonable. The EPA made adjustments in the final rule after consideration of comments, including adjustments that resulted in different costs in the final rule analysis. For example, based on consideration of specific comments on the cost of flow and gas composition monitoring requirements in the proposed rule and the EPA's assessment of the accuracy of different methods, the EPA has finalized additional alternative methods that will reduce the cost of determining flow and gas composition to use in calculating flare emissions and are expected to provide data of acceptable accuracy. See Sections 15.2.4 and 15.2.6 in this document and Section III.N.1 of the preamble to the final rule for a discussion of these comments and the EPA's response to them. In developing the final NSPS OOOOb, the EPA also incorporated less costly alternatives to monitoring such as the alternative to use a backpressure control valve instead of flow monitoring to ensure that flow remains above minimum specified levels. Facilities subject to NSPS OOOOb or electing to comply with the tier 2 flare destruction and combustion efficiencies for the calculation methodology under the final subpart W may use either of these methods as part of their demonstration that the specified efficiencies are being achieved.

15.2.4 Monitoring to Determine Gas Flow to the Flare

Commenter: American Exploration and Production Council
Comment Number: EPA-HQ-OAR-2023-0234-0295
Page(s): 7

Comment 1: **Flares**

Flare flow monitoring:

The current version of Subpart W does not require any specific monitoring. However, if a flare is monitored for an alternative compliance purpose, such as with a continuous flow monitor or gas composition analyzer, Subpart W does require that monitoring data to be used in emission calculations.

Under the Proposal, flow to the flare would be required to be measured continuously, with flow measured either directly or indirectly, by measuring parameters such as line pressure and burner nozzle dimensions with engineering calculation. The Proposal would allow the flow measurements to be of either total input to the flare, or of each stream sent to the flare.

While we understand EPA's intent in proposing direct or indirect measurements to increase the accuracy of reported flare emissions, extending this requirement to every flare poses significant technical installation challenges and financial burden on companies which has not been fully accounted for the regulatory impact analysis. For example, many older flares are very basic, only monitor if the pilot light is on or off, and aren't yet tied into Supervisory Control and Data Acquisition (SCADA) systems used for controlling, monitoring, and analyzing industrial devices and processes. AXPC suggests that EPA amend the Proposal to allow for data from continuous flow monitors where/when available, and allow for engineering estimates in the event that the data is unavailable which may happen for a variety of reasons including SCADA downtime, meter malfunctions, etc.

There is no accommodation in the Proposal for temporary flares, which may be used in the early well development and completion stages of production facilities. The requirement to install costly flow monitoring or parametric monitoring systems on temporary flares is unduly burdensome and could disincentivize the use of temporary flares for maintenance activities to avoid venting gases, where allowed. As such, AXPC requests an exemption from monitoring for temporary flares.

Additionally, this aspect of the Proposal is one instance of the issue discussed in the legal section of these comments, where we note that EPA is proposing here to accelerate the implementation of some aspects of the pending NSPS OOOOb rule. As we explain below, this is improper, particularly in the case of existing sources where the design of Section 111(d) and EPA's regulations implementing that provision provide that existing sources will not be subject to EG OOOOc's requirements for years after that rule is finalized. In addition to this legal objection, it is premature to proceed in this manner, because there are issues of concern in this aspect of the pending Section 111 rulemaking which may yet yield changes in the final rulemaking that would then not align with this Proposal. AXPC has discussed several of these issues in our comments on the initial proposal in that rulemaking, *see* EPA-HQ-OAR-2021-0317-083, at page 45 (Feb. 2, 2022), our comments on metering in the supplemental proposal, *see* EPA-HQ-OAR-2021-0317-1460, at page 1 (Feb. 15, 2013), and our supplemental comments provided in response to questions raised during a March 2023 meeting with EPA staff, see EPA-HQ-OAR-2021-0317-1460. AXPC incorporates here by reference these comments submitted in the pending Section 111 rulemaking as they relate to the flare flow monitoring issue.

Response 1: Regarding the commenter's suggestion that the EPA revise subpart W to allow use of continuous flow monitoring data when it is available and allow for engineering estimates in the event that such data is unavailable, see the compilation of related comments in Comment 2 of this section and the EPA's response to these comments in Section III.N.1 of the preamble to the final rule.

The EPA has not included an exemption from monitoring for temporary flares in the final rule because in addition to including the proposed flow measurement methods as options, the final rule also includes other options for determining flow and composition of streams from individual sources that are routed to flares that are based on using process simulation or engineering calculations. See the EPA's response to comments in Section III.N.1 of the preamble to the final rule for a discussion of these options that have been added to the final rule.

The final NSPS OOOOb was promulgated on March 8, 2024. The flare requirements in the final subpart W align with the final NSPS OOOOb requirements. Thus, the comment regarding cross-references to the pending NSPS OOOOb are no longer relevant. Additionally, we disagree with the commenter's assertion that subpart W accelerates the implementation of some aspects of either NSPS OOOOb or EG OOOOc because as discussed above, continuous flow monitoring is specified as an option rather than a requirement in the final rule, and flow determination methods based on process simulation or engineering calculations requirements are included as additional options in the final rule. NSPS OOOOb allows alternatives to continuous flow measurement (e.g., the use of backpressure regulator valves). These alternatives are allowed under subpart W as one of the requirements for ensuring the tier 2 efficiencies are achieved for purposes of accurately calculating emissions under subpart W. However, since they do not provide flow data that are needed to calculate emissions, subpart W also specifies flow determination methods for all flared streams.

Finally, we reviewed the commenter's comments on NSPS OOOOb in Docket ID No. EPA-HQ-OAR-2021-0317 (docket items -0831, -2326, and -3818) for comments related to flow monitoring in the proposed NSPS OOOOb. It appears the only comment related to flow monitoring requests that NSPS OOOOb allow monitoring of pressure as a direct alternative to measuring flow. The EPA disagreed with this suggested change (Response II-17-21) in the Response to Comments document for the final NSPS OOOOb. Consistent with our rationale there, this methodology has also not been included in the final subpart W.

Commenter: Marcellus Shale Coalition (MSC)
Comment Number: EPA-HQ-OAR-2023-0234-0275
Page(s): 12

Commenter: GPA Midstream Association
Comment Number: EPA-HQ-OAR-2023-0234-0299
Page(s): 44

Commenter: Independent Petroleum Association of New Mexico (IPANM)
Comment Number: EPA-HQ-OAR-2023-0234-0337
Page(s): 6

Commenter: Providence Photonics, LLC
Comment Number: EPA-HQ-OAR-2023-0234-0370
Page(s): 10

Commenter: ConocoPhillips
Comment Number: EPA-HQ-OAR-2023-0234-0374
Page(s): 2

Commenter: Endeavor Energy Resources, L.P.
Comment Number: EPA-HQ-OAR-2023-0234-0381
Page(s): 15

Commenter: Baker Hughes
Comment Number: EPA-HQ-OAR-2023-0234-0383
Page(s): 2

Commenter: CrownQuest Operating
Comment Number: EPA-HQ-OAR-2023-0234-0393
Page(s): 209, 214, 229

Commenter: American Petroleum Institute et al. (Part 1 of 2)
Comment Number: EPA-HQ-OAR-2023-0234-0402
Page(s): 33-36

Commenter: American Petroleum Institute et al. (Part 1 of 2)
Comment Number: EPA-HQ-OAR-2023-0234-0402
Page(s): 36

Commenter: American Petroleum Institute et al. (Part 1 of 2)
Comment Number: EPA-HQ-OAR-2023-0234-0402
Page(s): 8-9

Comment 2: Commenter 0275: Flares

3. The MSC supports the use of engineering calculations for determining pre-controlled emissions going to a flare. Many emission sources going to the flare are from blowdown events. Typical examples are compressor blowdowns or venting from pigging vessels or similar equipment with defined volumes and known temperatures and pressures. The gas composition for these events are generally known via gas analyses taking on a periodic basis. Other sources, such as dehydrator still vent or flash tank emissions can be accurately modeled using GRI-GLYCalc or ProMax software. In addition, process streams and resulting pre-controlled emissions can be estimated utilizing incoming gas analysis and engineering/process simulation software such as ProMax or HYSYS.

Commenter 0299: **Best available data must be reinstated as a minimum option for flare flow and composition.**

The reporting outlined for flares in the proposed rule is too prescriptive and attempts to impose compliance requirements for operators. The minimum level of monitoring for these sources goes well beyond current requirements for these sources under CAA permits and other EPA or state regulations. Where monitoring is not required by regulation or permit, engineering calculations should continue to be allowed to estimate emissions. EPA must reinstate the proposed removal of best available data calculation methods for flow rate … .

Midstream operators, similar to upstream operators, have many dispersed sites of operation. Many (if not most) of these operators use a combustion control device at the site to control VOC and/or methane emissions. The level of monitoring proposed under Subpart W, however, for these control devices requires continuous monitoring of flow rate … . It is not feasible or economically reasonable to require this level of instrumentation and monitoring to determine flare emissions. Process simulators (combined with monitored operating conditions) and engineering estimates can reasonably estimate flowrates to control devices without costly instrumentation needing to be added to thousands of control devices, particularly control devices that are controlling glycol dehydrators and tanks. These same flowrates are produced from software simulation models that are approved methods for calculating emissions throughout this rule. There is no reason they shouldn't also be included here. This option should also be reflected in reporting requirements in 98.236(n).

Commenter 0337: **40 CFR § 98.233(n) Flares**

In the current version of Subpart W, in § 98.233(n)(1), it states, "If you have a continuous flow measurement device on the flare, you must use the measured flow volumes to calculate the flare gas emissions. If all the flare gas is not measured by the existing flow measurement device, then the flow not measured can be estimated using engineering calculations based on best available data or company records. If you do not have a continuous flow measurement device on the flare, you can use engineering calculations based on process knowledge, company records, and best available data."

EPA now is proposing to require total flow to be measured using continuous parameter monitoring to determine volume. This includes direct flow measurement or parameter monitoring combined with engineering calculations (such as line pressure and burner nozzle dimensions), where measurements must be taken at least once per hour. This is burdensome and costly. EPA should retain the option of determining flare gas volumes using engineering calculations based on process knowledge, company records, or best available data. Using continuous direct flow measurement or parameter monitoring is impractical for most flares in the onshore production and gathering & boosting industry segments based on lack of availability of field offices and/or electrical power.

Commenter 0370: In the proposed rule, flow to the flare (either at the flare header for the total flow or at each source and then summed up for total flow) must be measured by flowmeter(s) or other parameter monitoring systems combined with engineering calculations. This requirement is not as specific and strict as some other rules, e.g., 40 CFR 63.670 & 671 where minimum accuracy and calibration requirements for flare vent gas flow are specified in Table 13. In addition, there are requirements for temperature and pressure sensors for calculating flowrate from actual to standard conditions. It appears that the EPA's intention is to get as accurate a flowrate measurement as practically possible. This brings some issues and opportunities. The issue we see is related to the Tier 1 method for flare combustion efficiency. Tier 1 requires continuous monitoring of NHVcz as in 40 CFR 63.670 & 671. For refineries that are already subject to 40 CFR 63.670 & 671, this should not be a problem. However, for non-refinery facilities, especially upstream and mid-stream facilities, this is a potential issue. Without accurate flowrate measurement of all streams, including T & P sensors for calculating flowrate in standard conditions, and synchronization of these measurements, significant errors could be introduced into the NHVcz metric. The issue could be significant enough to make Tier 1 not practical for non-refinery sources even though it is allowed on paper. Again, this may push all non-refinery sources to go with Tier 2 or even Tier 3 and artificially elevate reported GHG emissions. This will not be consistent with the purpose of revising the Subpart W.

There is an opportunity in this space to apply some innovative measurement methods to the flowrate measurement. For example, flare vent gas flowrate can be measured remotely by the same VISR instrument that monitors flare NHVcz. Exhibit 5 is a paper presented at the 2019 Industrial Combustion Symposium organized by American Flame Research Committee (AFRC). This IR radiometry based remote flare gas flowrate measurement can be especially valuable for two types of flares: 1) flares not equipped with a flowmeter, which is more common in upstream and midstream; and 2) flares where the flowrate is primarily low (at the extreme low end of the flowmeter range). In the second scenario, a conventional flowmeter is installed, but the flowrate measurement can be highly inaccurate when the flowrate is so low that it barely registers in the conventional flowmeter. The VISR based flow measurement has a much higher dynamic range (high turn-down ratio). It will measure the flow that generates just a small number of pixels in the VISR imager and the surge that generates a large flame.

As demonstrated in Exhibit 5, using the VISR device to remotely monitor flare gas flow rate is definitely more accurate than an engineering estimate. Our comment is to revise the proposed rule to allow a facility to use this VISR measurement method to measure flow rate.

Commenter 0374: **Use of Empirical Flow Monitoring for flares**

The deployment of new continuous metering or parametric monitoring equipment can pose significant auxiliary challenges. This is particularly true for extensive oil and natural gas production sites as they often lack Supervisory Control and Data Acquisition (SCADA) systems or comparable infrastructure. This deficiency limits the connectivity of in-field instrumentation and access to a data historian. Additionally, the absence of necessary infrastructure, such as electricity and data infrastructure including Wi-Fi and even cellular coverage, further diminishes any cost-effective means for installing new instruments.

In summary, we believe that EPA should retain the current Subpart W language for flare stack emissions stating that, "If all of the flare gas is not measured by the existing flow measurement device, then the flow not measured can be estimated using engineering calculations based on best available data or company records. If you do not have a continuous flow measurement device on the flare, you can use engineering calculations based on process knowledge, company records, and best available data."

Commenter 0381: *Second*, EPA proposes to require continuous parameter monitoring for gas flows …[45] This is a departure from the existing approaches, which are more permissive and discretionary as to use of continuous monitoring.[46] Many in the industry use continuous monitoring systems, like SCADA (Supervisory Control and Data Acquisition) systems or similar detection systems, for many of their high-pressure flares. For low-pressure flares, however, the lower pressures and volumes generally do not justify continuous monitoring like their high-pressure counterparts. EPA's proposal will thus be unjustifiably costly, as reporters within the reporting segment would likely need to outfit continuous monitoring across their operations, which is simply infeasible and not cost-effective for low-pressure flares. Endeavor thus recommends that EPA eliminate the proposed *requirement* for continuous monitoring of gas parameters …, and instead retain the discretion presently in place in 40 C.F.R. § 98.233(n)(1) … If EPA declines to do so, the Agency should draw a distinction between high-pressure and low-pressure flares and exclude the latter from the continuous monitoring requirements.

Commenter 0383: Baker Hughes flare.IQ technology helps to monitor, control, and reduce emissions associated with flaring. It can reduce methane slip, minimize costs, and improve transparency. flare.IQ is a full-stream flare solution based on a well-proven ultrasonic flare flow measurement technology. It covers everything from assisted flares associated with downstream petrochemical and refinery flare operations to unassisted flares associated with upstream operations.

The EPA is proposing to amend requirements that apply to the petroleum and natural gas systems source category of the Greenhouse Gas (GHG) Reporting Rule to ensure that reporting is based on empirical data, accurately reflects total methane emissions and waste emissions from applicable facilities and allows owners and operators of applicable facilities to submit empirical emissions data that appropriately demonstrate the extent to which a charge is owed. In these proceedings, EPA can accelerate these goals by incentivizing operators to measure emissions data in real time. Further modifications to the rule are needed to account for the benefits of existing ultrasonic flow measurement technologies such as flare.IQ.

Commenter 0393: Adding meters … on gas routed to flare lines would increase costs not only in equipment, but also labor hours. Another note is that the meters … that would be connected to these lines would be very difficult to calibrate as the flow is inconsistent and likely very low pressure. …

…

Flaring is a component of the oil and gas industry. The Environmental Partnership launched a flaring program in 2020 we have advanced best practices to reduce flare volumes, promote beneficial use of associated gas and improve flare reliability and efficiency when necessary. To track this progress, we report data annually to calculate flare intensity which is a measurement of flare volume relative to production. The 2022 annual report shows a 2.4% reduction in flare intensity and 14% reduction in total flare volumes reported from the previous year. All this while US oil and gas production grew by 5.6% and 4% respectively during that same time. The proposed rules including flare efficiency tiers seems very burdensome and not cost effective. With all this data available, operators are doing their part in mitigating flaring, but at the end of the day it will always come down to takeaway capacity and the inevitability of compressor stations being shut in for maintenance. The option to use flared gas as an alternative fuel, injection back into the producing well, or other production methods is viable, however, the location and indeterminacy and temporary basins they are no way to consistently use this. Measuring low pressure flares is highly variable and not feasible.

…

Flare meter accuracy: these meters can become inaccurate in dynamic flow situations.

Many examples of this could be routine flow rapidly increases/decreases, non-routine flare events, etc. Ultrasonic flare meters are the most reliable meters for measuring gas flow rates under various conditions, but these certainly are not economically feasible to install on such many flares across the industry. An estimated cost for this equipment is $20,000-$30,000 for each meter.

<u>Commenter 0402</u>: **EPA's requirement to directly meter or use continuous parametric monitoring to estimate flare volume is technically and economically infeasible, and may actually lead to reporting inaccuracies, especially for low-flow streams**. The Industry Trades propose that EPA allows reporters the option to continue to use engineering estimates for flare volume. Please refer to Section 3.8.1.

…

Flares

Flow Measurement

EPA Should Continue to Allow Process Simulation and Engineering Calculations for Flare Flow Volumes

The Industry Trades recommend that EPA continues to allow the use of process simulation and engineering calculations that indirectly measure flare flow volumes as an alternative to meters or parametric monitoring devices. The proposed flare metering requirements are infeasible, burdensome and may lead to inaccuracies for most flares in production and gathering and boosting operations. Furthermore, EPA did not address the need to measure flare flow in the proposed rule's TSD. Likewise, the proposed parametric monitoring does not provide a more accurate or cost-effective alternative to metering. **EPA should retain the current Subpart W language stating that, "…If all of the flare gas is not measured by the existing flow measurement device, then the flow not measured can be estimated using engineering calculations based on best available data or company records. If you do not have a**

continuous flow measurement device on the flare, you can use engineering calculations based on process knowledge, company records, and best available data."[26]

Proposed Flare Measurement Methods are Inaccurate and Infeasible for Low Pressure Flares

The proposed flare flow measurement methods are inaccurate, as well as infeasible, for low pressure flares in production and gathering and boosting operations.

The primary streams that are routed to flare at typical oil and gas facilities include:

- Low-flow pilot, purge, sweep, and/or auxiliary gas used to ensure flares are lit, operating safely, and have optimal destruction efficiencies;
- Low- pressure gas that is intermittent and turbulent from tank flashing, working, and breathing losses;
- Mid- pressure flaring from low pressure/secondary separators, heater treaters, and vapor recovery towers that have become technically and economically compressed to sales that has intermittent and turbulent flow; and
- High pressure separator gas flaring in areas with stranded gas pipeline take-away loss that has intermittent flow and is decreasing across the country.

Most meters are unable to accurately measure the flow of low-volume, low-pressure, intermittent, and turbulent streams.

In addition to the concerns surrounding the metering of each individual stream, the Industry Trades are concerned with EPA's application of flow meters or parametric monitoring across every upstream application. EPA's requirement to use continuous flow measurement devices or parametric monitoring for low-pressure flares and purge/sweep/auxiliary gas streams is technically infeasible. Meters require steady pressure and flow to accurately measure flow rates. Most meters are unable to accurately measure low pressure and flow conditions found in purge/sweep/auxiliary gas and storage tank streams, or variable flows affecting several streams, such as tanks due to production slugs or when separators dump fluids, sporadic flaring of associated natural gas, and high-pressure equipment blowdowns. Furthermore, the flare volumes rapidly decline from the initial production of the well and become more sporadic. Metering the scenarios described is challenging, and industry needs a flexible array of options to ensure proper combustion and accurate reporting. The incorrect application of meters or parametric monitoring devices can lead to inaccurate flare volumes relative to using process simulations, engineering estimates, and indirect measurement allowed under the current rule. **The Industry Trades recommend the use of process simulation and engineering calculations that indirectly measure flare flow volumes as an alternative to meters or parametric monitoring devices.** The industry utilizes reliable process simulation and engineering calculations which are often more accurate than metering low pressure, low flow, and highly variable streams within the upstream oil and gas industry. The Agency and industry rely on process simulation and engineering calculations in permitting, designing and maintaining facilities for safety and environmental reasons, and have made great strides in the accuracy of these approaches in recent decades. Additionally, the GHGRP allows process simulation to estimate composition and volume of gas for emissions (e.g., tank flash gas, dehydrators, etc.) that are not going to flare so the same methods should be allowed for gas streams that do go to flare. As such, it does not make sense to expend significant capital and operational resources to install continuous monitoring when engineering estimates are more reliable and allowed for uncontrolled sources (e.g., storage tank vents and dehydrators). Interestingly, EPA couples burdensome, although potentially less accurate, measurement technology for flow with default destruction efficiencies, without allowance for measurement or performance test data; this would negate any possible improvements in flare emissions accuracy.

In Colorado, the Air Pollution Control Division (APCD) recognized that flow meters have low accuracy at low vapor volumes by first approving a variance in 2022 to their flow meter requirements and more recently amending their Regulation 7 rule language in 2023 to include pressure actuators as an alternative to flow meters. Pressure actuators are an example of a solution implemented to ensure combustion. For reporting purposes, engineering estimates and simulation software based on site specific information (e.g., GOR and liquid throughput) are more accurate to generate emissions reporting information for flares in the production and gathering and boosting operations. It is important that the EPA understands that proper combustion and accurate reporting go hand in hand and should be viewed holistically so that operators are efficiently managing both concerns.

Meters available in the market and widely used in upstream oil and gas applications include differential pressure meters (e.g., orifice plate and v-cones), thermal mass meters, and ultrasonic meters. Differential pressure meters work by measuring the upstream and downstream pressure from a plate or cone with an orifice that allows gas to pass through. The amount of differential pressure can be increased or decreased for any given flow rate by selecting plates or cones with smaller and larger orifices. The flow of the gas passing through the meter can be inferred by the differential pressure between both points. The ratio of minimum and maximum capacities of meters, known as the turndown ratio, typically should not exceed 4:1 for differential pressure. This causes three primary considerations for differential pressure meters: first, they are inaccurate in low-pressure conditions; second, they are unable to accurately measure variable flow rates given their relatively tight turndown ratio (Zhang & Wang, 2021);[27] and lastly, they are sensitive to liquid and debris clogging the orifice causing an artificial increase in differential pressure and inaccurate high flow volume measurements. The relationship between low-pressure conditions, tight turndowns, and sensitivity to operating conditions is exacerbated by the fact that smaller orifices must be selected for lower pressures, causing even tighter turndown ratios that are more inaccurate with variable rates, and increasing the likelihood of clogging. Orifices can also become blown out by sudden increases in flow volume or debris, which causes a decrease in differential pressure and inaccurate low flow volume measurements. This makes differential pressure meters technically infeasible to measure purge, sweep and auxiliary gas lines that operate at low pressures, tank vent lines that operate at near atmospheric conditions, and high-pressure gas lines that are more variable than the turndown ratio of these meters.

Thermal mass meters operate on the principle of thermal dispersion, which states that the amount of heat absorbed by a fluid is proportional to its mass flow. These meters work by either comparing heat loss between two elements, or by measuring the amount of energy that must be expended to heat gas to a certain setpoint. Similar to differential pressure meters, thermal mass meters cannot accurately detect lower flow rates due to the unmeasurably small differences in temperature between the two elements or energy required to heat gas for low flow volumes. As noted in Kerr-McGee's letter to Colorado Department of Public Health & Environment Air Pollution Control Division (APCD) dated April 12th, 2022[28], the turndown ratio of thermal mass meters is typically 33:1, which means the meter is unreliable until 3% of the meter's maximum flowrate of 1,180 thousand standard cubic feet per day (MCFD) is achieved. Additional information regarding this comment can be found in Annex C of this letter. This also makes thermal mass meters technically infeasible to measure pilot/purge gas lines and tank vent lines as these streams do not meet the minimum flowrates required for thermal mass meters due to their low rates and declining production over time. In addition to issues with low flow rates, thermal mass meters are highly susceptible to entrained mist, liquid, or particles that can affect the thermal properties of the gas being measured (API, 2021).[29] For example, the specific heat capacity of propane increases from 1.67 kJ/Kg-K in the gaseous phase to 2.4 kJ/Kg-K in the liquid phase. Thermal mass meters can measure dry gas in steady flow conditions above their minimum capacity, which makes them suitable for select flare scenarios depending on facility design and process. However, they do not have the level of accuracy required to form any basis for the methane fee.

Ultrasonic meters operate on the principle of doppler shift by measuring the time it takes for sound to travel from an ultrasonic signal transmitter to a receiver upstream and downstream of gas flow. Generally, ultrasonic meters do not work well in low flow conditions because of the unmeasurably small doppler shift that occurs at lower velocities. Thus, they are technically infeasible to accurately measure low pressure pilot/purge gas and storage tank streams. They are also sensitive to mist, liquids, or particulates that may block the receiver from receiving the ultrasonic signal, but not as much as differential pressure or thermal mass meters. They are also sensitive to surrounding equipment that may produce vibrations or sounds near the same frequency as the ultrasonic signal. For more information, refer to *API Manual of Petroleum Measurement Standards*, Chapter 14.10. [30]

It is important to note that meters can only be used when facilities have a dedicated high-pressure flare as opposed to a single control device (i.e., a flare that controls tanks, associated natural gas (ANG), and potentially other sources). Ultrasonic meters are also economically infeasible given they can cost $20,000 to $30,000 each to purchase, and additional capital required for installation and labor. API commented on this in our comments on NSPS OOOOb and EG OOOOc Supplemental Proposal, submitted on February 13, 2023, and included in Annex C of this letter. Furthermore, this does not include the cost to install SCADA communications systems that can cost up to $100,000 per facility for unconnected remote locations.

Footnotes:

[26]Current § 98.233(n)(1).

[27]Zhang, Y and Wang, J. Review of metering and gas measurements in high-volume shale gas wells, Journal of Petroleum Exploration and Production Technology, 12:1561-1594, December 2021, https://doi.org/10.1007/s13202-021-01395-9.

[28]APCD-PHS-EX-035.

[29]American Petroleum Institute (API), *Manual of Petroleum Measurement Standards, Chapter 14.10, Natural Gas Fluids Measurement – Measurement of Flow to Flares*, Second Edition, December 2021.

[30]Ibid.

Commenter 0402:

3.8 Flares

3.8.1 Flow Measurement

3.8.1.1 EPA Should Continue to Allow Process Simulation and Engineering Calculations for Flare Flow Volumes

Proposed Parametric Monitoring Does Not Provide a More Accurate Alternative

The proposed alternative of parametric monitoring does not provide a more accurate or cost-effective alternative to metering.

Based on operator experience, field testing programs comparing parametric monitoring and metered flare volumes have shown that parametric monitoring over-estimates flow volumes. Implementing parametric monitoring to estimate flow is complex and requires detailed data on the appropriate flow orifice diameter, installing additional instrumentation to monitor temperature and pressure difference across the orifice, as well as the need to install SCADA communication systems at remote locations and analytical software to estimate flow rate. The requirement to either install meters or parametric monitoring systems is burdensome and unnecessary considering that the main contribution to GHG emissions from flaring is unlit flares, which are addressed separately in the proposed rule.

For all the reasons stated above, **the Industry Trades recommend that EPA continues to allow the use of process simulation and engineering calculations** that indirectly measure flare flow volumes as an alternative to meters or parametric monitoring devices.

Response 2: See Section III.N.1 of the preamble to the final rule for the EPA's response to this comment.

Commenter: GPA Midstream Association
Comment Number: EPA-HQ-OAR-2023-0234-0299
Page(s): 44-45

Comment 3: EPA should not specify monitoring technology to allow flexibility for new technology development.

…

As stated in our comments regarding the proposed NSPS OOOOb and EG OOOOc on storage tank control devices,[104] requiring flow meter measurement is not feasible in many cases because flow measurement cannot meet the accuracy requirements in intermittent and low flow scenarios. The proposed rule, however, would require that flow meters be accurate up to 2% at maximum flow rates.[105] In most cases, such accuracy could be achieved only with an optical meter or an ultrasonic flow meter. These typically cost about $30,000 for basic models; however, there is no evidence in the record that justifies compelling the use of these precise and expensive flow meters over less costly flow meters. As with many other types of flow meters, these also struggle with accuracy at lower flow rates such as when the device is only controlling breathing losses from tanks or pressure safety valve discharges at gas plants. As a result of these operating issues, even the most accurate flow meters will lose some accuracy. Accuracy at lower rates can increase with additional flow meter monitoring devices installed in tandem with the basic ultrasonic meter; however, this significantly increases the overall cost of this monitoring equipment. GPA would like to ensure that meters with an accuracy of up to 10 percent at maximum flows, such as thermal dispersion flow monitoring devices, can be used to calculate emissions under this proposed reporting rule, but EPA should not require monitoring and must allow alternative methods of estimating emissions that have significantly lower costs with similar accuracy of emissions.

…

Footnotes:

[104] GPA Comments on NSPS OOOOb and EG OOOOc at 41-42 (Comment VI.B.2).

[105] Proposed 40 C.F.R. § 98.234(b) ("You must operate and calibrate all flow meters, composition analyzers and pressure gauges used to measure quantities reported in § 98.233 according to the procedures in § 98.3(i) and the procedures in paragraph (b) of this section."); *id.* § 98.3(i)(3)(i) ("For each transmitter, the CE value at each measurement point shall not exceed 2.0 percent of full-scale.").

…

Response 3: The EPA has decided not to reduce the accuracy requirement for flow meters used to determine flow to flares. . The commenter suggested reducing the required accuracy of all flow meters used to measure flared gas flow to ±10 percent, but this would be inappropriate for meters used to measure streams where ±2 percent can be met. The calibration requirements in 40 CFR 98.3(i)(2) and (3) also apply to flow meters in all other subparts under the GHGRP, and it is not clear that some flows to flares in the oil and gas sector are sufficiently unique as to warrant a reduced level of accuracy for the flow meters. Moreover, the EPA finalized additional methods in 40 CFR 98.233(n)(3)(ii)(B) of the final rule that allow determination of flow of individual streams for flared sources based on either process simulation, engineering calculations, or process knowledge, depending on the source type. See Section III.N.1 of the preamble to the final rule for a response to comment that discusses the EPA's rationale for including the additional flow determination methods in the final rule. If a reporter determines that flow of a particular stream cannot be measured within the required accuracy range, then one of the additional options provided in the final rule should be an acceptable alternative.

In 40 CFR 60.5417b(d)(8)(iv) of the final NSPS OOOOb, flow meters with an accuracy of ±10 percent are allowed for measuring flow to flares and enclosed combustion devices. If an owner or operator elects to measure flow (rather than using a backpressure regulator valve or a parameter monitoring systems combined with engineering calculations), then the measured flow rates are used to ensure flow remains between the minimum and maximum flow rates that have been established for the flare or enclosed combustion device. Maintaining flow within the defined range is one condition that must be met to demonstrate that the flare is achieving the required efficiency. This section of the final NSPS OOOOb is referenced in the calculation methodology under Tier 2, 40 CFR 98.233(n)(1)(ii), of the final rule. Thus, a flow meter with an accuracy of ±10 percent may be used to demonstrate compliance with this aspect of the tier 2 option's requirements. However, either the flow meter must also be accurate to within ±2 percent, or one of the other flow determination methods in 40 CFR 98.233(n)(3) of the final rule must be used to determine flow for use in calculating flared emissions under subpart W using the Tier 2 efficiency.

Commenter: Environmental Defense Fund, et al.
Comment Number: EPA-HQ-OAR-2023-0234-0413
Page(s): 56-57

Comment 4: 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 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."

Footnotes:

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

[97] 88 Fed. Reg. 50332 (Aug. 1 2023).

[98] Id.

[99] See, e.g., Festa-Bianchet et al., Methane 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/wpcontent/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://lawslois.justice.gc.ca/eng/regulations/SOR-2018-66/FullText.html.

[103] Id.

Response 4: The EPA acknowledges the commenter's support of the proposed revisions to the methodology for determining the volume of associated gas routed to flares. However, the response to this comment in Section III.M.2 of the preamble to the final rule explains the EPA's reasons for including a GOR-based option for determining flow to flares in the final rule. The proposed measurement methods also are finalized as proposed, except that they are options in the final rule.

15.2.5 Presence of Pilot Flame or Combustion Flame

Commenter: GPA Midstream Association
Comment Number: EPA-HQ-OAR-2023-0234-0299
Page(s): 44-45

Commenter: Independent Petroleum Association of New Mexico (IPANM)
Comment Number: EPA-HQ-OAR-2023-0234-0337
Page(s): 6-7

Commenter: Providence Photonics, LLC
Comment Number: EPA-HQ-OAR-2023-0234-0370
Page(s): 10-11

Commenter: American Petroleum Institute et al. (Part 1 of 2)
Comment Number: EPA-HQ-OAR-2023-0234-0402
Page(s): 38-39

Comment 1: Commenter 0299: **EPA should not specify monitoring technology to allow flexibility for new technology development.**

…. EPA should allow flexibility for flame presence monitoring.

GPA supports the concept of reporters incorporating their best available data in all parts of the rule, including flare flame presence monitoring. GPA does not support, however, GHGRP requirements to monitor for flame presence (see Comment 6). If this requirement is retained, EPA should allow flexibility for this monitoring. Remote visual observation of flares through a video camera should be allowed as an alternative method of verifying flame presence. Operators can view multiple stacks remotely in a control room. Visual observation provides adequate determination of flame presence. EPA should not require that on-site observations are the only opportunity for visual inspection. Newer technology must be allowed under these rules. Allowing remote visual observation not only more efficiently utilizes manpower but can also result in more timely discovery of unlit or malfunctioning flares and implement corrective actions.

EPA should not specify monitoring technology to allow flexibility for new technology development.

….

Additionally, auto-ignition systems should be allowed to verify flame presence. Texas allows autoignition systems where flow to the flare is intermittent,[106] and EPA should do the same here. This eliminates the need for a continuous pilot and reduces the amount of pilot and sweep gas necessary to operate the flare.

Footnote:

[106] Texas Comm'n on Envtl. Quality, Air Quality Standard Permit for Oil and Gas Handling and Production Facilities, https://www.tceq.texas.gov/permitting/air/newsourcereview/chemical/oil_and_gas_sp.html.

Commenter 0337: **40 CFR § 98.233(n) Flares**

An automatic ignition system with a flame monitoring device should be allowed as an alternative to the requirement for monitoring the presence of a flame or monthly visual inspections. To reduce emissions, many operators are installing automatic ignition systems that activate when flow to the flare is detected instead of maintaining a continuous pilot flame. By design, an automatic ignition system will be unlit during periods with no detectable flow to the flare, thus combusting less pilot and purge gas. Some state rules, such as New Mexico and Texas, allow for the use of an automatic ignition system with a flame monitoring device in lieu of a continuous pilot flame. We propose that § 98.233(n)(2) be revised to include the option to use an automatic ignition system with a flame monitoring device be allowed as an alternative to continuously monitoring the presence of a flame or visual inspections.

Commenter 0370: Because the VISR method is an IR imaging-based measurement device, a pilot flame will register as a small cluster of high radiance pixels. If these pixels disappear, the VISR algorithm can generate a signal indicating the absence of the flame. This is a very straightforward application of the VISR instrument. It is particularly beneficial because unlike a thermal couple-based approach to monitor the presence of the pilot flame, the VISR based method is essentially maintenance free. When combined with the continuous monitoring of NHVcz and flow measurement as discussed above, there is no incremental cost for monitoring this important flare parameter. When no flame presence is detected and logged, the occurrence and duration of potentially unlit flare will be documented.

Our comment is to revise the proposed rule to allow a facility to use the VISR device to monitor the presence of pilot flame.

Commenter 0402: Flares

Pilot Flame Monitoring

The Industry Trades generally agree that it is more appropriate to identify discrete periods where flares are unlit for the purposes of estimating emissions that go un-combusted; however, several revisions should be made to the specific requirements:

1. **…**
2. … (ii) Additionally, automatic ignition systems have been deployed many operators and include a flame monitoring device. Since these devices include a flame monitoring device, they would satisfy the obligation, where EPA affirms the requirements for monitoring only apply during periods of flare flow. To reduce emissions or in areas where supplemental gas is needed because the well does not produce gas or enough gas, many operators are installing automatic ignition systems that activate when flow to the flare is detected instead of maintaining a continuous pilot flame. By design, an automatic ignition system will be unlit during periods with no detectable flow to the flare or the valve to the flare is closed. Some state rules, such as in New Mexico and Texas, allow for the use of an automatic ignition system with a flame monitoring device in lieu of a continuous pilot flame. The Industry Trades commented on the benefits of automatic ignition systems in Section 5.6.3 in our response to EPA's Supplemental Proposal "Standards of Performance for New, Reconstructed, and Modified Sources and Emissions Guidelines for Existing Sources" Oil and Natural Gas Sector Climate Review, Submitted February 13, 2023 (included in Annex C of this letter).
3. …
4. As an alternative to thermocouple monitoring, the Industry Trades recommend that visual inspections can be performed using cameras on location.

The Industry Trades commented on the benefits of automatic ignition systems in Section 5.6.3 in our response to EPA's Supplemental Proposal "Standards of Performance for New, Reconstructed, and Modified Sources and Emissions Guidelines for Existing Sources" Oil and Natural Gas Sector Climate Review, Submitted February 13, 2023 (included in Annex C of this letter).

Response 1: See Section III.N.1 of the preamble to the final rule for the EPA's response to this comment.

Commenter: Williams Companies, Inc.
Comment Number: EPA-HQ-OAR-2023-0234-0394
Page(s): 7

Comment 2: Williams supports monitoring for flame presence on a 15-minute interval (and not a 5-minute interval as proposed by EPA) ….

Response 2: We proposed a 5-minute frequency for continuous monitoring of pilot flame because this is the frequency specified in NSPS OOOOb as one of the monitoring requirements for demonstrating compliance with the emissions standard. Thus, this frequency must be used by facilities that are subject to the NSPS or that are electing to comply with the tier 2 destruction efficiency and combustion efficiency in subpart W. Since this frequency is readily achievable, this frequency is also required for monitoring of flares that comply with the tier 3 efficiencies in subpart W. We note that facilities electing to comply with the requirements in 40 CFR 63.670 in order to use the tier 1 efficiencies in subpart W under the calculation methodology must monitor at least once per minute.

Commenter: Encino Energy (EAP Ohio, LLC)
Comment Number: EPA-HQ-OAR-2023-0234-0408
Page(s): 6-7

Commenter: American Petroleum Institute et al. (Part 1 of 2)
Comment Number: EPA-HQ-OAR-2023-0234-0402
Page(s): 38-39

Comment 3:

Commenter 0402:

3.8 Flares

3.8.2 Pilot Flame Monitoring

The Industry Trades generally agree that it is more appropriate to identify discrete periods where flares are unlit for the purposes of estimating emissions that go un-combusted; however, several revisions should be made to the specific requirements:

1. **…**
2. Monitoring for the presence of a pilot flame or combustion flame using a device capable of detecting that the pilot or combustion flare is present should **only be required for periods of time where there is flow of regulated material** going to the flare rather than "at all times." (i) It is illogical to track the length of time a flare is both unlit and there is zero flow because it has no impact on the estimated emissions.
3. **…**

Commenter 0408:

EPA lists a requirement to continuously monitor for the presence of a pilot flame or combustion flame.

- EAP Ohio, LLC flares and enclosed combustion devices (combustors) work in conjunction with a waste gas valve which actuates in conjunction with a pressure regulator. If the vapor recovery unit is able to successfully control waste gas emissions, the waste gas valve is closed and the tank battery operates effectively as a zero emissions tank battery. During times when the waste gas valve is shut, there is no environmental reason to burn gas and produce emissions through a pilot light.
- EAP Ohio, LLC requests EPA remove the requirement to maintain a pilot light at all times to protect the environment and ensure industry is not disincentivized from installing Tank Emission Management systems which send waste gas to sales and limits the amount of waste gas sent to combustion.

Response 3: The requirement for either continuous monitoring or periodic visual inspections (where allowed) to determine the presence of a pilot flame is finalized as proposed. Flares that are subject to NSPS OOOOb must maintain a continuous pilot flame and continuously monitor for the presence of a pilot flame or combustion flame because that is a requirement in that rule. Similarly, if a facility elects to implement the requirements in either the either the refinery NESHAP or NSPS OOOOb in order to use the tier 1 or tier 2 efficiencies under subpart W, then continuous monitoring is required because that is necessary to ensure that the expected efficiency is being achieved for purposes of the subpart W calculation methodology (see the preamble to the final rule for the EPA's response to Comment 1 in this section for additional information regarding the need for pilot monitoring at all times). However, for other flares, we disagree with the assertion by Commenter 0402 that a pilot must be monitored at all times under the subpart W calculation methodology. Instead of complying with tier 1 or tier 2, a reporter may elect to comply with the tier 3 efficiencies. Under tier 3, a reporter may conduct periodic visual inspections at least once per month as an alternative to continuous monitoring.

We also disagree with the assertion by Commenter 0408 that subpart W requires facilities to maintain a pilot flame at all times. As discussed above, a continuous pilot is required only if the flare is subject to NSPS OOOOb, and that requirement is under that program not this one, or the facility elects to implement the requirements incorporated in the subpart W calculation methodology (either the specified refinery NESHAP or NSPS OOOOb requirements) in order to use either the tier 1 or tier 2 efficiencies under subpart W. A reporter that elects to comply with the tier 3 efficiencies under subpart W must conduct either periodic visual inspections or continuous monitoring for the presence of a pilot flame in order to have empirical data on periods of time when the flare is unlit for purposes of calculating emissions, but neither the tier 3 requirements specified in 40 CFR 98.233(n)(1)(iii) of the final rule nor the pilot flame monitoring requirements specified in 40 CFR 98.233(n)(2) of the final rule require the facility to maintain a pilot flame at all times.

Commenter: American Petroleum Institute et al. (Part 1 of 2)
Comment Number: EPA-HQ-OAR-2023-0234-0402
Page(s): 38-39

Comment 4: Flares

Pilot Flame Monitoring

The Industry Trades generally agree that it is more appropriate to identify discrete periods where flares are unlit for the purposes of estimating emissions that go un-combusted; however, several revisions should be made to the specific requirements:

1. **…**
2. **…**
3. Additional monitoring flexibility will improve accuracy of reporting and should be afforded to the pilot monitoring. The Industry Trades recommend either removing the sentence in 40 CFR 98.233(n)(2), stating "if you continuously monitor, then periods when the flare are unlit must be determined based on those data" or revising it to allow redundant and/or additional parametric monitoring or visual inspection to be used. This is because monitoring device malfunctions are not uncommon for thermocouples (or equivalent devices) resulting in false readings; however, other monitored parameters can confirm that the pilot is, indeed, lit even if the monitoring device errantly indicates the pilot is unlit. For example, operators that have flares with multiple thermocouples to monitor flame temperature report that the readings can be widely variable and have observed that the presence of a flame can be indicated by a single thermocouple within the installed group. There are also cases where a pilot has malfunctioned, but visual inspection using site visits or cameras on location reveal a robustly lit combustion flame. In extreme weather conditions, such as in Alaska, Wyoming, or North Dakota, the thermocouple reading will be affected by the ambient temperature and wind conditions. So, where a monitoring device indicates the absence of a pilot flame or combustion flame, an operator should have the option to confirm that finding through other means and eliminate that period from the log of time in which the flare is unlit if supported by other data….

Response 4: See Section III.N.1 of the preamble to the final rule for the EPA's response to this comment.

Commenter: Endeavor Energy Resources, L.P.
Comment Number: EPA-HQ-OAR-2023-0234-0381
Page(s): 15

Comment 5: EPA Should Reconsider the Proposed Revisions to Calculation Methods for Several Emission Sources.

Flare Stack Emissions

…

Second, EPA proposes to require … either continuous monitoring or monthly visual inspections for the presence of pilot flames.[45] This is a departure from the existing approaches, which are more permissive and discretionary as to use of continuous monitoring.[46] Many in the industry use continuous monitoring systems, like SCADA (Supervisory Control and Data Acquisition) systems or similar detection systems, for many of their high-pressure flares. For low-pressure flares, however, the lower pressures and volumes generally do not justify continuous monitoring like their high-pressure counterparts. EPA's proposal will thus be unjustifiably costly, as reporters within the reporting segment would likely need to outfit continuous monitoring across their operations, which is simply infeasible and not cost-effective for low-pressure flares. Endeavor thus recommends that EPA eliminate the proposed *requirement* for continuous monitoring of … pilot flames, and instead retain the discretion presently in place in 40 C.F.R. § 98.233(n)… If EPA declines to do so, the Agency should draw a distinction between high-pressure and low-pressure flares and exclude the latter from the continuous monitoring requirements.

...

Footnotes:

[45] 88 Fed. Reg. at 50,334.

[46] Id.; *see* 40 C.F.R. § 98.233(n)(1), (2).

Response 5: It appears the commenter either misinterpreted the proposed requirements for pilot flame monitoring or inadvertently included pilot flame monitoring in a comment regarding concerns with the proposed requirement for continuous flow monitoring. To clarify, the final amendments, like the proposed amendments, require <u>either</u> continuous monitoring or visual inspections at least monthly to determine the presence of a pilot flame; continuous monitoring is not the only option for monitoring to detect the presence of a pilot flame. We also do not believe pilot flame monitoring should be infeasible or unjustifiably costly for low-pressure flares. Thus, we have not finalized the commenter's suggestion to develop separate pilot flame monitoring requirements for low-pressure flares and high-pressure flares. See Comment 2 in Section 15.2.4 of this document for the commenter's comment regarding the proposed requirement for continuous flow monitoring and see section III.N.1 of the preamble to the final rule for the EPA's response to that comment.

Commenter: MiQ
Comment Number: EPA-HQ-OAR-2023-0234-0392
Page(s): 10-11

Comment 6: 98.233(k)(2)(ii): At least once per month visually inspect for the presence of a pilot flame or combustion flame. If a flame is not detected, assume the pilot has been unlit since the previous inspection and that it remains unlit until a subsequent inspection detects a flame. Use the sum of the measured flows, as determined from measurements obtained under paragraph (n)(1) of this section, during all time periods when the pilot was determined to be unlit, to calculate the fraction of the total annual volume that is routed to the flare when it is unlit.

MiQ Comments: For EPA to expect accurate and consistent reporting amongst operators, EPA will need to set expectations on how they expect a visual inspection is conducted for monitoring the presence of a pilot flame. For example, existing pilot flames may not be visible to operations from the ground dependent on environmental conditions and the relative height of the flare stack. In these cases, operators reporting to (n)(2)(ii) may be placed in a difficult position to verify the presence of a pilot flame with no other information available. Most unlit flares on remote oil and gas sites are detected and accurately reported by operators through the use of advanced monitoring and measurement data, especially aerial and satellite methods, or through the use of process monitoring via thermocouples or other flare monitoring technologies pursuant to 98.233(k)(2)(i). The inclusion of a visual inspection option for sites currently without additional flare monitoring technologies installed will help improve flare operations. However, we request that EPA explore and further specify what, if any, other indicators exist for ensuring the pilot flame for both flare stacks and enclosed combustion devices are operating properly, to ensure more consistent reporting between operators and to maximize the effect of this proposed requirement. A relevant method for visually inspecting flares, or additional requirements to increase the consistency and quality of these inspections across all operators, will directly lead to more accurate reporting.

Response 6: The requirements for visual inspections in 40 CFR 98.233(n)(2)(ii) have been finalized as proposed. The commenter requested that the EPA develop a protocol for conducting visual inspections to ensure consistency among facilities. As an example of the need for a protocol, the commenter indicated that a pilot flame may not be visible to operators from the ground due to certain environmental conditions and the height of the stack. However, we believe the plain meaning of the word “visible” is sufficient for this requirement. If an inspector cannot physically see whether a flame is present or not, then they have not conducted a visible inspection. Either the inspector must use a different monitoring method or conduct the visible inspection at another time when conditions allow for visual confirmation of whether the flame is present. We are unsure what concerns the commenter has with the requirement being applied inconsistently and how the commenter thinks these concerns can be resolved. For these reasons, we have not finalized a protocol for conducting visual inspections.

Commenter: American Exploration and Production Council
Comment Number: EPA-HQ-OAR-2023-0234-0295
Page(s): 8

Comment 7: Flares

Pilot flame monitoring:

The Proposal would require that the flare pilot flame is either continuously monitored, or visually inspected monthly. If a continuous monitor was down, weekly visual inspections would be required. The proposed flare pilot monitoring data collected will also now be required to be used in emission calculations. Calculations must assume a flare was not operating for any duration of time prior to an observed lack of pilot flame up until the previous time pilot flame was confirmed. This will likely overestimate reported emissions. AXPC recommends the duration of the unlit flare be based on site-specific estimates from operational knowledge rather than the overly conservative assumptions in the Proposal. For example, a pilot flame could be out, but the control valve that regulates the waste gas stream to the flare could be closed; therefore, there is no impact to emissions. Revising the rule in this way would improve the accuracy of reporting, including avoiding the double-counting of emissions assumed in the proposed 92% DRE as that emission factor was derived based on a study that included unlit and malfunctioning flares.

Response 7: We are finalizing as proposed the requirement to assume the flare was unlit since the last demonstration that it was lit upon discovering an unlit flare because the final rule allows continuous monitoring as well as visual inspections more frequently than once per month. If a facility implements continuous monitoring, the interval between readings typically is only 5 minutes (only one minute if the facility elects to implement the tier 1 procedures that are based on 40 CFR 63.670). For periodic inspections, a facility also can elect to conduct the inspections more frequently than once per month to minimize the amount of time between inspections.

The commenter cited a situation where a flared gas stream valve is closed for the entire time since the previous inspection during which the flare was determined to be lit and identified this as an example of how the proposed requirement to assume the flare was unlit the entire time would likely overestimate reported emissions. However, the unlit fraction to use in the emissions calculations (equations W-19 and W-20) is based on the fraction of volume routed to the flare during the unlit period. If the volume is measured and there is no flow between inspections (including no purge or sweep gas flow), then the fraction unlit for that period would be 0. Similarly, if flow is calculated using process simulations or engineering calculations, and the facility determines based on process knowledge that there was no flow between the inspections, then the unlit fraction for that time period again would be 0.

Finally, according to the commenter, allowing facilities to use operational knowledge to determine the duration the flare was unlit would avoid double-counting of emissions from unlit periods that are included in the 92 percent default efficiency for tier 3. Other comments regarding the basis for the 92 percent efficiency are consolidated in Comment 3 of Section 15.2.3 of this document. Please see Section III.N.1 of the preamble to the final rule for the EPA's response to this comment.

Commenter: American Petroleum Institute et al. (Part 1 of 2)
Comment Number: EPA-HQ-OAR-2023-0234-0402
Page(s): 38-39

Comment 8: Flares

Pilot Flame Monitoring

The Industry Trades generally agree that it is more appropriate to identify discrete periods where flares are unlit for the purposes of estimating emissions that go un-combusted; however, several revisions should be made to the specific requirements:

1. Double counting of emissions during periods of time when the flare is unlit should be avoided. Because operators will identify discrete periods of time where the flare is operating with 0% combustion efficiency and report emissions accordingly, this volume of emissions should not be included in destruction/combustion efficiency (more in section 3.8.4 below).
2. …

Response 8: See response to Comment 3 in Section 15.2.3 of this document and see Section III.N.1 of the preamble to the final rule for the EPA's response to this comment.

15.2.6 Gas Composition

Commenter: American Exploration and Production Council
Comment Number: EPA-HQ-OAR-2023-0234-0295
Page(s): 6-7

Commenter: Independent Petroleum Association of New Mexico (IPANM)
Comment Number: EPA-HQ-OAR-2023-0234-0337
Page(s): 6

Commenter: ConocoPhillips
Comment Number: EPA-HQ-OAR-2023-0234-0374
Page(s): 2

Commenter: Encino Energy (EAP Ohio, LLC)
Comment Number: EPA-HQ-OAR-2023-0234-0408
Page(s): 7

Commenter: CrownQuest Operating
Comment Number: EPA-HQ-OAR-2023-0234-0393
Page(s): 218

Commenter: GPA Midstream Association
Comment Number: EPA-HQ-OAR-2023-0234-0299
Page(s): 45-46

Commenter: American Petroleum Institute et al. (Part 1 of 2)
Comment Number: EPA-HQ-OAR-2023-0234-0402
Page(s): 40

Commenter: American Petroleum Institute et al. (Part 1 of 2)
Comment Number: EPA-HQ-OAR-2023-0234-0402
Page(s): 42

Commenter: Enerplus Resources (USA) Corporation
Comment Number: EPA-HQ-OAR-2023-0234-0342
Page(s): 2-3

Commenter: Marcellus Shale Coalition (MSC)
Comment Number: EPA-HQ-OAR-2023-0234-0275
Page(s): 12

Commenter: GPA Midstream Association
Comment Number: EPA-HQ-OAR-2023-0234-0299
Page(s): 44

Comment 1:

Commenter 0275:

Flares

…

2. Annual gas analysis should be sufficient to estimate emissions in most cases. In order to comply with NESHAP HH and other permit requirements, an annual gas sample is taken and extended gas analysis performed. Minimal variation from year to year for heating value or components is typical. Additional analysis or continuous online measurement would provide negligible change in most cases and should not be required.

…

Commenter 0295:

I. Flares

B. Composition monitoring or quarterly sampling:

The Proposal would require either a continuous composition analyzer or quarterly stream sampling for all flares. The rule would allow this composition monitoring on either total input to flare, or on each stream sent to the flare. This is a significant departure from the current Subpart W under which the most recent sample may be used as long as it is still representative of operations, and in the absence of site-specific samples, representative samples from similar sites in similar hydrocarbon basins are acceptable.

As described in more detail above, the produced gas stream composition in the upstream sector is relatively stable and is not as variable as in other sectors like refineries; therefore, composition monitoring with a quarterly sampling frequency is unnecessary and does not meaningfully increase the accuracy of the reported emissions. Additionally, production sites may operate hundreds of sources across a basin that are routed to a flare. For example, there are many upstream production companies that operate hundreds of tank batteries in a given basin, and these tank batteries in close proximity to each other often have very similar reservoir characteristics and consequently very similar product compositions. In such cases, where there is geographic proximity, similar reservoir characteristics, and similar operating practices, the samples drawn will return constant and similar compositions. For these reasons, we support the representative sampling requirements in the current Subpart W.

Additionally, to require quarterly sampling of every flare at every tank battery would present severe logistical challenges for companies, as there are limited numbers of labs capable of conducting this type of analysis, without any significant change in the accuracy of the reported emissions. In fact, this perpetual sampling of gas streams will result in an increase in emissions for little to no discernible environmental or inventory benefit. AXPC urges EPA to reconsider the practicality of complying with a requirement of this scale coupled with the low value of the generated data. The Proposal's requirement to complete quarterly stream sampling for all flares will add significant sampling costs for companies. These samples will return relatively constant results, and therefore will not be of much use, making it irrational to require this type and frequency of sampling.

For these reasons, AXPC recommends allowing facilities to use annually updated site-specific sample measurements and use representative samples to cover similar facilities in the absence of site-specific data, as this would still provide EPA with updated measurements without compromising on the accuracy of the reported data. If more demonstration is still required, we request that at a minimum the EPA allow companies the opportunity to prove stability in the waste gas stream, upon which companies should be permitted to stop quarterly sampling altogether, or at least to reduce the frequency to annual sampling when the margin of error is proven to be less than 5%.

<u>Commenter 0299</u>:

56. Best available data must be reinstated as a minimum option for flare flow and composition.

The reporting outlined for flares in the proposed rule is too prescriptive and attempts to impose compliance requirements for operators. The minimum level of monitoring for these sources goes well beyond current requirements for these sources under CAA permits and other EPA or state regulations. Where monitoring is not required by regulation or permit, engineering calculations should continue to be allowed to estimate emissions. EPA must reinstate the proposed removal of best available data calculation methods for … composition. The flares in midstream operations control streams that are generally consistent in composition.

Midstream operators, similar to upstream operators, have many dispersed sites of operation. Many (if not most) of these operators use a combustion control device at the site to control VOC and/or methane emissions. The level of monitoring proposed under Subpart W, however, for these control devices requires … at least periodic sampling for composition. It is not feasible or economically reasonable to require this level of instrumentation and monitoring to determine flare emissions. … This option should also be reflected in reporting requirements in 98.236(n).

Commenter 0299:

58. EPA should not mandate quarterly collection of flare gas composition data for all flares.

Flares operated by midstream operators control streams with a consistent composition that falls well above the minimum requirements in 40 C.F.R. § 60.18 in most cases. Therefore, EPA should allow operators to use best available data to calculate emissions. It is not cost effective to conduct continuous or even quarterly monitoring for composition on these thousands of control devices when the gas routed to the flare is consistent. Operators should be able to use process simulations to calculate the vent gas stream composition to these flares or provide other available data that represent the gas composition. Like flowrates, the composition of gas going to flare is the same composition that comes from the various facilities, which are accurately calculated using simulation software. … Additionally, on sour gas streams, collecting regular gas samples increases the safety risk associated with collecting a sample because of high H_2S concentrations, and this safety risk does not result in any significant benefit to determining emission rates. There are other ways that operators can calculate emissions from these streams with reasonable accuracy. Prescriptive requirements for calculations restrict getting the best estimate of emission rates. Therefore, EPA must reinstate the language for estimating emissions from flares.

Commenter 0337:

40 CFR § 98.233(n) Flares

Section 98.233(n)(3) proposes that the flare gas composition be determined using a continuous analyzer or quarterly sampling. Quarterly (and even annual) sampling requirements on flare composition are overly burdensome, specifically in the onshore production and gathering and boosting industry segments where there could be a high number of flare stacks. The gas routed to flares, specifically in these industry segments, is relatively stable and the composition is not expected to change significantly over time. This requirement is costly, burdensome, and doesn't add value relative to the associated cost. Additionally, for streams routed to flare and emissions calculated within their own source type, it seems inconsistent to sample those streams when sampling is not required in the calculation methods for those source types. Moreover, the composition of the total stream may not be reflective of the composition of the emissions within the flare source type.

Similarly, requiring continuous calorimeters in these industry segments is impractical, costly, and adds no additional assurance of flare performance. Across EPA regulations, 300 btu/scf is considered the minimum heat content needed for a waste stream to be properly combusted in a flare. Excluding waste streams from Amine treating, Nitrogen Removal Units, and EOR operations, these industry segments do not operate equipment that is capable of generating waste streams with a heat value less than that of the natural gas that is produced. In all cases produced natural gas will significantly exceed 300 btu/scf.

Commenter 0342:

1. Flares

…

1b. Composition monitoring or quarterly sampling The Proposal would require either a continuous composition analyzer or quarterly stream sampling for all flares. The rule would allow this composition monitoring on either total input to flare, or on each stream sent to the flare. The produced gas stream composition in the upstream sector is relatively stable and is not as variable as other sectors like refineries; therefore, composition monitoring with a quarterly sampling frequency is unnecessary and does not increase the accuracy of the reported emissions substantially. To require quarterly sampling of every flare at every tank battery would present severe logistical challenges for Enerplus, as there are a limited number of labs capable of conducting this type of analysis, without any significant change in the accuracy of the reported emissions. If EPA does not accept the comment that the composition monitoring is not necessary in the production segment, Enerplus recommends EPA allow companies the opportunity to prove stability in the waste gas stream, upon which companies should be permitted to stop quarterly sampling altogether, or at least to reduce the frequency to annual sampling when the margin of error is proven to be less than 5%.

…

Commenter 0374:

Flare gas composition sampling or monitoring

EPA's requirement for continuous monitoring or quarterly gas sample collection for each stream that goes to flare is technically challenging and does not improve the emission reporting. The technical and logistical challenges associated with continuous monitoring include installation of sample ports, calibration and maintenance for thousands of meters, lack of infrastructure, field connectivity etc. Similarly, there are technical challenges associated with collecting samples in low-pressure flare lines with intermittent flows. Instead, we believe that there are other approaches including those currently in use. For example, a more accurate representation of high-pressure gas composition, as well as pilot/assist gas, would be sales gas composition which is ultimately what is being combusted at the flare. Also, process simulation would be a more accurate representation for intermittent emissions associated with tank gas.

In summary, we suggest that EPA allow the methods currently used to determine gas composition for flared gas, including the use of available sales composition information and process simulation in lieu of requiring continuous monitoring or quarterly sample collection.

Commenter 0393: The EPA is proposing gas composition analyzers on all flares including sampling for compositional gas analysis at least once per quarter. We go back to the effectiveness of representative sampling here. With the proximity of these facilities and them producing from the same formation(s) it would make sense to allow operators to utilize representative sampling. It is of our opinion that the EPA underestimated the cost burden of obtaining quarterly gas composition for all flares. Our estimated cost for quarterly sampling across our assets is ~ $43,000. this is a very large cost for data that can be accurately obtained through representative sampling. It would drastically cut down on number of samples while still getting accurate data for the reasons listed above.

Commenter 0402: Flares

Gas Composition Requirements

Similar to the discussion regarding requirements for flow monitoring in this letter, the Industry Trades **urge EPA to retain the option "to use the appropriate gas composition for each stream of hydrocarbons going to the flare" in the absence of a continuous composition analyzer**. The proposed requirements to either use a continuous composition analyzer or take quarterly samples are both unnecessary (source flow composition is relatively stable at oil and gas facilities) and potentially conflict with the specific requirements and implementation timing of compliance assurance requirements in NSPS OOOOb and EG OOOOc.

EPA should provide an option to use process models for flared gas, which is how most compositions are currently being determined and with reasonable accuracy.

The proposed requirements to measure or sample the gas composition for each flare are economically and technically infeasible, and engineering estimates and representative analysis should be allowed.

EPA's requirement that quarterly gas samples be pulled for each stream that goes to flare has no basis and was not addressed in the proposed rule's TSD. The proposed requirement to install a continuous gas analyzer or take quarterly samples of the inlet gas to every flare is unreasonable and burdensome for several reasons.

1. **The gas composition is relatively stable over time rendering more frequent characterization of low value.** Flare gas composition in oil and gas operations is relatively stable and will not change significantly over time. As discussed above, the primary streams going to flare at typical oil and gas facilities include:

- Pilot, purge, sweep, and/or auxiliary gas;
- Low-pressure gas from tank flash, working, and breathing losses;
- Mid-pressure flaring from low pressure/secondary separators, heater treaters, and vapor recovery towers that have become technically and economically compressed to sales; and
- High-pressure separator flaring in areas with stranded gas pipeline take-away loss which is intermittent and decreasing across the country. [32,33]

EPA also recognized that the gas composition could be stable by proposing an alternate net heating value demonstration in NSPS OOOOb and EG OOOOc[34]. While Industry Trades commented that this demonstration should be simplified due to the relatively stable and generally sufficient heating value of the gas streams, its inclusion in the compliance assurance requirements of NSPS OOOOb and EG OOOOc recognizes that the gas streams could be demonstrated to be stable.

…

Finally, a continuous compositional monitor or quarterly sampling goes beyond the continuous net heating value (NHV) monitoring or NHV demonstration required under proposed NSPS OOOOb and EG OOOOc. As stated at the beginning of this section, Subpart W must not impose monitoring requirements beyond other applicable regulations. While a continuous compositional monitor could be used for NHV monitoring, compositional analyzers (e.g., gas chromatographs) are more expensive than NHV monitoring devices (e.g., calorimeters). Given the relatively stable composition of gas streams and cost for compositional monitoring, Subpart W should simply reference NSPS OOOOb and EG OOOOc monitoring requirement as they relate to methane destruction efficiency (see comments bellow) and not impose additional composition monitoring requirements.

Footnotes:

[32]https://www.api.org/news-policy-and-issues/blog/2022/05/24/reports-us-among-world-leaders-in-reducing-flaring.

[33]https://www.hartenergy.com/exclusives/us-reduces-flaring-and-flaring-intensity-world-bank-says-204724.

[34]Proposed § 60.5417b(d)(1)(viii)(C)(1) to (5).

<u>Commenter 0402</u>:

3.8 Flares

3.8.3 Gas Composition Requirements

3.8.3.2 Technical Feasibility Issues

Additionally, it is technically infeasible to pull gas samples from low pressure flares. A positive pressure is required to pull gas samples from flare lines. Low pressure flare vent lines operate at near atmospheric conditions, which would either take hours to collect a large enough sample (i.e., fill a bag with enough gas) to send to laboratory for analysis or require a gas chromatograph equipped with a pump to be brought on location. Requiring a gas chromatograph to pull quarterly gas samples is economically infeasible. Process simulation would be a more accurate representation of tank gas. It would be equally difficult to pull samples for mid- and high-pressure flaring given the intermittent nature of these events. A more accurate representation of high-pressure gas composition, as well as pilot/purge gas, would be sales gas composition which is ultimately what is being combusted at the flare. Finally, as stated above, EPA does not address why this frequency in sampling is being proposed in either the Technical Support Document or the preamble.

Commenter 0408:

For gas composition, EPA requests industry take samples of the emission streams from each source that routes gas to the flare at least once every quarter […].

- EAP Ohio, LLC requests EPA eliminate quarterly gas composition sampling.
- EPA should allow annually updated site-specific sample measurements and allow the use of representative samples to cover similar facilities, in the absence of site-specific data, without any repercussions to the reporter or at least drop the minimum sample to no more than twice per year separated by a minimum of 120 days.

Response 1: See Section III.N.1 of the preamble to the final rule for the EPA's response to this comment.

Commenter: Encino Energy (EAP Ohio, LLC)
Comment Number: EPA-HQ-OAR-2023-0234-0408
Page(s): 7

Comment 2: EPA requests operators to take samples of purge gas, sweep gas, and auxiliary fuel at least annually, and analyze for methane, ethane, propane, butane, pentanes plus, and CO2.

- EAP Ohio, LLC requests EPA remove the requirement to sample annually and add that sampling may be completed at the discretion of the operator and/or provide a volume threshold under which annual sampling of purge gas, sweep gas, and auxiliary fuel would not be required.
- Removing the annual sampling requirement will reduce undue burdens on the operator on evaluating the emissions from these otherwise insignificant streams.
- Removing annual sampling of purge gas, sweep gas, and auxiliary fuel will not significantly impact emissions reported under Subpart W.

Response 2: See Section III.N.1 of the preamble to the final rule for the EPA's response to this comment.

Commenter: American Petroleum Institute et al. (Part 1 of 2)
Comment Number: EPA-HQ-OAR-2023-0234-0402
Page(s): 42

Comment 3: Flares

Gas Composition Requirements

Supply Chain Constraints

As noted above for flow meters, operators are currently facing ongoing COVID-induced supply chain delays of up to 12 months for monitoring equipment for flares; these delays are expected to be lengthened to up to 24 months upon NSPS OOOOb finalization. Requiring compositional monitoring under Subpart W would further exacerbate the existing supply chain constraints with minimal benefit to reported GHG emissions.

Response 3: As discussed in Section III.N.1 of the preamble to the final rule, the final rule allows process simulations and engineering calculations as alternatives to the use of continuous gas composition analyzers for determining composition of streams routed to flares. This change is expected to resolve any potential supply chain issues.

Commenter: CrownQuest Operating
Comment Number: EPA-HQ-OAR-2023-0234-0393
Page(s): 229

Comment 4: Adding … composition analyzers or requiring periodic sampling on gas routed to flare lines would increase costs not only in equipment, but also labor hours. Another note is that the … analyzers that would be connected to these lines would be very difficult to calibrate as the flow is inconsistent and likely very low pressure. As stated before, this would cost upwards of $40,000 per facility for little benefit to emissions reductions.

…

Response 4: As discussed in Section III.N.1 of the preamble to the final rule, the final rule allows process simulations and engineering calculations as alternatives to the use of continuous gas composition analyzers for determining composition of streams routed to flares. The additional alternative methods in the final amendments result in reduced monitoring and emission calculation costs. Potential technical challenges associated with the use of continuous gas composition analyzers also should be alleviated because use of continuous gas composition analyzers is an option rather than a requirement in the final amendments.

Commenter: Endeavor Energy Resources, L.P.
Comment Number: EPA-HQ-OAR-2023-0234-0381
Page(s): 15

Comment 5: EPA Should Reconsider the Proposed Revisions to Calculation Methods for Several Emission Sources.

Flare Stack Emissions

…

Third, Endeavor supports EPA's proposed approach to allow for either a continuous gas analyzer or periodic compositional analysis to determine flared gas composition.[47] Continuous gas analyzers can be extremely costly and may not be practicable in many instances. Endeavor thus supports greater flexibility and reporter discretion with respect to gas composition analysis.

Footnote:

[47] 88 Fed. Reg. at 50,335.

Response 5: The EPA acknowledges the commenter's support of the proposed revisions. As discussed in Section III.N.1 of the preamble to the final rule, the final amendments provide additional flexibility for determining composition of individual streams by allowing process simulations and engineering calculations in addition to the proposed options of using continuous gas analyzers or periodic sampling.

Commenter: GPA Midstream Association
Comment Number: EPA-HQ-OAR-2023-0234-0299
Page(s): 86-87

Comment 6: Proposed Change: EPA is proposing to require the flow-weighted annual average mole fraction of CH_4 over all streams from a particular emission source type that are used in equation W–19 to calculate the reported flared CH_4 emissions from that emission source type (and used in equation W–20 to calculate CO_2 emissions). [98.233(n)(5)]

> **Comment**: The changes EPA is proposing are unnecessarily prescriptive and will not result in the most accurate emission calculations. Depending on how a site is configured, it can be very difficult, if not impossible, to determine specific flow volumes from each source being controlled by a flare, particularly for miscellaneous sources. Flow from individual sources to a flare is not usually metered, especially in cases where comingled flow is metered at the flare header.
>
> Reporters should be allowed to report composition based on best available data, including but not limited to comingled waste gas stream samples, comingled waste gas stream continuous analyzers, engineering estimates, and flow-weighted annual average mole

fractions. These methods would provide as valuable information for characterizing flare stack emissions as flow-weighted annual average mole fractions would and are much less burdensome for reporters. Other compliance programs involve periodic (e.g., monthly) sampling of the gas sent to flares, yet the proposed rule would not allow for the use of such data. The proposed rule should therefore be revised to align its requirements with other, similar programs.

Suggested text:

98.233(n)(2)(ii) For onshore natural gas processing, ~~when the stream going to flare is natural gas, use the GHG mole fraction in feed natural gas for all streams upstream of the de-methanizer or dew point control, and GHG mole fraction in facility specific residue gas to transmission pipeline systems for all emissions sources downstream of the de-methanizer overhead or dew point control for onshore natural gas processing facilities. For onshore natural gas processing plants that solely fractionate a liquid stream, use the GHG mole fraction in feed natural gas liquid for all streams.~~ use best available data.

98.233(n)(5) Calculate GHG volumetric emissions from flaring at standard conditions using Equations W-19 and W-20 of this section~~. Emissions may be calculated per stream routed to the flare and then summed over all streams per emissions source type. Alternatively, you may sum the total volume of all streams from a particular emission source type, determine the flow-weighted average CO_2 and hydrocarbon concentrations over all streams per source type, and then perform a single calculation using Equation W-19 and a single calculation using Equation W-20 to calculate the total CH_4 and CO_2 emissions per source type.~~

Eq. W-19, Eq. W-20 X_{CH4} = Mole fraction of CH_4 in the feed gas to the flare per emission source type as determined in paragraph (e)(5)(ii), (g)(4)(ii), (h)(2)(ii), (j)(5)(ii), (l)(6)(ii), (m)(5)(ii), or (n)(2) of this section. ~~Use a flow-weighted mole fraction if multiple streams from the same source type are combined for the emissions calculation.~~

Eq. W-19, Eq. W-20 X_{CO2} = Mole fraction of CO_2 in the feed gas to the flare per emission source type as determined in paragraph (e)(5)(ii), (g)(4)(ii), (h)(2)(ii), (j)(5)(ii), (l)(6)(ii), (m)(5)(ii), or (n)(2) of this section. ~~Use a flow- weighted mole fraction if multiple streams from the same source type are combined for the emissions calculation.~~

98.236(n)(1)(ix) ~~Flow-weighted average mole~~ Mole fraction of CH_4 in the feed gas from miscellaneous flared sources to the flare ("XCH_4" in Equation W-19 of this subpart).

98.236(n)(1)(x) ~~Flow-weighted average mole~~ Mole fraction of CO_2 in the feed gas from miscellaneous flared sources to the flare ("XCO_2" in Equation W-20 of this subpart).

Response 6: The provisions cited by the commenter are from the June 6, 2022, proposal. Significant changes to the flow and gas composition requirements were made for the August 1, 2023, proposal. The 2023 proposal would have required continuous flow measurements and either continuous composition measurements or periodic sampling and analysis to produce empirical data for use in calculating flared emissions. As explained in Section III.N.1 of the preamble to the final rule, the final rule includes process simulation and engineering calculation options for determining both flow and composition as alternatives to the continuous measurement and periodic sampling options that have been finalized largely as proposed. Section III.N.1 of the preamble to the final rule also explains that these added options address both cost impact concerns and potential technical challenges associated with using continuous meters and analyzers on certain variable flow and low-pressure streams while still producing data of acceptable quality for the purposes of estimating emissions.

Many of the suggestions from the commenter have been included in the final rule. For example, the final rule allows flow and composition to be determined for comingled streams. The final rule, like the 2023 proposal, also allows reporters to measure flow and composition of the total stream into the flare instead of determining flow and composition only for streams from individual sources as would have been required in the June 6, 2022, proposal. The final rule also generally requires calculation and reporting of annual average mole fractions rather than flow-weighted annual average mole fractions because flow-weighted averages are not needed when the calculation and reporting is per the total stream to the flare, per individual source stream, or per comingled stream. The final rule includes only one requirement for calculation of flow-weighted mole fractions. As specified in 40 CFR 98.233(n)(5)(iii)(B) of the final rule, if a reporter elects to calculate flows and composition for individual streams (or comingled streams) to the flare, but then aggregates those data for use in equations W-19 and W-20 to calculate total CH_4 and CO_2 emissions from the flare (instead of calculating emissions per stream and summing to obtain the total emissions from the flare), then flow-weighted mole fractions must be used in the calculations.

We have not finalized the commenter's suggestion to replace the composition determination requirements for processing facilities in 40 CFR 98.233(n)(2)(ii) of the existing rule (or the June 6, 2022, proposal) with a requirement to determine the composition based on best available data. These requirements are in a different section in the final amendments, but they have not been removed because they provide a baseline methodology for collecting empirical composition data for streams routed to flares from different points in a processing facility. Other alternatives include the use of continuous composition analyzers or annual sampling as specified in 40 CFR 98.233(u)(2)(ii).

15.2.7 Higher Heating Value

Commenter: Baker Hughes
Comment Number: EPA-HQ-OAR-2023-0234-0383
Page(s): 4-5

Comment 1: The regulations should allow the use of measured HHV when calculating N2O emissions. At proposed regulatory text 40 CFR 98.233(n)(8), EPA requires operators to calculate N_2O emissions from flare stacks using Equation W-40.[4] The text also provides operators three options for calculating higher heating values (HHV) to use in Equation W-40 calculations.[5]

We believe that operators should have the opportunity to measure flare gas HHV directly using, for example, continuous gas analyzers or by using a sound speed methodology from an ultrasonic flowmeter (see above). This latter method can provide reliable real-time measurement, is highly accurate (3 to 5 percent), can be implemented with minimum cost, and is easy to maintain.

As above, from vent gas SOS, the average MW can be derived using virial equation of state for an ideal gas. From the average MW, flare gas net/higher heating value can be determined providing concentrations of inert gases (noncombustible gases such as N_2, CO_2), see U.S. patent publication “Online Analyzers for Flare Gas Processing”.[6] The method has very fast response time, typically with 6 seconds, and has been deployed in the field for flare gas MW and NHV/HHV measurement and for flare control.

We recommend EPA include in the regulatory text the option for operators to use the above-mentioned measured HHV in Equation W-40 as an alternative to calculated values.

Footnotes:

[4] 40 CFR 98.233(z)(3)(ii)(F)

[5] 40 CFR 98.233(n)(8)(i)-(iii)

[6] US Patent Pub . No .: US 2022/0107289 A1. April 7, 2022. Available at: https://patentimages.storage.googleapis.com/6b/46/97/d1524f32c62da7/US20220107289A1.pdf

Response 1: See Section III.N.1 of the preamble to the final rule for the EPA’s response to this comment.

Commenter: GPA Midstream Association
Comment Number: EPA-HQ-OAR-2023-0234-0299
Page(s): 45-46

Comment 2: EPA should not mandate quarterly collection of flare gas composition data for all flares.

…

By extension, site specific HHV can also be provided using a process simulator. This option should be reflected in the reporting requirements of 98.236(n).

…

Response 2: The commenter did not provide specific details on their proposed use of process simulators to determine the HHV. It is not clear from their statement if they are suggesting that process simulators can be used for the total inlet to the flare or for individual streams. If the commenter is suggesting use of a process simulator for the total inlet to the flare, this is not allowed in the final rule. The options for determining HHV of the total inlet stream to the flare are continuous direct measurement of the HHV, or calculation of the HHV from either continuous measurement of the composition or from annual measurements of composition in accordance with final 40 CFR 98.233(n)(8)(i) or (ii), respectively.

As discussed in response to comment in Section III.N.1 of the preamble to the final rule, 40 CFR 98.233(n)(4)(iii)(B)(*1*) through (*3*) of the final rule specify that gas composition of streams from acid gas removal units, glycol dehydrators, and hydrocarbon liquids and produced water storage tanks may be determined using process simulation. According to final 40 CFR 98.233(n)(8)(iv), the compositions determined in accordance with any of the methods specified in 40 CFR 98.233(n)(4)(iii) may be used to calculate the stream-specific HHVs.

15.3 Reporting and Recordkeeping Requirements for Flared Emissions

15.3.1 General/Overview of Reporting Requirements

Commenter: CrownQuest Operating
Comment Number: EPA-HQ-OAR-2023-0234-0393
Page(s): 214

Commenter: American Petroleum Institute et al. (Part 1 of 2)
Comment Number: EPA-HQ-OAR-2023-0234-0402
Page(s): 33

Comment 1:

Commenter 0393: EPA is proposing to require reporting to gas venting and flaring on a site-by-site basis. We recommend the EPA keep this combined into county level reporting.

Commenter 0402: Flares

…

Finally, flared emissions should be reported at the facility level rather than at the individual well pad or site, and especially not with attribution to the flare gas source.

Response 1: The EPA is finalizing the proposed requirement to report flared emissions and other flare data elements at the flare level (and per well pad site or gathering and boosting site for facilities in the onshore production segment and the onshore gathering and boosting segment, respectively) rather than at the mix of levels required in the current rule (i.e., flared associated gas, atmospheric tank, and completions/workovers emissions are currently reported at the sub-basin level; flared well testing emissions are reported at the facility and well type level; flared emissions from large glycol dehydrators are reported at the source level; flared emissions from small glycol dehydrators and desiccant dehydrators are reported at the facility level; and flared emissions from other flare stack sources are reported collectively at the flare level).

As noted in our response in Section III.D.2 of the preamble to the final rule to more general comments concerning disaggregated reporting in the onshore production segment and onshore gathering and boosting segment, the aggregation of data currently collected for these industry segments "can present challenges in the process of emissions verification, with corresponding potential impacts on data quality, and it also limits data transparency." The directive under CAA section 136(h) to ensure that reporting under subpart W accurately reflects total methane emissions is inexorably linked to verification of reported data. Absent a robust system of emissions verification, the EPA cannot ensure the accuracy of reported data. As such, the final amendments to improve the quality and verification of subpart W data are supportive of the directive of CAA section 136(h). Further, as discussed in section II.C of the preamble to the proposed rule, beyond carrying out the requirements of CAA section 136 the data collected under subpart W is used to support a range of policies and initiatives under the CAA including but not limited to provisions involving research, evaluating and setting standards, endangerment determinations, or informing EPA non-regulatory programs.

Regarding the specific comment that reporting per flare should not include attribution to the flare gas source, please see the responses to Comments 1 and 2 in Section 15.3.2 of this document.

Commenter: GPA Midstream Association
Comment Number: EPA-HQ-OAR-2023-0234-0299
Page(s): 89

Comment 2: RFC: EPA requests comment on the types of sources that may be generating large emissions from flares and whether other reporting elements could be specified that would better achieve EPA's objective of clearly characterizing the sources of flared emissions from facilities involved in Production, G&B, and Processing. For example, one potential additional reporting element could be a requirement to describe the primary source of miscellaneous flared emissions for any flare that reports CO_2 emissions greater than an amount that would be determined if such a reporting requirement were finalized.

> **Comment**: As noted in our previous comment, EPA should not proceed down this path. Parsing all flare emissions into their root sources would be an enormous burden to reporters. Depending on how a site or gathering system is configured, it can be very difficult to determine specific flow volumes from each source being controlled by a flare, particularly for miscellaneous sources. Flow from independent sources is not necessarily metered, especially in cases where comingled flow is metered at the flare header. This also applies in cases where a flare is shared by multiple facilities. It can take multiple months, multiple staff, and essentially a research project to understand certain flaring events. Without expending significant time and effort to research the root sources of all flaring activity, the data reported will be a rough estimate at best and would not

necessarily provide EPA with relevant information on sources of flared emissions. The intent of the GHGRP is to inform future rulemaking, and it is very unlikely that any trends to inform rulemaking could be derived from such reporting; even if there are common emission *sources*, the *causes* of such emissions are likely to be widely variable. If EPA has a desire to better understand flaring sources and root causes, then it should undertake appropriate research projects or data requests outside of this annual reporting program.

Response 2: We did not receive any comments in response to our request for comment on ways for reporters to more clearly identify specific types of sources that currently result in reporting of large quantities of flared emissions that currently are attributed to miscellaneous other flare stack sources. Therefore, the EPA is not taking action to include additional reporting requirements in the final rule at this time. We will continue to assess alternative means for defining these sources and may consider further updates in a future rulemaking.

15.3.2 Flare-Specific Reporting Elements

Commenter: Williams Companies, Inc.
Comment Number: EPA-HQ-OAR-2023-0234-0394
Page(s): 8

Commenter: American Exploration and Production Council
Comment Number: EPA-HQ-OAR-2023-0234-0295
Page(s): 8

Commenter: The Petroleum Alliance of Oklahoma
Comment Number: EPA-HQ-OAR-2023-0234-0398
Page(s): 16

Commenter: GPA Midstream Association
Comment Number: EPA-HQ-OAR-2023-0234-0299
Page(s): 47-48

Commenter: American Petroleum Institute et al. (Part 1 of 2)
Comment Number: EPA-HQ-OAR-2023-0234-0402
Page(s): 49

Comment 1:

<u>Commenter 0295</u>:

I. <u>Flares</u>

E. Flare Calculation Methodology:

The Proposal would also require that flare emissions resulting from certain sources be disaggregated and reported separately using measured values or engineering calculations: AGRs, glycol dehydrators, completions, storage tanks, well testing, associated gas, and other sources. It is unclear whether EPA's intention is to require source-specific information in addition to the flare total flow monitoring. There would be considerable uncertainty in engineering estimates that attempt to determine source-specific contributions to total flared volumes, therefore such an exercise would not provide any value in terms of enhancing the accuracy of flare date. Additionally, the proposed calculation methods for flares would increase the complexity of the emission calculations, requiring additional time and therefore additional expense to complete the calculations. AXPC urges EPA to remove the requirement to disaggregate flare emissions to the source type, as it would add significant compliance burden on facilities while providing no additional improvements to the accuracy of the reported flare data.

Commenter 0299:

63. GPA does not support reporting estimated "disaggregated" data for flares.

GPA strongly supports EPA's proposal to consolidate calculation and reporting of flared emissions in the "flare stack" emission source category (and not at individual sources that are controlled by a flare). This alleviates burden and will result in the best emission estimates.

However, EPA proposes two "disaggregation" reporting requirements that GPA does not support: … (2) estimated disaggregated CH_4, CO_2, and N_2O emissions attributed to each source ((i.e., AGRU vents, dehydrator vents, etc.) [98.236(n)(19)]. GPA firmly pushes back on these proposed requirements. As EPA acknowledges, without massive effort, reporters can only provide "estimates," but it is not appropriate for EPA to ask reporters to certify gross estimates under penalty of law. Additionally, it is not appropriate for EPA to collect estimates and then use these data for any purpose. This is not empirical data as mandated by the Inflation Reduction Act and therefore has no place in this proposal. …

As noted throughout these comments on flares, EPA is simply overreaching its authority, and EPA needs to pursue flare information and controls by other means. EPA proposes that the following parts of the proposed regulatory text be omitted from the final rule:

…
98.236(n)(19) ~~*Estimated disaggregated CH4, CO2, and N2O emissions attributed to each source type as determined using engineering calculations and best available data as specified in § 98.233(n)(10) (i.e., AGR vents, dehydrator vents, well venting during completions and workovers with hydraulic fracturing, gas well venting during completions and workovers without hydraulic fracturing, hydrocarbon liquids and produced water storage tanks, well testing venting and flaring, associated gas venting and flaring, other flared sources)*~~.

Commenter 0394:

(6) Disaggregation for Flare Reporting

Williams supports the proposal to report flared emissions in 40 CFR § 233(n) for individual waste streams originating from AGRs, dehydrators, hydrocarbon liquids and produced water storage tanks, and "Other (collective)" sources. We understand CO2, CH4, and N2O emissions will be reported for each of these emissions sources on a line-item basis in the e-GGRT reporting form for (n) - Flare Stack Emissions. Even so, this enhanced level of detail will result in additional reporting time in eGGRT for owner / operators. Therefore, to mitigate this additional burden, the EPA needs to review its proposed list of required flare activity data and remove all reporting requirements for activity data that are not needed to quantify emissions.

Commenter 0398:

EPA proposes to replace the current source-specific methodologies for calculating flared emissions (e.g., existing 40 CFR 98.233(e)(6) for dehydrators or existing 40 CFR 98.233(g)(4) for completions with a requirement (proposed 40 CFR 98.233(n)(10)) that the reporter use engineering calculations and best available data to disaggregate the calculated total emissions per flare to the source types that routed gas to the flare. Reporters may not be able to disaggregate emissions easily or as accurately under the current methodologies.

Action Requested: We request EPA continue to allow reporters to report aggregated data when more accurate information is not available or easily obtained.

Commenter 0402: Flares

Disaggregation of Flare Emissions

When data is not available to allow disaggregated reporting by individual sources controlled by a flare, EPA should allow aggregated emissions reporting by flare.

The Industry Trades understand that EPA wishes to allocate all individual sources controlled by a flare back to the contributing source. The Industry Trades support maintaining the ability to report emissions aggregated by flare when more accurate data is not available. As addressed in the "Flares" section of this document, metering individual sources may not result in more accurate data. Allowing the flexibility to continue reporting flare sources aggregated will give companies the ability to report the most accurate data available given a particular facility's operational design. However, it is important to note that EPA has not stated a clear benefit from requiring the disaggregation of sources, and therefore a true cost/benefit analysis cannot be determined.

Response 1: In response to comments, EPA has largely retained the existing flare calculation methodologies and made corresponding updates to the disaggregation calculation and reporting requirements in 40 CFR 98.233(n)(10) and 40 CFR 98.236(n)(19), respectively. These changes will reduce the disaggregated emissions that will have to be calculated using engineering calculations and best available data since it's likely that many sources will continue to use the existing methods. If total emissions from the flare are calculated in accordance with paragraph 40 CFR 98.233(n)(5)(iii) using stream-specific flow and composition, including combined streams that contain emissions from only a single source type, a reporter must use the source-specific emissions calculated using these data to calculate the disaggregated emissions per source type. If the total emissions from the flare are calculated using total flow and/or total annual average composition of the total inlet stream to the flare, or if flow or composition are determined for a combined stream that contains emissions from more than one source type, then a reporter must use engineering calculations and best available data to disaggregate the total emissions to the applicable source types.

We disagree with the assertion by Commenter 0299 that requiring certifications of estimates is inappropriate. The report certification requirement in 40 CFR 98.4(e)(1) requires the DR or ADR to certify that "the statements and information are *to the best of my knowledge and belief* true, accurate, and complete" (emphasis added). In 40 CFR 98.236(n)(19) of the final rule, reporters must report estimates of disaggregated amounts of total emissions from a flare to individual source types that routed emissions to the flare as determined using engineering calculations and best available data as specified in 40 CFR 98.233(n)(10). For these reporting elements, the DR or ADR is certifying that the reported values are estimates that have been developed based on engineering calculations and best available data. Subpart W also requires reporters to use engineering estimates, process knowledge, and best available data to estimate numerous other parameters that are used to calculate emissions.

We also disagree with the assertion by Commenter 0299 that it is not appropriate for the EPA to collect the referenced estimates. The EPA maintains that this is consistent with our authority under the Clean Air Act, as discussed in preamble Section I, and is not inconsistent with CAA section 136(h).

Commenter: GPA Midstream Association
Comment Number: EPA-HQ-OAR-2023-0234-0299
Page(s): 47-48, 87-88

Commenter: CrownQuest Operating
Comment Number: EPA-HQ-OAR-2023-0234-0393
Page(s): 225, 226

Comment 2: Commenter 0299: **GPA does not support reporting estimated "disaggregated" data for flares.**

GPA strongly supports EPA's proposal to consolidate calculation and reporting of flared emissions in the "flare stack" emission source category (and not at individual sources that are controlled by a flare). This alleviates burden and will result in the best emission estimates.

However, EPA proposes two "disaggregation" reporting requirements that GPA does not support: (1) an estimated fraction of total volume flared that was received from another facility solely for flaring [98.236(n)(10)] …. GPA firmly pushes back on these proposed requirements. As EPA acknowledges, without massive effort, reporters can only provide "estimates," but it is not appropriate for EPA to ask reporters to certify gross estimates under penalty of law. Additionally, it is not appropriate for EPA to collect estimates and then use these data for any purpose. This is not empirical data as mandated by the Inflation Reduction Act and therefore has no place in this proposal. Additionally, flaring is often caused by a pressure imbalance along the value chain; where that pressure is relieved (flared) may be determined by a variety of factors, but this flared gas is not easily classified as “received from another facility.” This can be something of a chicken-and-egg question.

As noted throughout these comments on flares, EPA is simply overreaching its authority, and EPA needs to pursue flare information and controls by other means. EPA proposes that the following parts of the proposed regulatory text be omitted from the final rule:

98.236(n)(10) ~~*For the onshore petroleum and natural gas production, onshore petroleum and natural gas gathering and boosting, and onshore natural gas processing industry segments, estimated fraction of total volume flared that was received from another facility solely for flaring (e.g., gas separated from liquid at a production facility that is routed to a flare that is assigned to an onshore petroleum and natural gas gathering and boosting facility).*~~

…

Proposed Change: For G&B and Processing, EPA is proposing to require an estimate of the fraction of the gas burned in the flare that is obtained from other facilities specifically for flaring as opposed to being generated in on-site operations [98.236(n)(1)(v)].

> **Comment**: This element of EPA’s proposed rule would not be reasonable for reporters and would not have any impact on the amount of greenhouse gas emissions reported. Requiring reporters to estimate the volume of gas flared from each emission source type, or from each facility in the case of shared flares, may result in flare volumes being inaccurately attributed to each emission source type or facility. Depending on how a site or gathering system is configured, it can be very difficult to determine specific flow volumes from each source being controlled by a flare, particularly for miscellaneous sources. Flow from all sources is not necessarily metered, especially in cases where comingled flow is metered at the flare header. This also applies in cases where a flare is shared by multiple facilities. Our operators note that it can take multiple months, multiple staff, and essentially a research project to understand certain flaring events. Without expending significant time and effort to research the root sources of all flaring activity, the data reported will be at best a rough estimate and would not necessarily provide EPA with relevant information on sources of flared emissions. Additionally, flaring is often due to a pressure imbalance along the value chain; where that pressure is relieved/flared may be determined by a variety of factors, but this flared gas isn’t easily classified as “obtained from other facilities” or “generated on site.” This can be something of a chicken-and-egg question. Finally, flared gas may not be Subpart W sources, such as pressure relief valves on pressurized vessels.
>
> **Suggested text**: *98.236(n)(1)(v)* ~~*Estimated fraction of total volume flared that was received from another facility solely for flaring (e.g., gas separated from liquid at a production facility that is routed to a flare that is assigned to an onshore petroleum and natural gas gathering and boosting facility).*~~

Commenter 0393: The … "obtained from other facilities specifically…" language is not based in reality. Each facility has its own flare.

The definition of facility is confusing again in this instance.

…

The definition of facility is scattered, so it is unclear what EPA is speaking. EPA should not be concerned where the gas came from but only where the emission occurred.

Response 2: See Section III.N.2 of the preamble to the final rule for the EPA's response to the comment regarding the proposed requirement to estimate that fraction of total volume routed to a flare that was received from another facility.

See the response to Comment 1 in this section for the EPA's response to one commenter's assertion that requiring certifications of estimates is inappropriate.

One of the commenters asserted that "flared gas may not be Subpart W sources, such as pressure relief valves on pressurized vessels." That statement is incorrect. The flare itself is a subpart W emission source type, just like a dehydrator or hydrocarbon liquids storage tank. Thus, all emissions from the flare, regardless of the source(s) that routed emissions to the flare, from either onsite or offsite sources, are subject to reporting as flared emissions under subpart W.

Commenter: CrownQuest Operating
Comment Number: EPA-HQ-OAR-2023-0234-0393
Page(s): 229

Comment 3: EPA will already have this information; operators don't need to submit it twice.

Response 3: The EPA has taken care to avoid duplicate reporting requirements in the final rule. However, the EPA has not made any changes to the final rule specifically in response to this comment because it is not clear what information in the proposed rule the commenter believes would be reported twice. The comment is linked to a statement in Section III.N.2 of the proposal preamble that describes the requirements in proposed 40 CFR 98.236(n)(7) and (8) that reporters indicate the types of methods they used to determine flow and composition of the gas streams routed to each flare. The same reporting elements are in the same sections of the final rule, except that they have been expanded to align with the additional flow and gas composition determination options that are included in the final rule in addition to the proposed measurement methods (i.e., process simulations or engineering calculations, as discussed in Section III.N.1 of the preamble to the final rule). It is not clear what other reporting elements the commenter believes overlap with these reporting elements.

Commenter: Environmental Defense Fund, et al.
Comment Number: EPA-HQ-OAR-2023-0234-0413
Page(s): 62

Comment 4: 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.

Response 4: The EPA acknowledges the commenter's support of the proposed revisions. The EPA is finalizing these amendments as proposed.

Commenter: GPA Midstream Association
Comment Number: EPA-HQ-OAR-2023-0234-0299
Page(s): 88-89

Commenter: Interstate Natural Gas Association of America (INGAA)
Comment Number: EPA-HQ-OAR-2023-0234-0387
Page(s): 19, 25, 40

Comment 5: Commenter 0299: **Proposed Change**: Annual reporting of information related to flare equipment.

> **Comment**: EPA should not request data that does not directly relate to calculating and verifying GHG emissions. EPA needs to have clear purpose for how any collected data will be used to validate GHG emissions. Broad information requests are not appropriate for this annual reporting rule. These new requirements should therefore be eliminated. If EPA proceeds with this unnecessary data collection, then EPA must add an option of "Other."
>
> **Suggested text:**
>
> ~~*98.236(n)(2)(ii) Indicate each emission source type that routed emissions to the flare stack during the reporting year (i.e., dehydrator vents, well venting during completions and workovers with hydraulic fracturing, gas well venting during completions and workovers without hydraulic fracturing, onshore production and onshore petroleum and natural gas gathering and boosting storage tanks, well testing venting and flaring, associated gas venting and flaring, miscellaneous flared sources).*~~
>
> ~~*98.236(n)(2)(iv) Indicate the type of flare (i.e., open ground-level flare, enclosed ground-level flare, open elevated flare, or enclosed elevated flare).*~~

~~*98.236(n)(2)(v) Indicate the type of flare assist (i.e., unassisted, air-assisted with single speed fan/blower, air-assisted with dual speed fan/blower, air-assisted with variable speed fan/blower, steam-assisted, or pressure-assisted).*~~

~~*98.236(n)(2)(vi) Indicate whether the flare has a continuous pilot or autoigniter.*~~

~~*98.236(n)(2)(vii) If the flare has a continuous pilot, indicate whether the presence of flame is continuously monitored.*~~

~~*98.236(n)(2)(viii) If the flare has a continuous pilot and the presence of a flame is not continuously monitored, indicate how periods when the pilot is not lit are identified (i.e., assumed pilot is always lit, assumed pilot was unlit for a fixed number of hours or fraction of operating hours, visual observations of flare flame, other (specify)).*~~

Commenter 0387: [T]hree additional items from the October 2022 Comments are highlighted here:

…

- §98.2326(n) includes unnecessary reporting requirements that should be eliminated. Information that is not used to calculate or validate GHG emissions should not be included; if EPA requires information for something other than GHG reporting, it should obtain it through a formal information request that includes rationale for why this information is needed instead of requiring the information for Subpart W.

…

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

…

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

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

Response 5: These comments were included as attachments to the commenter's letters, but they are comments on proposed reporting requirements in the 2022 GHGRP Proposal. Some of the reporting elements in the 2022 Proposal were retained in the 2023 Proposal and others have been changed. For example, the volume of gas routed to the flare and the fraction of gas routed to the flare when it was unlit in 40 CFR 98.236(n)(2)(iii) and (ix) of the 2022 proposal were retained in the 2023 Proposal. These elements also are finalized in 40 CFR 98.236(n)(11) and (12) as proposed, except to include clarifying language to align with the additional options for determining flow that are being finalized, because they are critical activity data used in conducting verification. Reporting elements for the type of flare and type of assist in 40 CFR 98.236(n)(2)(iv) and (v) of the 2022 Proposal were also included in the 2023 Proposal and are finalized as proposed in 40 CFR 98.236(n)(4) and (5). As explained in section III.N.2 of the 2023 Proposal preamble, these elements are needed to provide an understanding of the impact of flare design and operation on emissions.

The 2022 Proposal would have required reporting of the source types that route emissions to each flare (40 CFR 98.236(n)(2)(ii)). This proposed requirement was not included in the 2023 Proposal because the 2023 Proposal would instead require disaggregation of the total emissions per flare to each of the source types that route emissions to the flare. See comment 1 in this section for EPA's response to comments regarding the requirement to report disaggregated emissions for each flare.

Finally, the 2022 Proposal included reporting requirements in proposed 40 CFR 98.236(n)(2)(vi), (vii), and (viii) related to pilot operation and monitoring that were intended to provide information to help us better understand the prevalence of emissions from unlit flares. These proposed requirements were not included in the 2023 Proposal because the 2023 Proposal explicitly specified pilot monitoring requirements to meet the directive of CAA Section 136(h) to ensure reporting based on empirical data that accurately reflect the total methane emissions and waste emissions from applicable facilities. To align with the revised monitoring requirements, the proposed reporting requirements were also revised to require reporters to indicate whether the pilot flame or combustion flame was monitored continuously, visually inspected, or both. Additionally, if the pilot was visually inspected, then reporting the number of inspections during the year would be required. If the pilot flame was monitored continuously, reporting the number of times the continuous monitoring device was out of service or otherwise inoperable for a period of more than one week would be required. The EPA is finalizing these reporting requirements as proposed, except for making an edit to align with the provision in the final rule that allows the use of multiple or redundant continuous monitoring devices. If the reporter uses multiple monitoring devices, the final rule specifies that reporting the number of times devices were inoperable for more than a week is required only when all of the devices were inoperable for a period of more than a week. The reported data will be useful in conducting verification and in understanding the impact of the monitoring method on the reported unlit fractions and thus on the flared emissions as well.

Further, as discussed in section II.C of the preamble to the proposed rule, the data collected under subpart W is used to support a range of policies and initiatives under the CAA including but not limited to provisions involving research, evaluating and setting standards, endangerment determinations, or informing EPA non-regulatory programs.

Commenter: GPA Midstream Association
Comment Number: EPA-HQ-OAR-2023-0234-0299
Page(s): 88-89

Comment 6: Proposed Change: EPA is requesting that the fraction of gas sent to an unlit flare be reported twice for each flare – once for the source-level reporting, and then again for the flare event reporting.

> **Comment**: EPA should eliminate duplicative reporting requirements. These numbers will almost certainly be the same, as it will be extremely difficult for reporters to calculate the exact proportion of gas that is flowing to a flare from each source in any period when a flare is unlit and arrive at unique fractions for the individual sources versus the overall volume.
>
> **Suggested text:**
>
> For each flare stack used to control miscellaneous flared sources:
> ~~*98.236(n)(1)(vii) Fraction of the feed gas sent to an un-lit flare ("Zu" in Equation W-19 of this subpart).*~~
>
> For all flare stacks:
> *98.236(n)(2)(ix)* ~~*Estimated fraction of the total volume routed to the flare when it was not lit.*~~

Response 6: This comment was included as an attachment to the commenter's letter, but it is a comment on the 2022 GHGRP Proposal and is not relevant to the 2023 Subpart W Proposal.

15.3.3 Other Flare Reporting and Recordkeeping Comments

Commenter: Environmental Defense Fund, et al.
Comment Number: EPA-HQ-OAR-2023-0234-0413
Page(s): 61

Comment 1: 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, CO2 and N2O 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.

Footnote

[106] Proposed § 98.236(n)(19).

Response 1: The EPA acknowledges the commenter's support of the proposed requirements to measure gas flow to flares. However, for reasons discussed in Section III.N.1 of the preamble to the final rule, for facilities that determine flow from individual sources rather than measuring the total flow at the flare inlet, the EPA is adding options to determine flow of individual streams using process simulations and engineering calculations as alternatives to measuring the flows.

After consideration of the comment, we have decided not to include in the final rule requirements to determine and report flared associated gas emissions and activity data separate from data for other flared sources when a combined stream is routed to the flare and the operator measures total flow (and composition) at the inlet to the flare. We share the commenter's interest in being able to continue receiving reported flared data for individual source types that have been reporting source-specific flared emissions under the current rule because these data may be used for a number of purposes such as to inform policy on possible regulatory actions to address GHG emissions. However, requiring separate determination of flared associated gas emissions would impose an additional burden on such reporters that we do not believe is needed at this time.

Measurement of flow and composition of the total inlet stream to the flare will generate excellent empirical data for use in calculating total emissions from the flare. To develop disaggregated emissions per source type for such flares, we expect that reporters will be able to provide reasonable estimates of the fractions of the total emissions attributable to each source type that routes gas to the flare based on engineering calculations, process knowledge, and best available data. Additionally, as the commenter noted, disaggregation will only be needed when flow and composition are measured for the total inlet stream to the flare. If reporters elect to determine emissions for individual streams from each source type, then the reported disaggregated emissions per source type must be determined based on summing the reported emissions from the individual streams for each applicable source type. Since the final rule includes additional options for reporters to determine source-specific flow and composition that were added in response to numerous comments requesting such options (see sections 15.2.4 and 15.2.6 in this document and the responses to comments in Section III.N.1 of the preamble to the final rule), we anticipate that many reporters will determine and report stream-specific flare data. Some flares also are likely to be dedicated to associated gas emissions, further minimizing the number of flares for which disaggregation estimates will be needed.

We are unsure what types of potential inconsistencies in source designations the commenter is concerned that operators may use in reporting disaggregated source types. The source types to which flared emissions must be disaggregated under the final rule are unchanged from the source-types for which flared emissions must be reported under the current rule. However, we will assess the reported data each year and if any concerns are identified, we may consider further updates in a future rulemaking.

Commenter: Environmental Defense Fund, et al.
Comment Number: EPA-HQ-OAR-2023-0234-0413
Page(s): 61-62

Comment 2: 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 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.

Footnote

[107] 88 Fed. Reg. 50398 (Aug. 1, 2023).

Response 2: The EPA has decided not to require separate reporting of the amount of methane slip at a flare and the amount of methane emissions from the flare when it was unlit in the final rule. This would increase reporter burden to calculate and report data that we believe can be reasonably estimated from other reported data. Assuming the methane mole fraction during periods when the flare is unlit is comparable to the methane mole fraction when the flare is lit, the slip can be estimated using 1 for Z_L and 0 for Z_U in Equation W-19. This amount can be subtracted from the total reported emissions to estimate the amount of emissions from the flare when it was unlit.

Commenter: Environmental Defense Fund, et al.
Comment Number: EPA-HQ-OAR-2023-0234-0413
Page(s): 58-60

Comment 3: Calculating and reporting emissions from flare stacks

…

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.

Response 3: The EPA agrees with the commenter that additional recordkeeping is needed to ensure that facilities that are not subject to the refineries NESHAP or NSPS OOOOb but elect to comply with the tier 1 or tier 2 efficiencies are achieving the applicable efficiencies for purposes of the subpart W calculation methodology. Thus, the EPA has strengthened recordkeeping requirements in the final rule for facilities complying with the tier 1 or tier 2 efficiencies to align with the recordkeeping requirements for flares in the refineries NESHAP and NSPS OOOOb, respectively. Specifically, for tier 1, 40 CFR 98.233(n)(1)(i) requires compliance with the recordkeeping requirements in 40 CFR 63.655(i)(2) and (3) got enclosed combustion devices and 40 CFR 63.655(i)(9) for open flares. For tier 2, 40 CFR 98.233(n)(1)(ii)(A), (B), and (C) require compliance with the recordkeeping requirements in 40 CFR 60.5420b(c)(11).

For tier 2, the commenter cited the recordkeeping requirements in 40 CFR 60.5420b(c)(3)(ii)(A) through (H) of the December 6, 2022, Supplemental Proposal. These sections have been rearranged in the final NSPS OOOOb making it difficult to determine exactly which recordkeeping requirements in the final NSPS OOOOb the commenter would recommend including in subpart W. However, some of the provisions in the sections cited by the commenter involved records of certifications (e.g., for closed vent systems or to document why it is infeasible to comply with associated gas recovery requirements), records of periods of temporary venting of associated gas, records of bypass monitoring, and closed vent system inspection records that we have not included in the final subpart W. Certifications are not included in this rulemaking because subpart W is an emissions reporting rule, not an emissions control rule. Records related to associated gas venting are not addressed in 40 CFR 98.233(n) because the methodology for calculating vented associated gas emissions, including temporary venting of streams that are normally flared, is specified in 40 CFR 98.233(m) of the final rule. The recordkeeping requirements specific to flare design and operation in 40 CFR 60.5420b(c)(11) are also cross-referenced from 40 CFR 60.5420b(c)(3). Thus, for the final rule, we have directly cross-referenced the recordkeeping requirements in 40 CFR 60.5420b(c)(11). See Section III.N.2 of the preamble to the final rule for the EPA's response to the comments regarding recordkeeping for bypass devices and closed vent systems and requirements for estimating the volume of leaks from closed vent systems and the volume of gas diverted from entering a flare through a bypass line.

Finally, we disagree with the commenter's suggestion to require facilities that are subject to the refineries NESHAP and NSPS OOOOb to submit their compliance reports under subpart W. The EPA can access and review the reports that are submitted under the refineries NESHAP and NSPS OOOOb, if necessary. There is no need to submit a second copy of each report.

16 Compressors

16.1 Mode-Source Combination Measurement Requirements

Commenter: Williams Companies, Inc.
Comment Number: EPA-HQ-OAR-2023-0234-0394
Page(s): 13

Commenter: Environmental Defense Fund, et al.
Comment Number: EPA-HQ-OAR-2023-0234-0413
Page(s): 63-64

Comment 1: Commenter 0394: **Centrifugal and Reciprocating Compressors**

Williams supports the addition of dry seal vent measurements for centrifugal compressors, and rod packing vent measurements for reciprocating compressors in standby mode. Williams also supports removing the requirement to measure a compressor in not-operating-depressurized mode every 3 years for the processing and transmission & storage segments.

Commenter 0413: 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.

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.

Response 1: The EPA acknowledges the commenters' support of the proposed revisions. The EPA is finalizing these amendments as proposed.

Commenter: GPA Midstream Association
Comment Number: EPA-HQ-OAR-2023-0234-0299
Page(s): 49-50, 90

Comment 2: Reporter emission factor requirements need to accommodate additional scenarios.

EPA is proposing to remove the requirement to measure in the NOD mode every three years, and EPA is proposing to add new mode-source combinations. Because of these changes, it is possible that mode-source combination measurements may occasionally not exist, especially if a reporter calculates emission factors at the facility level. EPA should include provisions to allow a reporter to either use the last valid reporter emission factor or (if facility emission factors are otherwise used) allow use of a company-wide emission factor. GPA suggests the following changes to the proposed regulatory text to accomplish this:

98.233(o)(6)(iii) …
Eq. W-23
EFs,m = Reporter emission factor to be used in Equation W-22 of this section for compressor mode-source combination m, in standard cubic feet per hour. The reporter emission factor must be based on all compressors measured in compressor mode-source combination m in the current reporting year and the preceding two reporting years. If the mode-source combination was not measured in the current reporting year and the preceding two reporting years, use the last valid reporter emission factor at the facility, or use a company-wide factor.
98.233(p)(6)(iii) …
Eq. W-28
EFs,m = Reporter emission factor to be used in Equation W-27 of this section for compressor mode-source combination m, in standard cubic feet per hour. The reporter emission factor must be based on all compressors measured in compressor mode-source combination m in the current reporting year and the preceding two reporting years. If the mode-source combination was not measured in the current reporting year and the preceding two reporting years, use the last valid reporter emission factor at the facility, or use a company-wide factor.

…

Proposed Change: EPA is proposing to remove the requirement to measure in the not-operating-depressurized mode every three years, and EPA is proposing to add new mode-source combinations.

> **Comment**: It is possible that mode-source combination measurements may occasionally not exist, especially if a reporter calculates emission factors at the facility level. EPA should include a provision for using the last valid reporter emission factor in that circumstance.
>
> **Suggested text:**
>
> *98.233(o)(6)(iii) …*
> *Eq. W-23*

EFs,m = Reporter emission factor to be used in Equation W-22 of this section for compressor mode-source combination m, in standard cubic feet per hour. The reporter emission factor must be based on all compressors measured in compressor mode-source combination m in the current reporting year and the preceding two reporting years. If the mode-source combination was not measured in the current reporting year and the preceding two reporting years, use the last valid reporter emission factor at the facility, or use a company-wide factor.
98.233(p)(6)(iii) ...
Eq. W-28
EFs,m = Reporter emission factor to be used in Equation W-27 of this section for compressor mode-source combination m, in standard cubic feet per hour. The reporter emission factor must be based on all compressors measured in compressor mode-source combination m in the current reporting year and the preceding two reporting years. If the mode-source combination was not measured in the current reporting year and the preceding two reporting years, use the last valid reporter emission factor at the facility, or use a company-wide factor.

Response 2: The EPA disagrees with this suggested change. Equation W-23 and Equation W-28 already allow for the use of a company-wide factor using "all measurements from a single owner or operator instead of only using measurements from a single facility." See 40 CFR 98.233 (o)(6)(iv) and 98.233 (p)(6)(iv). In addition, the commenter offers no definition or method of determining the "last valid reporter emission factor." Without more information, the suggested changes have not been made to Equation W-23 or Equation W-28.

As for all other years of the GHGRP, reporters should conduct compressor measurements in the as-found mode and use the measurements to determine emission factors as detailed in 40 CFR 98.233(o)(6)(ii) and 98.233(p)(6)(ii).

Commenter: Interstate Natural Gas Association of America (INGAA)
Comment Number: EPA-HQ-OAR-2023-0234-0387
Page(s): 19, 39

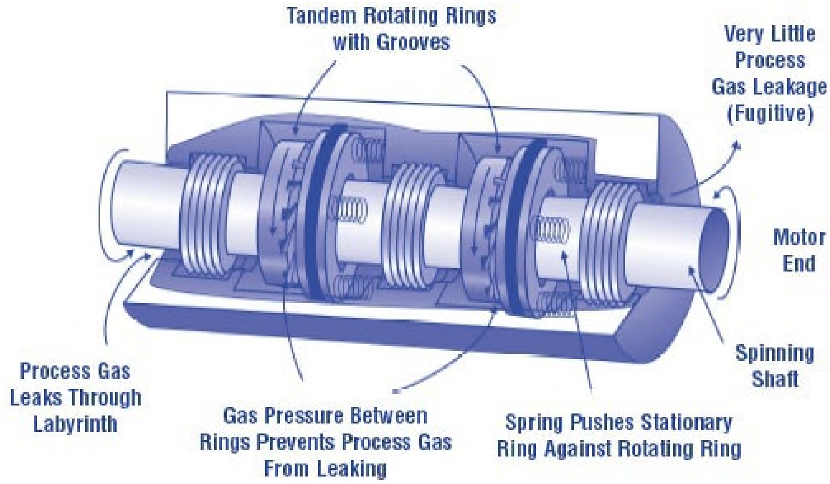
Comment 3: [T]hree additional items from the October 2022 Comments are highlighted here:

- For dry seal monitoring, clarity is needed to ensure that only the compressor side dry seal is monitored. As explained in previous comments, the measurement should be conducted on the "inboard" / compressor side but should not be required on the "outboard" seal on the air side motor and shaft bearing.

…

Clarity is needed on dry seal monitoring.

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



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

Footnotes:

[30] From https://www.epa.gov/sites/default/files/2017-09/documents/reducingemissionsfromcompressorseals.pdf p.16

Response 3: See Section III.O.1 of the preamble to the final rule for the EPA's response to comments regarding the location of the dry seal vent measurements for centrifugal compressors.

16.2 Measurement Methods

Commenter: Interstate Natural Gas Association of America (INGAA)
Comment Number: EPA-HQ-OAR-2023-0234-0387
Page(s): 17-18, 41-42

Comment 1: Use of acoustic technology for manifolded systems should not be eliminated.

…

<u>Acoustic technology should be allowed to identify the leak source in a manifolded system</u>

The Proposed Rule retains the acoustic device for quantification of through-valve leakage but eliminates its use for manifolded lines. EPA should *selectively* retain the use of acoustic devices for manifolds when determining which line (e.g., which compressor valve) is leaking in manifolded systems. In this application, the technology is used to identify the source, but not used to quantify emissions, which would be measured downstream of the manifold using accepted methods such as a high-volume sampler, calibrated bag, or meter.

As noted in October 2022 Comments, INGAA understands that acoustic technology is a method allowed for measuring through valve leakage and should not be used to quantify emissions in manifolded systems. However, acoustic technology can be a valuable tool for assessing manifolded systems, where the acoustic signal may be used to identify which line includes flow – i.e., identify the leak or vent source that is passing through a line into the manifold.

INGAA believes that eliminating the use of acoustic leak detection from manifold groups ignores the important function that can be provided – i.e., not leak quantification but rather the fact that acoustic leak detection is a valuable tool in attributing source contribution to manifolded compressors. A real-world example is application by an INGAA member where the leak source from four reciprocating engines venting to a single stack (i.e., manifolded compressors) was identified with the acoustic device so that the compressor emissions could be attributed to the appropriate compressor source / leaking valve and operating mode. The acoustic detection was done upstream of the manifold to identify which valve was leaking and the associated flowrate was measured downstream.

INGAA recommends that Subpart W continue to allow the use of acoustic leak detection for manifolds to *identify which line (e.g., which compressor valve) is leaking*.

…

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

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

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

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

Response 1:

See Section III.O.2 of the preamble to the final rule for the EPA's response to comments regarding the retaining of the use of acoustic devices for manifolded compressors to identify the source of the leak, but not to quantify emissions.

Commenter: Interstate Natural Gas Association of America (INGAA)
Comment Number: EPA-HQ-OAR-2023-0234-0387
Page(s): 17-18

Comment 2: INGAA recommends the rule allow flexibility to integrate advanced technologies that become available, such as the option of using an OGI emissions quantification system as an accepted technology for methane emissions quantification. Use of acoustic technology for manifolded systems should not be eliminated.

INGAA's October 2022 Comments emphasized the need to accommodate technology advances that improve the quality of reported GHG data, and that objective is consistent with the IRA and provides the ability to more readily integrate the results of successful IRA-funded MERP measurement and monitoring projects into Subpart W. To accommodate measurement and monitoring technological progress, the rule should add more flexibility for integrating new technologies.

For example, INGAA recommends the rule allow flexibility to integrate advanced technologies that become available, such as the option of using optical gas imaging (OGI) emissions quantification system as an accepted technology for methane emissions quantification. Technology advancements may confirm the performance of OGI emissions quantification systems that are under development, but the current regulations do not provide an efficient mechanism to incorporate such technological advances into Subpart W. It's possible that related projects will be funded under the IRA MERP program, and that program could even be used as a technical platform to expedite and facilitate technology approval, including using the MERP to develop standardized methodology for streamlined technology review and acceptance. INGAA's previous comments include additional discussion, and INGAA welcomes the opportunity to explore with EPA the methodologies and metrics that could be used to facilitate and expedite acceptance of new measurement and monitoring technologies.

Response 2: See Section III.O.3 of the preamble to the final rule for the EPA's response to comments regarding the incorporation of quantitative OGI or other technologies that are still under development.

16.3 Onshore Petroleum and Natural Gas Production or Onshore Petroleum and Natural Gas Gathering and Boosting

Commenter: American Exploration and Production Council
Comment Number: EPA-HQ-OAR-2023-0234-0295
Page(s): 19

Commenter: Enerplus Resources (USA) Corporation
Comment Number: EPA-HQ-OAR-2023-0234-0342
Page(s): 4

Comment 1: Commenter 0295: **Compressor Venting**

AXPC is in favor of proposed rule changes allowing for the use of site-specific measurement data to estimate emissions from compressor venting for operators who elect to do so or may be required to do so under NSPS OOOOb/OOOOc …

Commenter 0342: Compressor Venting

Enerplus is in favor of proposed rule changes allowing for the use of site-specific measurement data to estimate emissions from compressor venting for operators who elect to do so or may be required to do so under NSPS OOOOb/OOOOc …

Response 1: The EPA acknowledges the commenters' support of the proposed revisions. The EPA is finalizing these amendments as proposed.

Commenter: American Exploration and Production Council
Comment Number: EPA-HQ-OAR-2023-0234-0295
Page(s): 19

Commenter: GPA Midstream Association
Comment Number: EPA-HQ-OAR-2023-0234-0299
Page(s): 48-49

Commenter: Independent Petroleum Association of New Mexico (IPANM)
Comment Number: EPA-HQ-OAR-2023-0234-0337
Page(s): 7-8

Commenter: Enerplus Resources (USA) Corporation
Comment Number: EPA-HQ-OAR-2023-0234-0342
Page(s): 4

Commenter: Williams Companies, Inc.
Comment Number: EPA-HQ-OAR-2023-0234-0394
Page(s): 14

Commenter: Western Energy Alliance
Comment Number: EPA-HQ-OAR-2023-0234-0399
Page(s): 9

Commenter: American Petroleum Institute et al. (Part 1 of 2)
Comment Number: EPA-HQ-OAR-2023-0234-0402
Page(s): 51

Commenter: Environmental Defense Fund, et al.
Comment Number: EPA-HQ-OAR-2023-0234-0413
Page(s): 63

Comment 2: Commenter 0295: **Compressor Venting**

However, AXPC has significant concerns with the proposed changes in the default population emission factors for reciprocating compressor vents. EPA is proposing to increase the factor for both CH_4 and CO_2 by more than 2000% based on the 2019 Zimmerle study[6] . However, this study was conducted only at gathering facilities, and as stated directly in the study's report, emissions are likely to differ at other types of facilities for functional and operational reasons[7] . For example, the study reports that average unit size involved in the study was 1,800 HP for 4SLB units and 1,360 HP for 4SRB units. Not only are these units considerably larger than those typically used at production facilities (for example, a 50 HP single-stage compressor would be commonly found at a wellhead site), but they also are likely to operate at considerably higher pressures, and therefore would not be representative of compressors at production facilities. Finally, the derivation of the emission factor in Table 8-3 of the Technical Support Document assumes that all compressors operate 8,760 hours per year, which is overly conservative and not likely to be the case at production facilities.

Footnotes:

[6] Characterization of Methane Emissions from Gathering Compressor Stations. Zimmerle, Bennett, Vaughn, Luck, Lauderdale, Keen, Harrison, Marchese, Williams, Allen. 2019.

[7] "Although there is overlap in the classes of equipment on gathering stations with those on production sites or transmission stations that have been measured recently, emissions are likely to differ for functional and operational reasons." Characterization of Methane Emissions from Gathering Compressor Stations. Zimmerle, et al.

Commenter 0299: **EPA should not require NOD mode measurements for the gathering and boosting segment, and the Agency should instead develop an emission factor (and also allow companies to use their own emission factors developed for other industry segments).**

…

To alleviate these significant complexities, EPA should use the abundant data provided by GHGRP reporters over many years on NOD mode emissions to develop emission factors. EPA could also allow reporters to use their own emission factors calculated from different industry segments, particularly natural gas processing. This surely aligns with the Inflation Reduction Act's directive to use empirical data. The compressor/engine types and sizes found at natural gas processing facilities are similar to the ones found at gathering and boosting facilities, so isolation valve emission factors could be transferred across these industry segments. Because these compressors do not commonly operate in the NOD mode, emission factors should sufficiently represent emissions.

Commenter 0337: **40 CFR § 98.233(p) Reciprocating Compressors**

The default emission factors in Equation W-29D in § 98.233(p) in the Proposed Rule are not based on measured data from reciprocating compressors in the Onshore Production industry segment. This is acknowledged in the 2019 Zimmerle study, "AECOM partnered with nine U.S. midstream operators to characterize emissions from natural gas gathering and boosting stations ("gathering stations") – a sector of the natural gas supply chain where few measurements have been made and little data are available for component emissions. Although there is overlap in the classes of equipment on gathering stations with those on production sites or transmission stations that have been measured recently, emissions are likely to differ for functional and operational reasons." According to the Technical Source Document, all 412 rod packing vent measurements were from the onshore gathering & boosting segment.

EPA is proposing to use an emission factor from a study in the G&B segment only, where the study admits that emissions are likely to be different in the production segment. Yet EPA intends, nonetheless, to require the factor on the production segment. There is no evidence to support the use of this factor for the onshore production segment where compressors are generally smaller and handling less gas at lower pressures. The emission factor for the onshore production segment should remain unchanged until enough empirical evidence is available to support a new factor.

Commenter 0342: Compressor Venting

EPA is proposing to increase the factor for both CH_4 and CO_2 by more than 2000%. The study used to develop the emission factors looked at an average unit size considerably larger than those typically used at production facilities and would not be representative of compressors at production facilities. Finally, the emission factor assumes that all compressors operate 8,760 hours per year, which is overly conservative and not likely to be the case at production facilities.

Commenter 0394: Williams supports the amendment of the CH_4 emission factor for reciprocating compressor rod packing emissions from 1.08 scfh to 24.32 scfh. This increase is supported by studies performed by Zimmerle and is further supported by historical rod packing emissions reported by companies in eGGRT.

Commenter 0399: Within the current proposal, EPA is greatly increasing the default emission factor for compressor venting… These default emission factors are not supported by published studies or EPA's own reported measured data within the GHGRP.

Commenter 0402: Centrifugal and Reciprocating Compressor Venting

Emission Factor Methodology - Utilize Measurement Data Reported Under Subpart W for Onshore Production and Gathering and Boosting

EPA should utilize the vast dataset of historically reported compressor measurements in different operating modes to derive population emission factors to ease the burden of compressor measurements and reclassify leakage from isolation and blowdown valves (open-ended lines) as equipment leaks.

While we believe all leaks besides rod packing and seal vents should be captured under the fugitive emissions reporting, EPA could consider an alternative to the measurement protocol. This alternative could utilize the vast dataset of compressor measurements in different operating modes historically reported under Subpart W to derive emission factors to reduce the burden of compressor measurement requirements. Because of the large sample size of actual measurement data, methane emissions can be reasonably estimated using emission factors derived from the data reported Subpart W.

Additionally, EPA should consider the use of the historically reported Subpart W compressor leakage dataset to derive population emission factors rather than rely on the much smaller dataset from the Zimmerle *et al* study.

Commenter 0413: 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.

Response 2: One commenter noted that the Zimmerle study was not appropriate because it employed compressors with an average unit size larger than typically used at production facilities. According to the Zimmerle study, rod packing measurements were made on approximately 100 compressors, ranging from 68 horsepower (hp) to 17,750 hp, and averaging approximately 4,400 hp. Unfortunately, the commenter offered no details on the average unit size used at production facilities, so no further comparisons can be made.

One commenter disagreed with the use of the Zimmerle study in favor of using the full historic GHGRP data set to establish new emission factors for the Onshore Petroleum and Natural Gas Production industry segment and the Onshore Petroleum and Natural gas Gathering and Boosting industry segment. The main advantage of using the study to establish emission factors instead of data gathered over the course of the GHGRP is the use of a consistent methodology and data that have been reviewed for accuracy. First, the GHGRP has evolved over the period from 2010 until now, by allowing different measurement methods and changing the compressor mode-source combinations that are required to be measured. Second, due to the verification process, the EPA often asks for clarification or resubmittals from reporters. If these questions are not answered and no new submittals are received, reports can be marked as Unverified. Data from these reports should not be used to determine average emission factors because they have not been verified.

Further, as stated in the proposal preamble, Zimmerle et al. (2019) uses a larger and more representative sample of 412 rod packing vent measurements, compared to the 40 compressor measurements available in the 1996 GRI/EPA study, which was used to establish the previous emission factors. In response to assertions by commenters that Zimmerle et al. (2019) should not be used, including suggestions to instead use GHGRP historic data (addressed above), EPA analyzed and compared the historically reported GHGRP compressor measurements of rod packing emissions in operating mode from the past three years (RY2020, RY2021, and RY2022) to the proposed emission factors.

The overall average CO_2 emission factors for rod packing emissions in operating mode for RY2020, RY2021, and RY2022 are 5.09 x 10^4 scf CO_2/yr/compressor, 8.04 x 10^4 scf CO_2/yr/compressor, and 3.71 x 10^4 scf CO_2/yr/compressor, respectively. The average using all three years is 5.35 x 10^4 scf CO_2/yr/compressor. The proposed CO_2 emission factor of 1.18 ×10^4 scf/yr/compressor is similar to the average emissions reported to the GHGRP over the past three years.

Similarly, the overall average CH_4 emission factors for rod packing emissions in operating mode for RY2020, RY2021, and RY2022 are 5.95 x 10^5 scf CH_4/yr/compressor, 6.68 x 10^5 scf CH_4/yr/compressor, and 6.99 x 10^5 scf CH_4/yr/compressor, respectively. The average using all three years is 6.56 x 10^5 scf CH_4/yr/compressor. The proposed CH_4 emission factor of 2.13 ×10^5 scf/yr/compressor is similar to the average emissions reported to the GHGRP over the past three years.

Thus, we conclude, consistent with statements made by one commenter, that the proposed emission factors are similar to the average emissions reported to the GHGRP. For the reasons further described in the preamble, the EPA has finalized the emission factors as proposed.

With regard to the two commenters that noted that the "the emission factor assumes that all compressors operate 8,760 hours per year," see Section III.O.3 of the preamble to the final rule for the EPA's response to comments regarding an adjustment for gas composition and operating hours within Equation W-29D.

See Section III.O.3 of the preamble to the final rule for the EPA's response to comments regarding the proposed language to require compressor measurements in NOD mode.

Commenter: Independent Petroleum Association of New Mexico (IPANM)
Comment Number: EPA-HQ-OAR-2023-0234-0337
Page(s): 7

Comment 3: 40 CFR § 98.233(p) Reciprocating Compressors

Equation W-29D in § 98.233(p) does not allow for adjustment based on gas composition. Due to the wide variety in the composition of gas produced from different basins and formations across the U.S., the Emission Factor method should allow for adjustment based on CO_2 and CH_4 composition reflective of each compressor. Composition adjustment of Emission Factor-based calculations is allowed for in source categories such as pneumatic devices, pneumatic pumps, equipment leaks. Including this empirical adjustment would improve the accuracy of the emissions data. As an example, CO_2 injection compressor in an EOR operation, injecting 99.9% CO_2 would potentially underestimate CO_2 emissions and grossly overestimate methane emissions.

Equation W-29D in § 98.233(p) does not allow for adjustment based on the number of hours a compressor operates during a calendar year. Compressors can be moved on and off location during a year. This will result in inaccurate data. Without adjustment for actual hours, a compressor installed on December 1st in a given year, would report 4.09 tons of methane, instead of the more accurate 0.35 tons. It may also be appropriate to adopt an 'in service' definition for compressors defined as annual hours that a compressor is connected in a Production or G&B System and is in a pressurized mode. Adjustment of EF based calculations is allowed for source categories such as pneumatic devices, pneumatic pumps, equipment leaks and improves the accuracy of the inventory.

Response 3:

See Section III.O.3 of the preamble to the final rule for the EPA's response to comments regarding an adjustment for gas composition and operating hours within Equation W-29D.

Commenter: EnerVest Operating, LLC
Comment Number: EPA-HQ-OAR-2023-0234-0229
Page(s): 4

Commenter: American Exploration and Production Council
Comment Number: EPA-HQ-OAR-2023-0234-0295
Page(s): 19

Commenter: GPA Midstream Association
Comment Number: EPA-HQ-OAR-2023-0234-0299
Page(s): 48-49

Commenter: Enerplus Resources (USA) Corporation
Comment Number: EPA-HQ-OAR-2023-0234-0342
Page(s): 4

Commenter: Permian Basin Petroleum Association (PBPA)
Comment Number: EPA-HQ-OAR-2023-0234-0346
Page(s): 6, 7

Commenter: Arkansas Independent Producers and Royalty Owners (AIPRO)
Comment Number: EPA-HQ-OAR-2023-0234-0382
Page(s): 14

Commenter: CrownQuest Operating
Comment Number: EPA-HQ-OAR-2023-0234-0393
Page(s): 231, 232

Commenter: Williams Companies, Inc.
Comment Number: EPA-HQ-OAR-2023-0234-0394
Page(s): 13-14

Commenter: The Petroleum Alliance of Oklahoma
Comment Number: EPA-HQ-OAR-2023-0234-0398
Page(s): 16

Commenter: Western Energy Alliance
Comment Number: EPA-HQ-OAR-2023-0234-0399
Page(s): 9

Commenter: Chesapeake Energy Corporation
Comment Number: EPA-HQ-OAR-2023-0234-0400
Page(s): 13-15

Commenter: American Petroleum Institute et al. (Part 1 of 2)
Comment Number: EPA-HQ-OAR-2023-0234-0402
Page(s): 6, 49

Comment 4: Commenter 0229: Compressors -Reciprocating Compressor Venting

- Unlike gas plants, reciprocating compressors are used throughout both gathering and boosting and exploration and production in very high numbers. Many thousands of artificial lift compressors are used in the gas lift capacity. The requirement for measuring different modes of operation puts an undue burden to companies who operate in specific formations. Often the engines are either running non-stop or moved to another location. There is no mode where it is shut-in and pressurized due to the nature of the use. There is little time the engine is substantially on location where it is unpressurized and on the ground. These engines are on skids or trailer mounted. They are shut down and immediately moved to another location.
- It is suggested that a subset of similar-kind gas lift engines be used to determine an average factor.

- In the Barnett Shale, it is often the case that hundreds of gas lift compressors are employed for artificial stimulation. This is cost prohibitive and singles out individual formations and operations and puts them at a disadvantage to others.
- We also propose that only the Gathering and Boosting section be subject to this rule. This is similar to what has been done for years at the Gas Processing Plants.
- Alternatively, we propose a subset of like-kind-engines be used to determine the emission factors for each of the three modes.

Commenter 0295: **Compressor Venting**

[AXPC] supports EPA retaining default population emission factors as a calculation option.

Commenter 0299: **EPA should not require NOD mode measurements for the gathering and boosting segment, and the Agency should instead develop an emission factor (and also allow companies to use their own emission factors developed for other industry segments).**

EPA proposes to remove mandatory periodic NOD mode measurements for compressors located at gas plants and transmission compressor stations. For compressors at onshore petroleum and natural gas production facilities or an onshore petroleum and natural gas gathering and boosting facilities that will be subject to the compressor standards in NSPS OOOOb or EG OOOOc, however, EPA proposes that at least one-third of the subject compressors must be measured during any three consecutive calendar year period for compressors in those industry segments [98.233(o)(10)(i)(B), 98.233(p)(10)(i)(B)].

In our comments on the 2022 proposed rule and in a previous communication with EPA, GPA thanked EPA and noted its support for removing the mandatory NOD mode measurements for compressors at gas plants. [109] GPA now requests that EPA allow, but not require, NOD mode measurements for compressors in the gathering and boosting segment.

Requiring NOD mode measurements at gathering and boosting sites would be even more difficult to implement than at gas plants. EPA states, that "[b]ased on an analysis of all reciprocating and centrifugal compressor measurements for the other industry segments since 2015, approximately one-third of all compressor measurements were performed in [NOD] mode." [110] This occurs purely because the GHGRP currently requires reporters to measure NOD mode once every 3 years; this is not happening because one-third of compressors are in NOD mode at any given time. Gathering and boosting facilities typically have a lower number of compressors (sometimes only 1 or 2 per site), and they are generally running. Compressors are expensive to purchase and operate, and we avoid having compressors running unloaded or sitting idle. As such, compressors are not commonly in NOD mode and collecting this measurement would almost certainly necessitate an otherwise unforced compressor shutdown and blowdown, which could result in the entire site being shut down and potentially upstream emissions if the gas has nowhere else to go.[111] Unneeded shutdowns will increase emissions, increase the reporter's methane fee burden, and likely cause supply disruptions.

Administratively, keeping track of the percent of compressors measured in the NOD mode over three consecutive calendar year periods and then deciding which compressors will be shut down to satisfy the requirement is unreasonable and adds complexity to compliance and recordkeeping. EPA also fails to indicate a statistical significance to the proposed measurement frequency.

Footnotes:

[109] GPA Comments on 2022 Proposed Rule at 21.

[110] 88 Fed. Reg. at 50,341.

[111] Although compressors sometimes shut down, aligning these shutdowns with NOD mode monitoring (which is often performed by a contractor) is difficult to coordinate, based on the experiences of GPA members collecting NOD measurements as gas plants.

Commenter 0342: Compressor Venting

[Enerplus] supports EPA retaining default population emission factors as a calculation option.

Commenter 0346: **Operations and Facilities Vary Between Upstream, Midstream, and Downstream Oil and Gas Sectors and Should Not Be Treated the Same**

Furthermore, there are distinct geographic differences that mandate the upstream, midstream, and downstream sectors be treated differently. Upstream and midstream assets are spread across large areas and are typically unmanned, whereas downstream assets are located in concentrated areas and are manned.

The compressor testing requirements for pressurized/standby mode are another example. It appears that these standards are copied from or modeled directly after the requirements for plants. The sheer number of compressors utilized in upstream operations and spread over large geographic areas does not appear to have been considered in the development of the Proposed Rule. These tests can be accomplished in roughly three to four weeks for plants. PBPA recommends that operators be allowed to use a representative sample for compressor testing due to the significant time and costs needed to test these facilities spread over such a large geographic area and the need to shut down operations in order to perform these tests.

Commenter 0382: Centrifugal and Reciprocating Compressor Venting:

AIPRO opposes the proposed requirements for reporters to measure at least 1/3 of compressors in “not-operating-depressurized” mode every three years. This requirement is infeasible, overly burdensome, poses potential safety hazards to personnel and may result in additional unnecessary natural gas/methane emissions in order to comply with the proposed requirements. As such, AIPRO strongly encourages EPA to remove these requirements from the proposed Subpart W revisions and allow operators to measure compressor venting in their “as found” mode.

Commenter 0393: EPA is proposing that operators must measure at least 1/3 of their reciprocating and centrifugal compressors in non-operating/depressurized mode each year. We do not support this for multiple reasons:

- To quantify emissions in non-operating/depressurized mode, a forced blow-down would have to take place. This would lead to significant methane emissions from the compressors
- in the complicated operations of upstream oil and gas, shutting down a unit to measure venting will result in very costly downtime of production. For some measurements, this would mean shutting in multiple wells to a facility resulting in lost production and the risk of not being able to regain stable production/operations.

It is recommended that EPA allows operators to measure compressor venting on a case by case or "as found" scenario. We can utilize company records or engineering estimates/calculations to determine "representative" values. This includes but not solely, service type, valve age or type.

…

The "as found" language is critical and is helpful in practicality of taking these measurements. If the EPA wants a non-operating measurement for each compressor, they should leave the language as "next planned scheduled shutdown" or allow for representative samples from similar compressors on site. If compressor stations are required to obtain a non-operating measurement and force a shutdown, that will likely lead to more emissions at the well sites or facility upstream of the station.

Commenter 0394: **Centrifugal and Reciprocating Compressors**

Williams proposes removing the requirement to measure at least 1/3 of compressors in not-operating-depressurized mode for the gathering and boosting segment. Compressors in the gathering and boosting segment are generally in operating mode. Requiring this measurement every 3 years would require more frequent shutdowns and increased GHG emissions.

Commenter 0398: EPA is proposing that reporters of onshore production and gathering and boosting would be required to measure one-third of their reciprocating and centrifugal compressors in non-operating depressurized-mode each year.

This testing results in unnecessary and possibly significant emissions to the atmosphere. Operators in the production and gathering and boosting segments do not typically operate these compressors in that mode because of the emissions. Additionally, this testing requires operators to shut in producing wells while the compressor is not operating. This may negatively impact the well or will take time for the well to return to stable operation. There are a substantial number of compressors used in onshore production and gathering and boosting sectors. As a practical matter, testing personnel and equipment may not be available to conduct the necessary tests in a timely manner.

Action Requested: We request EPA allow operators to test in the “as found” mode.

Commenter 0399: Within the current proposal, EPA is greatly increasing the default emission factor for compressor venting, which will at least in the short-term result in over-reporting emissions until annual leak testing/rod packing replacement or routing the emissions to the process are implemented for OOOOc facilities. … By precluding operators from using an accurate factor or allowing measurement in the "as found" mode, EPA will be violating the intent of the IRA and the purpose of the GHG by artificially increasing reported emissions as compared to actual emissions in the field.

> **Recommendation:** EPA should allow greater flexibility for venting emission calculations, allowing them to measure the equipment as it sits in the field.

Commenter 0400: **EPA should retain the option to rely on population emission factors for rod packing and develop a flexible mechanism to include demonstrated emission reductions based on future advancements.**

Current Subpart W regulations require onshore petroleum and natural gas production and onshore petroleum and natural gas gathering and boosting facilities to calculate compressor emissions—including rod packing—using population emission factors. [40] EPA's Proposed Rule would eliminate this option and instead require these facilities to conduct volumetric emissions measurements from each reciprocating compressor rod packing every 8,760 hours of operation.[41] In doing so, EPA is attempting to align Subpart W regulations with the requirements under NSPS Subpart OOOOb.[42]

However, as the Marcellus Shale Coalition emphasized in its comments on the NSPS Supplemental Proposed Rule, requiring regular monitoring of the rod packing using volumetric measurements are unwieldly and not reasonably implementable. [43] Instead, the Coalition and others encouraged EPA to permit operators to exercise a fixed schedule option for replacing rod packing at reciprocating compressors.[44] A fixed schedule for replacements would ensure that rod packing is still timely replaced in order to secure needed emissions reductions, while providing more flexibility for operators to choose whether to invest the substantial time and resources in obtaining regular volumetric emissions measurements.[45]

EPA's Proposed Rule for reporting worsens this problem—rather than increase flexibility for operators to cost-effectively monitor emissions, EPA is now proposing to expand the restrictive requirements proposed for Subpart OOOOb to Subpart W. These requirements substantially increase compliance burdens for onshore petroleum and natural gas gathering and boosting facilities. EPA's 2023 Regulatory Impact Analysis estimates that these industries will bear some of the highest compliance burdens across all industry sectors, ranging from $5,503,379 to $64,258,946.[46] These compliance costs make up over 75% of the total, economy-wide regulatory burden of EPA's Proposed Rule.[47]

Importantly, regular volumetric monitoring will not increase emissions reporting accuracy to a level anywhere comparable to the costs associated with it. Any minimal increase in accuracy is hugely offset by inordinate costs. Chesapeake strongly encourages EPA to instead provide a range of options for operators to measure rod packing emissions, including through reliance on a population emissions factor. Operators best positioned to utilize direct measurements will choose this option, while operators without ready access to necessary technology for volumetric measurement will still be able to achieve compliance, without incurring excessive costs. Retaining the option to directly measure rod packing emissions allows operators to account for emissions reductions based on advanced rod packing emissions control measures.

This flexible approach would be consistent with other aspects of EPA's Proposed Rule where EPA permits operators to rely on direct measurement, but does not require it. For instance, EPA is expanding available options for emissions reporting for pneumatic devices and pumps, rather than only permitting direct measurement.[48] EPA is also proposing to retain default population emission factors for intermittent bleed pneumatic devices as a compliance option.[49]

As EPA acknowledged in its NSPS Supplemental Proposed Rule, Subpart W and Subpart OOOOb involve overlapping but not necessarily identical requirements and goals.[50] Subpart W is part of a broad data collection program that applies to facilities in nearly all categories of industry, and EPA uses this data to evaluate and implement GHG mitigation policies.[51] However, this requirement does not impose emission limits. By comparison, Subpart OOOOb includes very targeted emissions reduction requirements based on an in-depth analysis of "the cost of achieving such reduction and any non-air quality health and environmental impact and energy requirement," as well as an assessment of whether emissions limits have been "adequately demonstrated."[52]

While Chesapeake appreciates EPA's efforts to align these programs to avoid inconsistency, EPA's rulemaking power under Section 114 does not justify a substantial increase in compliance burdens without due consideration of the statutory factors that the agency is required to consider in setting the best system of emission reduction under Subpart OOOOb.

Footnotes:

[40] See 88 Fed. Reg. at 50,341.

[41] Id.

[42] See id.

[43] See Comments, Marcellus Shale Coalition, EPA-HQ-OAR-2021-0317-0599, at 13 (Jan. 31, 2022), https://www.regulations.gov/comment/EPA-HQ-OAR-2021-0317-0599.

[44] Id.

[45] See id.

[46] 2023 Regulatory Impact Analysis, at 14.

[47] See id.

[48] See 88 Fed. Reg. at 50,310.

[49] See 88 Fed. Reg. at 50,314.

[50] See 87 Fed. Reg. at 74,798.

[51] See 42 U.S.C. § 7414.

[52] 42 U.S.C. § 7411(a)(1).

Commenter 0402: We urge EPA to seek true alignment and harmonization with other federal regulatory requirements, particularly the NSPS OOOOb and EG OOOOc "Methane Rules" and the GHGRP itself. Below are a few examples that are articulated in our comments:

…

- Compressor vent measurements should align with the Methane Rules. Subpart W should not mandate additional measurements for those sources.

…

Centrifugal and Reciprocating Compressor Venting

Measurements in Not-Operating-Depressurized Mode

The Industry Trades support EPA's efforts to increase the accuracy of reported information for venting from centrifugal and reciprocating compressors by allowing direct measurement, but measurement should not be required in Subpart W if not required in other regulatory programs. Additionally, Subpart W should not force operators to measure emissions in a not-operating depressurized mode.

EPA's proposed expansion from an emission factor to measurement approach for onshore production and gathering and boosting will further improve the quality of reported emissions across the segments. The Industry Trades support the expanded assortment of measurement methodologies and appreciate EPA's use of data from other programs (e.g., proposed NSPS OOOOb and EG OOOOc) for emissions calculations under subpart W, however there are numerous issues with the proposal. Although the compressor measurement provisions have been expanded from the gas processing reporting source category to include onshore production and gathering and boosting, there are unique differences that should be accounted for within the proposed requirements. The Industry Trades have provided suggested edits to account for these differences.

EPA is proposing to require that onshore production and gathering and boosting operators shall measure at least one-third of their reciprocating and centrifugal compressors subject to NSPS OOOOb in not-operating-depressurized mode each year. The Industry Trades do not support this requirement for several technical, safety and practical reasons. The Industry Trades recommend that EPA align with proposed NSPS OOOOb and EG OOOOc and limit the measurements to the rod packing for reciprocating compressors and dry seal vents for centrifugal compressors.

Testing the compressors in a not-operating depressurized mode is unnecessary and very difficult to implement for the following reasons:

- Forcing a unit into a not-operating depressurized mode will result in unnecessary venting of methane emissions to the atmosphere and could pose an unnecessary safety risk to the testing personnel or others at the site. Operations in upstream production and gathering and boosting segments are characterized by stable operation with full utilization of installed compression capacity. In order to measure emissions in not-operating depressurized mode, a forced blowdown event leading to significant methane emissions would be required for these compressors.
- As a practical matter, it would be very difficult if not virtually impossible for an operator to know at which point during the year to force units into a not-operating-depressurized mode in order to reach a prescriptive annual target. Additionally, the number of units change on a frequent basis due to acquisitions/divestitures, such that the number that would constitute "one-third" changes from month to month. Compressors are also added and removed throughout the year to address operation needs from the wells and gathering system based on production rates.
- In the dynamic operations of upstream and midstream oil and gas, shutting down a compressor for the sole purpose of measuring the venting could result in shut-in and blowdown of other process equipment resulting in additional methane emissions, as well as costly prolonged downtime of a facility. Taking a compressor off-line in production and gathering and boosting segments would result in shutting in a well(s), which can be problematic to restart and regain stable operation. As anecdotal evidence, our members have noted these tests take upwards of three weeks at their 10 gas plants with 140+ compressors. Extending this requirement to upstream facilities that are geographically spread across hundreds of miles would be extensive due to the thousands of compressors in use. The gas plant measurements are streamlined due to the units being co-located and the designed redundancy in place.
- Additionally, due to the integrated nature of the upstream/midstream environment, shutting down compression would not only have an effect on that company, but would additionally impact other companies that are connected to the system (i.e., shutting a compressor down would cause high pressure issues for the upstream operator and low-pressure issues for the downstream operator potentially resulting in additional flare and/or vented emissions for additional companies.
- Methane emissions from compressors in not-operating depressurized mode represent the emissions across the isolation valve, with potentially high flow rates due to the extreme line pressure on the upstream, pressurized side of the valve. Many operators, especially in production and gathering and boosting segments, do not normally operate compressors in this mode due to the potentially large methane leakage and associated safety risks. Additionally, good operating practice is to leave the blowdown/depressurization valve closed when units are offline.
- Finally, many compressors serve a critical function in the electricity generation supply chain and operate with limited or no excess capacity; forcing operators to shut down units to take measurements in a not-operating depressurized mode could strain the electrical generation supply chain. In 2022, the Texas Railroad Commission (TRRC) adopted weatherization rules for natural gas facilities to protect gas flow to power generators and

> ensure that residents have electricity during weather emergencies. The new rule requires critical gas facilities to weatherize, to ensure sustained operation during a weather emergency. The testing requirements as described would add an additional layer of complexity with little to no emissions reporting accuracy improvements.

Response 4: See Section III.O.3 of the preamble to the final rule for the EPA's response to comments regarding the proposed language to require compressor measurements in NOD mode.

Commenter: Williams Companies, Inc.
Comment Number: EPA-HQ-OAR-2023-0234-0394
Page(s): 14

Comment 5: Williams asks the EPA to confirm that these emission factors will be used for gathering and boosting compressors until they are subject to OOOOb/c, upon which they will transfer to annual measurements to be collected with leaking blowdown and isolation valve measurements.

Response 5: As stated in 40 CFR 98.233(o)(10)(i) and (ii) and 98.233(p)(10)(i) and (ii) of the proposed and final rule, you must conduct the measurements outlined in those sections if the compressor is "subject to the centrifugal compressor standards in § 60.5380b of this chapter or an applicable approved state plan or applicable Federal plan in part 62 of this chapter for dry seals and self-contained wet seals" or is "subject to the reciprocating compressor standards in § 60.5385b of this chapter or an applicable approved state plan or applicable Federal plan in part 62 of this chapter."

As stated in 40 CFR 98.233(o)(10)(iii), if "paragraph (o)(10)(i) of this section does not apply and you do not elect to conduct the volumetric measurements specified in paragraph (o)(1) of the section, you must calculate total atmospheric wet seal oil degassing vent emissions from all centrifugal compressors at either an onshore petroleum and natural gas production facility or an onshore petroleum and natural gas gathering and boosting facility using Equation W–25A of this section."

As stated in 40 CFR 98.233(p)(10)(iii), if "paragraph (p)(10)(i) of this section does not apply, and you do not elect to conduct the volumetric measurements specified in paragraph (p)(1) of the section, you must calculate total atmospheric rod packing emissions from all reciprocating compressors at either an onshore petroleum and natural gas production facility or an onshore petroleum and natural gas gathering and boosting facility using Equation W-29D of this section."

Commenter: GPA Midstream Association
Comment Number: EPA-HQ-OAR-2023-0234-0299
Page(s): 48-49

Comment 6: EPA should not require NOD mode measurements for the gathering and boosting segment, and the Agency should instead develop an emission factor (and also allow companies to use their own emission factors developed for other industry segments).

…

It is also unclear if reporters are to count the unique compressors measured in NOD mode or unique compressor-year measurements (e.g., if the same compressor was measured in NOD mode in both 2025 and 2026, it is unclear whether that is considered one measured compressor or two).

Response 6: See Section III.O.3 of the preamble to the final rule for the EPA's response to comments regarding the proposed language to require compressor measurements in NOD mode.

Commenter: GPA Midstream Association
Comment Number: EPA-HQ-OAR-2023-0234-0299
Page(s): 48-49

Comment 7: EPA should not require NOD mode measurements for the gathering and boosting segment, and the Agency should instead develop an emission factor (and also allow companies to use their own emission factors developed for other industry segments).

…

Another uncertainty surrounds what EPA means by gathering and boosting compressors that "are subject to the reciprocating compressor standards in 40 C.F.R. § 60.5385b of this chapter or an applicable approved state plan or applicable Federal plan in part 62 of this chapter."[112] What does it mean to be subject to the reciprocating compressor standards? For example, what happens if an approved state plan under EG OOOOc says existing equipment must begin annual measurements within 36 months? Are those compressors subject to the approved state plan when the plan is approved, or when the first measurement is conducted? Or is it some other time?

Footnote:

[112] 88 Fed. Reg. at 50,403.

Response 7: Subpart W of Part 98 does not require compressor measurements in the onshore petroleum and natural gas gathering and boosting industry segment until the compressor is "subject to the reciprocating compressor standards in § 60.5385b of this chapter or an applicable approved state plan or applicable Federal plan in part 62 of this chapter." While the applicability of the reciprocating compressor standards in "§ 60.5385b of this chapter or an applicable approved state plan or applicable Federal plan in part 62 of this chapter" is not determined by Subpart W of Part 98, the EPA's intention is that as soon as a reporter is required to begin taking measurements from a specific reciprocating compressor according to the reciprocating compressor standards in 40 CFR 60.5385b or an applicable approved state plan or applicable Federal plan in 40 CFR part 62, those measurements must be reported to the GHGRP as well.

Commenter: CrownQuest Operating
Comment Number: EPA-HQ-OAR-2023-0234-0393
Page(s): 241

Comment 8: If EPA wants operators to factor in data from OOOOb then EPA should make it clear instead of the confusing language currently stated.

Response 8: This comment appears to be referring to the following preamble text: "The EPA is proposing that reporters conducting measurements of compressors under NSPS OOOOb or the applicable approved state plan or applicable Federal plan in 40 CFR part 62 would conduct measurements of any other compressor sources required to be measured by subpart W at the same time. Second, because the time between measurements under the proposed standards in NSPS OOOOb and the proposed presumptive standards in EG OOOOc may not result in measurements being taken every reporting year, the EPA is proposing to specify that reporters would use equation W-22 or equation W-27, as applicable, to calculate emissions from all mode-source combinations for any reporting year in which measurements are not required."

This appears to be a misinterpretation of the proposal. The intent is that as soon as a reporter is required to begin taking measurements from a specific compressor according to the compressor standards in 40 CFR 60.5385b for reciprocating compressors or 40 CFR 60.5380b(a)(5) for centrifugal compressors, or an applicable approved state plan or applicable Federal plan in 40 CFR part 62, those measurements must be reported to the GHGRP as well. These reporters are also required to conduct all additional compressor measurements required for subpart W of Part 98 in 40 CFR 98.233(o)(1) and 98.233(p)(1) at the same time in the calendar year.

16.4 Compressors Routed to Controls

Commenter: AQC Environmental Brokerage Services, Inc.
Comment Number: EPA-HQ-OAR-2023-0234-0233
Page(s): 1-4

Commenter: Anonymous
Comment Number: EPA-HQ-OAR-2023-0234-0366
Page(s): 1

Comment 1: Commenter 0233: Under the proposed “Greenhouse Gas Reporting Rule: Revisions and Confidentiality Determinations for Petroleum and Natural Gas Systems,” section “4. Compressors Routed to Controls,” the EPA states:

“Centrifugal and reciprocating compressors are the only sources for which capture for fuel use and thermal oxidizers currently are specifically listed as dispositions for emissions that would otherwise be vented (see 40 CFR 98.233(o) and (p) introductory text). The EPA’s intent with the provisions is to differentiate flares, which are combustion devices that combust waste gases without energy recovery (per 40 CFR 98.238), from combustion devices with energy recovery, including for fuel use. However, some thermal oxidizers combust waste gases without energy recovery and therefore may instead meet the subpart W definition of flare. Consistent with section II.D of this preamble, in order to emphasize that the EPA’s intent is generally to treat emissions routed to flares and combustion devices other than flares consistently, we are proposing to remove the references to fuel use and to thermal oxidizers in 40 CFR 98.233(o) and (p) and 40 CFR 98.236(o) and (p). Instead, we are proposing to define ‘‘routed to combustion’’ in 40 CFR 98.238 to specify the types of non-flare combustion equipment for which reporters would be expected to calculate emissions.”

Under this amendment, the EPA is proposing to eliminate references to thermal oxidizers and instead, emissions routed to thermal oxidizers would be considered “routed to combustion.”

While we acknowledge the EPA's intent to differentiate between (1) flares and (2) combustion devices with energy recovery, we respectfully urge the agency to reconsider the proposed removal of references to thermal oxidizers. In alignment with the EPA's overarching goals in this revision, we propose an alternative approach: reporters should explicitly specify whether the employed thermal oxidizers incorporate energy recovery or do not incorporate energy recovery.

Our argument for retaining these references and adding this specification is grounded in several key considerations:

1. Regulatory Clarity and Consistency

The incorporation of thermal oxidizers as emissions dispositions within 40 CFR 98.233(o) and (p) contributes significantly to regulatory transparency. Numerous stakeholders within the relevant industries have incorporated thermal oxidizers into their emissions management strategies, recognizing them as effective methods for waste gas disposal. To sustain alignment with prevailing industry norms and to clarify the nature of the control technology in operation, it is logical for the EPA to preserve references to thermal oxidizers while including a differentiation based on energy recovery. This approach not only upholds consistency with established industry practices, but also furnishes essential clarity regarding the deployed emissions control mechanisms.

2. Further Incentivize Technological Advancements

Over time, the development of thermal oxidizers integrating energy recovery systems has yielded a dual benefit of emissions reduction and energy harnessing for productive applications. This has led to increased operational efficiency and a decrease in overall energy consumption. The preservation of references to thermal oxidizers in conjunction with the stipulation for reporters to distinctly indicate whether the thermal oxidizer incorporates or omits energy recovery serves as a compelling incentive for industries to embrace cleaner technologies. Moreover, it fosters an environment conducive to ongoing innovation in emissions mitigation—a central aim of the EPA's methane emissions reduction program objectives.

3. Precise Emissions Accounting and Improved Data Elements

Substituting the term "routed to combustion" for references to thermal oxidizers may introduce ambiguity into emissions reporting. Thermal oxidizers, irrespective of their energy recovery capabilities, are specifically designed to eliminate hazardous emissions. Their retention in the reporting framework ensures detailed emissions tracking, as opposed to their potential categorization under a broader term, which may not precisely illustrate the emissions disposition. Furthermore, distinguishing between thermal oxidizers with and without energy recovery holds significance for improvements in reported data elements. This differentiation would not only furnish the EPA and stakeholders with an additional data source but also guide informed decision-making for affected industries when selecting appropriate and effective emissions control strategies.

4. Aligning with Methane Emissions Reduction Efforts

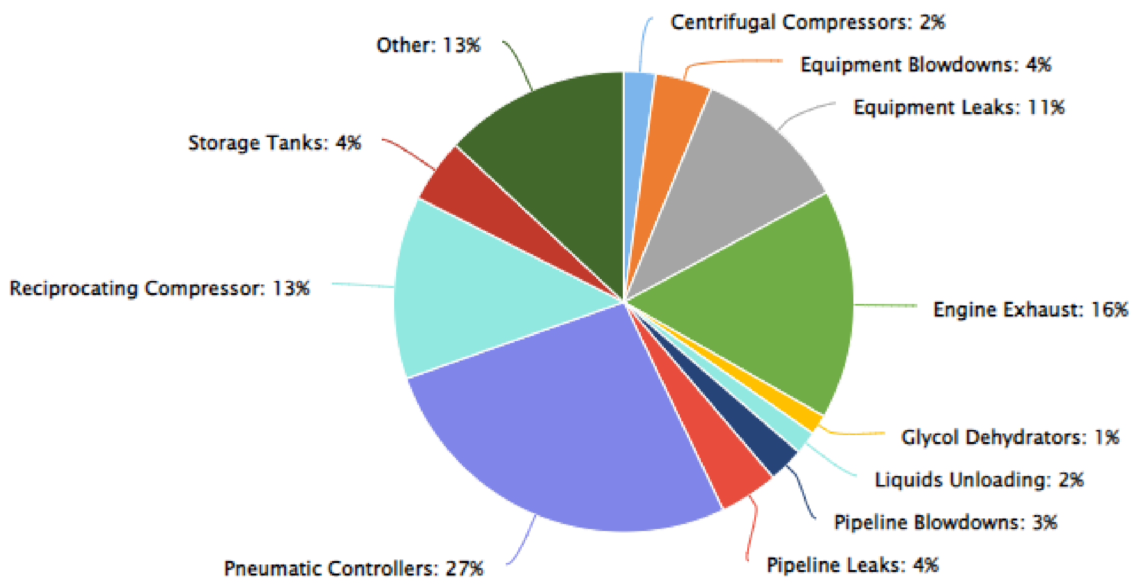
Thermal oxidizers assume a pivotal role in mitigating methane emissions, a potent greenhouse gas. They stand as a well-established technology for effective emissions management. By preserving references to thermal oxidizers and introducing specifications regarding their energy recovery capabilities, the EPA establishes precise delineations for reporting diverse control technologies and their respective efficiencies in emissions reduction. This consistent reporting framework facilitates a more accurate evaluation of advancements in curbing methane emissions across industries. Moreover, the removal of references to thermal oxidizers could inadvertently discourage the adoption of cleaner emission control technologies, potentially leading to the deployment of less efficient combustion devices. Such a shift might impede the industry's progress towards sustainable emission reduction and monitoring practices.

By recognizing the significance of thermal oxidizers and distinguishing between those with and without energy recovery capabilities, the EPA recognizes the environmentally beneficial solutions implemented by reporters and encourages their continued utilization by industries.

5. Thermal Oxidizers Are An Effective Methane Mitigation Technology

From the EPA website (Methane Mitigation Technologies Platform | US EPA) [https://www.epa.gov/natural-gas-star-program/methane-mitigation-technologies-platform], we learn that compressors and pneumatic controllers comprise 42% of methane emissions as shown here:

Percent of Total Oil and Gas Methane Emissions by Emission Source (Year 2021)



The most recent EPA 430-R-23-002, Inventory of U.S. Greenhouse Gas Emissions and Sinks finds that over 70 MMT CO_2e are contributed annually by these devices in the normal course of operation.

Along with retaining and encouraging the use of thermal oxidizers, the current EPA language states:

"Centrifugal compressor venting. If you are required to report emissions from centrifugal compressor venting as specified in § 98.232(d)(2), (e)(2), (f)(2), (g)(2), and (h)(2), you must conduct volumetric emission measurements specified in paragraph (o)(1) of this section using methods specified in paragraphs (o)(2) through (5) of this section; perform calculations specified in paragraphs (o)(6) through (9) of this section; and calculate CH_4 and CO_2 mass emissions as specified in paragraph (o)(11) of this section. If emissions from a compressor source are routed to a flare, paragraphs (o)(1) through (11) do not apply and instead you must calculate CH_4, CO_2, and N_2O emissions as specified in paragraph (o)(12) of this section. **If emissions from a compressor source are captured for fuel use or are routed to a thermal oxidizer, paragraphs (o)(1) through (12) do not apply and instead you must calculate and report emissions as specified in subpart C of this part.** If emissions from a compressor source are routed to vapor recovery, paragraphs (o)(1) through (12) do not apply. If you are required to report emissions from centrifugal compressor venting at an onshore petroleum and natural gas production facility as specified in §98.232(c)(19) or an onshore petroleum and natural gas gathering and boosting facility as specified in §98.232(j)(8), you must calculate volumetric emissions as specified in paragraph (o)(10); and calculate CH_4 and CO_2 mass emissions as specified in paragraph (o)(11)."

Given that compressors and pneumatic controllers are such a significant source of methane emissions without current and cost-effective solutions, the potential for an easy to implement thermal oxidizer solution and reporting structure as currently provided in the language of Subpart C can hasten the reduction of fugitive methane emissions. Enabling reporting under Subpart C will encourage more immediate action. We request that EPA retain the original language (above) but allow for both compressors and pneumatic controllers that utilize thermal oxidizers to report under Subpart C.

In conclusion, retaining references to thermal oxidizers under Subpart W is essential to provide regulatory clarity, support industry adoption of responsible emission control practices, and maintain alignment with the overarching goals of the proposed amendments. These references serve a dual purpose: firstly, they mirror prevailing industry norms, and secondly, they serve as a catalyst for the adoption of cleaner technologies, with a particular emphasis on thermal oxidizers incorporating energy recovery. Additionally, maintaining the ability for reporting under Subpart C for thermal oxidizers applied in both compressors and pneumatic controller applications will accelerate reductions of fugitive methane emissions. This strategic approach is instrumental in advancing the EPA's methane emissions reduction objectives, ultimately contributing to the attainment of the agency's goals.

We appreciate the EPA's commitment to improving emissions reporting accuracy, and we urge careful consideration of the associated challenges and effects that may arise with the proposed amendments. We recommend a balanced approach that minimizes the burden on reporting entities and encourages the use of beneficial emission control technologies, while still achieving the intended results in Subpart W reporting and the incentive to accelerate a change in operations with reporting under Subpart C by implementing thermal oxidizers. Thank you for considering our comments and feedback on this important matter.

Commenter 0366: EPA proposed to remove specific references to thermal oxidizers for compressors, which helps to make it clear that EPA did not mean for thermal oxidizers to be treated as something different than a flare or combustion equipment. It also helps to make clear that if units that aren't compressors are routed to a thermal oxidizer, they're not treated differently than compressors routed to a thermal oxidizer. EPA should keep this change.

Response 1: Commenter 0366 agreed with the proposed change to remove the references to fuel use and to thermal oxidizers in 40 CFR 98.233(o) and (p) and 40 CFR 98.236(o) and (p). Specifically, the proposal defined "routed to combustion" in 40 CFR 98.238 to specify the types of non-flare combustion equipment for which reporters would be expected to calculate emissions.

However, Commenter 0233 disagreed, asking for an alternative approach, wherein reporters would specify whether the thermal oxidizer used incorporates energy recovery or does not incorporate energy recovery.

One of the purposes of this amendment is to promote consistency across subpart W in treating emissions routed to combustion devices and emission routed to flares. The commenter's approach would continue to treat emissions routed to a thermal oxidizer differently from flared emissions and from emissions routed to combustion devices. There does not appear to be any difference in the information being reported or treatment of the emissions between the two approaches. Therefore, to retain consistency, the EPA is finalizing these amendments as proposed.

Commenter 0233 also asked that the EPA retain the previous language in 40 CFR 98.233, "If emissions from a compressor source are captured for fuel use or are routed to a thermal oxidizer, paragraphs (o)(1) through (12) do not apply and instead you must calculate and report emissions as specified in subpart C of this part."

The new language allows reporting under subpart C or paragraph (z) of subpart W: "If emissions from a compressor source are routed to combustion, … you must calculate and report emissions as specified in subpart C of this part or paragraph (z) of this section, as applicable…" The commenter's intent is unclear, especially when the proposed language offers an additional option. Therefore, the EPA is finalizing these amendments as proposed.

16.5 General Compressor Comments

Commenter: GPA Midstream Association
Comment Number: EPA-HQ-OAR-2023-0234-0299
Page(s): 17, 105-106

Commenter: Environmental Defense Fund, et al.
Comment Number: EPA-HQ-OAR-2023-0234-0413
Page(s): 62-63

Comment 1: Commenter 0299: The following is a list of substantive proposed changes that GPA expressly supports.

- Removal of the requirement to measure each compressor in the not-operating-depressurized ("NOD") mode every three years [98.233(o)(1)(i)(C) and (p)(1)(i)(D)];

…

- Allowing use of calibrated bags and high-volume samplers for centrifugal compressor wet seal oil degassing vent measurements [98.233(o)(2)(ii)];
- Removal of redundant reporting requirements of manifolding/controls at both the compressor and leak/vent level [98.236(o)(1)(vi)-(ix) and 98.236(p)(1)(vi)-(ix)];

…

Appendix A

Table of changes GPA supports as proposed.

Subpart	Citation	Change
…		
W	98.233(o)(1)(i)(A) 98.233(o)(1)(i)(B)	Centrifugal Compressors: Revising 98.233(o)(1)(i)(A) and (B) to reference 40 CFR 98.233(o)(2)(i) instead of specific subparagraphs of that paragraph that may be construed to limit the methods allowed for blowdown or isolation valve leakage measurements.
W	98.233(o)(10) 98.236(o)(5)	Centrifugal Compressors: Clarify that the compressor count used in Equation W-25 should be the number of centrifugal compressors with atmospheric (i.e., uncontrolled) wet seal oil degassing vents.
W	98.233(p)(1)(i)(A) 98.233(p)(1)(i)(B) 98.233(p)(1)(i)(C)	Reciprocating Compressors: Revising 98.233(p)(1)(i)(A), (B) and (C) to reference 40 CFR 98.233(p)(2)(i) instead of specific subparagraphs of that paragraph that may be construed to limit the methods allowed for blowdown or isolation valve leakage measurements.
W	98.233(p)(10) 98.236(p)(5)(B)	Reciprocating Compressors: Clarify that the compressor count used in Equation W-29D should be the number of reciprocating compressors with atmospheric (i.e., uncontrolled) rod packing emissions.
W	98.236(o)(1)(xiv) 98.236(p)(1)(xiv)	Compressors: Remove reporting requirement of whether compressor had scheduled shutdown.

<u>Commenter 0413</u>: 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 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.

Response 1:

The EPA acknowledges the commenters' support of the proposed revisions.

Commenter: American Petroleum Institute et al. (Part 1 of 2)
Comment Number: EPA-HQ-OAR-2023-0234-0402
Page(s): 51

Comment 2: Centrifugal and Reciprocating Compressor Venting

Alignment with NSPS measurement provisions should extend beyond onshore production and gathering and boosting industry segments.

Industry Trades support referring to the data made available through the provisions located at §60.5380b(a)(5) for centrifugal compressors and §60.5385b(b) and (c) for reciprocating compressors at onshore production and onshore natural gas gathering facilities, but do not support incorporating measurement requirements in Subpart W. The Industry Trades recommend that EPA should also do the same for any compressor subject the NSPS OOOOb or EG OOOOc, including those located at onshore gas processing, natural gas transmission and underground storage. Without this alignment for all compressors subject to the NSPS, many operators will be required to calibrate measurements according to two separate standards, which we do not believe was EPA's intent.

Response 2: The commenter noted that there should be alignment for all compressors that are subject to NSPS OOOOb, not only the compressors in the onshore production and gathering and boosting industry segments. Changes were made in subpart W for compressors in the onshore production and gathering and boosting industry segments to align with NSPS OOOOb because these compressors were not required to conduct as-found measurements for subpart W. If the compressors are going to be measured according to NSPS OOOOb, the EPA has requested that the measurement data be reported to subpart W as well. The commenter specifically referred to alignment for the onshore gas processing, natural gas transmission and underground storage industry segments. Compressors in these three industry segments are already required to conduct measurements for subpart W and will now be required to conduct measurements for NSPS OOOOb as well, so the intent of the comment is unclear. Without more specific recommendations, the EPA is unable to make other changes to the compressor requirements at this time.

See Section III.O.3 of the preamble to the final rule for the EPA's response to comments regarding the proposed language to require compressor measurements in NOD mode.

Commenter: American Petroleum Institute et al. (Part 1 of 2)
Comment Number: EPA-HQ-OAR-2023-0234-0402
Page(s): 51

Comment 3: Centrifugal and Reciprocating Compressor Venting

Alignment with NSPS Protocols – Measurement of Compressor Sources

In the proposal for NSPS OOOOb, rod packing, and seal vents are the only compressor sources that require monitoring. All other compressor leaks would be captured during the fugitive emissions inspections. The Industry Trades recommend that EPA align with the monitoring and fugitive emissions requirements of NSPS and consider leaks from other sources (e.g., blowdown valve leakage) fugitive leaks. This modification would eliminate the need for specific compressor mode testing and align with other EPA regulations for other sources.

Response 3: Subpart W has always distinguished between fugitive emission leaks, under 40 CFR 98.233(q) and 40 CFR 98.233(r), and compressor emissions measurements by specifying the compressor mode and the location where the emissions should be measured for each mode-source combination in 40 CFR 98.233(o) and 40 CFR 98.233(p). To avoid confusion between compressor monitoring and equipment leak inspections, the EPA is finalizing these requirements as proposed.

Commenter: Kirk Frost
Comment Number: EPA-HQ-OAR-2023-0234-0389
Page(s): 3

Comment 4: Within the natural gas supply chain, substantial methane emissions occur at every section of the supply chain… In reviewing over the documentation of the EPA docket, it is clear there are millions if not billions of tons of methane not being accounted for in the EPA greenhouse gas inventory. I have known this because I have tracked the annual emissions reporting from various transmission pipeline companies. Where for electric compressor stations, no emissions were being reported despite owner/operators reporting to FERC anticipated 100 to 150 tons of methane emitted each year from electric compressor stations (from venting and other fugitive sources). Additionally, the natural gas fired turbine compressor stations claiming impossibly low annual emissions amounts such as 1 ton of methane each year, despite the Solar specifications for the turbines indicate that 4 to 8 tons of methane would be emitted as unburned methane in the smokestack. Note, the owner operator provided the Solar specifications in their application to FERC. It isn't like the owner operator isn't aware of it. But since AP-42 doesn't appear to recognize this source of emission, it isn't being reported.

Response 4: The sources covered by AP-42 do not determine what is or is not reported to Subpart W. Regardless, the rule does not exclude electric compressors. 40 CFR 98.238 defines "Compressor" as "any machine for raising the pressure of a natural gas or CO_2 by drawing in low pressure natural gas or CO_2 and discharging significantly higher pressure natural gas or CO_2." While "compressor station" is not specifically defined in Subpart W, there are no exclusions in Subpart W for electric compressor stations.

17 Equipment Leak Surveys

17.1 Revisions and Addition of Default Leaker Emission Factors

Commenter: Teledyne FLIR, LLC
Comment Number: EPA-HQ-OAR-2023-0234-0244
Page(s): 1-2

Commenter: SENSIA Solutions S.L.
Comment Number: EPA-HQ-OAR-2023-0234-0279
Page(s): 1-2

Commenter: Arkansas Independent Producers and Royalty Owners (AIPRO)
Comment Number: EPA-HQ-OAR-2023-0234-0382
Page(s): 15

Commenter: Step2compliance
Comment Number: EPA-HQ-OAR-2023-0234-0395
Page(s): 1-2

Commenter: American Gas Association (AGA) and American Public Gas Association (APGA)
Comment Number: EPA-HQ-OAR-2023-0234-0418
Page(s): 12

Comment 1:

Commenter 0244: Teledyne FLIR (f.n.a. FLIR Systems, Inc.) has a longstanding tenure working with the Environmental Protection Agency, the Oil and Gas industry, state regulatory agencies, LDAR service providers, and many others in the methane and VOC emissions mitigation industries to ensure that the appropriate solution is used to guarantee the most effective, and efficient, means to reduce emissions in the United States' Oil and Natural Gas Sector, and beyond. As the pioneer of Optical Gas Imaging (OGI) with the release of the first commercial OGI camera, the GasFindIR, in 2005, we have worked diligently to lead the transition of emissions mitigation to include innovative technologies that can achieve desired emissions mitigation in a cost-effective manner while limiting the operational impact to the oil and natural gas infrastructure in the United States.

Our goal is to ensure that technology can appropriately support regulation for emissions mitigation that ensures the safety of the environment and public health in an economically and technically feasible manner. As the technology leader for OGI which has been determined in other U.S. EPA regulations, specifically the 2016 Methane NSPS OOOOa regulation, as the Best System for Emissions Reduction (BSER), we would like to submit our feedback and questions on the numerous requests for comment in the docket ID No. EPA-HQ-OAR-2023-0234.

In this regulatory framework tied to greenhouse gas reporting, we feel that the technology of Optical Gas Imaging has been unfairly targeted and punishes oil and gas operators that advocate for advanced Leak Detection and Repair (LDAR) technologies in order to reduce more methane emissions affecting our environment and the U.S. population as a whole. Additionally, the technology of Optical Gas Imaging has advanced greatly over the past few years to include the ability to quantify leaks directly, while using the technology as determined by other U.S. EPA regulations.

This regulation on Greenhouse Gas Reporting does an effective job in highlighting the updated empirical data available since the previous versions of these regulations yet only provides limited reporting that is taken with small subsets of information encompassing very minimal parts of the U.S. oil and gas operations footprint. The Pacsi study referenced in this docket considers only 700 leaks found during the study whereas the state of Colorado reports that annually, in 2021 specifically[1], there are 16,778 leaks in that state alone. It is even stated in this study that "there are more than one million active oil and gas wells (U.S. EPA 2017a) in the United States, and the 67 sites in this study would compose a small fraction of overall sites". [1]

Additionally, the data is used with only some of the information available in the report to seemingly encourage higher emission factors while ignoring the data that highlights how advanced technology, like Optical Gas Imaging, reduces emissions more effectively when used. As an example, the Pacsi study referenced in the docket is a baseline for adding an "OGI enhancement factor" for leaker emissions factors for onshore petroleum and natural gas production and onshore petroleum and natural gas gathering and boosting. Much of this is based on the fact that OGI is able to find leaks that are higher in size than Method 21 (66% of total leaks were only detected by an FID) but these missed leaks were both under the defined leak definition by the U.S. EPA in Subpart OOOOa of 60 grams per hour and only accounted for 3.3% of the overall emissions in the study.

In this study, it is highlighted that Optical Gas Imaging can detect leaks that reduce the overall impact of emissions to the environment better than Method 21. As an example, OGI reduces overall emissions 15% better compared to Method 21 using 10,000 PPM as a leak definition. This shows that OGI as a technology is better at reducing emissions in the oil and gas sector overall than other technologies that are specifically designed to detect the smallest of leaks. In fact, the study stated that Optical Gas Imaging may have "a larger emission reduction potential" than FID is used in the field.

We feel that the "OGI enhancement factor" should be removed from the leaker emission factors to help encourage, and not punish, operators interested in leveraging advanced technology in reducing the overall emissions in the U.S. more effectively. If the U.S. EPA chooses to keep this in the regulation and is going to punish operators interested in reducing overall emissions in the oil and gas sector, we feel that there should also be an "OGI factor" when using population counts as emission factors. This should allow operators using OGI to reduce the emissions required to report by, at a minimum, 15% lower than the designated population emission factor of Method 21 to align with the Pacsi study leveraged in the enhancement factor. As an example, if the current regulations call for an emission factor of 9 scf whole gas/hour/unit, this number should be the population emission factor when using Method 21 and the population emission factor for operators using OGI should be 7.65 scf whole gas/hour/unit (Method 21 population emission factor * 0.85), at a maximum.

Footnote:

[1] https://cdphe.colorado.gov/2021-ldar-annual-reports

Commenter 0279: Emissions Factors

The rationale of assigning a higher emissions factor to the oil and gas producers using OGI for emissions measurement and reporting is contradicted by the very source cited as evidence in Subpart W. As stated in Subpart W where citing the study Pacsi et al. (2019) on page 50345 of the Federal Register Vol. 88 No. 146, Tuesday, August 1, 2023 of Proposed Rules, OGI detects 15% more leak events than Method 21 at a leak definition of 10,000 ppm and 1% more effective than Method 21 with a leak definition of 500 ppm. This finding is contradictory to the proposed reporting calculation of higher emissions being assigned to companies that utilize OGI technology. This study accompanied by our field expertise calls for a revision of the proposed emissions factor reporting guidelines of Subpart W that would effectively dissuade the oil and gas industry from using a more accurate emissions measurement technology than Method 21, leading to more methane emissions than would be reported. This could lead to inaccurate data of emissions quantifications and could have a wide range of negative implications to the environment and the future decisions taken by implementing the proposed reporting framework.

Commenter 0382: **Equipment Leak Surveys:**

AIPRO disputes that the "multiple" studies referenced as the basis for proposed revisions which would: 1) establish different leaker emissions factors in Table W-2 for leaks detected via methods other than Method 21, compared to those that are detected with Method 21, and 2) support the addition of the requirement to use an "OGI Enhancement" factor for surveys in other segments required to report under Subpart W besides the Onshore Production and Gathering & Boosting segments. The studies are not representative of all operations required to calculate and report GHG emissions under Subpart W and would arbitrarily cause emissions to be higher for leaks detected with the most commonly used and approved technique, OGI leak surveys in accordance with NSPS OOOOa. Further, AIPRO specifically incorporates the comments prepared by API related to proposed revisions to default whole gas leaker emissions in Table W-2.

Commenter 0395: In these proposed changes tied to greenhouse gas reporting, we feel that the technology of Optical Gas Imaging (OGI) has been unfairly targeted and punishes oil and gas operators that have made investments in advanced Leak Detection and Repair (LDAR) technologies in order to reduce more methane emissions. Additionally, OGI technology has advanced over the past few years to include the ability to quantify leaks directly and while using the technology as determined by other U.S. EPA regulations, like NSPS OOOOa. In the proposed NSPS OOOOb and EG OOOOc, OGI was determined to be the Best System for Emissions Reduction (BSER), yet this proposed rulemaking implements an "OGI enhancement factor" for the leaker emission factors that penalizes the use of OGI. If OGI was determined to be BSER over Method 21 with a 500ppm leak definition under the proposed NSPS OOOOb and EG OOOOc, it seems that the same logic for BSER should carry through to the GHG reporting rule and the leaker emission factors. The proposed OOOOb/c work to encourage operators and vendors to continue to pursue and develop advanced monitoring technologies, yet the proposed emission factors in subpart W disincentivize that due to the Inflation Reduction Act and the corresponding methane waste emissions fee that will be charged on a per ton basis based on what is reported by operators in their annual subpart W report.

Congress recognized that the current Subpart W, that relies on the use of presumptive, activity based emission factors was inadequate for the purpose of implementing a Methane Waste Emission Charge, as the current framework only provides limited reporting that utilizes emissions factors taken with small subsets of information from a minimal portion of the U.S. oil and gas operations footprint. Congress directed the EPA to revise the Subpart framework to "ensure the reporting under such subpart, and calculation of charges under subsections (e) and (f) of this section, are **based on empirical data**…accurately reflect the total methane emissions and waste emissions from the applicable facilities, and **allow owners and operators of applicable facilities to submit empirical emissions data**…" Yet, the Pacsi study referenced in the docket that was the primary study leading to the adjustment to the OGI leaker factors was a very limited study. It only considered 700 leaks found at 67 sites, whereas the state of Colorado consistently reports a minimum of 16,000 plus leaks annually since the start of its annual LDAR reporting program in 2014. Those leak numbers are for a single state. The Pacsi study references that there are "more than one million active oil and gas wells (U.S. EPA 2017a) in the United States, and the 67 sites in this study would compose a small fraction of overall sites." The study was also limited to four different geological regions, to a single OGI camera make and model, and did not provide the details of the training or certification of the camera operator who was performing the inspection. Although the report was written in 2019, the surveys referenced in the study were conducted in June through December of 2015, nearly 8 years ago, which does not seem representative of what is currently feasible with OGI. Additionally, the study found that OGI can detect leaks that reduce the overall impact of emissions to the environment better than Method 21.

We believe that the data being used to implement the new OGI enhancement factors is insufficient and is not representative of the capabilities of OGI. EPA should consider newer studies that include newer OGI technology, a broader spectrum of facility types and regions, a larger number of leaks, and defined standards of camera technician experience. There are many companies and vendors who have conducted field trials and blind release studies over the past couple of years that should be considered as part of the determination for estimating emission factors for inspections performed using OGI.

<u>Commenter 0418</u>: **While the Associations support EPA's proposal to allow the use of direct measurement to quantify emissions from equipment leak components, several additional improvements would increase the accuracy of distribution segment emissions estimates.**

EPA is proposing to revise the method of quantifying emissions via equipment leak surveys under Subpart W. The current calculation method uses (1) the count of leakers detected using a leak detection method listed in 40 C.F.R. § 98.234(a), (2) the Subpart W leaker emission factors for specific component types and leak definitions, and (3) an estimate of the total time that the surveyed components were assumed to be leaking and operational. In the 2022 Proposal, EPA proposed to provide separate leaker factors for leaks detected using optical gas imaging ("OGI") vs. other leak detection methods. For downstream industry segments, the proposed OGI emission factors were estimated using an "OGI enhancement factor," which was estimated as the ratio between the OGI emission factors and the Method 21 emission factors that EPA proposed for the upstream industry segments. The Proposed Rule would maintain the previously proposed approach of having separate emission factors for OGI-detected leaks but would update the proposed downstream emission factors based on a revised "OGI enhancement factor" that uses more recent study data.[39]

…

The Associations oppose both of these proposed adjustment factors.

Footnotes:

[39] According to EPA, the Zimmerle et al. (2020) and Pasci et al. (2019) studies use more recent data and a larger dataset than what was used for the current emission factors. *See* Proposed Rule, 88 FR 50343. The Associations concur in INGAA's detailed analysis of why these studies should not be used to estimate downstream emissions

Response 1: See Section III.P.1 of the preamble to the final rule for the EPA's response to this comment.

Commenter: Independent Petroleum Association of America (IPAA)
Comment Number: EPA-HQ-OAR-2023-0234-0265
Page(s): 4-5

Commenter: GPA Midstream Association
Comment Number: EPA-HQ-OAR-2023-0234-0299
Page(s): 51, 91

Commenter: Endeavor Energy Resources, L.P.
Comment Number: EPA-HQ-OAR-2023-0234-0381
Page(s): 17

Commenter: CrownQuest Operating
Comment Number: EPA-HQ-OAR-2023-0234-0393
Page(s): 247, 250, 640

Commenter: Williams Companies, Inc.
Comment Number: EPA-HQ-OAR-2023-0234-0394
Page(s): 11-12

Commenter: The Petroleum Alliance of Oklahoma
Comment Number: EPA-HQ-OAR-2023-0234-0398
Page(s): 16

Commenter: Western Energy Alliance
Comment Number: EPA-HQ-OAR-2023-0234-0399
Page(s): 11

Commenter: American Petroleum Institute et al. (Part 1 of 2)
Comment Number: EPA-HQ-OAR-2023-0234-0402
Page(s): 53-54

Commenter: Encino Energy (EAP Ohio, LLC)
Comment Number: EPA-HQ-OAR-2023-0234-0408
Page(s): 2-3

Commenter: Environmental Defense Fund, et al.
Comment Number: EPA-HQ-OAR-2023-0234-0413
Page(s): 64-65

Commenter: North Dakota Petroleum Council (NDPC)
Comment Number: EPA-HQ-OAR-2023-0234-0417
Page(s): 8-9

Comment 2:

Commenter 0265: Specific Proposals

EPA actions to revise component emissions factors raise serious questions about both the approach and the proposal. As discussed above, the Inflation Reduction Act mandate to revise Subpart W requires EPA to conduct thorough analyses of the numerous emissions factors and either independently validate them or develop its own valid factors. It failed to do either.

Instead, it turned to three reports as the basis for new emissions factors. These reports are generally referenced as Zimmerle[5], Pacsi[6] and Rutherford[7].

However, EPA's use of these materials demonstrates a callous disregard for the mandate EPA must meet in revising Subpart W. The Zimmerle report addresses emissions from gathering compressor stations; the Pacsi report addresses emissions from oil and natural gas production equipment leaks. Each of these studies conclude that the current emissions factor calculation process under Subpart W overstates emissions that they studied. The Zimmerle report states:

> Combining study emission data with 2017 GHGRP activity data, the study indicated statistically lower national emissions of … 66% … of current GHGI estimates, despite estimating 17% … more stations than the 2017 GHGI ….

The Pacsi report states:

> The most common EPA estimation method for greenhouse gas emission reporting for equipment leaks, which is based on major site equipment counts and population-average component emission factors, would have overestimated equipment leak emissions by 22% to 36% for the sites surveyed in this study as compared to direct measurements of

> leaking components because of a lower frequency of leaking components in this work than during the field surveys conducted more than 20 years ago to develop the current EPA factors.

To show the EPA lack of regard for its mandate, EPA ignores these conclusions and cherry picks elements of the reports to increase the component emissions factors in Subpart W. The Rutherford study takes a different approach. It makes the assumption that component based emissions estimates understate actual emissions because it believes that ambient monitoring presents more accurate results. Consequently, it surveys a variety of component based emissions studies to create emissions factors higher than those in the current Subpart W and adopts them as more accurate.

Critically, EPA embraces all these various changes that increase the Subpart W emissions factors, but it never attempts to independently validate them. The effect of this action is increases in virtually every component emissions factor, some of which would yield emissions estimates 5 times or more than the current Subpart W calculations. Not only is this approach a clear dereliction of EPA's responsibilities, but it also has the effect (along with changing the GWP for methane) of de facto lowering the 25,000 mt/year threshold and raising the emissions subject to methane tax. Enverus Intelligence Research, a subsidiary of the energy-focused Software as a Service firm Enverus, has found the proposed regulations would more than double 2021 reported methane and increase overall carbon dioxide-equivalent emissions by 41%. If EPA is intentionally revising the Congressionally enacted methane tax through its rulemaking actions, it should be held to a standard that requires it prove that its revisions are valid.

Footnotes:

[5] Zimmerle, D., *et al.* "Methane Emissions from Gathering Compressor stations in the U.S." *Environmental Science & Technology* 2020, 54(12), 7552-7561, available at *https://doi.org/10.1021/acs.est.0c00516*.

[6] Pacsi, A. P., *et al*. "Equipment leak detection and quantification at 67 oil and gas sites in the Western United States." *Elem Sci Anth*, 7: 29, available at *https://doi.org/10.1525/elementa.368*. 2019

[7] Rutherford, J.S., Sherwin, E.D., Ravikumar, A.P. *et al*. *Closing the methane gap in US oil and natural gas production inventories*. Nat Commun 12, 4715 (2021). *https://doi.org/10.1038/s41467-021-25017-4*

<u>Commenter 0299</u>: **EPA should not finalize the proposed whole gas emission factors for OGI.**

GPA proposes that EPA retain the current alignment between the whole gas leaker emission factors for Method 21 at a 10,000 parts per million ("ppm") leak definition and OGI.[113] In the final NSPS OOOOa rule, EPA specified in response to a comment within the published version of NSPS 40 C.F.R. Part 60, Subpart OOOOa that:

Available data show that OGI can detect fugitive emissions at a concentration of at least 10,000 ppm when restricting its use during certain environmental conditions such as high wind speeds. Due to the dynamic nature for the OGI detection capabilities, OGI may also image emissions at a lower concentration when environmental conditions are ideal. Because an OGI instrument can only visualize emissions and not the corresponding concentration, any components with visible emissions, including those emissions that are less than 10,000 ppm, would be repaired.[114]

It is improper for EPA to create a whole gas leaker emission factor for the proposed 98.234(a)(1) (OGI) that is almost double the proposed value of 98.234(a)(7) (Method 21 at a 10,000 ppm leak definition). It would not be empirical data specifying an emission factor of this magnitude simply because of the leak detection instrument, especially when according to EPA in NSPS OOOOa, OGI achieves the same level of emission detection as using the Method 21 instrument when it is calibrated to detect emissions at a threshold of 10,000 ppm or greater.

In addition, EPA's analysis for the proposed NSPS OOOOb identified OGI as both cost-effective and as the BSER for well sites and compressor stations, providing a viable alternative to Method 21. Further, as corroborated by the studies referenced in this proposal, namely Pacsi et al. (2019) and Zimmerle et al. (2019), OGI has emerged as a predominant tool for leak detection in the oil and gas industry. It appears that EPA has transitioned from one effective leak detection method in the final version of NSPS OOOOa, which offered cost-effective relief, to imposing seemingly unrealistic emission factors for whole gas leakers in this proposed version of Subpart W. This shift raises concerns that EPA may be penalizing those who rely on OGI as their primary leak detection method by limiting the potential for substantial emission reductions and is in direct conflict with NSPS OOOOa.

…

Proposed Change: EPA is proposing to separate leaker emission factors based on the survey technique: (1) Method 21 > 10,000 pm (2) Method 21 > 500 ppm and (3) OGI/IR/Acoustic.

> **Comment**: GPA finds many of EPA's conclusions regarding the addition of leaker emission factors for survey methods other than Method 21 troubling. First, EPA chose to ignore results from two of the four recent studies for equipment leak emissions based on a weak rationale. EPA disregarded the 2011 Fort Worth Study primarily because it was geographically limited and utilized the Bacharach Hi-Flow Sampler. EPA also ignored the 2013 Allen Study because it utilized the Bacharach Hi-Flow Sampler. Geographic constraints should have no bearing on the validity of data, and the Bacharach Hi-Flow Sampler is widely used for measurement of methane emissions. There is no known rationale for assuming the Bacharach Hi-Flow Sampler results are invalid. The equipment was not discontinued by the manufacturer due to issues in its performance, but because it was no longer profitable for them to manufacturer. As EPA notes in the Technical Support Document, Bacharach is the sole manufacturer of a commercial high flow sampler. Furthermore, EPA was comfortable in using the 2020 Zimmerle Study results even though the study utilized a "redesigned" high-flow sampler fabricated with Bacharach parts by Colorado State University and SLR Consulting that has not undergone extensive testing to validate its accuracy. It makes no sense to disregard one

study for use of a commercial high-flow sampler, but use a study based on a piece of equipment designed as part of collegiate research. In doing so, EPA appears to be cherry-picking scientific studies to justify revision of emission factors.

EPA also states that "these studies showed that OGI finds fewer yet larger leaks than EPA's Method 21. Therefore, the application of the same leaker emission factor to leaking components detected with OGI and Method 21 with a leak definition of 10,000 ppm, as is currently done in Subpart W, underestimates the emissions from leakers detected with OGI.[27]" GPA disagrees with this conclusion, as the only study to compare OGI with Method 21 was the 2011 Forth Worth Study, which has been disregarded. Furthermore, the 2020 Zimmerle study focused on OGI camera operator bias and not technological capabilities. EPA is also ignoring years of technical support justification for the use of OGI in lieu of Method 21 at 10,000 ppm that has been used in promulgating NSPS OOOOa and other Alternative Work Practices, including in the recently proposed OOOOb/c, where EPA states, "our analysis shows that the proposed standards, which use OGI, achieve equivalent reduction of VOC and methane emissions as the current standards, which are based on EPA Method 21, but at a lower cost."[28] Absent any new comprehensive studies comparing technological capabilities of OGI and Method 21 simultaneously at facilities, GPA believes that the justification of revised leaker emission factors is flawed. At minimum, based on previous technical support documentation, the leaker emission factors for OGI should be the same as Method 21 at 10,000 ppm.

Footnotes:

[113] Table W-1E, W-3A, and W-4A of 2017 revision of Subpart W

[114] 81 Fed. Reg. 35,824, 35,856-57 (June 3, 2016).

[27] Technical Support Document at 35 ("TSD"); *see also* 87 Fed. Reg. at 36,976**.**

[28] 86 Fed. Reg. 63,110, 63,182 (Nov. 15, 2021).

Commenter 0381: **EPA Should Reconsider the Proposed Revisions to Calculation Methods for Several Emission Sources.**

Equipment Leak Surveys

Endeavor supports the retention of flexibility to use either direct measurement or calculation methods to determine emissions from equipment leaks.[52] We also support the option to develop site-specific emission factors for use in lieu of default emission factors.[53] We believe both proposals will help advance the IRA's call for accurate, empirical data collection, while also ensuring flexibility for reporters to account for disparities in resources, assets, and geography.

That said, Endeavor has concerns with EPA's new set of higher default emission factors for leaks detected via optical gas imaging ("OGI"), infrared laser, or acoustic methods.[54] Many within the industry use OGI in concert with other systems (e.g., SOOFIE, aerial flyovers) to conduct leak detection across their assets. EPA is proposing a new set of higher emission factors. But the Agency does so based on studies such as Zimmerle *et al*. (2020) and Pacsi *et al*. (2019), [55] which cannot support increased emissions factors. For one thing, Zimmerle *et al*. (2020), as EPA acknowledges, did not include Method 21 inspections in its analysis and thus could not have drawn any comparison between Method 21 and OGI, much less justify a new set of OGI-specific emission factors. [56] For another, Pacsi *et al*. (2019), which did use both Method 21 and OGI inspection results, noted that (1) the leaks detected using OGI had higher average emissions per leaking component than in previous direct measurement studies and (2) "the current default emission estimation approach" for equipment leaks "would have overestimated detected and measured emissions from leaking components at the[] [studied] sites by 22% to 36%, depending on the handling of instrument response factors."[57] These limitations and findings thus do not support a finding that higher, OGI-specific emission factors would lead to more accurate, empirical emissions data, as required by the IRA. Likewise, because these studies do not support the proposed emissions factors, EPA does not have the record support for the proposed factors as required by the APA.

Endeavor thus urges EPA to reconsider the use of higher, OGI-specific emission factors and withdraw the currently proposed set of factors until additional studies are conducted to verify the need for new factors to increase accuracy. Retaining the higher emission factors would conflict with the IRA's directive to ensure more accurate reporting.

Footnotes:

[52] *Id*. at 50,345 (characterizing direct measurement "[a]s an alternative" to calculation via emission factors).

[53] *Id*. at 50,346–47.

[54] *Id*. at 50,343–45.

[55] *Id*.; *see id*. at 50,438–39 (proposed Table W-2).

[56] *See* Daniel Zimmerle et al., *Methane Emissions from Gathering Compressor Stations in the U.S.*, 54 Env't Sci. & Tech. 7552–61 (2020), *available from docket* at https://tinyurl.com/534hejef; *see also* 88 Fed. Reg. at 50,343 (noting that Zimmerle *et al*. (2020) "study contains hundreds of quantified leaks detected using OGI," in contrast with Pacsi *et al*. (2019), which "also contains hundreds of equipment leak measurements from sites that were screened using Method 21").

[57] *See* Adam P. Pacsi et al., *Equipment Leak Detection and Quantification at 67 Oil and Gas Sites in the Western United States,* 7(29) Elementa: Sci. of the Anthropocene 8–9 (2019), *available from docket at* https://tinyurl.com/5btdb63t.

Commenter 0393: The onshore petroleum and natural gas production emission factors are vastly overestimated based off limited data and a few studies. API's program The Environmental Partnership has been learning, corroborating, and acting on leaks since 2017. The Partnership is comprised of more than 100 companies covering 47 of the 50 states and nearly 70% of US onshore oil and natural gas production.

In the 2022 annual report, the Partnership boasts some excellent progress in emissions reductions. In terms of leak detection and repair, the program reported a 0.07% leak occurrence rate, or less than 1 component leaking in a thousand. More than 157,000 site surveys, more than 664,000 surveys conducted, and more than 202 million component inspections performed. In terms of accelerating progress for the leak detection and repair program, from 2019-2022 the program boasts the following numbers: more than 903 million component inspections performed and nearly 1.9 million surveys conducted.

As you can see, the partnership has compiled quite the amount of data showing excellent progress in terms of leak detection. With all this public and pertinent data, the EPA should review and adjust the proposed emission factors. They are too high, and not representative of what is taking place in the field. As stated in other comments throughout this package, the EPA should allow operators to derive their own emission factors through actual measurement and engineering.

…

It is of our opinion that the EPA needs to look at the available data through leak surveys and data from the Environmental Partnership to adjust the emission factors. An alternative for the emission factors would allow the operator to institute OGI surveys to provide more realistic emission factors, with the possibility of being able to use OGI cameras to document and quantify ACTUAL emission factors. Along with the use of OGI cameras, operators should be allowed to implement a representative emission factors based off equipment type. Similar to representative sample analysis for calculations, obtaining these emission factors would be much less-time consuming, less expensive, less burdensome and would provide actual measurements that are most realistic instead of using highly inaccurate factors picked from a couple of studies.

…

These studies did have a significant amount of data for a study, but they pale in comparison to the amount of data that has been obtained through LDAR surveys and The Environmental Partnership database.

…

Site specific leaker emission factors:

…

It is concerning the proposed higher emission factors that EPA have derived from the Pasci et al and Zimmerle et al studies, especially for OGI detection. This is in comparison to the existing Subpart W and Pacsi et al leaker emission factors. When we compared the published study results from Pasci and Zimmerle that EPA proposed, it seems unclear on how the EPA came up with these proposed factors. For example, the EPA states that the Pasci et al study OGI captured ~80% of emissions, and Method 21 (500 ppm) detected 79%, and Method 21 (10,000 ppm) captured 65% of emissions. But the EPA is proposing much higher leaker emission factors for OGI than Method 21 factors for all components. We disagree with the proposal to use higher emission factor to OGI surveyed components since the Pasci study supports that OGI found more leaks than Method 21. OGI should show a lower factor than Method 21.

Zimmerle et al study shows that emissions from compressor type components have much higher leak rates due to vibration. EPA did not distinguish between components associated with or not with compressors. The average proposed emission factors seem to include compressor-related components. This would overstate emissions from the more obvious non-compressor related components. It is our opinion that EPA carefully review the emission factors and consider including compressor related components in the breakdown of the leaker factors. This would substantially lower emission factors for non-compressor related components. Doing this would also avoid significant overstatement of methane emissions from the more common population of non-compressor related components.

Commenter 0394: Increases in Optical Gas Imaging (OGI) Emission Factors

In the current Subpart W Rule, the EPA lists leaker emission factors in Tables W-2, W-4, and W-6 according to the industry segment, equipment component type, and survey method employed. The three survey methods are: (1) Method 21 using an organic vapor analyzer calibrated to a minimum detection level of 10,000 ppm; (2) Method 21 using an organic vapor analyzer calibrated to a minimum detection level of 500 ppm; and (3) optical gas imaging (OGI). The Proposed Rule updates leaker emission factors for equipment components in Tables W-2, W-4, and W-6 based on published data by Pacsi et al.[28] and Zimmerman et al.[29]. In most cases, the updated emission factors are significantly higher than the emission factors in the current Subpart W Rule, with increases in the OGI survey method emission factors being most apparent.

Williams questions the validity of the updated emission factors for the OGI survey method. OGI is widely regarded by many, including the EPA[30], to be capable of detecting equipment leaks to = 10,000 ppm under normal conditions. This fact raises the question of why the OGI emission factors proposed in Tables W-2, W-4, and W-6 are up to 1.7 times higher than those proposed for Method 21 with an equivalent 10,000 ppm detection level. This obvious contradiction calls into question the representativeness of the data set and the methodology employed by the Agency to derive the OGI emission factors. The EPA should not revise the emission factors for the OGI survey method while it gathers data from additional research utilizing larger and more representative data sets. Otherwise, owners / operators may be hesitant to use the OGI survey method, a method the EPA identified as a Best System of Emissions Reduction (BSER) for fugitive emissions from compressor stations.[31]

Footnotes:

[28] Pacsi, A.P., et al. Equipment Leak Detection and Quantification at 67 Oil and Gas Sites in the Western United States, ELEM SCI ANTH, 7: 29, Item No. EPA–HQ–OAR–2014–0831–0006.

[29] Zimmerle, D., et al., Methane Emissions from Gathering Compressor stations in the U.S., ENVIRON. SCI. & TECH. 2020, 54(12), 7552–7561, available at https://pubs.acs.org/doi/abs/10.1021/acs.est.0c00516.

[30] "Oil and Natural Gas Sector: Emission Standards for New, Reconstructed, and Modified Sources" (Final Rule), Docket ID No. EPA–HQ–OAR–2010–0505; FRL–9944–75– OAR, 81 Fed. Reg. 35836-37, 35826, June 3, 2016.

[31] Id.

Commenter 0398**:** Revisions and Addition of Default Leaker Emission Factors. EPA is proposing to add an "enhancement factor" to the leaker emission factors.

The Alliance is concerned that adding enhancement factors on top of existing estimated emission factors for sources in all situations will result in overestimation of emissions. In reviewing the supporting studies (Pasci et al and Zimmerle et al) that EPA is relying on, it is unclear how EPA derived these enhancement factors.

Action Requested: We request EPA provide specific details of how it derived these enhancement factors and clarify how these enhancement factors do not overestimate emissions under all scenarios.

Commenter 0399: The Alliance supports the revision of emission factors for equipment leaks and the data sources referenced within the proposal. However, the final emission factor numbers that EPA derived from that source are puzzling and do not align with the published literature. Revised component emission factors both for surveyed leaks and by population count are increasing several times on average to be much higher than published values and more importantly, for Optical Gas Imaging (OGI) surveys, the leaker factors are much higher than for Method 21 surveys. This conflicts with the goals of both EPA's OOOOb/c rules and various state emissions rulemakings, which continue to emphasize the importance and efficacy of OGI and alternative technologies. Instead, Subpart W appears to be incentivizing using Method 21 in lieu of more modern, advanced measures. Not only would this shift operators towards using methodology that takes more time and effort, thus reducing the availability of staff to do more frequent, yet still very effective OGI and other surveys, it also would inaccurately shift emissions data to somehow show that operators using Method 21 somehow had fewer emissions, which is not demonstrated in the data.

…

Recommendation: EPA should adopt the emission factors as proposed for the use of Method 21 regardless of survey methodology used. EPA should also eliminate the proposed use of an enhancement factor.

Commenter 0402: Equipment Leaks

Method 1 - Default Leaker Emission Factors

The derivation of the proposed OGI leaker emission factors is unclear and values appear high relative to the underlying studies and would overstate emissions from the more prevalent non-compressor related components.

The Industry Trades support the use of data from the Pacsi *et al* study to develop the leaker emission factors. However, we are concerned about the significantly higher emission factors that EPA has derived from the Pacsi *et al* and Zimmerle *et al* studies, especially for OGI leak detection, as compared to the existing Subpart W and Pacsi *et al* leaker emission factors. When comparing the published study results from Pacsi and Zimmerle to the EPA proposed emission factors (see comparison table below), it is unclear how the proposed emission factors were derived and while a generalized description is provided in the TSD, the supporting calculations are necessary to fully understand the approach EPA has taken.

Component	EPA Proposed Emission Factors (scf/hr/component)			Pacsi et al (scf/hr/component)	Zimmerle et al, (scf/hr/component)[a]	
	OGI	Method 21 @ 10,000 ppm	Method 21 @ 500 ppm		Non-compressor components	Compressor components
Leaker EFs, Gas Service – Onshore Production & Gathering and Boosting						
Valves	16	9.6	5.5	6.0	7.1	36.9
Flanges	11	6.9	4.0	13.7	6.2	8.8
Connectors	7.9	4.9	2.8	2.8	4.7	11.9
OELs	10	6.3	3.6	8.5	3.94	
PRVs	13	7.8	4.5	1.1	10.0	18.5
Pump Seals	23	14	8.3	-	29.9	
Other	15	9.1	5.3	4.2	21.7	
Leaker EFs, Oil Service – Onshore Production & Gathering and Boosting						
Valves	9.2	5.6	3.3	4.9	7.1	36.9
Flanges	4.4	2.7	1.6	-	6.2	8.8
Connectors	9.1	5.6	3.2	1.1	4.7	11.9
OELs	2.6	1.6	0.93	-	3.94	
Pump Seals	6.0	3.7	2.2	0.23	29.9	
Other	2.9	2.2	1.0	12.7	21.7	

[a] Zimmerle *et al* study published results did not distinguish between gas and oil service.

As shown in the table above, the Zimmerle *et al* study data show and the study report indicates that emissions from compressor-related components have higher leak rates due to vibration. Since EPA did not distinguish between components associated with or not associated with compressors, the average emission factors proposed that appear to include compressor-related components would overstate emissions from the more prevalent non-compressor related components. The Industry Trades request that EPA critically review the derived emission factors and include compressor-related components in the breakdown of leaker emission factors, with commensurately lower emission factors for non-compressor-related components, to avoid significant overstatement of methane emissions from the higher population of non-compressor related components.

Applying gathering and boosting derived emission factors to onshore production with compressor-related component emissions included in the Subpart W emission factors would significantly overstate methane emission because far fewer compressors are operational in production compared to gathering and boosting operations.

Commenter 0408: If emission factors cannot be used, time taken to measure releases will result in higher emissions as the repair would not begin until emission measurements are complete. LDAR Measurement requirements would slow down the LDAR technician, prevent immediate leak repair, and result in an incentive to delay the repair if there is an issue with the measurement or measurement device where the emissions appeared erroneously high or low. The right emission factor based calculations are not expected to result in significant differences in the emission results.

Table W-2 to Subpart W of Part 98— Default Whole Gas Leaker Emission Factors provided by EPA in the proposed regulation appear disjointed from those in the documents referenced in the proposed rule. For example, Pacsi et al., 2019 is a research study of measured vs FID & OGI surveys and does not break down the leaks found by component type.

**Pacsi, A. P. et al. Equipment leak detection and quantification at 67 oil and gas sites in the Western United States. Elementa (2019). https://doi.org/10.1525/elementa.368. Available in the docket for this rulemaking, Docket Id. No. EPA-HQ-OAR-2023-0234. Rutherford, J.S., Sherwin, E.D., Ravikumar, A.P. et al. Closing the methane gap in US oil and natural gas production inventories. Nat Commun 12, 4715 (2021). https://doi.org/10.1038/s41467- 021-25017-4. Available in the docket for this rulemaking, Docket Id. No. EPA-HQ-OAR-2023-0234*

…

EAP Ohio, LLC cannot validate the referenced research is comparable to the emission factors proposed by EPA especially given that the emission factors based on the 1995 EPA document EPA-453/R-95-017 are lower by over 90%. Since the emission factors are significantly higher than the emission factors in the effective Subpart W, EPA may give the impression to some that the numbers were inflated artificially or in error. EAP Ohio, LLC recommends EPA consider other research in addition to their referenced documents and/or retain the emission factors in the current Subpart W rule until more substantial data can be collected. EAP Ohio, LLC agrees EPA should allow an option for emission factor use in leu of measurement to ensure timely repair.

Commenter 0413: 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.

Commenter 0417: NDPC supports the revision of emission factors for equipment leaks and the data sources referenced within the proposal. However, the final emission factor numbers that EPA derived from that source are puzzling and do not align with the published literature. Revised component emission factors both for surveyed leaks and by population count are increasing several times on average to be much higher than published values. More importantly, for OGI surveys, the leaker factors are much higher than for Method 21 surveys. This conflicts with the goals of both EPA OOOOb/OOOOc rule proposals as well as various state emissions rulemakings, which continue to emphasize the importance and efficacy of OGI and alternative technologies. Instead, Subpart W appears to be incentivizing using Method 21 in lieu of more modern, advanced measures. This would shift operators towards using methodology that takes more time and effort, thus reducing the availability of staff to do more frequent, yet still very effective OGI and other surveys. It would also inaccurately shift emissions data to show that operators using Method 21 somehow had fewer emissions, which is not demonstrated in the data.

Since before the implementation of NSPS OOOOa, the oil and natural gas industry has been conducting OGI camera surveys and has learned much about fugitive emission leaks, their causes, and potential mitigation. As such, the OGI camera is a sustainable methane detection technology in North Dakota. This is especially true given the challenges not present in or significantly different than other basins throughout the United States, such as inclement and harsh winter conditions presenting challenges precluding the use of a variety of methane detection technologies.

…

NDPC recommends EPA adopt the emission factors as proposed for the use of Method 21, regardless of survey methodology used

Response 2: See Section III.P.1 of the preamble to the final rule for the EPA's response to this comment.

Commenter: Diversified Energy Company
Comment Number: EPA-HQ-OAR-2023-0234-0267
Page(s): 2-3

Commenter: Heath Consultants Inc.
Comment Number: EPA-HQ-OAR-2023-0234-0341
Page(s): 1-5

Commenter: Physical Sciences Inc. (PSI)
Comment Number: EPA-HQ-OAR-2023-0234-0377
Page(s): 2-4

Comment 3:

Commenter 0267: Specific Proposed Rules Which Stifle Technology or Disincentivize Emission Reduction

1. Laser-Based Technology

In revising Table W-2 Default Whole Gas Leaker Emission Factors – laser-based technology which is widely known to be superior to Optical Gas Imaging (OGI), is forced to accept leaker factors for OGI, based on flawed assumptions by EPA. In 88 FR 50344 EPA states that:

"At onshore petroleum and natural gas production and onshore petroleum and natural gas gathering and boosting facilities, very few facilities use infrared laser beam illuminated instruments or acoustic leak detection devices to conduct equipment leak surveys and there are no data available to develop leaker emission factors specific to these methods. Based on our understanding of these alternative methods, we expect that their leak detection thresholds would be most similar to OGI, so that the average emissions per leak identified by these alternative methods would be similar to the emissions estimated using the proposed OGI leaker factors. Therefore, we are proposing that, if these alternative methods are used to conduct leak surveys, the proposed OGI leaker emission factors in proposed Table W–2 would be used to quantify the emissions from the leaks identified using these other monitoring methods. We are seeking comment on the performance of infrared laser beam illuminated instruments and acoustic leak detection devices including data that may support a separate detection method specific emission factor or that supports the proposal that OGI emission factors appropriately estimate leakers detected with these methods."

We disagree on EPA's characterization that "very few facilities use infrared laser beam illuminated instruments." Diversified, with its 65,000 wells and over 17,000 miles of gathering lines, along with numerous other companies have been using laser-based instruments for leak detection for years. Moreover, the gas distribution sector has been using these devices as best-in-class detection for even longer. Our direct experience over 2.5 years of use is that the laser-based technology such as the Tunable Diode Laser Absorption Spectroscopy ("TDLAS") Remote Methane Leak Detector (RMLD) devices manufactured by Heath Consultants consistently and reliably outperforms OGI in the accuracy and efficiency in finding leaks, especially in adverse weather conditions (e.g. windy, freezing temperatures) where OGI is ineffective. We currently use over 55 RMLD devices across our company and Heath advised us that there are over 7,200 RMLDs currently in use. Heath has spawned a worldwide industry and market for comparable tools as described by a recent market analysis by Stats N Data: Global Laser Methane Gas Leak Detectors Market, Size, Overview, and Forecast to 2028. Regarding EPA's expectation that "leak detection thresholds would be most similar to OGI," we also disagree. RMLD can detect emissions down to 1 ppm-m, whereas OGI is generally limited to 200-300 ppm-m.[1] OGI sensitivity is highly reliant on wind speed.[2] Further, the subjectivity of OGI (only as good as the operator) which is discussed by Zimmerle and Vaughn,[3] is also removed with RMLD and other laser-based technology and is therefore superior to OGI which requires user interpretation.

Elimination or reduction in the scope of an approved method simply because EPA believes, based on no evidence, that it is not being widely used is inappropriate. The record is clear that RMLD is in wide usage. Laser based technology is rapidly improving (e.g., a METEC study comparing laser-based technology to OGI was completed on September 29, 2023), and wholesale categorizations of laser technology without data to support assumptions is arbitrary and capricious.

At a minimum the existing laser technology options and leaker factors should be retained. A performance-based approach is advisable given the rapid movement of technology using laser-based surveys and quantification. For example, Diversified has been conducting field trials with Xplorobot to find and quantify leaks and to document surveys. Xplorobot has commercially available laser-based visual detection (which also meets the definition of OGI) with quantification that has been evaluated at Colorado State University Methane Emissions Technology Evaluation Center (METEC), Lawrence Berkley National Laboratory, and the Alberta Methane Emissions Project. Using TDLAS technology, Xplorobot has demonstrated reliable detection of emissions at rates of 2 grams per hour and above, whereas OGI is reliable at 30 g/hr and above, 15 times higher.[3] In addition, Heath and their development partner Physical Sciences Inc., working with GTI Energy and industry sponsors, are now performing extensive field tests and evaluations of an advanced laser-based handheld tool in an RMLD package that images and quantifies leaks. It provides images of the background scene overlaid with two-dimensional spatio-temporal maps of path-integrated methane concentration versus position. It gathers these images from distances (50-100 feet) safely away from the source of the plume. Knowing the local air speed and direction, the tool estimates methane emission rates and path-integrated concentrations. It already qualifies as an OGI under 40 CFR Subpart OOOOa Sec.60.5397a and will be priced significantly lower than current passive OGIs.

Requested Action: Retain the current factors for laser-based leak detection allowing laser-based technology to be used as a superior technology to OGI.

Footnotes:
[1] See Yousheng Zeng PhD P.E. and Jon Morris, Providence Photonics at EPA Optical Gas Imaging Stakeholder Workshop, November 9-10, 2020
[2] See Zimmerle, D. Vaughn T et. al, Environ. Sci. Technol. 2020, 54 11506-11514

Commenter 0341: Dear Administrator Regan:

Physical Sciences Inc. (PSI) is a ~240 person employee-owned small business headquartered in Andover, MA. PSI was established in 1973 to provide integrated experimental, analytical, engineering, and product development capabilities to government and industry, with the ultimate goal of technology transition to a broad range of user communities. We create novel technologies and nourish them from the embryonic stage to commercialization. PSl's culture and highly diverse technical staff bridge the gaps between basic research, production, and technology deployment. Our products serve the military, aerospace, industrial process, energy, telecommunications, environmental, and medical markets. Our Andover MA corporate headquarters occupies approximately 65,000 square feet of office, laboratory, and pilot assembly areas. The company is 100% employee-owned through an ESOP. PSI represents ~250 employees in six states.

PSl's Industrial & Environmental Sensors business area specializes in creating, prototyping, and commercializing instrumentation especially of sensor systems for industrial and defense applications. For nearly 30 years, PSI has pioneered the development, commercialization, and application of near- and mid-lR TDLAS and backscatterTDLAS. In the 1990's, PSI and its spin-out company Spectrum Diagnostix developed the world's first successful laser-based long-open-path gas leak detectors to continuously monitor environmental hazards. PSI and our exclusive licensee Heath Consultants Inc. transformed this technology into the industry-disrupting handheld RMLD®, and the recent Discover AMLD® products that facilitate walking, mobile and aerial survey of n_atural gas pipelines.

As written in Sec. lll(P) (Equipment Leak Surveys, p.50344)), the proposed revision of Table W-2 (Default Whole Gas Leaker Emission Factors) would require active laser-based leak detection and measurement technologies to accept leaker factors based on currently accepted passive Optical Gas lmager performance. We recognize that EPA is unaware of the prevalent use of infrared laser beam instruments to conduct equipment leak inspections and their superior performance relative to passive OGI. Here we correct that misperception.

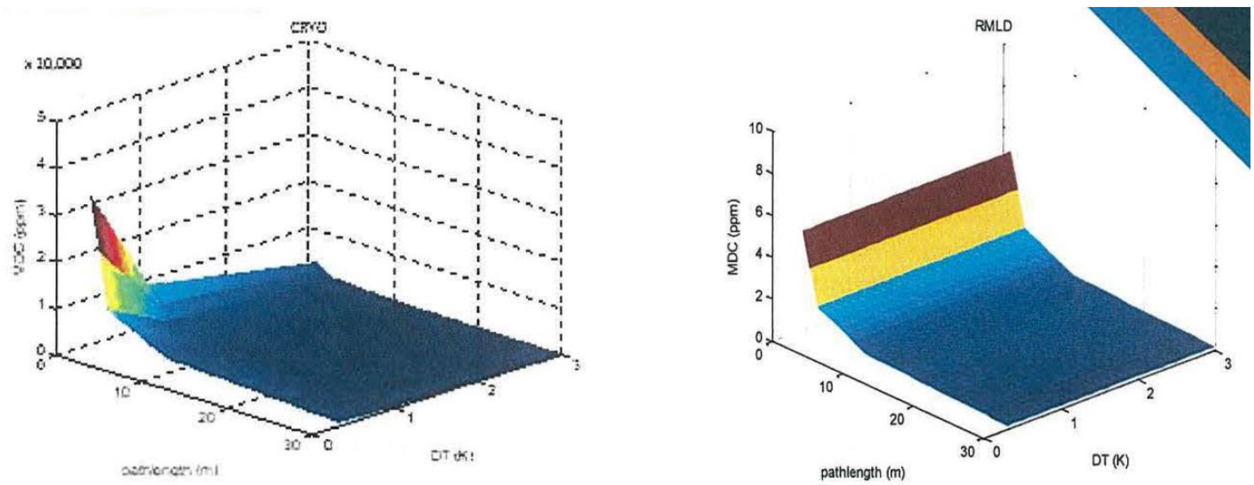
EPA states: "At onshore petroleum and natural gas production and onshore petroleum and natural gas gathering and boosting facilities, very few facilities use infrared laser beam illuminated instruments or acoustic leak detection devices to conduct equipment leak surveys and there are no data available to develop leaker emission factors specific to these methods. Based on our understanding of these alternative methods, we expect that their leak detection thresholds would be most similar to OGI, so that the average emissions per leak identified by these alternative methods would be similar to the emissions estimated using the proposed OGI leaker factors. Therefore, we are proposing that, if these alternative methods are used to conduct leak surveys, the proposed OGI leaker emission factors in proposed Table W-2 would be used to quantify the emissions from the leaks identified using these other monitoring methods. We are seeking comment on the performance of infrared laser beam illuminated instruments and acoustic leak detection devices including data that may support a separate detection method specific emission factor or that supports the proposal that OGI emission factors appropriately estimate leakers detected with these methods."

Contrary to the above:

1) Many facilities use infrared laser beam illuminated instruments to conduct equipment leak surveys. Indeed, numerous companies representing over 65,000 wells and >17,000 miles of

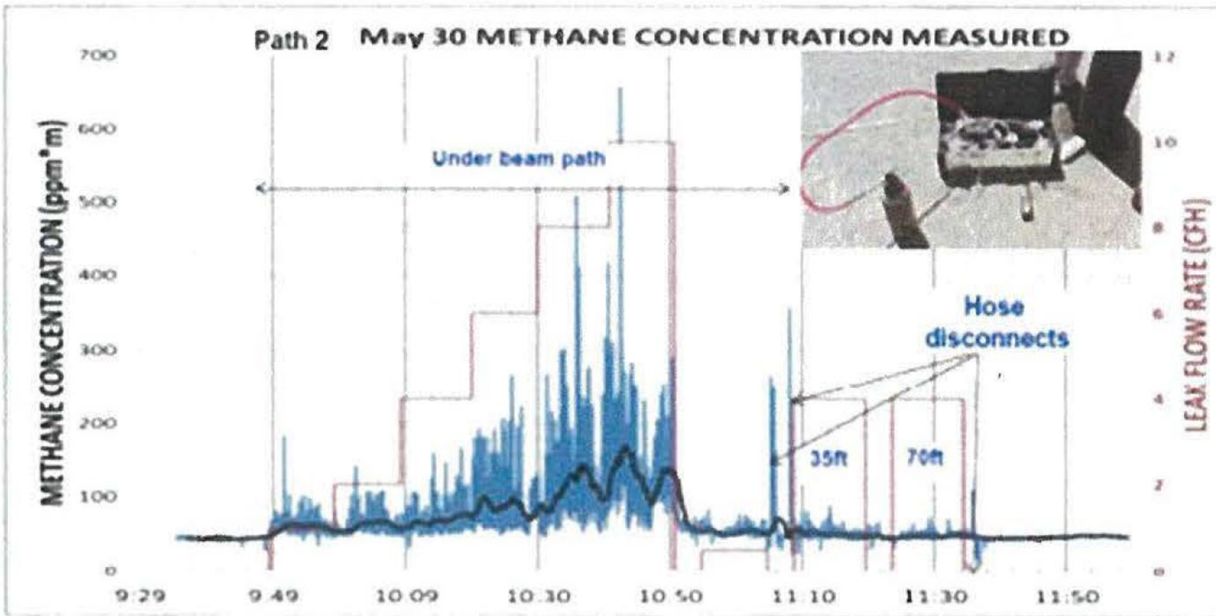
gathering lines, have been using laser-based instruments for leak detection for several years. One company currently uses over 55 devices. Moreover, the gas distribution sector has been using these devices as best in class detection for decades. The user experience is that the laser-based technology such as the Tunable Diode Laser Absorption Spectroscopy ("TDLAS") RMLD® devices manufactured by PSl's development partner and licensee Heath Consultants consistently and reliably outperforms OGI in the accuracy and efficiency in finding leaks, especially in adverse weather conditions (e.g. windy, freezing) where OGI is ineffective.

2) There are extensive data illustrating laser-based leak detection thresholds that are quite superior to passive OGI. Here we present theoretical and empirical analyses of RMLD TDLAS mass flow sensitivity and compare to OGI:



For methane, 1 CFH (cubic feet/ hour) = 472 ml/ min. 1000 ml/ min= 39.2 g / h. A leak flow rate of 2.1 CFH or 1000 ml/ min yields 39.2 g / h. The OGI minimum detectable concentration (MDC, left graph, above) is dependent on the path length (plume width) and temperature difference (DT) between the methane plume and the ambient background whilst the RMLD MDC is independent of temperature.

Portable Sandbox Leak Challenge



The best-performing cryogenically-cooled passive OGI is said to be generally reliable above 30g/hr (Yousheng Zeng PhD P.E. and Jon Morris, Providence Photonics, Air and Waste Management Association, October 24, 2018). The graph above shows RMLD® TDLAS technology measuring 120 ppm*m from a comparable 2.4 cfh plume. As RMLD® can detect path-integrated emissions down to 1 ppm-m, it is nominally 100x superior to traditional OGI.

Heath has deployed over 7200 RMLD® units since 2005. It has spawned a worldwide industry and market for comparable tools as described by a recent market analysis by Stats N Data: Global Laser Methane Gas Leak Detectors Market, Size, Overview, and Forecast to 2028.

Heath and PSI, working with GTI Energy and industry sponsors, are now performing extensive field tests and evaluations of an advanced laser-based hand held tool in an RMLD® package that images and quantifies leaks. It provides images of the background scene overlaid with two-dimensional spatio-temporal maps of path-integrated methane concentration versus position. It gathers these images from distances (50-100 feet) safely away from the source of the plume. Knowing the local air speed and direction, the tool estimates methane emission rates and path-integrated concentrations. It already qualifies as an OGI under 40 CFR Subpart OOOOa Sec.60.5397a and will be priced significantly lower than current passive OGIs.

Recommendation: We recommend that the existing laser technology options and leaker factors be retained. A performance-based approach is advisable given the rapid movement of technology using laser-based surveys and quantification.

<u>Commenter 0377</u>: As written in Sec. III(P) (Equipment Leak Surveys, p.50344)), the proposed revision of Table W-2 (Default Whole Gas Leaker Emission Factors) would require active laser-

based leak detection and measurement technologies to accept leaker factors based on currently accepted passive Optical Gas Imager performance. We recognize that EPA is unaware of the prevalent use of infrared laser beam instruments to conduct equipment leak inspections and their superior performance relative to passive OGI.

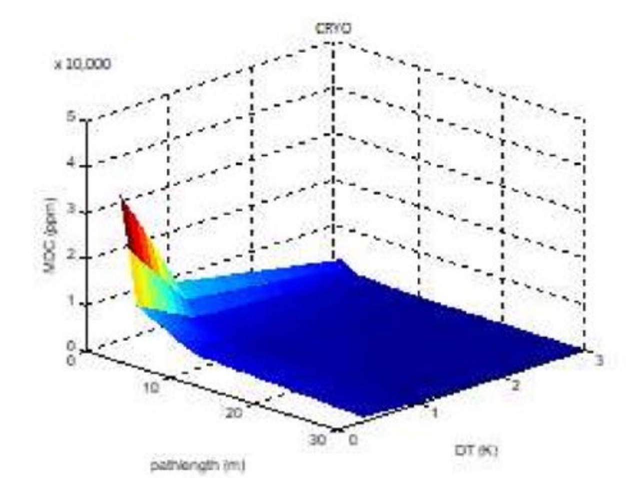
EPA states:

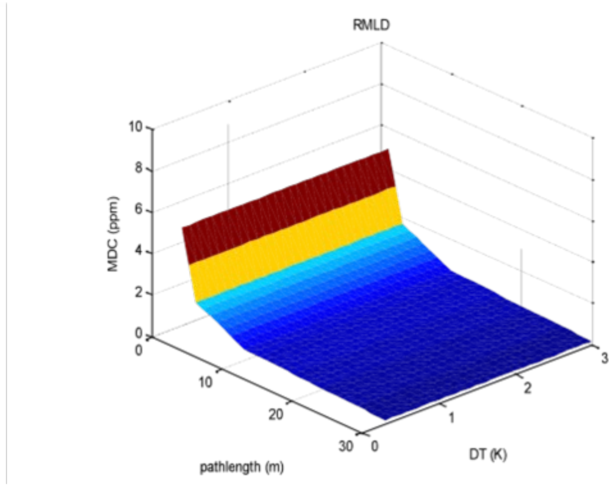
"At onshore petroleum and natural gas production and onshore petroleum and natural gas gathering and boosting facilities, very few facilities use infrared laser beam illuminated instruments or acoustic leak detection devices to conduct equipment leak surveys and there are no data available to develop leaker emission factors specific to these methods. Based on our understanding of these alternative methods, we expect that their leak detection thresholds would be most similar to OGI, so that the average emissions per leak identified by these alternative methods would be similar to the emissions estimated using the proposed OGI leaker factors. Therefore, we are proposing that, if these alternative methods are used to conduct leak surveys, the proposed OGI leaker emission factors in proposed Table W–2 would be used to quantify the emissions from the leaks identified using these other monitoring methods. We are seeking comment on the performance of infrared laser beam illuminated instruments and acoustic leak detection devices including data that may support a separate detection method specific emission factor or that supports the proposal that OGI emission factors appropriately estimate leakers detected with these methods."

Contrary to the above:

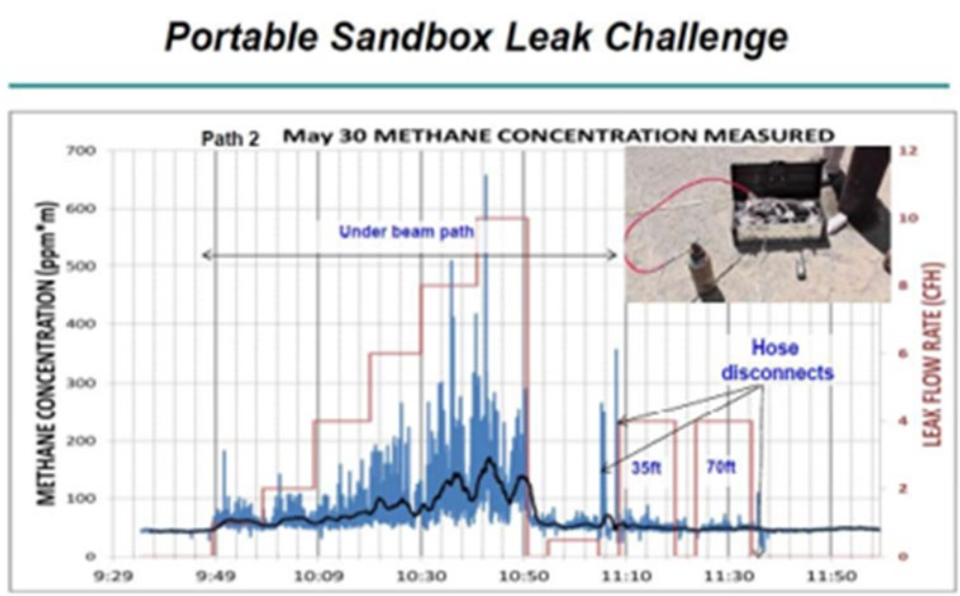
1) Many facilities use infrared laser beam illuminated instruments to conduct equipment leak surveys. Indeed, numerous companies representing over 65,000 wells and >17,000 miles of gathering lines, have been using laser-based instruments for leak detection for several years. One company currently uses over 55 devices. Moreover, the gas distribution sector has been using these devices as best in class detection for decades. The user experience is that the laser-based technology such as the Tunable Diode Laser Absorption Spectroscopy ("TDLAS") RMLD® devices manufactured by PSI's development partner and licensee Heath Consultants consistently and reliably outperforms OGI in the accuracy and efficiency in finding leaks, especially in adverse weather conditions (e.g. windy, freezing) where OGI is ineffective.

2) There are extensive data illustrating laser-based leak detection thresholds that are quite superior to passive OGI. Here we present theoretical and empirical analyses of RMLD TDLAS mass flow sensitivity and compare to OGI:





For methane, 1 CFH (cubic feet / hour) = 472 ml / min. 1000 ml / min = 39.2 g / h. A leak flow rate of 2.1 CFH or 1000 ml / min yields 39.2 g / h. The OGI minimum detectable concentration (MDC, left graph, above) is dependent on the path length (plume width) and temperature difference (DT) between the methane plume and the ambient background whilst the RMLD MDC is independent of temperature.



The best-performing cryogenically-cooled passive OGI is said to be generally reliable above 30g/hr (Yousheng Zeng PhD P.E. and Jon Morris, Providence Photonics, Air and Waste Management Association, October 24, 2018). The graph above shows RMLD® TDLAS technology measuring 120 ppm*m from a comparable 2.4 cfh plume. As RMLD® can detect path-integrated emissions down to 1 ppm-m, it is nominally 100x superior to traditional OGI.

Heath has deployed over 7200 RMLD® units since 2005. It has spawned a worldwide industry and market for comparable tools as described by a recent market analysis by *Stats N Data: Global Laser Methane Gas Leak Detectors Market, Size, Overview, and Forecast to 2028*.

Heath and PSI, working with GTI Energy and industry sponsors, are now performing extensive field tests and evaluations of an advanced laser-based handheld tool in an RMLD® package that images and quantifies leaks. It provides images of the background scene overlaid with two-dimensional spatio-temporal maps of path-integrated methane concentration versus position. It gathers these images from distances (50-100 feet) safely away from the source of the plume. Knowing the local air speed and direction, the tool estimates methane emission rates and path-integrated concentrations. It already qualifies as an OGI under 40 CFR Subpart 0000a Sec.60.5397a and will be priced significantly lower than current passive OGIs.

Recommendation: We recommend that the existing laser technology options and leaker factors be retained. A performance-based approach is advisable given the rapid movement of technology using laser-based surveys and quantification.

{Commenter also included an image from a brochure displaying the features and specifications of their laser-based handheld RMLD tool.}

Response 3: We are not aware of any field studies that directly compare infrared laser beam illuminated instruments with Method 21 or OGI. However, we find that the survey methods for infrared laser beam illuminated instruments are more similar to OGI in terms of the proximity to equipment leak components and thus factors affecting performance or limitations for detection are expected to be more similar.

Specific to some of the data provided by commenters, in Figure 2 the commenter shows the performance of its device relative to a 2.4 cfh leak which is equivalent to 46 g/hr (a level at which OGI performs well). While, the commenter asserts that its device can measure a 1 ppm plume, the commenter has not provided data demonstrative of this claim.

We continue to maintain, as proposed, that we expect the leak detection thresholds of the infrared laser beam illuminated instruments are most similar to OGI, so that the average emissions per leak identified by this method would be similar to the emissions estimated using OGI. We are finalizing, as proposed, that if this alternative method is used to conduct leak surveys, the final OGI leaker emission factors in final Table W-2 will be used to quantify the emissions from the leaks identified using these other monitoring methods. We intend to continue to evaluate additional data as they arise to determine the appropriateness of developing and providing in a future rulemaking an emission factor set for the infrared laser beam illuminated-specific method.

Commenter: Public Hearing Transcript
Comment Number: EPA-HQ-OAR-2023-0234-0224
Page(s): 14 (Lisa Beal)

Commenter: GPA Midstream Association
Comment Number: EPA-HQ-OAR-2023-0234-0299
Page(s): 92

Commenter: Duke Energy
Comment Number: EPA-HQ-OAR-2023-0234-0376
Page(s): 4-5

Commenter: Interstate Natural Gas Association of America (INGAA)
Comment Number: EPA-HQ-OAR-2023-0234-0387
Page(s): 8-11, 12-13

Commenter: Downstream Natural Gas Initiative
Comment Number: EPA-HQ-OAR-2023-0234-0396
Page(s): 7

Commenter: Environmental Defense Fund, et al.
Comment Number: EPA-HQ-OAR-2023-0234-0413
Page(s): 64-65

Commenter: American Gas Association (AGA) and American Public Gas Association (APGA)
Comment Number: EPA-HQ-OAR-2023-0234-0418
Page(s): 13

Comment 4:

Commenter 0224: The proposed updates to leak survey leak emission factors for transmission and storage is based on data from upstream operations, without detailing why the existing transmission and storage data was inadequate.

Commenter 0299: **Proposed Change**: For Onshore Natural Gas Processing, Onshore Natural Gas Transmission Compression, and Underground Natural Gas Storage, EPA is proposing new leaker emission factors for OGI that are 4.1 times higher than the current emission factors (Tables W-2A, W-3A, W-4A).

> **Comment**: These new emission factors are not based on actual study data for processing, transmission, or underground storage. EPA calculated ratios between the current and proposed emission factors for Production and G&B (Table W-1E). The average of these ratios (4.1) was multiplied by the current processing/transmission/underground storage emission factors to arrive at the proposed emission factors. This is inappropriate. EPA did not present information to support changing the leaker emission factors for processing, transmission, or underground storage. EPA did not reference any information to indicate that the current processing, transmission, and underground storage emission factors are not representative of actual emissions. EPA did not reference any information to support

that it is appropriate to apply the magnitude of change between the current versus proposed emission factors for production and G&B to the emission factors for processing, transmission, and underground storage. If EPA can justify applying production and G&B studies to processing, transmission, and underground storage, then EPA should instead update Tables W-2A, W-3A, and W-4A to have the *same* OGI leaker emission factors as Table W-1E.

Commenter 0376: 1. The proposed revisions to leaker emission factors are based on studies for optical gas imaging (OGI) at onshore production and gathering and boosting facilities and are not relevant to downstream sources. The creation of the OGI enhancement factor is not reasonable and is not based on technical data supporting applicability to sources downstream of the onshore production and gathering and boosting facilities. EPA should consider additional perspective studies and data gathered using OGI and other leak testing methods in other segments of the natural gas supply chain. These proposed changes are not justified and are not supported by the record.

EPA proposes to add new leaker emission factors[3] when leaks are detected using OGI, infrared laser beam, or acoustic technology versus Method 21. EPA states in the Technical Support Document (EPA TSD)[4] that "we find that the use of the developed OGI leaker factors would be an appropriate way to quantify the emissions from the leaks identified using these other monitoring methods. As noted, for the proposed rule we also find it appropriate to use the study data to update the Method 21 emission factors at both leak definitions," and "We expect that the leaker factors for other industry segments that are based on measurements of Method 21-identified leaks may similarly underestimate the emissions from leaking equipment when OGI (or other alternative methods besides Method 21) are used to detect the leaks. Therefore, in the proposed rule we are proposing to require the application of the 'OGI enhancement' factor (i.e., the ratio of the OGI emission factor and the Method 21 emission factors, or a value of 1.63 or 2.81 for leak definitions of 10,000 ppm or 500 ppm, respectively) identified from measurement study data in the Onshore Petroleum and Natural Gas Production and Onshore Petroleum and Natural Gas Gathering and Boosting industry segments to the leaker factors for the other Subpart W industry segments as a means to estimate an OGI emission factor set."

The EPA TSD goes on to state: "We also note that very few onshore production and gathering and boosting facilities use infrared laser beam illuminated instruments or acoustic leak detection devices to conduct equipment leak surveys and **there are no data available to develop separate leaker emission factors specific to these methods…. We expect** that the leaker factors for other industry segments that are based on measurements of Method-21-identified leaks may similarly underestimate the emissions from leaking equipment when OGI (or other alternative methods besides Method 21) are used to detect the leaks."[5]

In other words, EPA has not conducted studies or relied upon study data in any of the downstream industry segments to support the applicability of the proposed leaker emission factors based on the OGI enhancement factors for use in these industry segments. In fact, Duke Energy uses infrared laser beam instruments extensively within our Piedmont Natural Gas business units because this method has proven reliable and efficient for conducting the required annual leak testing on a combined system that includes over 1,000 transmission-distribution

(TD) transfer stations that must be tested. The use of the proposed leak factors will result in significant reported increases in methane emissions despite no change in actual operation of these facilities. The effect of requiring the reporting of methane emissions that are not representative of actual conditions may be to force facilities to move exclusively to Method 21 testing, which would be much more labor-intensive and not suitable for conducting numerous tests over a large natural gas distribution network.

It is also not clear how EPA would expect a natural gas distribution entity to report methane emissions using these new leaker emission factors when leak testing is performed over a multiyear period as allowed by the regulation. Would the new factors be applied to testing that was done within the previous years that are included in the calculation of the leak rates determined over the testing cycle?

Duke Energy recommends that EPA reconsider the OGI enhancement factors and, if appropriate, re-propose them in the future when more data are available. If, however, EPA persists in revising the factors, those revisions should apply only going forward, and data used from previous years' testing should continue to apply the current leaker emission factors.

Footnotes:

[3] Tables W-2, W-3, W-4, W-5, W-6 and W-7 to Subpart W of Part 98.

[4] "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," June 2023; Docket Item No. EPA-HQ-OAR-2023-0234-0163 (2023).

[5] Id. at 83-88 (emphasis added).

Commenter 0387: **Leak emissions estimates for T&S should not rely on upstream datasets and more flexibility should be included for leak estimates, including measurement-based approaches.**

§98.233(q) "Equipment Leak Surveys" includes the procedures for estimating emissions from leaking components in natural gas service. Leak detection surveys are conducted at least once in each calendar year and annual emissions from detected leaks are estimated using leaking component EFs (e.g., scf THC[16]/hr), estimated annual component hours in service, and concentrations of CH4 and CO2 in the hydrocarbon stream (Equation W-30). Proposed revisions for estimating leaking component emissions in the natural gas transmission and storage (T&S) sectors include: (1) revised (increased) EFs for leaks detected using optical gas imaging (OGI) based on "OGI enhancement factors", and (2) application of a leak detection method-based "k" factor to adjust emission estimates for undetected leaks (see Equation W-30 in Proposed Rule).

INGAA's October 2022 Comments addressed similar issues with the proposed EF updates, and although EPA's analysis was updated, similar flaws remain. Thus, INGAA strongly opposes EPA's proposed revisions to the T&S gas leak emission estimation methodology, and the proposed revisions should not be adopted. The OGI enhancement factors (i.e., the ratios of the OGI EFs and the Method 21 EFs) and the application of k factors are based on an EPA analysis, described in the Technical Support Document (TSD)[17], that selectively uses data from gas leak emissions studies conducted on “upstream” natural gas production wells and gathering and boosting stations. EPA has not provided a sound technical basis for its conclusion that the OGI enhancement factors and “k” factors based on upstream segment studies should apply to T&S leaker emission estimates. Further considerations include:

- The EPA analysis has shortcomings, including a small dataset, which are further discussed below;
- The leak rates implied by the proposed T&S OGI leaker EFs are large and inconsistent with OGI detection thresholds; and

…

Unless study design and in-depth analysis clearly supports applying upstream data to T&S segments, any future revisions to T&S component leak emissions estimation methodologies should be based on data from T&S sector-specific leak surveys.

…

Upstream Studies

As discussed in the TSD, the gas leak emissions studies conducted on “upstream” natural gas production wells and gathering and boosting stations that are the basis for the proposed revised EFs and application of k-factors are Pasci et al, 2019[18] and Zimmerle et al., 2020[19]. The Pasci study detected leaks using OGI and EPA Method 21 at 67 production and gathering and boosting oil and gas sites, and quantified leak rates with a high-flow sampler. The Zimmerle study detected gas leaks using OGI at 180 gathering stations, and quantified leak rates with high-flow samplers. During these studies, fewer, yet larger leaks were detected with OGI than by Method 21 and EPA concluded that leaker EFs based on OGI detection should be larger than leaker EFs based on Method 21 detection. EPA also used the data from these studies to update natural gas production and gathering and boosting leaker EFs for Method 21 (500 ppm and 10,000 ppm leak definition). The basic steps for calculating these revised upstream EFs were:

1. Develop OGI leaker EFs using combined data from the Pasci (101 OGI-detected leaks) and Zimmerle (593 OGI-detected leaks) studies; and
2. Calculate leaker EFs for Method 21 at 500 and 10,000 ppm leak definitions from the OGI leaker EFs times the ratio of Method 21 (at 500 and 10,000 ppm leak definitions) EFs to OGI EFs from the Pasci study alone (this ratio is the reciprocal of the OGI enhancement factor).

The proposed increased T&S OGI EFs were calculated from existing Subpart W Method 21 EFs and the OGI enhancement factors calculated in Step 2 above. Notably, and as discussed in October 2022 Comments, the original basis for upstream EFs (evolved from EPA's historical leak protocol document) differs significantly from the basis for T&S factors which were developed from measured leak data. The resulting component-specific EFs currently in Subpart W are thus much larger than the analogous EFs for upstream sources. Despite this significant difference, and the historical records already showing higher component level EFs for T&S, EPA adds a factor to further increase the T&S EFs. The legitimacy of the added bias is not adequately justified by EPA. In addition, the proposed T&S k-factors that further bias the calculation of leak emissions are assumed to be the same as the upstream k-factors.

The analysis and data used to calculate the revised upstream EFs and the k-factors have many shortcomings:

- The dataset for the Pasci study that is the basis for the OGI enhancement factors (i.e., reciprocal of above Step 2 calculation) and the calculation of the k-factors is relatively small, with a total of 300 leaks from ten different component types: connectors, flanges, instruments, OELs, other, piping, PRVs, regulators, valves, and vents[20] in both oil and gas service. Over half of the leaking components were connectors in gas service. This is not a large representative dataset suitable for calculating EFs and developing regulations, especially when significant positive bias is introduced for emission estimates. Notably, this dataset does NOT meet the "50 measurements per component" criteria specified by EPA in the Proposed Rule for developing *facility-specific* component leaker EFs. It is startling that EPA would propose *industry-wide*, bias factors that are *not from the associated industry segment* when the dataset does not meet criteria for "facility level" leaker EF updates in the Proposed Rule.

…

Table 1. Fifteen Largest Leaks *Solely* Detected by OGI from Pasci Study

Subpart W Equipment Class	Component Type	Emission Rate (scfh)	High-Flow Concentration (ppm)
Compressor	OELs	83.65	191,600
Compressor	Connectors	44.81	70,100
Compressor	Connectors	28.66	50,000
Other	Connectors	25.78	97,500
Minor Separator	Valves	17.98	21,000
Compressor	Piping	15.53	23,200
Separator	Regulator	12.70	40,100
Compressor	Connectors	8.74	20,000
Compressor	Valves	8.66	18,700
Separator	Valves	7.83	20,700
Compressor	Valves	6.98	22,200
Compressor	Connectors	6.53	11,600
Separator	Connectors	5.62	11,300
Separator	Instrument	4.41	10,800
Separator	Valves	2.88	9,200
	Total	**280.74**	

- The assumption that the OGI EF to Method 21 EF ratio is the same for the Zimmerle data as for the Pasci data (the basis for the Step 2 calculation above) adds a large uncertainty to the upstream Method 21 EFs. The Pasci data are only 15% of the OGI-detected leak measurements and the majority of the OGI-detected leak measurements (85%) are from the Zimmerle study (without corresponding Method 21 leak concentration measurements). The upstream segments Method 21 EFs thus have a very high uncertainty, which implies additional measurements should be conducted to develop updates to mandatory EFs.
- The OGI data are highly biased towards compressor components leaks. Over 80% of the gas-service components surveyed and measured for the Zimmerle and Pasci studies were at gathering and boosting facilities or otherwise in compressor-service (i.e., all 180 facilities in the Zimmerle study were gathering and boosting and over 40% of the leaking components for the Pasci study were at gathering and boosting facilities or otherwise in compressor service). Thus, the EFs are very likely not representative of all upstream operations and this could be a contributing factor to the proposed rule upstream leaker EFs being greater than the current Subpart W EFs.

Large leaks of the magnitude of the proposed T&S EFs would be readily detected

The proposed OGI leaking component EFs for T&S are very large (e.g., 65 scfh for PRVs, 32 scfh for meters, 28 scfh for OEL, and 24 scfh for valves). These equate to 1 to 2+ lbs/hr, about an order of magnitude or more above OGI methane leak detection thresholds[21]. Since EFs are averages of all measurements (i.e., total emissions divided by number of measurements), these EFs infer that only very large leaks, with emissions rates much higher than established (or work practice required) detection limits, are all that are detected by OGI at T&S facilities. INGAA is not aware of any study or EPA analysis that supports this conclusion.

Similarly, the bias factors imply that fugitive emissions are significantly under-estimated for T&S and implying that a significant percentage of emissions (i.e., compounding bias factors for the EFs and k-factor would nearly double estimates) are missed for T&S. This is not consistent with published *T&S segment studies*, where results consistently show that a small percentage of leaks comprise the vast majority of emissions. The bias factors proposed imply that "missed leaks" or erroneous leak measurements comprise a significant portion of total leak emissions, which is inconsistent with T&S sector literature. In fact, other papers by Zimmerle and colleagues from an industry-EDF sponsored study conducted contemporaneously with the upstream studies indicated that current estimation methods provided a relatively accurate estimate of T&S segment emissions and may *over-predict* emissions. This conclusion was in contrast to Zimmerle/EDF published papers for upstream sectors – and also inconsistent with applying bias factors to T&S leaker EFs and the leak emissions calculation equation.

Summary and Conclusions

EPA has not provided adequate justification or support to apply the OGI enhancement factor to T&S leaker EFs or to apply k-factors to T&S leaker emission estimates. The current OGI leaker EFs should be retained since it is inappropriate to apply an "enhancement" based on analysis of a small dataset from the upstream segment that includes significant disparities in both operational equipment and leak detection environment (e.g., wind conditions). In fact, the TSD does not provide any T&S data to support its conclusion or the proposed revisions. The TSD states:

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

An unsupported "expectation" that upstream segment emissions measurement data "may" similarly impact T&S does not adequately justify applying an OGI enhancement factor to T&S OGI EFs or applying k-factors to T&S leaker emission estimates, especially when underestimation of T&S segment emissions is not indicated by other literature / studies.

EPA's proposed revisions to the T&S gas leak emission estimation methodology should not be adopted. The related analysis and cited study are flawed and the supporting upstream data insufficient to warrant the proposed revisions. Further, there is no technical basis for applying these flawed revisions to T&S segments, which are not represented in the studies, especially since the original Subpart W EFs for T&S are based on a different methodology and dataset than the original Subpart W EFs for upstream operations.

The current Subpart W T&S EFs are supported by existing studies, including data specific to those segments, and should be retained and not updated. Comprehensive studies on T&S equipment would be needed to support changes to prescribed, industry-wide T&S leaking component EFs as well as application of adjustment to the leak emission estimation calculation using k-factors.

Footnotes:

[16] total hydrocarbons

[17] "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", U.S. Environmental Protection Agency, June 2023.

[18] Pacsi, A. P., Ferrara, T., Schwan, K., Tupper, P., Lev-On, M., Smith, R., & Ritter, K. 2019. Equipment leak detection and quantification at 67 oil and gas sites in the Western United States. Elementa: Science of the Anthropocene, 7(29). https://doi.org/10.1525/elementa.368.
[19] Zimmerle, D., Vaughn, T., Luck, B., Lauderdale, T., Keen, K., Harrison, M., Marchese, A., Williams, L., & Allen, D. 2020. Methane emissions from gathering compressor stations in the U.S. Environ. Sci. Technol. 2020, 54(12) 7552–7561.
[21] EPA alternative work practice criteria, proposed Appendix K requirements, and OGI vendor publications document detection thresholds significantly less than 100 g/hr.

Commenter 0396: **Default Leaker Emission Factors**

EPA has proposed updates to leaker emission factors using an "OGI enhancement factor" to differentiate leaker emission factors based on the leak detection method (Method 21 with 10,000 ppm, Method 21 with 500 ppm, all other methods).

While DSI agrees with the approach to have differing leaker emission factors based on different leak detection methods, DSI disagrees with the approach of using a study that was done in the Onshore Production and Gathering and Boosting industry segments and extrapolating its results to operations further downstream to transmission, storage, LNG, and distribution segments.

Throughput Subpart W, calculation methodologies and emission factors often vary by segment for a few reasons. First, gas properties (e.g., pressure, CH_4 content) can vary significantly in upstream vs. downstream segments. Further, geographic impacts (e.g., weather and temperature) are sometimes seen due to the limited locations of upstream operations (i.e., production fields), while midstream and downstream operations are widespread across the U.S. (i.e., gas customers in all 50 states). For example, how production equipment performs over time in Texas or Pennsylvania may differ from how that same equipment in T&S or distribution service performs in Washington or Florida. DSI recommends that EPA use a study on midstream or downstream assets to determine the appropriate leaker emission factor updates for these segments.

Commenter 0413: Revisions and Addition of Default Leaker Emission Factors

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.

Commenter 0418: **While the Associations support EPA's proposal to allow the use of direct measurement to quantify emissions from equipment leak components, several additional improvements would increase the accuracy of distribution segment emissions estimates.**

The proposed "OGI enhancement factor" and "k factor" should not apply to LDCs because they are based on upstream segment data and are therefore unrepresentative of distribution segment emissions.

According to EPA, OGI finds "fewer and larger leaks" at upstream facilities than Method 21 does and "the leaker emission factors for other industry segments that are based on measurements of Method 21-identified leaks may similarly underestimate the emissions from leaking equipment when OGI (or other alternative methods besides Method 21) are used to detect the leaks."[40] Consistent with the 2022 Proposal, EPA is once again proposing larger leaker emission factors for OGI screening than for Method 21 screening, which the Agency proposes to effectuate via an "OGI enhancement factor" applied to the leaker emission factors for each downstream segment.

….

For both factors, EPA is making a baseless assumption that upstream data is equally applicable downstream. The Associations oppose the proposed application of the OGI enhancement factor and the k factor to distribution segment leak emissions estimates for the same reasons that INGAA provides with regard to the transmission and storage segments. The Associations urge EPA not to add either adjustment factor to the leaker emission factors for LDC equipment.

Footnotes:
[40] *Id*. at 50344.

Response 4: See Section III.P.1 of the preamble to the final rule for the EPA's response to this comment.

Commenter: Marcellus Shale Coalition (MSC)
Comment Number: EPA-HQ-OAR-2023-0234-0275
Page(s): 10

Comment 5:

1. The MSC noted inconsistencies between Footnote 1 on Tables W-1 and W-2 and the requirements in the rule text to use only factors applicable to the type of site. Footnote 1 to Table W-1 states: "For multi-phase flow that includes gas, use the gas service emission factors." This directly conflicts with the statement in 98.233(r)(2) as proposed which reads as follows:

"(2) Onshore petroleum and natural gas production facilities and onshore petroleum and natural gas gathering and boosting facilities must use the appropriate default whole gas population emission factors listed in Table W-1 of this subpart. Major equipment associated with gas wells are considered gas service equipment in Table W-1 of this subpart. Onshore petroleum and natural gas gathering and boosting facilities shall use the gas service equipment emission factors in Table W-1 of this subpart. Major equipment associated with crude oil wells are considered crude service equipment in Table W-1 of this subpart."

Footnote 1 to Table W-2 as proposed, states: "For multi-phase flow that includes gas, use the gas service emission factors." This directly conflicts with the statement in 98.233(q)(2)(iii) and (iv) as proposed, which read as follows:

"(iii) Onshore petroleum and natural gas production facilities must, if available, use the site-specific leaker emission factor calculated in accordance with paragraph (q)(4) of section or use the appropriate default whole gas leaker emission factors consistent with the well type, where components associated with gas wells are considered to be in gas service and components associated with oil wells are considered to be in oil service as listed in Table W-2 to this subpart.

(iv). Onshore petroleum and natural gas gathering and boosting facilities must, if available, use the site-specific leaker emission factor calculated in accordance with paragraph (q)(4) of section or use the appropriate default whole gas leaker factors for components in gas service listed in Table W-2 to this subpart."

The U.S. EPA should revise these footnotes to align with the intent of the rule expressed in the preamble and the rule text.

Response 5: See Section III.P.1 of the preamble to the final rule for the EPA's response to this comment.

Commenter: Marcellus Shale Coalition (MSC)
Comment Number: EPA-HQ-OAR-2023-0234-0275
Page(s): 10

Comment 6:

Equipment Leaks 2. The MSC requests clarification on Footnote 2 to Table W-2 as proposed. Onshore petroleum and natural gas production and gathering and boosting sites now have the option to monitor compressor mode-sources in as-found condition. Footnote 2 to Table W-2 as proposed states:

"The open-ended lines component type includes blowdown valve and isolation valve leaks emitted through the blowdown vent stack for centrifugal and reciprocating compressors."

It should be specifically stated that if an entity elects to use as-found measurements to estimate emissions from isolation valve and blowdown valve leakage, that leaks detected from these sources should be calculated pursuant to paragraph (p) or (o) rather than paragraph (q). In addition, because there is no dry seal emission factor in §98.233(o), it should be clarified in Footnote 2 how dry seal vents are intended to be reported when a gathering and boosting or processing site elects to use population emission factors for compressor venting.

Response 6: See Section III.P.1 of the preamble to the final rule for the EPA's response to this comment.

Commenter: GPA Midstream Association
Comment Number: EPA-HQ-OAR-2023-0234-0299
Page(s): 17

Comment 7:

The following is a list of substantive proposed changes that GPA expressly supports.

…

- Adding total hydrocarbon leaker emission factors for onshore natural gas processing for Method 21 at 500 ppm [Table W-4];

Response 7: The EPA acknowledges the commenter's support of the proposed revisions. The EPA is finalizing these amendments as proposed.

Commenter: GPA Midstream Association
Comment Number: EPA-HQ-OAR-2023-0234-0299
Page(s): 90-91

Comment 8: Proposed Change: EPA is proposing many emissions factor changes in the table to Subpart W with inconsistent levels of precision.

> **Comment:** Rounding has been applied inconsistently to the emission factors. For example, in Table W-1E, the leaker emission factor for valves (if surveyed using any of

the methods in § 98.234(a)(1), (3), or (5)) is listed as 16 scf/hr/component. Based on the technical support document, this factor should be 15.6 scf/hr/device. There are emission factors at this level of precision within the same table; for example, 7.9 scf/hour/component is used for connector (other). EPA should maintain consistency on decimal precision of emission factors, especially within the same table, unless the underlying data truly supports different levels of precision.

Response 8: The factors EPA is adding to the tables generally use 2 significant figures, which is a consistent level of precision. Rounding to the same decimal place is not consistently precise. Using the commenter's example, the 15.6 scf/hr/component emission factor would be more precise than the 7.9 scf/hr/component factor.

17.2 Addition of Undetected Leak Factor for Leaker Emission Estimation Methods

Commenter: GPA Midstream Association
Comment Number: EPA-HQ-OAR-2023-0234-0299
Page(s): 50-51

Commenter: Williams Companies, Inc.
Comment Number: EPA-HQ-OAR-2023-0234-0394
Page(s): 12

Commenter: The Petroleum Alliance of Oklahoma
Comment Number: EPA-HQ-OAR-2023-0234-0398
Page(s): 17

Commenter: Western Energy Alliance
Comment Number: EPA-HQ-OAR-2023-0234-0399
Page(s): 11

Commenter: American Petroleum Institute et al. (Part 1 of 2)
Comment Number: EPA-HQ-OAR-2023-0234-0402
Page(s): 54

Commenter: Environmental Defense Fund, et al.
Comment Number: EPA-HQ-OAR-2023-0234-0413
Page(s): 66

Commenter: North Dakota Petroleum Council (NDPC)
Comment Number: EPA-HQ-OAR-2023-0234-0417
Page(s): 9

Comment 1:

Commenter 0299: **66. EPA should not require use of the proposed undetected leak factor for equipment leak emission estimates.**

GPA recognizes EPA's intent to ensure all equipment leak emissions are accounted for, but use of an undetected leak adjustment factor, k, based on the Pacsi et al. (2019) study data does not meet the criteria of empirical data. That study included surveys of 67 sites, but leaks were only detected at 52 sites, so the data gathered pertains only to these 52 sites. Moreover, of those 67 sites, 10 sites were identified as "boosting and gathering" with the remaining sites falling into the categories of well sites/well production/central production. For the 10 "boosting and gathering" sites, only 5 had leaks identified as part of the study. Observed leak data from just 5 sites in the gathering and boosting sector does not accurately represent the entirety of this sector, nor does this level of data qualify as a statistically significant data set of empirical data to justify the creation of an undetected leak factor to be applied to all surveyed gathering and boosting sector facilities.

The Pacsi et al. (2019) study compared the monitoring methods of OGI and flame ionization detector. These two monitoring methods have extremely different procedures and techniques while being used with federal or state leak detection and repair ("LDAR") compliance. GPA believes if EPA implies that leaks are inadvertently being "undetected," this may have unintended consequences for the oil and gas industry. GPA agrees that current GHGRP component emission factors may require an improved quantification value structured around practices and improvements to equipment within the industry segments subject to GHGRP, but just assuming components are going undetected during weekly, monthly, quarterly, semi-annual, and annual inspections via audio, visual, and olfactory inspections, OGI, and Method 21 is an inappropriate approach. EPA implies in the proposed rule that industry segments subject to the GHGRP are not making every available effort to comply with regulatory LDAR standards in current federal and state policies. This is simply untrue.

GPA proposes that EPA remove undetected leak adjustment factor, k, in equation W-30. It would be more beneficial if EPA would use the result from any as-found leak detection method without implied adjustments to the count of components found. Indeed, the Pacsi et al. (2019) study expressly specifies that "this study was not designed to understand the differences in emission detection technology deployment but may explain differences in emission estimates from this study compared to current US emission factors."

The current and proposed Subpart W rules allow for the use of various handheld devices for leak detection (OGI, Method 21, etc.). Any detected leaks, coupled with leaker emission factors developed from published empirical data, then comprise the total observed emission leaks at each site. The addition of an undetected leak factor assumes that the observed leak data collected from the leak surveys is unreliable--even though the associated survey is performed based on EPA monitoring and training criteria (98.234(a) and the requirements referenced therein such as OOOOb). This assumption is arbitrary and capricious. GPA supports EPA's existing monitoring and training criteria related to the use of the above noted leak detection technologies but does not support the implication in the proposed rule that these technologies and EPA's regulatory guidance result in insufficient leak detection.

<u>Commenter 0394</u>: (2) Undetected Leak Emission Factor, "k"

Williams opposes proposed emission factors designed to account for undetected leaks during a Method 21 or OGI leak survey. Properly trained leak detection surveyors follow Method 21 survey protocol in 40 CFR Part 60 Appendix A-7 and are proficient in OGI camera operation; the use of undetected leak detection factors is unjustified.

At a fundamental level, the EPA should emphasize proper training of leak surveyors in lieu of imposing atypical and questionable undetected leak emission factors. Pushing owners / operators to commit the resources needed to perform accurate leak surveys will result in improved leak detection and ultimately reduce emissions more than adjusting emission factors.

Commenter 0398: Addition of Undetected Leak Factor for Leaker Emission Estimation Methods. EPA proposes an adjustment factor to emissions quantified using the direct measurement.

We think this is unreasonable and excessive. Direct measurement would provide the most accurate information, and applying an adjustment factor would skew the results and overestimate emissions.

Action Requested: We request EPA remove this adjustment factor for direct measurement or at a minimum provide clear and concise details justifying how applying an adjustment factor would be reasonable and appropriate.

Commenter 0399: Additionally, EPA proposes the use of individualized "enhancement factors" on top of all the other conservative assumptions within the proposed rule. The Alliance does not support the use of an enhancement factor generally, as it assigns emissions that are neither calculated, measured, or observed to operators who will then be subject to a methane fee for those emissions that EPA cannot substantiate. On top of this, the justification and calculations for the "k" factor have not been revealed through the rulemaking process, providing the public with no opportunity to provide comment on the actual value of the factor, regardless of its appropriateness as a reporting mechanism.

Commenter 0402: 3.10 Equipment Leaks

3.10.3 Enhancement Factor

EPA's 'Enhancement Factor" or "k factor" derivation and rationale are unclear; testing of the proposed approach using the underlying study data to corroborate results should be confirmed.

EPA states in the TSD that the Pacsi *et al* study OGI captured approximately 80% of overall emissions, Method 21 (500 ppm leak detection threshold) captured 79% of emissions, and Method 21 (10,000 ppm limit) captured 65% of emissions, respectively. However, the Pacsi *et al* study is clear that even though using Method 21 identified more leaks (293 vs. 113 with OGI), the majority (67%) of additional leaks found were very small (1 scf/hr. or less). Further, both

FID and OGI methods, while finding different leaking components, found a very similar total volume of emissions from leaking components at the site.

The Industry Trades disagree with EPA's proposed "Enhancement Factor" or "k" factor. It seems that EPA has proposed the "k" factor to account for both method's quantification differences as well as other variables, such as the percentage of emissions found by survey methods (e.g., due to accessibility of components, etc.). Applying such logic to specific emission factors for specific equipment is not appropriate as the intent seems to include both updates for a specific leak factor for an individual component as well as capturing emissions from other components that may not be otherwise detected (i.e., the remaining 20% or 21% of emissions not directly identified by OGI or M21 respectively in the Pacsi *et al* study). Grossing up individual component emission factors is not a logical approach to account for leaks not directly identified. While the Industry Trades disagree in principle with EPA's approach, if such an approach were to be applied, it would only be appropriate on an aggregate basis. That is, if EPA were to apply such logic, doing so as part of the National Inventory process would be more appropriate than grossing up emissions from individual components or individual operators.

Additionally, and importantly, the Industry Trades have been unable to replicate the calculations EPA used to derive the "k" factors and request transparency regarding the approach and use of data relied upon by EPA prior to finalizing any rulemaking. The Industry Trades also request confirmation if EPA tested their "k" factors by applying to the M21 data in order to recalculate the emissions at site level using study data and confirm if it matches with the measured emissions.

Commenter 0413: 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.

Footnotes:

[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.

Commenter 0417: Additionally, EPA proposes the use of individualized "enhancement factors" on top of all the other conservative assumptions within the proposed rule. NDPC does not support the use of an enhancement factor generally, as it assigns emissions that are not calculated, measured, or observed to operators that will then be subject to a methane fee for those emissions that EPA cannot substantiate. On top of this, the justification and calculations for the "k" factor itself has not been revealed through the rulemaking process, providing the public no opportunity to comment on the actual value of the factor, regardless of its appropriateness as a reporting mechanism.

…**The EPA should also eliminate the proposed use of an enhancement factor.**

Response 1: See Section III.P.2 of the preamble to the final rule for the EPA's response to this comment.

Commenter: Duke Energy
Comment Number: EPA-HQ-OAR-2023-0234-0376
Page(s): 6

Commenter: Interstate Natural Gas Association of America (INGAA)
Comment Number: EPA-HQ-OAR-2023-0234-0387
Page(s): 9-11

Commenter: Downstream Natural Gas Initiative
Comment Number: EPA-HQ-OAR-2023-0234-0396
Page(s): 7

Commenter: American Gas Association (AGA) and American Public Gas Association (APGA)
Comment Number: EPA-HQ-OAR-2023-0234-0418
Page(s): 12-13

Comment 2:

Commenter 0376: EPA also proposes to add an "Undetected Leak Factor"[6] for various screening methods for detecting leaking components. EPA states: "[v]ariability inherently exists in each method's ability to detect leaks and can be attributed to reasons associated with the instrument, leak detection procedures, the operator or site conditions…Operators with varying levels of training or expertise deploy the screening devices, resulting in operator variability. Site-level conditions such as wind speed can also impact the detection of leaks." Therefore, EPA proposes to account for the quantity of emissions that remain undetected by applying a method specific adjustment factor, k, for the calculation method used to quantify emissions from equipment leaks using the leaker method (in 40 C.F.R. § 98.233(q)). The Undetected Leak Factor is to be used in calculations to quantify emissions using these monitoring methods. This is based on study data from onshore production and gathering and boosting facilities. Because EPA has not conducted an evaluation of testing methods beyond the upstream onshore production and gathering and boosting industry segments or for testing methods besides OGI, applying this leak factor to other industry segments is not reasonable or scientific. EPA's proposal serves to disincentivize adoption of advanced leak detection, and EPA should not propose a change of this significance simply because it "expects" other industry segments might also have higher emissions. EPA should therefore withdraw its proposed "Undetected Leak Factor" for downstream industry segments and only re-propose one when sufficient data are available.

If EPA does adopt these new, higher leaker emissions factors, it should not eliminate the current provision that allows a facility to verify any leaks detected by conducting a second test using Method 21.

Footnotes:
[6] 88 Fed. Reg. at 50,345

Commenter 0387: §98.233(q) "Equipment Leak Surveys" includes the procedures for estimating emissions from leaking components in natural gas service. Leak detection surveys are conducted at least once in each calendar year and annual emissions from detected leaks are estimated using leaking component EFs (e.g., scf THC 16/hr), estimated annual component hours in service, and concentrations of CH4 and CO2 in the hydrocarbon stream (Equation W-30). Proposed revisions for estimating leaking component emissions in the natural gas transmission and storage (T&S) sectors include: (1) revised (increased) EFs for leaks detected using optical gas imaging (OGI) based on "OGI enhancement factors", and (2) application of a leak detection method-based "k" factor to adjust emission estimates for undetected leaks (see Equation W-30 in Proposed Rule). INGAA's October 2022 Comments addressed similar issues with the proposed EF updates, and although EPA's analysis was updated, similar flaws remain. Thus, INGAA strongly opposes EPA's proposed revisions to the T&S gas leak emission estimation methodology, and the proposed revisions should not be adopted. The OGI enhancement factors (i.e., the ratios of the OGI EFs and the Method 21 EFs) and the application of k factors are based on an EPA analysis, described in the Technical Support Document (TSD)[17], that selectively uses data from gas leak emissions studies conducted on "upstream" natural gas production wells and gathering and boosting stations. EPA has not provided a sound technical basis for its conclusion that the OGI enhancement factors and "k" factors based on upstream segment studies should apply to T&S leaker emission estimates. Further considerations include:

…

- The majority of upstream equipment are outdoors; thus, leak surveys are complicated by wind and a range of OGI detection backgrounds. Such adverse conditions likely contributed to undetected leaks identified by the upstream studies and the application of k-factors. Conversely, the majority of leaking T&S components are on compression equipment which are housed; wind and background have much less adverse impact on leak surveys (i.e., far fewer undetected leaks). Thus, k-factors developed for upstream operations should not be applied for T&S.

- Unless study design and in-depth analysis clearly supports applying upstream data to T&S segments, any future revisions to T&S component leak emissions estimation methodologies should be based on data from T&S sector-specific leak surveys.

…

EPA then calculated three leak detection method-based "k" factors from the Pasci data to adjust upstream emission estimates for undetected leaks by dividing total emissions from all leaks detected by OGI and Method 21 (some leaks were detected by one of the methods but not both) and:

- Total emissions from leaks detected by OGI;
- Total emissions from leaks detected by Method 21 with a leak definition of 10,000 ppm; and
- Total emissions from leaks detected by Method 21 with a leak definition of 500 ppm.

…

The analysis and data used to calculate the revised upstream EFs and the k-factors have many shortcomings:

…

- The single, small Pasci dataset is the sole basis for the OGI enhancement factor and the k factors. Thus, any biases or anomalies in the measurements will fully propagate to the proposed rule revisions. For example, Table 1 lists the 15 largest leaks that were solely detected by OGI. For each of these leaks the high-flow sampler gas concentration was orders of magnitude greater than the 500 ppm leak definition, and it is questionable how such large leaks were not detected by the Method 21 survey. The largest leak for the entire study is an 83.65 scfh OEL leak, and OELs are typically the simplest components on which to detect leaks. These results suggest an inexperienced survey person or other study deficiencies. If these large leaks had been detected by the Method 21 survey, then there would have been very little difference between the Method 21-detected leaks emissions and the OGI-detected leaks emissions. Basing a rule on a single small study – especially a study where questionable results are reported – is not good practice. Segment-specific and replicate studies should be conducted to develop more robust and reliable dataset for updating prescribed Subpart W EFs.

Footnotes:

[16] total hydrocarbons

Commenter 0396: EPA is also proposing a "K factor" to account for undetected leaks. The K factor is derived from "the Pacsi study" (as noted in the TSD), a study performed in the Production and Gathering and Boosting segment using Method 21 (10,000 ppm and 500 ppm) and OGI. DSI recommends that EPA use data from studies in downstream segments to determine appropriate K factors for the distribution segment. The TSD states that "site conditions" such as inaccessibility can contribute to undetected leaks. Since downstream operations are inherently different than upstream operations, and much less likely to be inaccessible, EPA should evaluate the "K factor" for the distribution segment independently of the transmission segment.

Commenter 0418: **D. While the Associations support EPA's proposal to allow the use of direct measurement to quantify emissions from equipment leak components, several additional improvements would increase the accuracy of distribution segment emissions estimates.**

EPA is proposing to revise the method of quantifying emissions via equipment leak surveys under Subpart W. The current calculation method uses (1) the count of leakers detected using a leak detection method listed in 40 C.F.R. § 98.234(a), (2) the Subpart W leaker emission factors for specific component types and leak definitions, and (3) an estimate of the total time that the surveyed components were assumed to be leaking and operational. … EPA also is proposing to apply a factor to account for undetected leaks for facilities that use the leaker calculation methods. The Associations oppose both of these proposed adjustment factors.

…

The proposed "OGI enhancement factor" and "k factor" should not apply to LDCs because they are based on upstream segment data and are therefore unrepresentative of distribution segment emissions.

….

EPA is similarly using upstream study data to justify a proposed "undetected leak factor," which the Agency calls the "k factor," that purports to reflect the inherent variability in leak screening methods and survey conditions that can result in undetected, unreported leaks.[41] The k factor would be applied to the emissions quantified by leaker calculation methods. For both factors, EPA is making a baseless assumption that upstream data is equally applicable downstream. The Associations oppose the proposed application of the OGI enhancement factor and the k factor to distribution segment leak emissions estimates for the same reasons that INGAA provides with regard to the transmission and storage segments. The Associations urge EPA not to add either adjustment factor to the leaker emission factors for LDC equipment.

Footnotes:
[41] "Based on the Pacsi et al. (2019) study data, OGI observes 80 percent of emissions from measured leaks, Method 21 at a leak definition of 10,000 ppm observes 65 percent of emissions from measured leaks, and Method 21 at leak definition of 500 ppm observes 79 percent of emissions from measured leaks. . . . [V]ery few onshore petroleum and natural gas production and onshore petroleum and natural gas gathering and boosting facilities use infrared laser beam

illuminated instruments or acoustic leak detection devices to conduct equipment leak surveys, so there are no data available to develop a method-specific adjustment factor, k, for these detection methods. Based on our understanding of these alternative methods, we expect that their leak detection thresholds would be most similar to OGI, so that the average emissions per leak identified by these alternative methods would be similar to the emissions estimated using OGI." *Id*. at 50,345.

Recommendation: EPA should also eliminate the proposed use of an enhancement factor.

Response 2: See Section III.P.2 of the preamble to the final rule for the EPA's response to this comment.

Commenter: Sensirion Connected Solutions
Comment Number: EPA-HQ-OAR-2023-0234-0293
Page(s): 23

Commenter: Project Canary, PBC
Comment Number: EPA-HQ-OAR-2023-0234-0348
Page(s): 19

Comment 3:

Commenter 0293: **4. From the Preamble in Section P. Equipment Leak Surveys, Subsection 2. Addition of Undetected Leak Factor for Leaker Emission Estimation Methods, EPA asks, "We are seeking comment on the application of this factor to scale detected leak emissions. Specifically, we are seeking additional data that either support the application of this factor and the appropriate method-specific value for this factor, or support for why the proposed factor should not be applied to equipment leak estimates."**

The study used to generate the undetected leak factor, or k factor, was performed specifically for OGI, Method 21 at 500 ppm and Method 21 at 1000 ppm. Per NSPS OOOOb/c, many operators will be utilizing EPA approved advanced technology methodologies, including continuous monitoring systems, to satisfy their fugitive emissions facility requirements. Applying a k factor to leaks detected through the use of these technologies will result in an inaccurate accounting of emissions.

This study was also performed on only 67 oil and gas sites in the Permian, Anadarko, Gulf Coast and San Juan basins. This is not representative of emissions from all operators across all basins in the United States. Operators use varying methods of fugitive emissions control and abatement. By requiring the k factor regardless of where or how a site is operated, EPA is disincentivizing continuous improvement and fugitive emissions reduction investment.

Commenter 0348: **Responses to EPA's Specific Solicitation of Comments**

From the Preamble in Section P. Equipment Leak Surveys, Subsection of Undetected Leak Factor for Leaker Emission Estimation Methods, EPA asks, “We are seeking comment on the application of this factor to scale detected leak emissions. Specifically, we are seeking additional data that either support the application of this factor and the appropriate method-specific value for this factor, or support for why the proposed factor should not be applied to equipment leak estimates.”

The study used to generate the undetected leak factor, or k factor, was performed specifically for OGI, Method 21 at 500 ppm and Method 21 at 1000 ppm. Under the NSPS OOOOb and EG OOOOc final regulation, many operators will likely be utilizing more accurate EPA-approved advanced technology methodologies, including continuous monitoring systems, to satisfy their fugitive emissions facility requirements. Applying a k factor to leaks detected through the use of these technologies will result in inaccurate accounting of emissions.

The study used to generate the undetected leak factor, or k factor, was also performed on only 67 oil and gas sites in the Permian, Anadarko, Gulf Coast and San Juan basins. This is not representative of emissions from all operators across all basins in the U.S. Operators use varying methods of fugitive emissions control and abatement. By requiring the k factor regardless of where or how a site is operated, EPA is disincentivizing continuous improvement and fugitive emissions reduction investment.

Response 3: As described in the preamble and technical record for the proposed rule, the undetected leak factor was developed to ensure emissions represent as accurately as possible the actual emission inventory of a facility and, therefore, we are finalizing the undetected leak factor, as proposed. We would also note that the commenter references the use of advanced technologies including continuous monitoring systems. As continuous monitoring systems are not included in this final subpart W rulemaking for the detection of equipment leaks, the undetected leak factor is not being applied to leaks identified using this technology. We expect that fugitive emission reduction investments will result in a reduction in the reported quantity of equipment leaks to subpart W.

Commenter: MiQ
Comment Number: EPA-HQ-OAR-2023-0234-0392
Page(s): 5

Comment 4: Use of Information in Alternative Periodic Screenings

Equation W-30: Introduction of 'k' factor to adjust for undetected leaks

MIQ Comments: We applaud EPA's proposal to include adjustment factors based on the type of survey that are based on empirical data surrounding the effectiveness of survey detection. We believe this methodology will ultimately more accurately account for equipment leak emissions across the industry reported through leak inspection results and incentivize operators to develop and maintain strong, integrated LDAR programs to keep reportable emissions events as low as possible. We do not believe that the most accurate method of individual operator differentiation is for all operators to use the same adjustment factor regardless of their equipment leak inspection practices. Research on handheld OGI methods has shown that undetected leaks are partly due to poorly trained OGI operators. Updates to Appendix K attempt to resolve this issue across the industry as well as others. MiQ suggests EPA consider developing a construct to allow operators to remove the usage of the 'k' factors over time if exceptional performance above and beyond the industry standard is showcased that provides additional assurance.

Response 4: The EPA acknowledges the commenter's support of the proposed revisions. We are finalizing the amendments to add default survey method specific undetected leak factors, as proposed. We may consider the approach of providing a regulatory framework by which reporters could adjust and/or remove the undetected leak factor on a performance basis in a future rulemaking.

17.3 Addition of Method to Quantify Emissions Using Direct Measurement

Commenter: Environmental Defense Fund, et al.
Comment Number: EPA-HQ-OAR-2023-0234-0413
Page(s): 66-67

Comment 1:

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.

Response 1: The EPA acknowledges the commenter's support of the proposed revisions. The EPA is finalizing these amendments as proposed.

Commenter: Ascent Resources, LLC
Comment Number: EPA-HQ-OAR-2023-0234-0339
Page(s): 3-4

Commenter: The Petroleum Alliance of Oklahoma
Comment Number: EPA-HQ-OAR-2023-0234-0398
Page(s): 17

Comment 2:

Commenter 0339: Ascent supports the option to use measured volumetric flow rates to develop site-specific leaker factors in 98.233(q)(4), but requests clarification on certain elements in the proposed regulatory text. 98.233(q)(3) states that you "must determine the volumetric flow rate of each natural gas leak." This requirement may be difficult to meet for leaks that are not easily accessible especially when the acceptable measurement equipment is limited to flow meters, calibrated bags, and high-volume samplers as in 98.234(b) – (d) (see Comment No. 2 hereinabove <regarding request for allowance of advanced technologies when measuring volumetric emissions rates>). Ascent is requesting that the EPA provide the option to use default leaker factors for individual leaks where flow rate measurement is difficult or impossible alongside of measurements for the rest of the leaks at the site.

Commenter 0398: Addition of Method to Quantify Emissions Using Direct Measurement. EPA proposes to provide an option that would allow reporters to quantify emissions using direct measurement of equipment leaks. EPA states that to use this proposed option, all leaks identified during a ''complete leak detection survey'' must be quantified; in other words, reporters could not use leaker emission factors for some leaks and use direct measurement on other equipment during the same leak detection survey.

There may be situations at a facility where direct measurement is not feasible or is safe to conduct. This should not prevent reporters from conducting direct measurement of equipment elsewhere on the facility. EPA's proposal disincentivizes the use of direct measurement, the most accurate means of emission quantification.

Action Requested: We request EPA allow reporters the option to use direct measurement and/or EFs as appropriate during a complete leak detection survey.

Response 2: See Section III.P.3 of the preamble to the final rule for the EPA's response to this comment.

Commenter: Environmental Defense Fund, et al.
Comment Number: EPA-HQ-OAR-2023-0234-0413
Page(s): 64-65

Comment 3: X. Equipment Leak

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.

…

Revisions and Addition of Default Leaker Emission Factors
…

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.

Response 3: The EPA is finalizing an other large release event threshold of 100 kg/hr. For sources for which there is a calculation method in subpart W, the 100 kg/hr threshold in the final rule must be compared with emissions exceeding those resulting from calculations using the method specified for that source. This threshold exceeds any expected equipment leak measurement and similarly this threshold far exceeds any of the default emission factors provided for equipment leaks. However, for the purposes of example, in the unlikely event that a facility is using calculation method 2 for equipment leaks (*i.e.*, measurement method) and measures a leak of 200 kg/hr, they must report this equipment leak measurement as an equipment leak emission source since there is a measurement method provided in the final rule. If this facility was instead utilizing the either the default leaker emission factors or the default population emission factors to quantify equipment leak emissions, and obtained credible evidence that they had a leak in excess of more than 100 kg/hr of the emissions that would be calculated using the default emission factors they would report the emissions as an other large release event.

Commenter: American Gas Association (AGA) and American Public Gas Association (APGA)
Comment Number: EPA-HQ-OAR-2023-0234-0418
Page(s): 14

Comment 4:

While the Associations support EPA's proposal to allow the use of direct measurement to quantify emissions from equipment leak components, several additional improvements would increase the accuracy of distribution segment emissions estimates.

The Associations support EPA's proposal to allow emissions to be quantified using direct measurement results from leak surveys.

We are pleased that the Agency is proposing an option for facilities in the natural gas value chain to calculate emissions based on the results of direct measurement of equipment leaks, as this will allow for more accurate reporting. The Associations have long advocated for such a direct measurement option, which would employ methods such as calibrated bagging or a high-volume sampler to detect leaks at above-grade T-D stations. Under this proposed option, leak quantification would be via a "complete leak detection survey," *i.e.*, facilities using this option could not use leaker emission factors for some leaks and direct measurement for others.

In recognition of the fact that a "facility" in the natural gas distribution segment is not limited to the traditional notion of a "facility" within a fence line, [42] but is instead much more expansive and may involve as many as hundreds or even thousands of T-Ds across a single state, EPA is proposing to allow LDCs to conduct leak detection surveys across multiple years[43]— provided that each year's survey monitors approximately the same number of stations each year and the entire cycle of surveying all T-Ds does not exceed five years.[44] For LDCs that use the multi-year survey option, EPA is proposing that all of the T-Ds surveyed during a calendar year would be considered a "complete leak detection survey" for the purpose of being able to use the direct measurement option.[45] This provision is important to the feasibility of the direct measurement option because using a high-volume sampler or calibrated bag is time consuming, and there are numerous components to be measured, so most gas utilities would need to spread their leak surveys over more than one year.

Recognizing that use of the direct measurement option requires a "complete leak detection survey," which for LDCs may take up to five years to complete, the Associations request that companies/utilities be allowed to continue using their previous T-D emission factors for any stations that have not yet been subject to direct measurements until such time as all of that LDC's stations have gone through one full cycle of surveying. Once the full cycle of measuring all T-Ds has been completed, the previous emission factors would no longer be used.

Footnotes:
[42] The current Subpart W definition of a "facility" with respect to natural gas distribution is: "the collection of all distribution pipelines and metering-regulating stations that are operated by a Local Distribution Company (LDC) within a single state that is regulated as a separate operating company by a public utility commission or that are operated as an independent municipally-owned distribution system." 40 C.F.R. § 98.238. EPA is not proposing to change the current definition; however, it is proposing to remove the "inadvertent identical duplicative definition" from the regulatory text. *See* Table 4 to Proposed Rule, 88 FR 50364 (listing proposed technical corrections).
[43] The Associations have identified an apparent typographical error in the proposed regulatory text: proposed 40 C.F.R. § 98.233(q)(3)(viii)(B) contains a cross-reference to "paragraph (q)(3)(vii)(A)," however, neither the current nor the proposed text contain the referenced citation.
[44] *See* Proposed 40 C.F.R. § 98.233(q)(1)(vii) shown on 88 Fed. Reg. at 50,405.
[45] *See* Proposed 40 C.F.R. § 98.233(q)(1)(vi)(G) shown on 88 Fed. Reg. at 50,404–05.

Response 4: See Section III.P.3 of the preamble to the final rule for the EPA's response to this comment.

In addition, we are finalizing a correction to a typographical error identified by the commenter in proposed 40 CFR 98.233(q)(3)(viii)(B) to cross reference "paragraph (q)(3)(viii)(A)" instead of "paragraph (q)(3)(vii)(A)."

Commenter: Duke Energy
Comment Number: EPA-HQ-OAR-2023-0234-0376
Page(s): 7-8

Commenter: Downstream Natural Gas Initiative
Comment Number: EPA-HQ-OAR-2023-0234-0396
Page(s): 5-6

Comment 5:

Commenter 0376: **3. Duke Energy appreciates EPA's proposal to provide facilities with a method to develop company-specific emission factors. However, the use of additional methods or advanced methane leak detection (AMLD) and direct measurement technologies by companies is needed as an alternative way to quantify leaks and is critical to document results of methane emissions reduction initiatives.**

EPA has proposed an option to allow reporters to quantify emissions from equipment leak components by performing direct measurement.[9] EPA is also seeking comment on alternative methods for quantifying leaks for use for equipment leak measurements along with supporting information and data.

Duke Energy appreciates EPA's willingness to consider allowing reporters to quantify emissions by performing direct measurement. Duke Energy has been a leader in performing pilot initiatives to directly identify, measure, quantify, and remediate leaks on our local distribution system. As we broaden our pilots into standard operating processes, the ability to report our directly measured emissions to EPA versus reporting emissions pursuant to Subpart W emission factors and facility counts will provide a more accurate accounting of our emissions and demonstrate our year-over-year progress in reducing emissions. Despite our very best efforts to reduce emissions and identify enhanced measures to quantify real emissions, EPA's current prescribed method to report emissions with national emission factors and facility counts will never represent the progress we are making in reducing emissions.

Duke Energy is concerned that EPA's proposal does not allow reporters to utilize a combination of directly measured emissions where the technology and corresponding processes are deployed, and the national emission factors/facility counts in parts of the system where reporters do not yet have the technology deployed. This could result in not encouraging direct measurement when possible. The requirement to deploy direct measurement for leak detection across an entire LDC (which EPA defines as the "reporting facility") or not at all would essentially eliminate, or at least significantly delay, reporters' ability to provide more accurate information based on advanced technology. Duke Energy urges EPA to consider the use of sampling of measurements by asset class, sub-class and facility type versus a requirement to deploy direct measurement across the entire "facility." This approach provides operators an ability to scale technology faster and in a prudent manner and facilitate the development of company-specific emission factors, which create a far more accurate emissions inventory.

AMLD technologies vary and are advancing rapidly. Duke Energy has several different pilots underway along with the creation of an emissions data platform developed in partnership with

Accenture and Microsoft. We have selected various parts of our distribution system, across several states, to use the technology, develop processes, study data, validate data, and make improvements. We believe it is beneficial to both Duke Energy and our customers and communities to implement these pilots and eventually deploy these new technologies in a phased, deliberate approach. In implementing these pilots, we must consider the cost of the technology, each of the diverse operational areas within the state, and our limited resources to ramp up direct measurement of emissions. Waiting until such time that we are able to perform direct measurement across all assets within an entire state would serve to discourage companies like Duke Energy from voluntarily beginning to directly measure their emissions and adapt processes and operational activities accordingly. Duke Energy believes EPA should permit a company to utilize direct measurement on facilities where it is deployed within the state, in addition to traditional EPA Subpart W surveys where emissions are not being directly measured.

…

Footnotes:

[9] 88 Fed. Reg. at 50,345; 40 C.F.R. § 98.233(q)(1) & (q)(3).

DIRECT MEASUREMENT

DSI supports EPA's efforts to improve estimates of methane emissions by allowing direct measurements. Specifically, DSI supports EPA's proposal to allow LDCs to quantify emissions from transmission-distribution stations using direct measurements. More broadly, DSI encourages EPA to allow companies to use company-specific data and advanced methane detection and quantification technologies to estimate methane emissions. For LDCs, DSI supports flexibility to allow companies to develop company-specific emission factors and calculate emissions using the number of leaks in the distribution system.

The population emission factor approach based on main mileage and service counts assumes that all pipelines of a given material are leaking at all times, regardless of age. This approach does not allow LDCs to show progress reducing actual emissions through strategies such as eliminating grade 3 leak backlogs. An approach that combines company-specific emission factors and the number of system leaks would allow for more accurate quantification of actual emissions than is currently possible using EPA's default population-based emission factors and enable companies that are investing in more frequent and advanced methods (AMLD) to find and eliminate leaks to demonstrate progress in reducing emissions.

EPA should consider deriving leaker-based factors from the Lamb study to allow distribution companies to use leak screening as a form of measuring emissions. The Lamb study contains the equivalent leaks per mile or service. By dividing the proposed factor (scf/hr/mile or service) by the equivalent leaks per mile or service, a factor in units of scf/hr/leak can be determined. Companies could then screen for leaks on an annual or multi-year basis (e.g., two to five years) to determine a total number of equivalent leaks. A similar approach for transmission pipeline leaks (previously discussed) could be taken. Pipeline leak detection could include a variety of leak detection methodologies such as Method 21, OGI, IR camera, laser detection, and mobile technologies.

In order to derive company specific emission factors for pipeline leaks (distribution or transmission) and to determine a large enough sample size, EPA could adopt a similar approach as another source category. For example, EPA is proposing to allow operators of transmission stations to develop specific emission factors if there are 50 measurements of a given component. EPA could allow a transmission company to develop specific emission factors if 50 measurements of a specific pipe material were taken. Companies should be allowed to use a mix of methods (e.g., survey/leak data for cast iron and unprotected steel, population counts for plastic and protected steel).

EPA could also reference standards set by CARB (California Air Resources Board) or the recently released Veritas Protocols to determine specific emission factors.

Response 5: We are finalizing the proposed population emission factors for local gas distribution companies based on the combination of data from Lamb *et al.* and the GRI/EPA studies as discussed elsewhere in this document and the preamble for the final rule.

We did not propose and are not finalizing default leaker emission factors for the pipeline mains and services based on the Lamb *et al.* study. In our review of the Lamb *et al.* study and its supporting information, we did not find the leak survey method reported for the quantified leaks. We note that the accuracy of default leaker emission factors is dependent on the survey method detection limit and therefore likely would need to be specific to each survey approach. So, without information about the leak survey method relative to the measurement data, we are not utilizing this study to provide default leaker emission factors. We acknowledge that some leak detection, particularly for distribution, are found by odor due to the addition of methyl mercaptan and thus, no survey method is associated with the leak.

We did not propose and are not finalizing advanced mobile leak detection as a survey method or including default leaker emission factors for this survey method. We are aware of one AMLD study that we have evaluated which surveyed and quantified leaks, the Weller *et al.* study. As described in the TSD for the final rule, which is available in the docket for this rulemaking, we evaluated the Weller *et al*. study for the potential to utilize the study for updating the population count emission factors for distribution mains (which we are not finalizing as noted in the preamble), but recognize it could potentially be used to develop default leaker emission factors. We evaluated the measurement data included in this study and noted the quantification associated with AMLD does not appear to be as accurate as existing subpart W quantification techniques (*e.g.*, high flow sampling). Due to the concerns over the accuracy of the resulting leak measurements from AMLD, we are not including it as a subpart W method at this time; however, we will continue to evaluate AMLD study data as they become available to determine the appropriateness of its inclusion in a future rulemaking.

Finally, we did not propose and are not finalizing the applicability of the calculation method 2 for leaker (*i.e.*, direct measurement) and the ability to develop facility-specific leaker factors in accordance with section 98.233(q)(4) for the distribution pipeline mains and services emission sources using advanced technologies for the reasons stated above and as explained in section II.B of the preamble. However, we intend to take this into consideration for future rulemakings which could provide advanced technologies for equipment leak survey and measurement, as well as broaden the applicability of various leaker estimation approaches including direct measurement and facility-specific emission factor development.

Commenter: Kairos Aerospace
Comment Number: EPA-HQ-OAR-2023-0234-0240
Page(s): 11-13

Comment 6:

V. The Equipment Leaks Reporting Category Should be Revised to Incorporate a Broader Spectrum of Technology

The Equipment Leaks reporting category currently allows for a limited set of measurement and/or leak detection techniques, including EPA Method 21 and OGI camera inspections. In the proposed rule, EPA notes remote sensing technologies "can provide very useful information about emissions during snapshots in time, and thus help to greatly improve the completeness and accuracy of emission reporting, they generally cannot by themselves estimate annual emissions."

EPA appears to be suggesting that the "snapshot" nature of remote sensing measurements makes them unsuitable for estimating equipment leaks on an annual basis. However, we believe this premise is flawed. If remote sensing measurements represent a snapshot because they are taken during a specific moment in time, the same is true of OGI surveys and EPA Method 21 surveys. Granted, these ground-based techniques may measure for a small amount of time at the component level, but an entire survey takes less than a day for a single site and provides only a snapshot on what happened on that day. Moreover, the component-by-component measurement approach means each fugitive emissions component has only a snapshot of measurement.

It also ignores the fact that due to their lower cost, remote sensing measurements can be taken more frequently and provide arguably better insight into emissions over time. A monthly aerial measurement certainly would provide more information about fugitive emissions over the course of a year than a single OGI survey.

Remote sensing methods cannot always identify component-level emissions, but remote sensing can still provide valuable information on smaller sources of emissions that fall below the Other Large Release Event threshold, particularly quantification.

Moreover, ground follow-up surveys are commonly paired with remote sensing techniques notably in the proposed OOOOb and OOOOc rules. Remote sensing LDAR programs within those rules will typically screen sites for emissions and then direct ground resources to follow up and confirm the cause of emissions for repair. In many cases, this follow up work will be done with OGI cameras. While OGI cameras can provide component-level attribution of emissions, they typically cannot reliably quantify emissions. However, many remote sensing methods can quantify emissions with a high degree of reliability and accuracy.

We propose that EPA allow reporters the option to use site-level quantification data from remote sensing technologies to report emission volumes identified in follow-up ground surveys. In such a situation, a reporter may receive a report of elevated emissions from a site from a remote sensing technology. Upon follow up, OGI inspections may reveal three leaks that are combining to result in the aerially-detected emissions. We propose operators be given the option to use aerial quantification in lieu of emission factors for the emissions associated with the leaks identified by the ground. This would support EPA's ultimate objective of incorporating more empirical data into the rule as well as reduce uncertainty resulting from the use of OGI emission factors.

Notably, many measurement technologies include a margin of error when quantifying emissions. We suggest that if EPA were to use advanced measurement technologies as an option to quantify, operators should be allowed the option to select another approved quantification technique (e.g. high-flow sampling, bagging of leaks, etc.) to quantify emissions. This approach should be applied both to the Equipment Leaks reporting category as well as the Other Large Release Event reporting category

Response 6: We did not propose and for the reasons discussed in section II.B of the preamble are not finalizing an option for reporters to use site-level quantification data from remote sensing technologies to report emission volumes identified in follow-up ground surveys (*i.e.*, use aerial quantification in lieu of survey specific leaker emission factors). While we are not finalizing site-level quantification from remote sensing, we are undertaking research on and exploring options for using remote sensing for this purpose and may consider these changes in a future rulemaking.

Commenter: Lambda Energy Resources
Comment Number: EPA-HQ-OAR-2023-0234-0405
Page(s): 1, 2

Comment 7:

For operators that must comply with these rules it may be impractical to gather direct measurement leak data from all their equipment …

…

Also, in the event that an organization decides that it is practical to develop a way to collect actual emissions, the process to implement the method should be streamlined. A third option to report accurate emissions that should be considered is to allow in-house or third-party engineering studies. This too would need a streamlined approval process so reporters could integrate the manner of data collection to their program in a timely manner.

Response 7: We did not propose and are not finalizing a process for facilities to conduct in-house or third-party engineering studies to inform their emissions reporting. It is unclear exactly what is meant by an in-house or third-party engineering study. If the commenter meant that such a study could provide facility-specific leaker emission factors, we note that we are finalizing such a method in this rulemaking. If the commenter meant that an in-house or engineering study would be used to estimate the facility's emissions, we disagree. The rule provides consistent and prescriptive methods to estimate emissions to ensure both accuracy and consistency across all reported data.

Commenter: Kairos Aerospace
Comment Number: EPA-HQ-OAR-2023-0234-0240
Page(s): 17

Commenter: Teledyne FLIR, LLC
Comment Number: EPA-HQ-OAR-2023-0234-0244
Page(s): 2

Commenter: Ascent Resources, LLC
Comment Number: EPA-HQ-OAR-2023-0234-0339
Page(s): 3

Commenter: Arkansas Independent Producers and Royalty Owners (AIPRO)
Comment Number: EPA-HQ-OAR-2023-0234-0382
Page(s): 15

Commenter: Environmental Defense Fund, et al.
Comment Number: EPA-HQ-OAR-2023-0234-0413
Page(s): 64

Comment 8:

Commenter 0240: We also believe there are other opportunities to better incorporate advanced measurement into the Proposed Rule, particularly within the Equipment Leaks reporting category, to better align with other regulations and standards.

Commenter 0244: In the docket, there was a direct request for comment related to alternative methods for quantifying leaks tied to the proposed addition of method to quantify emissions using direct measurement. In recent years, the technology of QOGI (Quantification of Optical Gas Imaging) has advanced considerably and has even become an accepted protocol in regulatory initiatives from other countries like Canada and Mexico. FLIR QOGI technology, available in various forms over the recent years, has been vetted by numerous 3rd party validation studies including CONCAWE[2] where it was proven to be 6 times more accurate than Method 21 and the Alberta Methane Field Challenge (AMFC)[3] where it was deemed to be "effective in providing comprehensive estimates of all methane emissions at oil and gas facilities". The AMFC study stated that QOGI technology from FLIR, specifically with the algorithm in the FLIR QL320 tablet, has an 18% aggregate error when compared to control releases. To further this investigation, FLIR performed an internal study at the Colorado State University METEC facility, the same facility used in a main study leveraged for much of this regulation, in which we established a 4% aggregate error from controlled releases.

Additionally, the QOGI technology provides considerable advantages over other technologies approved in 40 CFR 98.234(b) through (d). Since QOGI allows operators to both detect, and measure, emissions from a distance and outside of the plume itself, there is a great safety consideration for this technology to be included as a direct measurement method to protect the health of the oil and gas worker measuring emissions in the field. This also simply provides measurement capabilities in some DTM (Difficult to Measure) components unavailable with other technologies. Compared to bagging or high-volume sampling technology, QOGI has an advantage of measuring high flow leaks including up to 3,000 SCFH vs 480 SCFH for the Hi-Flow, as referenced in the AMFC study. We feel that this technology could fit well in the framework of regulatory action to provide direct measurement for emissions detected while using OGI as a technology.

In summary, FLIR feels that Optical Gas Imaging should be embraced as a technology to detect and mitigate emissions, instead of punished with an "enhancement factor". As a detection method that was highlighted as superior in reducing overall emissions compared to other methods in the research studies provided by the docket, OGI is the most effective way to both ensure compliance and protect the environment. With the advancements in this technology over the previous 5 years to include the ability to quantify emissions safer than other technologies, Quantitative Optical Gas Imaging should be added as a direct measurement method. This both protects the oil and gas worker but also provides a more efficient quantification method.

Footnotes:

[2] CONCAWE, An evaluation of an optical gas imaging system for the quantification of fugitive hydrocarbon emissions. January 2017 https://www.concawe.eu/wp-content/uploads/2017/01/rpt_17-2.pdf

[3] Alberta Methane Field Challenge. August 2020 https://auprf.ptac.org/wp-content/uploads/2020/11/AMFC_FinalReport_v6.pdf

Commenter 0339: 2. The EPA has not proposed any changes to the equipment that can be used to measure volumetric emissions rates in 98.234(b) – (d) which includes flow meters, calibrated bags, and high-volume samplers. The EPA should broaden this section with performance-based requirements to allow for the use of advanced technologies to quantify volumetric emissions rates.

Commenter 0382: **h. Equipment Leak Surveys:**

…

ii. AIPRO generally supports the proposed option to quantify leak rates via approved methods as an alternative to using "one-size fits all" emissions factors. That said, AIPRO proposes that EPA allow all available and proven reliable alternatives for doing so.

Commenter 0413: X. Equipment Leak
… 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.

Response 8: The EPA did not propose and for the reasons discussed in section II.B of the preamble is not finalizing measurement methods other than high flow samplers, calibrated bags, or flow meters, however, we intend to take this information into consideration for future rulemakings which could provide advanced technologies for equipment leak measurement (*e.g.*, quantitative OGI).

17.4 Addition of a Method to Develop Site-Specific Component-level Leaker Emission Factors

Commenter: Public Hearing Transcript
Comment Number: EPA-HQ-OAR-2023-0234-0224
Page(s): 14 (Lisa Beal)

Commenter: GPA Midstream Association
Comment Number: EPA-HQ-OAR-2023-0234-0299
Page(s): 52-53

Commenter: Independent Petroleum Association of New Mexico (IPANM)
Comment Number: EPA-HQ-OAR-2023-0234-0337
Page(s): 9-10

Commenter: Interstate Natural Gas Association of America (INGAA)
Comment Number: EPA-HQ-OAR-2023-0234-0387
Page(s): 5, 13

Commenter: MiQ
Comment Number: EPA-HQ-OAR-2023-0234-0392
Page(s): 4

Commenter: CrownQuest Operating
Comment Number: EPA-HQ-OAR-2023-0234-0393
Page(s): 261, 640

Commenter: Williams Companies, Inc.
Comment Number: EPA-HQ-OAR-2023-0234-0394
Page(s): 15

Commenter: Step2compliance
Comment Number: EPA-HQ-OAR-2023-0234-0395
Page(s): 3

Commenter: Range Resources Corporation
Comment Number: EPA-HQ-OAR-2023-0234-0397
Page(s): 6-7

Commenter: The Petroleum Alliance of Oklahoma
Comment Number: EPA-HQ-OAR-2023-0234-0398
Page(s): 17-18

Commenter: American Petroleum Institute et al. (Part 1 of 2)
Comment Number: EPA-HQ-OAR-2023-0234-0402
Page(s): 51-52

Commenter: Environmental Defense Fund, et al.
Comment Number: EPA-HQ-OAR-2023-0234-0413
Page(s): 67

Commenter: American Gas Association (AGA) and American Public Gas Association (APGA)
Comment Number: EPA-HQ-OAR-2023-0234-0418
Page(s): 12, 15

Comment 1:

Commenter 0224: And the ability to develop company-specific emission factors based on measured data really should be streamlined and simplified.

Commenter 0299: **69. GPA does not anticipate many reporters will use Calculation Method 2 "Leaker measurement methodology."**

EPA proposes Calculation Method 2 to measure the volumetric flow rate of each natural gas leak identified during a complete leak survey. While optionality around emission calculations is ideal, GPA notes that this is a very burdensome method, and we do not anticipate this being realistic for reporters to adopt. This is another reason that the proposed OGI leaker emission factors must be revised to not be punitive for using that method.

Due to the constraint of the short commenting period (see Comment 1), GPA was not able to evaluate it thoroughly. We do note, however, that the requirement to "accumulate a minimum of 50 leak measurements total for a given component type and leak detection method combination before you can develop and use a site-specific component-level leaker emission factor" is unreasonable for Pressure Relief Valves, Open Ended Lines, and Pump Seals.[115] These components do not leak that often, and five measurements (rather than 50) is a more reasonable standard.

We note that many gas plants use Method 21 to detect leaks, and reporters have access to leak measurements in ppm concentrations. EPA should explore translation of these measurements to volumetric emissions (e.g., as described in the 1995 document – EPA Protocol for Equipment Leak Estimates).

Footnotes:

[115] Proposed 40 C.F.R. § 98.233(q)(4)(ii).

<u>Commenter 0337</u>: **40 CFR § 98.233(q) Pop Counts & Equip Leaks**

Section 98.233(q)(4)(ii) states, "You must accumulate a minimum of 50 leak measurements total for a given component type and leak detection method combination before you can develop and use a site-specific component-level leaker emission factor." This is impractical and does not consider the realities of onshore oil and gas operations.
EPA should not require 50 measurements to create site-specific leaker factors. Most operators would have to perform measurements for multiple years before reaching 50 measurements, either because 1) the number of sites in the facility is relatively low, and/or 2) LDAR programs have become robust enough that leaks are minimized. Operators in these cases should not be penalized with potentially higher default leaker factors or indefinitely equipping LDAR crews to conduct measurements. The table below shows the number of detected leaks from one operator's 2022 regulatory and voluntary OGI programs. The program includes eight Onshore Production facilities and three Gathering and Boosting facilities located across seven basins, conducting 13,924 surveys at 11,802 sites.

This data illustrates that if the proposed program was in place, operators would likely be able to measure 50 leaks per component type only in cases where there are a very large number of sites within a basin. With these 11 facilities each attempting to create factors for 7 component types, this operator would have only achieved site-specific leaker factors 5 times, twice for valves, twice for connectors, and once for the Other category.

# Sites Surveyed-->	**11802**	
# Surveys-->	**13924**	
	# Leaks	**#Surveys needed to find 50 leaks**
Valves	245	2842
Flanges	22	31645
Connectors	597	1166
Other	439	1586
PRV	8	87025
Pump Seal	2	348100

The significance of the required number should be relative to the size of the facility, but 50 leaks per component type for each reporting facility is just not realistic for the vast majority of reports.

We recommend a tiered approach and would revise § 98.233(q)(4)(ii) as follows:

"You must accumulate a minimum number of leak measurements as specified in (A)-(D) for a given component type and leak detection method combination before you can develop and use a site-specific component-level leaker emission factor for use in calculating emissions according to paragraph (q)(2) of this section.
(A) Your facility has less than 500 sites, then the minimum number of leaks to measure is 5.
(B) Your facility has at least 500 sites but not more than 1,000, then the minimum number of leaks to measure is 10.
(C) Your facility has at least 1000 sites but not more than 2,000, then the minimum number of leaks to measure is 20.
(D) Your facility has more than 2,000 sites, then the minimum number of leaks to measure is 30."

Commenter 0387: The Proposed Rule should include more flexibility to use measurement data to develop improved EFs

While INGAA supports measurement to improve emission estimates, measurement should not necessarily be required in perpetuity if improved EFs can be developed based on measured data. The Proposed Rule should include streamlined and straightforward paths for developing EFs as an alternative to ongoing measurement and should consider the relative importance of the emissions source (e.g., percent contribution to the segment methane emissions inventory) when considering data needs. In addition, EF development should be allowed based on company-wide data or data from collaborative, multi-company projects. In some cases, the Proposed Rule includes "site specific" data limitations for EF development, which is too constraining and not warranted. In fact, INGAA strongly believes that broader company-wide or collaborative projects to develop EFs is consistent with the intent of the IRA. Such programs should not be precluded by unnecessary Subpart W constraints

For example, and as discussed further in Comment 4, §93.233(q)(2)(vi) and (vii) indicate that "site-specific" EFs can be developed for transmission compressor stations or underground storage facilities following the criteria defined in §93.233(q)(4). As discussed in Comment 4, leak counts are typically low at T&S facilities, so it could take many years to meet data objectives defined by EPA at the site level. Broader datasets – i.e., company-wide or from multi-company collaborative projects – should be allowed for EF development and have access to IRA funds, consistent with IRA section 136(a) objectives. Additional discussion on this topic is included below – e.g., regarding pneumatic devices in Comment 3 and component leaker EFs in Comment 4.

…

Company-wide or collaborative program data should be allowed for updating leaker EFs

As discussed in Comment 1, the Proposed Rule should include more flexibility for developing EF updates, including updates to segment-specific leaker EFs. As proposed, at least 50 site-specific measurements would be required for a particular component to develop an EF. Rather than limiting the dataset to site-specific measurements, EF development should allow company-wide data as well as data from multi-company collaborative efforts. Such programmatic approaches are consistent with IRA objectives to advance the use of empirical data and to fund MERP projects to assist operators with Subpart W reporting.

Requiring 50 component-specific and site-specific measurements implies that EPA fails to understand the prevalence and frequency of T&S facility leaks. For example, a Pipeline Research Council International (PRCI) report[22] previously provided to EPA shows that 2011 – 2016 Subpart W data indicated an average of 12 to 25 total leaks per facility annually across all ten component types and services. GHGRP data also shows that T&S methane emissions have decreased since that PRCI data collection effort, thus leak counts are likely lower due to voluntary and mandatory leak survey and LDAR requirements. Thus, it would take years or decades to acquire 50 component-specific measurements at a site. There is no reason to not allow larger datasets for development of leaker EFs. Company-wide and collaborative-program data should be allowed for developing leaker EFs, and related projects could leverage IRA funds to assist operators with GHGRP reporting, which is consistent with IRA MERP objectives.

Footnotes:

[22] PRCI Catalog No. PR-312-16202-R03, "Methane Emissions from Transmission and Storage Subpart W Sources," August 2019.

Commenter 0392: 98.233(q)(4)(ii): "You must accumulate a minimum of 50 leak measurements total for a given component type and leak detection method combination before you can develop and use a site specific component-level leaker emission factor for use in calculating emissions according to paragraph (q)(2) of this section (Calculation Method 1: Leaker emission factor calculation methodology)."

MiQ Comments: MiQ recommends that EPA revise this requirement to a tiered approach to allow operators subject to GHGRP with fewer amounts of equipment to inspect within a Facility the ability to apply representative leaker emission factors based on a smaller number of leaker emitters found. EPA can achieve this in several ways, based on data availability. EPA should consider using their existing uncertainty analysis and consider applying their findings using a more scalable factor rather than an absolute number of leaks. For example, EPA could utilize research synthesized in Rutherford et al. (2021)[1] that provide empirical data to estimate the fraction of emitting components and propose a scalable factor of leaks based on the total number of estimated components for an individual operator.

Footnotes:
[1] Rutherford, J.S., Sherwin, E.D., Ravikumar, A.P. et al. Closing the methane gap in US oil and natural gas production emissions inventories. Nat Commun 12, 4715 (2021). https://doi.org/10.1038/s41467-021- 25017-4

Commenter 0393: Site-specific factors could possibly increase accuracy, but the EPA should allow operators to determine certain types of leaks or certain types of component leaks and use that factor as a representative for similar facilities rather than force the operator to have a site-specific factor for every single location if using this method. Also, the 50 individual measurements would be a difficult number to reach for a specific site. If meaning for a component type, that is more attainable, but no operator is going to want 50 individual measurements of a leak at one specific site. That would not be prudent operating.

…

We support EPA's proposal to allow for directly measured data to develop site-specific emission factors instead of the default leaker/population emission factors for leaks. We recommend that we are allowed more flexibility in the allowance of representative direct measurement instead of "site specific". in the upstream space, there may be many components that are representative even if they aren't on the same site. We recommend that the EPA let us use representative leak measurements. The proposed number of 50 measurements required to have site specific data is contrary to the number of data points. We recommend the EPA allow a more reasonable number of measurements to configure site-specific factors. This will lend to more accurate and representative conditions of the site than default emission factors from larger data sets.

<u>Commenter 0394</u>: L. Leak Detection and Measurement Methods

Williams supports the concept of identifying leaks while conducting a leak detection survey, quantifying the leakage rate per type of component, and developing a specific emissions factor. For the methodology to derive an equipment specific emission factor, Williams requests the EPA confirm the 50 individual measurements of leaks of a single type of component (i.e., valve, connector, open ended line, etc.) can be measured from the same type of component at multiple facilities from the same segment (i.e., gathering and boosting or underground storage). From there, a company can develop and utilize a company-wide emissions factor for that component for that segment. This flexibility would promote the gathering of additional empirical data, in addition to the data already used to update the leak emissions factors, to further refine the leak emissions factors, and improve data consistency while lessening the burden to operators so that multiple leak emissions factors are not being generated per company in the same segment.

<u>Commenter 0395</u>: In III.P.1, the Pacsi and Zimmerle studies that were used to derive the revised OGI enhancement factors were from a combined OGI dataset results that averaged only 44 measurements for each combination of well site type and component type that was used to in the words of EPA, "**estimate** that the leaks detected by OGI are 1.63 times larger than leaks detected by method 21 at a leak definition of 10,000 ppm…" The dataset utilized by the EPA to **estimate** the new emission factors is less than the proposed required "robust dataset" minimum of 50 measurements "to ensure a statistically representative dataset" for the purpose of establishing a site-specific component-level leaker emission factor. Additionally, EPA also states that "We have performed statistical analyses with measurements from compressors and determined that a minimum of 50 measurements is required to reduce uncertainty to factor of 3 of the true value." Based on this, EPA has not followed its own recommended practice of using a necessary robust dataset to determine the proposed OGI leaker emission factors. Reporters should not be required to use a larger dataset than EPA to determine a site-specific component-level leaker emission factor.

Commenter 0397: **Comment #7: EPA should clarify that an emission factor need not be developed for each well site.**

EPA proposes a new calculation methodology to allow for the development of "site-specific emission factors" for equipment leaks and pneumatic devices based on data collected "from direct measurement at the facility." 88 FR 50346. The intent of the rule appears to be that representative sampling can be conducted at a number of well-sites (e.g., 20) and then an emissions factor can be developed (based on that representative sampling) that will be applied facility-wide. Under subpart W, a facility is considered a group of well-sites within a basin.[2] The Proposed Rule goes on to explain, "EPA is also proposing to provide facilities with a method to use direct measurement from leak surveys to develop component level emission factors based on site-specific leak measurement data." 88 Fed Reg. at 50346.

Footnotes:
[2] 40 C.F.R. § 98.238 states, "Where a person or entity owns or operates more than one well in a basin, then all onshore petroleum and natural gas production equipment associated with all wells that the person or entity owns or operates in the basin would be considered one facility."

EPA gives a hypothetical in which a facility has 30 single-well pads at which leaks surveys and direct measurement are made. Leak surveys, but not direct measurement, are conducted at the remaining 10 well sites. EPA would allow an emissions factor for the leaks developed from the measurements at the first 20 well-sites to be applied to the other 10 well sites.

The intent is clear that an emissions factor for leaks will be based on multiple well sites and then applied to the greater basin-wide facility. 88 FR 50346 (to be codified at 40 C.F.R. § 98.233(q)(1), (3)). There is no need for an emissions factor for every single site in EPA's hypothetical. Accordingly, it is clear that EPA is not requiring operators to develop an emissions factor for every single well-site. Yet, there is a risk that some might imply that EPA is requiring a site-by-site emissions factor from the term, "site-specific." Consequently, Range suggests that EPA clarify that only a facility-wide emissions factor based on direct measurement at a representative sampling of well sites is needed.

Commenter 0398: Addition of a Method to Develop Site-Specific Component-Level Leaker Emission Factors. EPA proposes to provide reporters with a method to use direct measurement from leak surveys to develop component level emission factors based on site-specific leak measurement data. EPA states that reporters would have to compile at least 50 individual measurements of natural gas flow rate for a specific component type and leak detection method (e.g., gas service valves detected by OGI) before they can develop and use the site-specific emission factors for the component types at the facility.

It is unclear how EPA arrived at 50 individual measurements for a specific component. These measurements can be costly and demand for companies to conduct direct measurement may be limited or take many months to conduct. EPA is disincentivizing direct measurement by making the process so burdensome and costly that it will have limited use and will result in curtailing the collection of more accurate data.

Action Requested: We request EPA reconsider the proposed number of individual measurements required to develop site-specific EFs. At a minimum, EPA must provide details justifying why 50 individual measurements for a component is appropriate and reasonable.

Commenter 0402: Equipment Leaks

Method 2 - Site-Specific Leaker Emission Factors

EPA should allow more flexibility in the requirements for developing site-specific emission factors for equipment leaks.

The Industry Trades support EPA's proposal to allow for directly measured data to develop site-specific emission factors in lieu of the default leaker or population emission factors for equipment leaks. However, the Industry Trades recommend allowing more flexibility in allowing representative direct measurements rather than "site specific." For upstream operations, there can be many components that are representative even if they are not located at the same facility; and the same can be said for the gathering and boosting reporting segment. The Industry Trades recommend that EPA allow representative leak measurements where "representative" could mean components in gas or oil service, component types, and other considerations – but not otherwise limited to a single well pad or boosting and gathering ID.

The number of leak measurements required to develop site specific emissions factors, proposed as a minimum of 50 per component type, is arbitrary; accumulating 50 leak measurements will be difficult for less frequently used component types or operators with fewer sites. The Industry Trades recommend that EPA allow operators flexibility to determine an appropriate sample size using an appropriate statistical approach based on the complexity of the sites (based on variability of the streams at the sites) and available data and modify as more measurements are obtained. The requirement for a sample of 50 leak measurements per component type will penalize small operators with few sites, as the minimum requirement of 50 may not be possible. Further, as operators convert pneumatic systems to air or electric controllers, fewer sites will have natural gas-operated pneumatics. The Industry Trades also recommend allowing multiple years upon which operators can collect measured leak data and refine those factors as more data is available; this will ultimately be more accurate and representative of site conditions than default emission factors that were derived from larger data sets.

Commenter 0413: 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.

Footnotes:

[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.

Commenter 0418: **D. While the Associations support EPA's proposal to allow the use of direct measurement to quantify emissions from equipment leak components, several additional improvements would increase the accuracy of distribution segment emissions estimates.**

The Proposed Rule also would provide two alternatives to using the default leaker emission factors—either of which would be available to Subpart W reporters. One option would be to quantify emissions from equipment leak components by performing direct measurement of equipment leaks and calculating emissions using those measurement results. Another option would be for facilities to use their leak survey results to develop component-level emission factors, which would be based on a minimum of 50 individual measurements. The Associations appreciate that LDCs would be able to use direct measurements to either calculate or estimate their component-level emissions; however, the proposed criteria for developing site-specific emission factors are impracticable, making it unlikely that this option can realistically be put into practice for natural gas distribution facilities.

…

3. The Associations support the concept of site-specific leaker emission factors; however, the proposed criteria would effectively prevent LDCs from using this option.

EPA is proposing to allow facilities to use direct measurement from leak surveys to develop component-level emission factors based on site-specific leak measurement data. The Proposed Rule would require Subpart W reporters to compile at least 50 individual measurements of natural gas flow rate for a specific component type and leak detection method (*e.g.*, gas service valves detected by OGI) before a site-specific emission factor may be used for that component type at the reporter's facility.[46] To generate the site-specific emission factor, the reporter would add the 50 (or more) volumetric measurements and divide the sum by the total number of leak measurements for that component type and leak detection method combination, resulting in an emission factor in units of standard cubic feet ("scf") per hour-component.

As noted throughout these comments, the Associations conceptually support the option to develop site-specific emission factors. We also support the proposed option to allow reporters to use a combination of default leaker factors for some component types and site-specific leaker factors for other component types, given that component types will reach the minimum measurement threshold at different rates. However, this emission factor option would benefit from additional flexibilities—specifically with regard to the 50-measurement threshold. It could take some LDCs many years or even *decades* to obtain 50 individual measurements from a particular component type, if they ever do, because of how infrequently distribution components leak relative to those in other industry segments. The 50-measurement requirement would thus prevent many LDCs from being able to use site-specific emission factors. EPA could address this issue in several different ways, including by developing sub-classes of components that may use site-specific emission factors after fewer individual measurements and/or by allowing LDCs to develop company/utility-wide emission factors—or even collaboratively developed emission factors, as discussed in Section II.A.2. of these comments. Particularly with regard to collaborative emission factors, LDCs would be able to reach the 50-measurement minimum within a reasonable time frame if they were allowed to develop emission factors together. Without more flexibility, the site-specific, component-level emission factor option is not viable for the distribution segment.

Footnotes:
[46] Proposed Rule, 88 FR 50346–47.

Response 1: See Section III.P.4 of the preamble to the final rule for the EPA's response to this comment.

Commenter: Marcellus Shale Coalition (MSC)
Comment Number: EPA-HQ-OAR-2023-0234-0275
Page(s): 10

Commenter: Ascent Resources, LLC
Comment Number: EPA-HQ-OAR-2023-0234-0339
Page(s): 3-4

Commenter: MiQ
Comment Number: EPA-HQ-OAR-2023-0234-0392
Page(s): 4

Commenter: Range Resources Corporation
Comment Number: EPA-HQ-OAR-2023-0234-0397
Page(s): 7

Comment 2:

Commenter 0275: Equipment Leaks The MSC requests clarification on whether previous year's leak measurement data apply toward development of the site-specific emission factor. 98.233(q)(4)(vi) as proposed states:

"You must update the emission factor determined in (q)(4)(v) of this section annually to include the results from all complete leak surveys for which leak measurement was performed during the reporting year in accordance with paragraph (q)(3) of this section."

It is unclear from the rule language whether leak measurements from previous reporting years are included in the site-specific emission factor and the new measurements are used to update the factor (e.g., adjust the average site-specific emission factor), or if only measurements in the current reporting year could be used.

The preamble to the proposed rule seems to imply that the previous year's measurements would continue to be included in the site-specific emission factor (88 FR 50346):

"If in subsequent reporting years, the facility is required to perform additional surveys or elects to continue to survey and perform direct measurement, the facility will accumulate additional measurements which may be of a sufficient number to develop other component type site-specific emission factors. We also note that in accordance with proposed 40 CFR 98.233(q)(4), any additional measurements of a component for which a facility has developed a site-specific emissions factor (e.g., valves in the described example) would be required to be used to update the site-specific emission factor annually."

However, this is still possibly open to interpretation. The U.S. EPA should directly state that measurement data from previous reporting years would continue to apply toward the site-specific emission factor and if so, indicate whether all measurement data would be included in the site-specific emission factor in perpetuity.

Commenter 0339: 6…. Ascent also requests clarification in the regulatory text of 98.234(q)(4) around the timeframe over which the 50 measurements can be accumulated, how annual updates of site-specific factors should be handled, and how long site-specific factors can be used.

Commenter 0392: MiQ also requests clarification on if operators have already begun taking measurements that are consistent with 98.234(b) thru (d) methods, are they allowed to use this information to base their methodologies? We recommend that some allowance of historical information is given so that operators who are leaders in measurement are able to take advantage of voluntary measurement initiatives, prior to any regulatory driver, if the measurement methods are consistent with EPA's requirements.

Commenter 0397: **Comment #9: There is ambiguity in the requirements under 40 C.F.R. §§ 98.233(q)(2), (q)(3), and (q)(4).**

It is unclear how EPA anticipates proposed 40 C.F.R. §§ 98.233(q)(2), (q)(3), and (q)(4) will be implemented and additional clarification is needed. Under 40 C.F.R. § 98.233(q)(2), the Proposed Rule includes a "Calculation Method 1: Leaker emission factor calculation methodology." 88 Fed. Reg. at 50405. Under 40 C.F.R. § 98.233(q)(3), the Proposed Rule provides a "Calculation Method 2: Leaker measurement methodology." 88 Fed. Reg. at 50406. Under 40 C.F.R. § 98.233(q)(4), the Proposed Rule provides for the "Development of site-specific component-level leaker emission factors by leak detection method." 88 Fed. Reg. at 50407. Accordingly, an operator can either calculate emissions using an emissions factor (Method 1) or perform direct measurement (Method 2). However, if an operator utilizes Method 2 for direct measurement, the Proposed Rule would require the operator to perform additional work to develop a leaker emissions factor for use in Method 1. It is unclear why an operator would be required to perform this additional work and "mix-and-match" calculation methodologies. While it appears the intent, the final rule should clarify that an operator is allowed to either: (i) utilize Method 1 with the EPA provided default emissions factor or a facility-specific emissions factor developed by the operator; or (ii) perform direct measurement of emissions. This will eliminate confusion and allow operators to use different methods in different years even though operating conditions may change.

Response 2: Concerning the development of the facility-specific emissions factor, we note that we intended that each time a new measurement is made, the measurement will be added to the appropriate component level facility-specific emission factor dataset. Initially, the accumulation will continue until such time that the criteria for developing a facility-specific emission factor as specified in 40 CFR 98.233(q)(4)(ii) is met, at which time, the facility must begin to use the component level facility-specific emission factor. Once the facility has accumulated the minimum number of measurements, the facility will continue to update the dataset with any new measurement every reporting year and continue to utilize the facility-specific emission factor. There is no time restriction upon which a facility-specific emission factor may be used and the emission factor will continue to evolve as new measurements are made and added to the underlying dataset. This also means that once a facility-specific emissions factor has been established the facility may no longer use the default leaker emission factors in subpart W. This is consistent with the express purpose of this rulemaking which is to increase the accuracy of the facility's total emission estimates and that such estimates be based on empirical data.

One commenter inquired whether historical measurements could be used in the development of the emission factor. We are not permitting the use of historical data for informing a facility-specific emission factor for a few reasons. The first reason is that reporters will not have necessarily complied with the requirements in this provision and as a consequence we would not have the historical data upon which the emission factor would be built. This prevents us from following our verification procedures. The second reason is that allowing the use of historical data could provide an unfair advantage to some facilities which have been taking measurement. Now that we have included a rulemaking providing a facility-specific emission factor development option, facilities may choose to further invest in measurement – an option they may not have previously pursued because there was no regulatory framework within subpart W for which the measurement data could be utilized.

One commenter noted reporters can mix and match calculation options for a subpart W facility. This is true only for certain facility types which have a broad definition (*e.g.*, basin-level facility definition for onshore production) and a "complete leak detection survey" definition which may be smaller (*e.g.*, well sites subject to NSPS OOOOb) with a few exceptions:

- If a measurement is made, it must be reported.
- Any measurement made in any future reporting year, must be incorporated into the dataset for the component level site-specific emission factor.

So, as the commenter pointed out, there will be some burden for facilities electing to measure to update their emission factor annually with any new measurements. This regulatory construct is intentional. The regulatory structure is intended to prevent the omission of measurements from the calculation of the emission factor from year to year which could result from a facility switching between methods when conducting their leak detection survey(s). While there is an additional burden included in the requirement to update the emission factor calculation to utilize all measurements by component type and screening method combination annually, we find this burden necessary to ensure the completeness and accuracy in the development of the facility-specific component level emission factors.

Commenter: Range Resources Corporation
Comment Number: EPA-HQ-OAR-2023-0234-0397
Page(s): 6

Comment 3: Range agrees that representative sampling to determine an emissions factor for leaks is appropriate and appreciates EPA responding to previous comments on this issue.

Range appreciates that EPA is proposing the adoption of representative sampling for the direct measurement of equipment leaks. As Range previously communicated to EPA, this will promote more accurate information and reliable emissions factors for reporting methane emissions. Operators will be able to develop emissions factors for leaks that are specific to their facility, which will greatly improve reporting over a default emissions standard that is applied regardless of which area of the country a facility is located or how the well system is designed.

Response 3: The EPA acknowledges the commenter’s support of the proposed revisions. The EPA is finalizing these amendments as proposed.

Commenter: Range Resources Corporation
Comment Number: EPA-HQ-OAR-2023-0234-0397
Page(s): 7

Comment 4: EPA should clarify that operators have the option to develop emissions factors for component sub-groups, such as by component manufacturer.

EPA is proposing that facilities electing to use direct measurement must track the individual measurements of natural gas flow rate by specific “component type.” 88 Fed. Reg. at 50346. EPA gives valves and connectors as examples of component types. While this example is instructive, it is still ambiguous as to what EPA considers a “component type” in the context of the subpart W rule. Range believes that the most accurate reporting can be obtained by allowing operators to track emissions by a type of component, such as a valves or connectors, but also by component sub-groups, such as different types of valves or connectors or by valve or connector manufacturer. Allowing operators to track by such component sub-groups will result in more accurate reporting.

Response 4: In our proposal, we intended for the component types to be the same list of component types utilized in the default leaker and population count methods of the existing subpart W rule. These component types are based on terminology that is well understood by operators and many of the component types are defined terms in Part 98. Allowing owners and operators to begin defining component sub-groups could result in data being reported inconsistently by reporters. The intent of the method which allows reporters to develop facility-specific emission factors is to provide facilities with a mechanism to use site-specific data in lieu of the default emission factors. This inherently means that the default and the site-specific data need to be on the same basis. It is also unclear from the comment how differentiating by sub-group would result in more accurate reporting of emissions. It is also unclear from this request whether the sub-groups would be considered when accumulating sufficient data (*i.e.*, 50 measurements) to utilize the facility-specific emission factor development method. We are not including the option to subcategorize measurement data for informing component level emission factors by subgroups.

17.5 Amendments Related to Oil and Natural Gas Standards and Emissions Guidelines in 40 CFR Part 60

Commenter: Environmental Defense Fund, et al.
Comment Number: EPA-HQ-OAR-2023-0234-0413
Page(s): 67-68

Comment 1: 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 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.

Footnote

[114] See 87 Fed. Reg. 74732 (Dec. 2, 2022).

Response 1: In the final NSPS OOOOb and EG OOOOc, certain well site types are only required to be surveyed for equipment leaks using AVO inspections including single wellhead only sites and small well sites, while others are required to conduct both AVO inspections and regular OGI or Method 21 surveys. The commenter seems to suggest that we should amend subpart W to require follow-up surveys using the subpart W monitoring methods in 40 CFR 98.234(a) (*i.e.*, OGI or Method 21) for any leak that is detected through an AVO inspection required by the final NSPS OOOOb and EG OOOOc. We disagree that we should expand the subpart W regulatory framework to require additional surveys predicated upon the results of surveys conducted under other regulatory programs.

Separately, however, we note that subpart W requires all subject equipment leak components at subject facilities which have been surveyed in accordance with the NSPS OOOOb or EG OOOOc using one of the subpart W monitoring methods in 40 CFR 98.234(a) to use the results of those surveys for emissions estimation and reporting. For any site that is subject to NSPS OOOOb and EG OOOOc but is not required to be surveyed using one of the subpart W monitoring methods in 40 CFR 98.234(a) (*e.g.*, single wellhead only sites or small well sites), the final rule provides an option for these sites to elect to conduct surveys in accordance with 40 CFR 98.233(q) in lieu of using the population count method in 40 CFR 98.233(r). Therefore, all equipment leak components will be required to provide an emission estimate consistent with the requirements in subpart W irrespective of the monitoring requirements in the NSPS OOOOb and EG OOOOc.

Commenter: Clean Air Council
Comment Number: EPA-HQ-OAR-2023-0234-0203
Page(s): 1

Commenter: Public Hearing Transcript
Comment Number: EPA-HQ-OAR-2023-0234-0224
Page(s): 34 (Dr. Dakota Raynes), 50 (Christina Digiulio)

Commenter: Environmental Defense Fund et al.
Comment Number: EPA-HQ-OAR-2023-0234-0401
Page(s): 1

Commenter: Environmental Defense Fund, et al.
Comment Number: EPA-HQ-OAR-2023-0234-0413
Page(s): 63, 67

Commenter: Environmental Defense Fund, et al.
Comment Number: EPA-HQ-OAR-2023-0234-0413
Page(s): 68

Commenter: Environmental Defense Fund, et al.
Comment Number: EPA-HQ-OAR-2023-0234-0413
Page(s): 68

Comment 2:

Commenter 0203: I urge EPA to strengthen its proposed rule in the following ways:

…

- Require operators covered by this rule to use data from OGI inspections that will be required under EPA's forthcoming methane rule.

Commenter 0224: In addition to measurements from various types of aerial observation, the EPA should also require data from optical gas imaging inspections under the EPA's forthcoming methane rule to more accurately account for methane emissions.

…

The ease of [OGI] means it is not unreasonable to conduct testing more frequently than once per quarter. In comparison, EPA's Method 21 is a long intensive quantitative method of leak detection that requires readings to be taken by hand with the sensitive gas monitor-- by virtue of it being a long process performed by hand, it can also be susceptible to human error. We also would like to require -- we would like the EPA to require operators covered by the reporting threshold to use data from OGI and inspections that will be required under EPA's forthcoming methane rule to more accurately account for methane emissions.

Commenter 0401: Specifically, the EPA should adopt the following provisions:

…

- **Require operators to use data from regulatory leak inspections to enhance the accuracy of their reported emissions.**

Commenter 0413: 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.

…

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.

Commenter 0413: 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.

Commenter 0413: 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.

Footnote

[115] See 87 Fed. Reg. 74740 (Dec. 6, 2022).

Response 2: See Section III.P.6 of the preamble to the final rule for the EPA's response to this comment.

Commenter: GPA Midstream Association
Comment Number: EPA-HQ-OAR-2023-0234-0299
Page(s): 53**,** 93-94

Commenter: American Petroleum Institute et al. (Part 1 of 2)
Comment Number: EPA-HQ-OAR-2023-0234-0402
Page(s): 55-57

Comment 3:

Commenter 0299: **70. Subpart W leak survey requirements should be revised to better align with NSPS and NESHAP requirements.**

Regarding Subpart W leak survey requirements, EPA must consider revisions that enhance alignment with the NESHAP and NSPS programs. For example, while NSPS programs provide exemptions for components under insulation, Subpart W does not. As such, reporters must choose the OGI leak survey method—which has the highest emission factors—for those components but reporters have no other option. At a minimum, EPA should apply the same monitoring exemptions of the NSPS programs to Subpart W to improve rule alignment and eliminate confusion. To fix this issue, GPA recommends the following revision to the proposed regulatory text:

> *98.233(q)(vi)(F) For an onshore natural gas processing facility subject to the equipment leak standards for onshore natural gas processing plants in § 60.5400b of this chapter or an applicable approved state plan or applicable Federal plan in part 62 of this chapter, each survey conducted in accordance with the equipment leak standards for onshore natural gas processing plants in § 60.5400b of this chapter or an applicable approved state plan or applicable Federal plan in part 62 of this chapter will be considered a complete leak detection survey for the purposes of calculating emissions using the procedures specified in either paragraph (q)(2) or (3) of this section. At least one complete leak detection survey conducted during the reporting year must include all components listed in § 98.232(d)(7) and subject to this paragraph (q), ~~including~~ except components which are considered inaccessible emission sources as defined in part 60 of this chapter.*

Commenter 0299: **RFC:** "Under this proposed amendment, reporters would still have to meet the subpart W requirement to conduct at least one complete survey of all applicable equipment at the facility per year, so if there were components listed in 40 CFR 98.232(d)(7) not included in any NSPS OOOOb or 40 CFR part 62-required surveys conducted during the year (e.g., connectors that are monitored only once every 4 years), reporters subject to NSPS OOOOb or 40 CFR part 62 would need to either add those components to one of their required surveys, making that a complete survey for purposes of subpart W, or conduct a separate complete survey for purposes of subpart W. We expect that reporters with onshore natural gas processing plants implementing traditional leak detection and repair programs are already making similar decisions regarding how to meet the requirement to conduct a complete survey for subpart W, and our intention with this proposed amendment is not to change those decisions. Rather, this amendment would specify that surveys conducted pursuant to NSPS OOOOb or 40 CFR part 62 that do not include all component types listed in 40 CFR 98.232(d)(7) would be used for calculating emissions along with each complete survey." "We request comment on the proposed amendments to subpart W for onshore natural gas processing facilities subject to the equipment leak provisions of NSPS OOOOb or 40 CFR part 62, as well as whether there are other provisions or reporting requirements for these facilities that we should consider."[30]

> **Comment:** EPA should not mandate that data from so-called "incomplete" surveys be incorporated into the calculations. Doing so increases the complexity of the leak calculations, since some components will have different leak times in equation W-30.

Commenter 0402: 3.10 Equipment Leaks

3.10.6 Leak Detection at Onshore Gas Processing

…

Additionally, there are additional clarifications that are needed from EPA to the proposed equipment leak provisions as it pertains to onshore gas processing to better align with existing and proposed NSPS provisions.

The proposed use of NSPS OOOOb and EG OOOOc surveys for calculating emissions should be clarified and expanded.

EPA has proposed the following text at 98.233(q)(1)(vi)(F) to require the use of NSPS OOOOb and OOOOc survey data in calculating emissions from equipment leaks at onshore natural gas processing plants:

For an onshore natural gas processing facility subject to the equipment leak standards for onshore natural gas processing plants in § 60.5400b of this chapter or an applicable approved state plan or applicable Federal plan in part 62 of this chapter, each survey conducted in accordance with the equipment leak standards for onshore natural gas processing plants in § 60.5400b of this chapter or an applicable approved state plan or applicable Federal plan in part 62 of this chapter will be considered a complete leak detection survey for the purposes of calculating emissions using the procedures specified in either paragraph (q)(2) or (3) of this section. At least one complete leak detection survey conducted during the reporting year must include all components listed in § 98.232(d)(7) and subject to this paragraph (q), including components which are considered inaccessible emission sources as defined in part 60 of this chapter.

Industry Trades recommend the following updates to this requirement:

- **Inclusion of alternate leak standards**: References to § 60.5400b should also include a reference to the alternate equipment leak standards in § 60.5401b to clarify that both OGI surveys conducted according to Annex K and Method 21 surveys with a 500 ppmv leak definition should be used in emission calculations.
- **References to the equipment leak standards under the earlier NSPS KKK, OOOO, and OOOOa** should be included so that survey data can also be used in emission calculations. While the earlier equipment leaks standards were for VOC only as opposed to the VOC and methane under NSPS OOOOb and EG OOOOc, some components in VOC service (>= 10 wt% VOC) may also be required to be surveyed under Subpart W (>=10wt% CH_4 + CO_2), and the monitoring technique in the earlier NSPS are already included in the approved list in 98.234(a). This update would allow operators to avoid potentially duplicative surveys.

- **The inaccessible component exemption should be retained under Subpart W**.[45] For onshore gas processing, the term "Inaccessible" has a long-standing meaning under NSPS, which historically is limited to connectors that are monitored using Method 21 with specific criteria that extends well beyond the 2-meter clause noted in 98.234(a). This exemption is directly linked to the safety of our personnel or the technical use of monitoring equipment. Specifically, connectors that are "*buried*" or that are "*not able to be accessed at any time in a safe manner to perform monitoring (Unsafe access includes, but is not limited to, the use of a wheeled scissor-lift on unstable or uneven terrain, the use of a motorized man-lift basket in areas where an ignition potential exists, or access would require near proximity to hazards such as electrical lines or would risk damage to equipment)*" should not require additional leak detection provisions under subpart W.

Footnotes:

[45] EPA has proposed the following language per 98.234(a): Inaccessible emissions sources, as defined in 40 CFR part 60, are not exempt from this subpart. If the primary leak detection method employed cannot be used to monitor inaccessible components without elevating the monitoring personnel more than 2 meters above a support surface, you must use alternative leak detection devices as described in paragraph (a)(1) or (3) of this section to monitor inaccessible equipment leaks or vented emissions at least once per calendar year. For components located in the onshore production, natural gas gathering and boosting, transmission compression and underground storage (i.e. well sites, central production facilities, or compressor stations), the language proposed aligns with those that are identified at difficult-to-monitor when using M21 per the provisions in NSPS OOOOa and proposed NSPS OOOOb/c. The difficult-to-monitor components require annual monitoring under NSPS, which are consistent with the proposed language in 98.234(a). EPA could be consistent and use the term difficult-to-monitor if that was EPA's intent.

Response 3: See Section III.P.6 of the preamble to the final rule for the EPA's response to comments regarding cross-referencing the NSPS OOOOb alternative standard for natural gas processing plants.

We note that we contemplated cross-referencing NSPS KKK, OOOO, and OOOOa with respect to subpart W equipment leak survey requirements in past rulemakings in the *Greenhouse Gas Reporting Rule: Leak Detection Methodology Revisions and Confidentiality Determinations for Petroleum and Natural Gas Systems Final Rule* published in the Federal Register in 2016 (81 FR 86490). We received adverse public comment during the public comment period and elected not to finalize those amendments (reference "Response to Public Comments on Greenhouse Gas Reporting Rule: Leak Detection Methodology Revisions and Confidentiality Determinations for Petroleum and Natural Gas Systems" (Docket Item No. EPA–HQ–OAR–2015–0764-0067)). We did not re-proposed adding those cross-references in the 2023 proposed rule and commenters have not had an opportunity to comment on such revisions in this rulemaking. Additionally, after consideration of the complexity of applicability of the NSPS rules to natural gas processing plants, as identified by the commenters on the 2016 final rule, we are not adding cross-references to NSPS KKK, OOOO, and OOOOa in this final rule. The primary reason is because surveys conducted under NSPS KKK, OOOO, and OOOOa do not include all components in GHG service and thus, do not constitute a complete leak survey for the purposes of subpart W. However, under the final provisions, if the reporter conducts a complete leak survey for all GHG components while conducting surveys for NSPS KKK, OOOO, and OOOOa, then the results must be used for subpart W reporting.

See Section III.P.6 of the preamble to the final rule for the EPA's response to comments regarding the comments on the inaccessible component exemption.

Commenter: CrownQuest Operating
Comment Number: EPA-HQ-OAR-2023-0234-0393
Page(s): 265, 267

Comment 4: It seems like the EPA is referencing Appendix K in this proposed rule. The EPA should remove this from the proposed rule, as it has been removed.

Appendix K in the last rule was not included in OOOOb/c.

Response 4: The EPA finalized the protocol for the use of OGI in leak detection as appendix K to 40 CFR part 60 in the final action for the NSPS OOOOb and EG OOOOc. For NSPS OOOOb and EG OOOOc, EPA finalized the use of the protocol for application at natural gas processing plants. The protocol may be applied to other sources only when incorporated through rulemaking to a specific subpart. For subpart W, we are finalizing our cross references to this protocol in 40 CFR 98.234(a), as proposed.

Commenter: Honeywell International Inc.
Comment Number: EPA-HQ-OAR-2023-0234-0375
Page(s): 18

Comment 5:

B. EPA Assumes that the Supplemental Methane Leak Detection and Repair Rule Will Be Finalized As Proposed, and that OGI or Method 21 Surveys Will Be Used in All Leak Detection Instances.

EPA's proposed revisions to Subpart W expressly state that the intention is to be consistent with methods provided for under the OOOO leak detection and repair rules. 88 Fed. Reg. 50,285, 50,288. EPA improperly assumes, however, that (a) the OOOOb NSPS and OOOOc Emissions Guidelines will be finalized as proposed in the supplemental rulemaking, and (b) that when using continuous monitoring technology for a leak detection and repair program, an operator would in all instances conduct an OGI or Method 21 survey to confirm a detected leak.

Honeywell is concerned that EPA's understanding may be incorrect. When using continuous monitoring under the OOOOb leak detection and repair rules, an operator would not necessarily use ground-based OGI or Method 21 if a leak is detected. Rather, the continuous monitoring technology may be able to provide sufficiently equivalent emissions quantification such that an operator would use the empirical data from that system to support its emissions reporting. It would undermine the efficiencies of using such continuous monitoring systems if an operator were required to deploy a ground-based OGI survey of all fugitive emissions components every time a leak was detected by the continuous monitoring system, especially where the continuous monitoring system is able to pinpoint the leaking component with a fairly significant degree of accuracy. An overly prescriptive approach to the Subpart W revisions would disincentivize the use of continuous monitoring technologies, thereby deterring their maturation and advancement, rather than allow for continued technological advancements.

Response 5: We did not propose and are not finalizing continuous monitoring methods for identification or quantification of equipment leaks in the subpart W final rule, including for the reasons described in Section II.B of the preamble to the final rule. We may consider adding continuous monitoring methods in subpart W in a future rulemaking. As noted in the section III.P.6 of the preamble, we are requiring facilities that are subject to NSPS OOOOb and EG OOOOc that monitor subject sites using the survey methods in subpart W in 40 CFR 98.234(a) to report the results of those surveys for the purposes of estimating emissions in accordance with 40 CFR 98.233(q). For facilities that either are not subject to NSPS OOOOb and EG OOOOc or are subject but are not required to use the survey methods in subpart W in 40 CFR 98.234(a), the rule provides the option to elect to perform a survey and estimate emissions in accordance with 40 CFR 98.233(q) or alternatively, estimate emissions using the population count method in 40 CFR 98.233(r).

Commenter: Clean Air Council
Comment Number: EPA-HQ-OAR-2023-0234-0203
Page(s): 1

Comment 6:

I urge EPA to strengthen its proposed rule in the following ways:

…

- Require continuous optical gas imaging (OGI) for all facilities affected by this rule to allow for more frequent and accurate leak monitoring.

Response 6: We are not including continuous monitoring methods for methane in the subpart W final rule, consistent with our proposal, including for the reasons described in Section II.B of the preamble to the final rule. We may consider adding continuous monitoring methods in subpart W in a future rulemaking.

Commenter: Occidental (Oxy)
Comment Number: EPA-HQ-OAR-2023-0234-0276
Page(s): 4-5

Commenter: Sensirion Connected Solutions
Comment Number: EPA-HQ-OAR-2023-0234-0293
Page(s): 23

Commenter: Independent Petroleum Association of New Mexico (IPANM)
Comment Number: EPA-HQ-OAR-2023-0234-0337
Page(s): 9

Commenter: Enerplus Resources (USA) Corporation
Comment Number: EPA-HQ-OAR-2023-0234-0342
Page(s): 3-4

Commenter: Duke Energy
Comment Number: EPA-HQ-OAR-2023-0234-0376
Page(s): 8-9

Commenter: Step2compliance
Comment Number: EPA-HQ-OAR-2023-0234-0395
Page(s): 2-3

Commenter: Environmental Defense Fund, et al.
Comment Number: EPA-HQ-OAR-2023-0234-0413
Page(s): 66-67, 68-69

Comment 7:

Commenter 0276: IV. Oxy encourages EPA to promote the use of alternative technologies for leak detection in the context of emissions reporting.

In addition to the efforts described above, Oxy is actively engaged and has participated in numerous technology pilots to supplement our leak detection and repair (LDAR) capabilities, including fixed monitors, drone-mounted cameras, fixed-wing aircraft surveys, and satellite surveys.

Oxy deploys drones at several of our oil and gas production facilities. At our DJ Basin facilities, we use drones to survey thousands of wellheads as part of a voluntary initiative to reduce emissions. In addition, Oxy surveys wellheads, facilities, and pipeline segments across U.S. operations with fixed-wing aircraft, deploying both broad-coverage campaigns and individual asset surveys. Oxy participates in The Environmental Partnership and its collaborative efforts to better understand and utilize the capabilities of remote sensing technologies that are being developed. A summary of The Environmental Partnership's efforts and learnings can be accessed at https://theenvironmentalpartnership.org/collaboration-onremote-sensing-technologies/.

These innovative LDAR technologies show great promise as tools to supplement traditional LDAR methods. For instance, aerial surveys – both fixed-wing and satellite – allow operators to rapidly inspect large geographic areas, including remote sites, pipelines and gathering lines, that cannot readily be traversed at ground level as well as elevated equipment such as columns or towers at facilities. Fixed monitoring stations allow for operators to continuously gather monitoring data, creating additional opportunities to identify and address leaks that may otherwise not be identified until a periodic survey using currently approved LDAR inspection methods. These benefits can assist operators and inspection and maintenance personnel in efficiently and timely directing resources and response efforts to high priority sites, with less time spent traveling to remote locations that could be covered by fixed monitors or remote sensing.

Oxy encourages EPA to ensure the structure of the reporting program does not disincentivize the use of these technologies described above. In the context of emissions detections, the proposed rule only provides information regarding OGI, Method 21, infrared laser beam illuminated instruments or acoustic leak detection devices. Oxy encourages EPA to align with other federal programs that are adopting alternative technologies into their framework (e.g., NSPS OOOOb and EG OOOOc). Oxy is generally supportive of the proposed GHGRP framework and believes that EPA can support the continued innovation and accelerated deployment of these alternative technologies in the final rule by incorporating the feedback mentioned above. Accordingly, Oxy encourages EPA to work with all stakeholders to further develop the proposed advanced measurement technology framework prior to issuing the final rule.

Commenter 0293: **5. From the Preamble in Section 6. Amendments Related to Oil and Natural Gas Standards and Emissions Guidelines in 40 CFR Part 60, EPA asks, "We request comment on these proposed amendments and whether there are other provisions or reporting requirements relative to NSPS OOOOb or EG OOOOc that we should consider for revisions to the requirements under Subpart W."**

In the Preamble, EPA states: "This proposal would limit the burden for subpart W facilities with affected sources that would also be required to comply with the proposed NSPS OOOOb or a State or Federal Plan in part 62 implementing EG OOOOc by allowing them to use data derived from the implementation of the NSPS OOOOb to calculate emissions for the GHGRP rather than requiring the use of different monitoring methods." Within the proposed NSPS OOOOb and EG OOOOc, EPA has created a framework for the use of approved advanced measurement technologies, including continuous monitoring systems, to satisfy the LDAR requirements within fugitive affected facility provisions. Many of these technologies are capable of accurately quantifying emissions in addition to detecting them. EPA should allow for use of these technologies for quantification of emissions within this rule and is arguably obligated to do so by the statutory requirements of the IRA.

Commenter 0337: **40 CFR § 98.233(q) Pop Counts & Equip Leaks**

In both the proposed New Source Performance Standards (NSPS-OOOOb) and the proposed Emission Guidelines (NSPS-OOOOc), EPA has written a mechanism into the rule by which emerging technologies approved by EPA would be allowed for monitoring fugitive emission component affected facilities. EPA should consider including a similar allowance for emerging technologies to be used for equipment leaks as they are approved by EPA, rather than requiring a rule change to allow those alternate monitoring technologies.

Commenter 0342: Enerplus recommends using leaker emission factor approach for the production segment to meet the intention of the IRA by being empirically based. The absence of a leaker emission factor approach would also disincentivize voluntary leak surveys because operators would not be able to report lower empirical emissions based on a system that is demonstrated to be leak free. Making the standards performance-based, as outlined in the proposed OOOOb rulemaking, allows technology to advance without a cumbersome AMEL approval process.

Commenter 0376: In addition to the use of company direct measurements for leak surveys, Duke Energy urges EPA to consider an option for reporting that permits the use of direct measurement for other components, such as mains and services or the omission of components from the counts where it can be proven through empirical data there are zero emissions. These measurements may also be used to develop company-specific emission factors that would better represent and much more accurately report emissions and measure a company's progress toward reducing emissions. Duke Energy has a multi-state pilot underway using satellite technology and ground validation tools to detect methane emissions. We also utilized this work to participate in a demonstration project utilizing GTI's Veritas protocol. We recommend that EPA include in Subpart W a provision that will allow a "facility" to adopt alternate methodologies (subject to an expeditious EPA review and approval) for determining and reporting methane emissions based on its own studies using direct measurements and other empirical data.

As part of our portfolio of work, Duke Energy has also performed extensive testing and validation on satellite leak detection in a broad part of our LDC assets with impressive results in detecting even small leaks that can occur on a gas distribution system. In EPA's technical support document,[10] several satellite technologies are reviewed and it makes the statement:

"These technologies have the potential to help detect emissions in sectors including petroleum, mining, landfills, and agriculture. Furthermore, the ability to implement this technology is expected to increase in the upcoming years as the technology advances in capability and becomes more widespread in use."[11] EPA's proposal states that "while this top-down data is very useful in identifying possible large emissions events that are not captured by other reporting obligations, it is not presently able to provide annual emissions data to the degree of accuracy and certainty required by other provisions of this rulemaking."[12] Duke Energy's work suggests that satellite technology can be (and is) used in leak detection far smaller than "superemitter" events but is best suited as part of a "system-of-things" consisting of top-down and bottom-up leak detection, measurement and quantification. Where companies are voluntarily looking to adopt the use of AMLD technologies, including satellites, EPA should facilitate companies' adoption of this approach and application for the purpose of reporting emissions in Subpart W.

Footnotes:

[10] "Greenhouse Gas Reporting Rule: Technical Support for Revisions and Confidentiality Determinations for Data Elements Under the Greenhouse Gas Reporting Rule," June 2023; Docket Item No. EPA-HQ-OAR-2023-0234-0163 (2023) at 2.2.1.

[11] "Greenhouse Gas Reporting Rule: Technical Support for Revisions and Confidentiality Determinations for Data Elements Under the Greenhouse Gas Reporting Rule," June 2023; Docket Item No. EPA-HQOAR-2023-0234-0163 (2023) at 2.2.1.1

[12] 88 Fed. Reg. at 50,290

Commenter 0395: In the docket, there was a direct request for comment related to alternative methods for quantifying leaks tied to the proposed addition of a method to quantify emissions using direct measurement. In recent years, the technology of QOGI (Quantification of Optical Gas Imaging) has advanced considerably and has even become an accepted protocol in regulatory initiatives from other countries like Canada and Mexico. While we do not currently have the requested data to support a specific alternative method of quantification, we strongly believe that rather than limiting the methods of quantifying emissions using direct measurement to what is specified currently in 40 CFR 98.234(b) through (d), EPA should consider leaving room for the continued advancement of technology and additional methods of quantification that will be available in the near future. The proposed NSPS OOOOb and EG OOOOc have created a framework for the use of approved advanced measurement technologies, including continuous monitoring systems, to satisfy the LDAR requirements within fugitive affected facility provisions. And as this proposed rule states that it "would limit the burden for subpart W facilities with affected sources that would also be required to comply with the proposed NSPS OOOOb or a State or Federal Plan in part 62 implementing EG OOOOc by allowing them to use data derived from the implementation of the NSPS OOOOb to calculate emissions for the GHGRP rather than requiring the use of different monitoring methods …" EPA should allow for use of these technologies for quantification of emissions within this rule.

Commenter 0413: *Addition of method to quantify emissions using direct measurement*

…

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 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.

…

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 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.

Response 7: See Section III.P.6 of the preamble to the final rule for the EPA's response to this comment.

Commenter: LongPath Technologies, Inc.
Comment Number: EPA-HQ-OAR-2023-0234-0410
Page(s): 5-6, 6-7, 9-12

Comment 8: We recommend that EPA recognize additional leaker emission factors or adjustment factors for sites with more frequent monitoring than is required under Section 111

Subpart W recognizes specific leak detection screening methods in 40 CFR 98.234(a). Among these are OGI and Method 21.
Leaker emission factors and the adjustment factor, k, are meant to account for the fact that "there are undetected leaks for each method".
The screening methods listed do *not* yet include the leak detection screening methods that are expected to be recognized by EPA in the final Section 111 rules (advanced survey and continuous monitoring methods and procedures). For consistency across EPA regulations, we recommend that Section 111-recognized methods also be included in 40 CFR 98.234(a), for example at such time as they are approved under the Section 111 provisions.
We point out that higher frequency monitoring will identify (and lead to the mitigation of) many more emissions sources than less frequent methods. In particular, the introduction of very high frequency ("continuous") monitoring allows for finding and fixing intermittent emissions, which may otherwise go undetected. Specifically, we recommend that EPA use an objective measure, such as in Appendix A, to assign these factors, rather than relying on sparse empirical data for specific geographies, site types, and climatological conditions.

…

We recommend that leaker emission factors and adjustment factors be calculated using Observing System Completeness

On page 50345, EPA recognizes that subpart W's recognized methods do not detect equal percentages of emissions.

For example, EPA discusses the purpose of the adjustment factor, k, on page 50345: "The application of the k factor is intended to account for undetected emissions such that the reported emissions represent the actual site-level total, not limited to the fraction of detected leaks". EPA proposes to use empirical data to determine the adjustment factor, k, for a method.

Empirical data is important for informing parameter choices for comparing methods. However, the use of empirical data alone is limiting, given the wide variety of equipment types, geographies, and climate zones across the applicable reporting facilities. Further, as EPA notes, there is no empirical evidence to support some of the proposed adjustment factors, for example, for infrared laser beam illuminated instruments or acoustic leak detection devices.

We suggest that EPA instead adopt a technology-neutral, and geographically and climatologically inclusive framework for comparing the detection effectiveness of different methods and procedures (e.g., in collaboration with DOE's Office of Fossil Energy and Carbon Management). In **Appendix A** of this document, we lay out a simple framework published by Jacobs, et al. in the peer-reviewed journal Atmospheric Chemistry and Physics in 2022. [11] The framework offers an objective metric called "Observing System Completeness".

The Observing System Completeness framework also accounts for intermittent emissions. Given that observed emissions are overwhelmingly intermittent (in one study, 89% of large sources are only "on" <50% of the time of the total duration of the malfunction), accounting for this source of detection effectiveness is necessary for accurate calculation of comparison factors.[12, 13, 14, 15]

As is shown in Appendix A, the Observing System Completeness framework provides a single value, C, that ranges from 0 to 1, with 1 representing the highest possible coverage of a monitoring system for emissions. Therefore, taking a simple reciprocal of a method's Observing System Completeness value (1 / C) would yield an easily scalable and objective scaling factor metric.

…

Appendix A:

Observing System Completeness to Calculate a Method's Leaker Emission Factor or Adjustment Factor, k

Jacob et al.[16] define Observing System Completeness as "the capability of an instrument (or ensemble of instruments) to fully quantify their target emissions within a selected domain and time window".

Observing System Completeness provides a single, objective metric for direct comparison of what the EPA describes on page 50345 as "each method's ability to detect leaks".
It is a technology-neutral framework that allows for empirical data to inform 1) objective methodology parameters, including for different geographies, site types, and climatological factors, and 2) empirical understanding of the broad emissions characteristics of the facilities the methods are being used on.

Observing System Completeness

Equation 8 from Jacob et al. shows Observing System Completeness, C, for leak detection methods (combined technology, technique and program):
$C = C_D \times C_S \times C_T$

In this framework, a higher C value indicates better ability to catch and accurately characterize all emission sources, including considerations for intermittency.

Detection Threshold

C_D is the leak detection method's detection threshold, or "the fraction of point source emissions that can be detected on the basis of the instrument's detection threshold". This value depends on the method's sensitivity and the emissions distribution; an absence of large emitters combined with a high detection threshold may mean that a very small percentage of leaks are caught. By contrast, a typical skewed distribution in which the bulk of overall emissions result from higher-volume fugitive emissions means that a larger percentage of emissions will be caught even with a relatively high detection threshold.

Spatial Coverage

C_s is the spatial coverage of the leak detection method within the time window of the method's use.
Some methods see all or most sources with each measurement, but the time window may matter substantially. For example, an annual survey will not provide meaningful coverage for the many 1-week time windows in which no survey occurs. An aerial survey may "see" most emission sources above the detection threshold except, for example, those obscured from the sky view because of coverage by other equipment, such that C_s= 0.9 or higher. But if emissions are expected to change on an hourly, daily or weekly basis, then infrequent surveys may yield a C_s= 0.0 for substantial lengths of time.

Other methods only see part of a facility, or rarely "see" emissions from key equipment like tanks and flares regardless of how many measurements are taken, such that spatial coverage never exceeds a certain value, for example $C_s < 0.6$.
Still other methods see different portions of a facility with each measurement, such that multiple measurements will result in complete coverage ($C_s = 1$) over a period of days.
These examples illustrate the requirement that the selected time interval be clearly defined and incorporated as a factor into spatial coverage.

Temporal Coverage

C_T is defined as "the probability for an observed source to be actually detected within the time window given the number N ~ 1 of observations in the window, the source persistence p (fraction of time that the source is emitting above the detection threshold), and the fraction F of successful samples".
$C_T = 1 - (1 - F_p)^N$
For non-intermittent (persistent) emission sources, in which $p = 1$, the presence of a single measurement within the monitoring program time window results in a perfect temporal coverage score of $C_T = 1$, provided all samples are successful ($F = 1$, e.g., no clouds during flyover or no sensor malfunction). The presence of any degree of intermittency increases the importance that each sample is successful ($F \rightarrow 1$) and that more frequent observations occur (higher N).
Take, for example, an intermittent emission source with $p = 0.2$. This example might be appropriate for a malfunctioning flare that only emits under a set of conditions that are present 20% of the time. If each monitoring system measurement that is taken is successful ($F = 1$), then the temporal coverage (C_T) will continue to approach 1 as the number of observations of the source (N) increases.

Example of a Methods Comparison Framework to Derive Leaker Emission Factors or Adjustment Factors

To directly compare each method's ability to detect leaks, two tables must be filled in. First, empirical data for detection level, spatial coverage, frequency of readings and fraction of successful samples must be collected (Table 1). Eight different methods are shown below.

Monitoring Program	Detection Level (C_D)	Spatial Coverage (C_S for different time intervals)	Frequency of Readings (N per time interval)	Fraction of successful samples (F)
Continuous Line Sensor	[X] kg h^{-1} detection threshold	[X]% site coverage within one day, [X]% site coverage within one week, [X]% site coverage within two weeks	[X] readings per day	[X], e.g., given wind conditions and downtime
Continuous Point Sensor	[X] kg h^{-1} detection threshold	[X]% site coverage within one day, [X]% site coverage within one week, [X]% site coverage within two weeks	[X] readings per day	[X] e.g., given wind conditions and downtime
Weekly Aerial Survey	[X] kg h^{-1} detection threshold	[X]% site coverage with each survey	1 reading per week	[X], e.g., given wind conditions and cloud cover
Monthly Aerial Survey	[X] kg h^{-1} detection threshold	[X]% site coverage with each survey	1 reading per month	[X], e.g., given wind conditions and cloud cover
Quarterly Aerial Survey	[X] kg h^{-1} detection threshold	[X]% site coverage with each survey	1 reading per quarter	[X], e.g., given wind conditions and cloud cover
Weekly OGI Survey	[X] kg h^{-1} detection threshold	[X]% site coverage with each survey	1 reading per week	[X], e.g., given technician experience, wind and cloud cover
Monthly OGI Survey	[X] kg h^{-1} detection threshold	[X]% site coverage with each survey	1 reading per month	[X], e.g., given technician experience, wind and cloud cover
Quarterly OGI Survey	[X] kg h^{-1} detection threshold	[X]% site coverage with each survey	1 reading per quarter	[X], e.g., given technician experience, wind and cloud cover

Table 1. Eight leak detection methods with specifications for each describing detection level, spatial coverage, and temporal coverage (frequency of readings). Empirical data can be used to fill in all values marked [X].

Second, empirical knowledge of the intermittency of emissions sources and distribution of emission source rates in the target monitoring area must be collected (Table 2).

Source Persistence (p)	Emissions Distribution Parameters	Selected domain	Selected time window
[X]	[X,...]	[spatial boundary or applicable facilities]	[X] hours, days, weeks, years

Table 2. Information about the target emissions distributions and time window, common across all programs.

With this information, the Observing System Completeness for each method and for each time window - one day (*C*-daily), one week (*C*-weekly) or one quarter (*C*-quarterly) - can be calculated (Table 3).

Program	*C* - daily	*C* - weekly	*C* - quarterly
Continuous Line Sensor	[X]	[X]	[X]
Continuous Point Sensor	[X]	[X]	[X]
Weekly OGI Survey	[X]	[X]	[X]
Monthly OGI Survey	[X]	[X]	[X]
Quarterly OGI Survey	[X]	[X]	[X]
Weekly Aerial Survey	[X]	[X]	[X]
Monthly Aerial Survey	[X]	[X]	[X]
Quarterly Aerial Survey	[X]	[X]	[X]

Table 3. Observing System Completeness (*C*) for eight leak detection methods, assessed for comprehensiveness of coverage over a 1-day, 1-week, and 1-quarter timewindow. Tables 1 and 2 andthe Observing System Completeness equations are used tocalculate eachvalue [X].

Derivation of Leaker Emission Factor or Adjustment Factor

To calculate each Leaker Emission Factor or Adjustment Factor, k, the reciprocal of the Observing System Completeness can be used:

$k = 1 \div C$

The Observing System Completeness formulations cover all of EPA's examples provided on page 50345:

- "Variability inherently exists in each method's ability to detect leaks and can be attributed to reasons associated with the instrument, leak detection procedures, the operator or site conditions." These examples refer to the temporal coverage, detection limit, spatial coverage, and fraction of successful samples.
- " … For example, some components may be inaccessible to be surveyed with hand held devices that require close proximity to the leak to detect it (e.g., Method 21 flame ionization detectors (FID)), while the same leak could be visualized using an OGI camera

that is less dependent on proximity to the leak." This exam pie refers to spatial coverage of a given method.

- "Operators with varying levels of training or expertise deploy the screening devices, resulting in operator variability. Site-level conditions such as wind speed can also impact the detection of leaks." These examples refer to the fraction F of successful samples of a given method.

Footnotes:

[11] Jacob, Varon, Cusworth, et al., Quantifying methane emissions from the global scale down to point sources using satellite observations of atmospheric methane, Atmos. Chem. Phys., 22, 9617-9646, 2022. https://doi.org/10.5194/acp-22-9617-2022

[12] Cusworth, Duren, Thorpe, et al., lntermittency of large methane emitters in the Permian Basin, Environ. Sci. Technol. Lett., 8, 567-573, 2021.

[13] Wang, Daniels, Hammerling, et al., Multiscale methane measurements at oil and gas facilities reveal necessary frameworks for improved emissions accounting, Environ. Sci. Technol., 56, 14743-14752, 2022.

[14] Chen, Yacovitch, Dau be, et al., Reconciling methane emission measurements for offshore oil and gas plat forms with detailed emission inventories: accounting for emission intermittency, ACS Environ. Au, 3, 87-93, 2023.

[15] Riddick, Mauzerall, Celia, et al., Variability observed over time in methane emissions from abandoned oil and gas wells, Int. Journ. of Greenhouse Gas Control, 100, 103116, 2020.

[16] Jacob, Varon, Cusworth, et al., Quantifying methane emissions from the global scale down to point sources using satellite observations of atmospheric methane, Atmos. Chem. Phys., 22, 9617-9646, 2022. https:/ / doi.org /10.5194/ acp-22-9617- 202 2

Response 8: As discussed in Sections II.B and III.P.6 of the preamble to the final rule, at this time we are not finalizing a framework for the adoption of advanced survey or measurement methane technology analogous to the process laid out in the comment or analogous to the performance-based technology approval process included in the NSPS OOOOb and EG OOOOc.

Commenter: Nevada Nanotech Systems
Comment Number: EPA-HQ-OAR-2023-0234-0238
Page(s): 2

Commenter: Ascent Resources, LLC
Comment Number: EPA-HQ-OAR-2023-0234-0339
Page(s): 3

Comment 9:

Commenter 0238: Regarding Section P, Equipment Leak Surveys, Subsection 6, Amendments Related to Oil and Natural Gas Standards and Emissions Guidelines in 40 CFR Part 60, a request for comment on additional methods or advanced technologies that can identify leaking components, we have the following comments:

- MethaneTrack™ is ideal for identifying individual leaking components in the oil and natural gas industry because it is a low-cost and intrinsically safe device.
- MethaneTrack™ can be mounted adjacent to known problematic components and provide rapid notification in the event of a leak.

Commenter 0339: 1. Section 98.234(a) is still overly restrictive in what technologies can be used for monitoring of equipment leaks. The EPA should broaden this section with performance-based requirements to allow for the use of advanced technologies in place of conventional OGI and Method 21 monitoring devices.

Response 9: As discussed in Sections II.B and III.P.6 of the preamble to the final rule, we did not propose and are not finalizing the approval of certain technologies for methane monitoring and measurement a priori in subpart W at this time. While we are not finalizing specific technologies, we are undertaking research on and exploring options for using advanced technologies for the purpose of methane leak detection and measurement and may consider adding specific methods or technologies in a future rulemaking.

17.6 Exemption for Components in Vacuum Service

Commenter: American Petroleum Institute et al. (Part 1 of 2)
Comment Number: EPA-HQ-OAR-2023-0234-0402
Page(s): 57

Commenter: Lambda Energy Resources
Comment Number: EPA-HQ-OAR-2023-0234-0405
Page(s): 2

Comment 1: Commenter 0402: Equipment Leaks

Component Applicability

The Industry Trades support EPA's proposal to exempt "components in vacuum service" from the equipment leak provisions in 98.233(q) and (r). These components have been historically exempt from the NSPS leak detection standard since no fugitive leaks are expected. However, we do not support inclusion of reporting requirements that include reporting of component counts for components in vacuum service.

Commenter 0405: The proposed exemption for components in vacuum service is a welcomed proposal and example of how industries voices were heard.

Response 1: The EPA acknowledges the commenters' support of the proposed revisions. The EPA is finalizing these amendments as proposed.

17.7 Other Equipment Leak Survey Comments

Commenter: GPA Midstream Association
Comment Number: EPA-HQ-OAR-2023-0234-0299
Page(s): 53-54

Commenter: Duke Energy
Comment Number: EPA-HQ-OAR-2023-0234-0376
Page(s): 7-8

Commenter: Interstate Natural Gas Association of America (INGAA)
Comment Number: EPA-HQ-OAR-2023-0234-0387
Page(s): 13-14

Commenter: MiQ
Comment Number: EPA-HQ-OAR-2023-0234-0392
Page(s): 5

Commenter: CrownQuest Operating
Comment Number: EPA-HQ-OAR-2023-0234-0393
Page(s): 278

Commenter: American Petroleum Institute et al. (Part 1 of 2)
Comment Number: EPA-HQ-OAR-2023-0234-0402
Page(s): 54, 55

Commenter: Environmental Defense Fund, et al.
Comment Number: EPA-HQ-OAR-2023-0234-0413
Page(s): 64-65

Commenter: American Gas Association (AGA) and American Public Gas Association (APGA)
Comment Number: EPA-HQ-OAR-2023-0234-0418
Page(s): 10

Comment 1:

<u>Commenter 0299</u>: **71. Subpart W leak duration assumptions should be revised to align with the NSPS and NESHAP repair requirements.**

EPA must remove the requirement to assume a leak persists until the next complete survey if the leaking component is subject to repair requirements under other regulations. For example, under NSPS OOOOa, if a gas plant connector[116] is found to be leaking, it must be reinspected within 90 days of repair. Similar provisions for repair and reinspection are included in NSPS OOOOb and EG OOOOc. For other component types, re-monitoring occurs monthly for the next two months following the repair, and the component is then monitored quarterly. Because NSPS rules and proposed EG OOOOb require repair and monitoring after repair, it makes little sense for Subpart W to force operators to calculate and pay fees assuming a leak persists beyond the repair date. This is overly conservative, it does not align with NSPS and EG requirements, and it does not align with the Inflation Reduction Act mandate to incorporate empirical data. To address this issue, EPA should revise Equation W-30, variable $T_{z,p}$ to allow the end of the leak to be based on when a resurvey of the leaking component confirmed it as repaired. EPA should also provide more clarity in the explanation of determining leak duration.

98.233(q)(2), equation W-30:
T p,z = The total time the surveyed component "z," component type "p," was assumed to be leaking and operational, in hours, which shall be determined as follows: The start date is when the last survey showed the component was not leaking. If only one survey is conducted in the year, the start date shall be assumed to be the first day of the calendar year. The end date is the date of verified repair or the date of the next survey that shows the component is not leaking. If repair is not verified within the calendar year, the end date is the last day of the year, and the leak must be assumed to persist until the next survey or verified repair shows the component is not leaking. ~~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.

Footnote:

[116] Connectors are surveyed annually.

Commenter 0376: **3. Duke Energy appreciates EPA's proposal to provide facilities with a method to develop company-specific emission factors. However, the use of additional methods or advanced methane leak detection (AMLD) and direct measurement technologies by companies is needed as an alternative way to quantify leaks and is critical to document results of methane emissions reduction initiatives.**

…

Duke Energy has also accelerated our leak survey program to clear our leak inventory and is working toward a "find it – fix it" business strategy so leaks are remedied much faster than regulations specify. Since making this change, we have decreased the number of leaks by more than 85%. Where a leak was detected as part of the Subpart W survey, we believe we should be permitted to account for the remediation of the leak in leak data reporting records.

Commenter 0387: “Leak time” for emission estimates should be based on component-specific repair confirmation
Rather than requiring a complete survey to validate that a repair has been completed, repair verification that meets regulatory LDAR requirements should be allowed. For LDAR, repair confirmation is directed at the affected component; Subpart W requires a complete facility survey to use a “leaking time” indicative of the time that an affected component leak. It is not reasonable or rational to include more stringent criteria for leak verification in a reporting rule than in emissions control regulations, reflected in NSPS and NESHAPs LDAR requirements. The Subpart W criteria should be adjusted accordingly and should allow the leak “time” in Equation W-30 to be based on component-specific repair confirmation. This approach is consistent with IRA direction to improve emission estimates based on empirical data. Leaking component repair may occur and be confirmed immediately after leak discovery and this “empirical data” should be used as the basis for estimating emissions, rather than current methods which would assume the leak remains for many days or months – up to as long as a year if another complete survey is not conducted unit the next annual Subpart W survey. The current estimation approach clearly conflicts with Congress’ direction toward empirical data, and component-level repair confirmation, which is sufficient to demonstrate LDAR compliance, is a clear example of definitive empirical data.

Commenter 0392: Use of Information in Alternative Periodic Screenings

MiQ Comments: We observe discrepancies and potential loopholes or disincentives that could be exacerbated through the proposed calculations for equipment leaks in relation to the proposed OOOOb and OOOOc rules. Operators who choose to comply with OOOOb and OOOOc using alternative periodic screenings are at a disadvantage if they only complete one OGI per year since they must assume that a leak lasts for an entire year. However, on the flip side, operators using periodic screenings will have more permissible data requiring greater scrutiny and likely larger total emissions reported via the “other large release events” category. For both reasons above, these proposed calculation methodologies may ultimately disincentivize operators to use screening technologies for quantification. Please refer to the comments below responding to EPA’s questions around further use of top-down data and how to couple top-down data with bottom-up inventory.

Commenter 0393: We support the effort to properly identify and repair leaks timely and as soon as practicable. We recommend the EPA change the definition of Tp,2 in Equation W-30 to better show the implementation of monitoring/repair programs by knowing the duration of the leak can be subject to the repair action and verification, and not only by a survey and/or the beginning of the reporting year. This is like what we propose for other leak times.

Commenter 0402:
3.10 Equipment Leaks

3.10.2 Method 1 - Default Leaker Emission Factors

…

The Industry Trades support efforts to properly characterize a leak by the period in which that leak is detected. This will further align subpart W with the proposed methane rule, which mandates that any leaks must be repaired as soon as practicable. To that extent, we recommend EPA amend the definition of Tp,z in Equation W-30 to better reflect the implementation of monitoring and repair programs by acknowledging that the duration of the leak may be subject to the action of repair and verification, and not solely by a traditional survey and/or the start or end of the reporting year, similar to what the Industry Trades propose for other leak durations, thief hatch openings, etc.

We also recommend that EPA revise the approach to include other activities in addition to leak detection surveys that may offer an indication of a repaired leak. While the current proposed language refers only to a "survey", an operator will have other clear indicators that a leak has been addressed including the repair date or other detection approach. EPA should include any other such activity on which an operator seeks to assign a repair date other than a survey as a reporting element.

Commenter 0402: 3.10 Equipment Leaks

3.10.4 Leak Duration

The leak duration should be revised to reflect a more reasonable and representative assumption that the leak duration is half the time since the last survey.

The leak duration associated with the Method 1 leaker emission factor approach should be half the time since the last survey. Assuming that the leak duration was the entire period since the last survey is an overstatement of the leak duration, as it implies the leak occurred on the date of the last survey which is unreasonable. Since the actual time the leak started is unknown, it is more reasonably accurate to assume that, on average, that the leak would have started in the mid-point of the survey cycle. This assumption accounts for that some leaks will occur before the mid-point and some will occur after the mid-point, but that on average, it is a reasonable assumption and much more representative than the conservative assumption that the leak started at the time of the last survey.

Commenter 0413: Revisions and Addition of Default Leaker Emission Factors

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.

Footnotes:
[110] 88 Fed. Reg. 50405.

Commenter 0418: **B. The Associations support EPA's proposed methods of quantifying distribution segment equipment leaks via population count but offer additional recommendations for further improving the proposed methods.**

3. EPA should provide an option for companies/utilities to develop their own emission factors, which would allow for even more accurate reporting and incentivize further reductions of GHG emissions from distribution mains, services, and below-grade stations.

…

Further, in the event of a leak, where the utility follows detection with repair, the utility should not be required to assume that the leak continued for the entire year or until the next above-ground T-D survey. Instead, the completion date of the leak repair should be used as the end point for the leak—because it is the end point for the leak. This approach is not only more accurate, but it also leverages data that LDCs are already required to collect regarding leak detections and repairs, and incentivizes emission reductions via speedy leak repairs.

Response 1: We have previously received comments and performed analyses of various options regarding leak duration as it applies to the calculation method in 40 CFR 98.233(q). These analyses considered how to account for the use of multiple surveys which could include remonitoring after repair. As a result of these analyses, we made amendments to the leak duration or time variable, $T_{p,z}$, in the *Greenhouse Gas Reporting Rule: Leak Detection Methodology Revisions and Confidentiality Determinations for Petroleum and Natural Gas Systems Final Rule published in the Federal Register in 2016* (81 FR 86490). The purpose of the 2016 final rule was to align subpart W requirements with NSPS OOOOa, as appropriate, while maintaining accuracy in the quantification and reporting of emissions resulting from leak surveys. In the 2016 final rule amendments, we revised the definition of $T_{p,z}$ which clarified how to determine the duration of a leak if more than two leak surveys are conducted in a year and which instructs reporters to sum the individual durations to determine the total time the component was leaking during the year. Specifically, the amendments to the time variable $T_{p,z}$ defined each equipment leak survey as covering a unique, non-overlapping time period and clarified our intent that a leak detected in the first or any intermediate survey is not considered to continue leaking past the date of that specific equipment leak survey. For the last survey conducted in the calendar year, the leak is assumed to continue until the end of the year.

As described in the RTC document for the 2016 final rule, we have also previously considered commenter's suggestion that the duration of leaks be assumed to be one-half the time period between the equipment leak surveys when multiple surveys are performed. With respect to this suggestion, assuming that a leak begins somewhere near the midpoint of the period between surveys, it is important to note that subpart W does not require repair of leaking components and many leak detection and repair programs include provisions for delay of repair. The start time of the leak duration for an individual equipment leak survey would be dependent on the results from (not just the date of) the previous equipment leak survey and whether repairs were made. That is, if a leak was present during the previous survey and that leak was not repaired, the duration of that leak would be the entire time period between surveys, and if it was not present during the previous survey, then only half the time period between surveys would be used. One would also assume that the leak would occur the entire period between the equipment leak survey identifying the leak and the time the leak was actually repaired. This adds a level of complexity to the calculations. On the other hand, the existing leak duration methodology is only dependent on the date of the previous equipment leak survey and not on the particular results from that survey. As such, one only needs to know the count of leakers for a given component type for each equipment leak survey. If a mid-point concept were to be incorporated, then the leak result from each individual component would need to be tracked to determine if the midpoint or full period should be assigned as the duration for that interval. This could create additional burden for reporters. We also note that we did not propose this approach and thus did not provide public review and comment on revisions under such an approach in this rulemaking. We would also need to consider the ramifications of this change in methodology (both in terms of accuracy, complexity, and timeline consistency) not only for the equipment leaks source, but for application to all leak duration terms within subpart W. At this time, we are not finalizing a mid-period duration assumption for equipment leaks under 40 CFR 98.233(q). Furthermore, in our analysis of various options regarding leak duration as it applies to the calculation method in 40 CFR 98.233(q) provided in the "Greenhouse Gas Reporting Rule: Technical Support for Leak Detection Methodology Revisions and Confidentiality Determinations for Petroleum and Natural Gas Systems Final Rule" (Docket Item No. EPA–HQ–OAR–2015–0764-0066) for the 2016 final rule, we assessed an option to allow remonitoring of individual components after repair to establish the leak duration. However, we found based on an analysis of example (or "model") facilities that this approach was likely to underestimate emissions whereas the current methodology provided an accurate quantification of leak emissions. We continue to think that the current methodology provides the most accurate means to estimate leak duration when leaks are routinely repaired while limiting all durations to a specific calendar year and that this approach is consistent with CAA section 136(h).

For a comprehensive review of our previous analyses and response to comments on the amendments in the 2016 final rule, please refer to the ''Response to Public Comments on Greenhouse Gas Reporting Rule: Leak Detection Methodology Revisions and Confidentiality

Determinations for Petroleum and Natural Gas Systems'' (Docket Item No. EPA–HQ–OAR–2015–0764-0067) and ''Greenhouse Gas Reporting Rule: Technical Support for Leak Detection Methodology Revisions and Confidentiality Determinations for Petroleum and Natural Gas Systems Final Rule'' (Docket Item No. EPA–HQ–OAR–2015–0764-0066).

We maintain the same conclusions regarding the time variable as we did in the 2016 final rule and find that no further amendments should be made in our efforts to align subpart W with the NSPS OOOOb and OOOOc. The amendments we made in the 2016 final rule which aligned, as appropriate, subpart W with NSPS OOOOa for the time variable continue to apply now.

For our response and discussion on use additional methods or advanced methane leak detection (AMLD), please refer to Sections II.B and III.P.6 of the preamble to the final rule and the response to comment 5 in Section 18.2 of this document, respectively.

Commenter: GPA Midstream Association
Comment Number: EPA-HQ-OAR-2023-0234-0299
Page(s): 52

Comment 2: EPA should allow the use of annual average GHG mole fraction in Equations W-30 and W-32A for Onshore Natural Gas Transmission Compression and Underground Natural Gas Storage.

EPA should allow the use of annual average GHG mole fraction GHGi in Equations W-30 and W-32A as allowed in Equation W-1A for Pneumatic Controllers. This would better align Equipment Leak calculations with other calculations of Subpart W and be consistent with the initiative of capturing empirical data. GPA suggests the following revisions to the proposed regulatory text:

98.233(q)(2)
Eq. W-30
GHGi = For onshore petroleum and natural gas production facilities and onshore petroleum and natural gas gathering and boosting facilities, concentration of GHGi, CH_4, or CO_2, in produced natural gas as defined in paragraph (u)(2) of this section; for onshore natural gas processing facilities, concentration of GHGi, CH_4 or CO_2, in the total hydrocarbon of the feed natural gas; for onshore natural gas transmission compression and underground natural gas storage, GHGi equals 0.975 for CH_4 and 1.1×10^{-2} for CO_2 <u>or concentration of GHGi, CH_4 or CO_2, in the total hydrocarbon of the feed natural gas</u>; for LNG storage and LNG import and export equipment, GHGi equals 1 for CH_4 and 0 for CO_2; and for natural gas distribution, GHGi equals 1 for CH4 and 1.1×10^{-2} CO_2.
98.233(r)
Eq. W-32A
GHGi = For onshore petroleum and natural gas production facilities and onshore petroleum and natural gas gathering and boosting facilities, concentration of GHGi, CH_4, or CO_2, in produced natural gas as defined in paragraph (u)(2) of this section; for onshore natural gas transmission compression, and underground natural gas storage, and onshore natural gas

transmission pipeline, GHGi equals 0.975 for CH_4 and 1.1×10^{-2} for CO_2 or concentration of GHGi, CH_4 or CO_2, in the total hydrocarbon of the feed natural gas; for LNG storage and LNG import and export equipment, GHGi equals 1 for CH_4 and 0 for CO_2; and for natural gas distribution, GHGi equals 1 for CH_4 and 1.1×10^{-2} CO_2.

Response 2: See Section III.P.1 of the preamble to the final rule for the EPA's response to this comment.

Commenter: GPA Midstream Association
Comment Number: EPA-HQ-OAR-2023-0234-0299
Page(s): 90

Comment 3: Fugitive Leak Surveys and Equipment Leaks by Population Count

The required (and allowable) leak measurement methods are extremely difficult to discern in the rule text (98.233(j)(1) and all its cross-references). EPA should include a table in the rule to show which methods are required and/or allowable for each industry segment.

Response 3: It seems the commenter is referring to equipment leaks, but the regulatory citation included in the comment is to tanks; nonetheless, we are not finalizing a table of applicability relative to equipment leaks. All equipment leaks provisions are contained in two sections of the rule and the citation to the applicable components is included in the introductory paragraph to each section. We do not believe putting these words into a tabular form would increase clarity.

Commenter: Environmental Defense Fund, et al.
Comment Number: EPA-HQ-OAR-2023-0234-0413
Page(s): 64-65

Comment 4: Revisions and Addition of Default Leaker Emission Factors

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.

Response 4: The EPA acknowledges the commenter's support of the proposed revisions regarding the reporting of the count of major equipment. We are finalizing the component-level leaker emission factors, as proposed. Given the new reporting requirements of counts of major equipment and measured leak rates, we may consider using these data to develop major equipment-based leaker factors in a future rulemaking.

18 Equipment Leaks by Population Count

18.1 Onshore Petroleum and Natural Gas Production and Onshore Petroleum and Natural Gas Gathering and Boosting Population Count Method

Commenter: CrownQuest Operating
Comment Number: EPA-HQ-OAR-2023-0234-0393
Page(s): 278

Commenter: American Petroleum Institute et al. (Part 1 of 2)
Comment Number: EPA-HQ-OAR-2023-0234-0402
Page(s): 55

Commenter: Environmental Defense Fund, et al.
Comment Number: EPA-HQ-OAR-2023-0234-0413
Page(s): 69-70

Commenter: Environmental Defense Fund et al.
Comment Number: EPA-HQ-OAR-2023-0234-0401
Page(s): 1

Commenter: Encino Energy (EAP Ohio, LLC)
Comment Number: EPA-HQ-OAR-2023-0234-0408
Page(s): 2-3

Comment 1:

Commenter 0393: It is concerning that the Rutherford et al study 2021 used for production and gathering/boosting emission factors included infrequent large emitters in the derivation of those factors. EPA is now proposing to report large events as "other large releases", we believe this is double counting.

Commenter 0402:

3.10 Equipment Leaks

3.10.5 Method 3 – Default Population Emission Factors

The proposed population emission factor approach should be revised to improve accuracy of emission factors and component counts, while allowing more flexibility for reporters.

The Industry Trades are concerned that the Rutherford *et al* study (2021) used for the production and Gathering and Boosting emission factor development included infrequent large emitters in the derivation of the emission factors, including emissions from sources covered elsewhere and not considered fugitive components. Additionally, Rutherford *et al* didn't conduct any actual measurements of equipment leaks. The study results are a synthesis of past studies and includes storage tank emissions as fugitives. Given that EPA is now proposing to report large events as "other large releases," the Industry Trades believe using this study will result in double-counting. The Industry Trades support the use of the Pacsi *et al* and Zimmerle *et al* studies, despite EPA's concerns noted in the preamble regarding the smaller sample size. The Industry Trades believe the Pacsi and Zimmerle studies to be more appropriate for upstream and midstream operations.

Commenter 0413: 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 regionallevel.[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.

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.

Footnotes:

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

[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.

Commenter 0401: Specifically, the EPA should adopt the following provisions:

- **Finalize emission factors for major equipment based on recent peer-reviewed research.** Ensure that reporting of leaks and malfunctions through other pathways is complete and incorporates emissions events from leaks and operational problems.

Footnotes:

Underlined text is a link to https://www.nature.com/articles/s41467-021-25017-4#MOESM2 (the Rutherford study)

Commenter 0408: In Rutherford et al. (2021) the discussion indicates that further research is needed as the emission factors provided may not represent all regions. EAP Ohio, LLC cannot validate the referenced research is comparable to the emission factors proposed by EPA especially given that the emission factors based on the 1995 EPA document EPA-453/R-95-017 are lower by over 90%. Since the emission factors are significantly higher than the emission factors in the effective Subpart W, EPA may give the impression to some that the numbers were inflated artificially or in error. EAP Ohio, LLC recommends EPA consider other research in addition to their referenced documents and/or retain the emission factors in the current Subpart W rule until more substantial data can be collected. EAP Ohio, LLC agrees EPA should allow an option for emission factor use in leu of measurement to ensure timely repair.

Response 1: In reviewing the supplementary information, specifically Supplementary Tables 8 and 9 of the Rutherford et al. (2021) study, we find that the maximum measurement value included in the study is about 30 kg/hr. We are finalizing a threshold of 100 kg/hr for other large release events. Furthermore, the final emission factors are significantly less than the OLRE threshold as they are the result of compiling all the measurement data and performing a bootstrapping analysis as described in more detail by study authors. We disagree that utilizing the emission factors based on the Rutherford et al. (2021) study results in any double counting of OLRE emissions. We also disagree that the final emission factors we included double count tanks emissions. As noted in the TSD for the final rule, we specifically excluded data from emission source types already covered by subpart W methods, including storage tank venting. We did, however, appropriately include an emissions factor for storage tank fugitive emissions from equipment leak components based on the Rutherford et al. (2021) study.

As stated in the TSD, the Rutherford data compiled leak screening and measurement data across multiple studies, providing a robust sample size (about 3,700 measurements across standardized component and equipment designations) and the study employed a bootstrap resampling statistical approach improving the representation of the inherent variability of equipment leaks in the developed emission factors. The Rutherford data and study methods provide a more statistically robust set of default population factors than other available peer reviewed data (e.g., Zimmerle et al. (2020); Pacsi et al. (2019)). We are finalizing the default population emission factors from the Rutherford et al. (2021) study, as proposed.

Commenter: GPA Midstream Association
Comment Number: EPA-HQ-OAR-2023-0234-0299
Page(s): 93

Commenter: CrownQuest Operating
Comment Number: EPA-HQ-OAR-2023-0234-0393
Page(s): 278

Commenter: Williams Companies, Inc.
Comment Number: EPA-HQ-OAR-2023-0234-0394
Page(s): 12

Commenter: The Petroleum Alliance of Oklahoma
Comment Number: EPA-HQ-OAR-2023-0234-0398
Page(s): 18

Commenter: American Petroleum Institute et al. (Part 1 of 2)
Comment Number: EPA-HQ-OAR-2023-0234-0402
Page(s): 55

Comment 2:

Commenter 0299: **Proposed Change:** Table W-1a is being revised to list equipment leak emission factors per major equipment type, rather than per component. This change impacts the Onshore Petroleum and Natural Gas Production and Onshore Petroleum and Natural Gas Gathering and Boosting segments. EPA is implementing this change to eliminate an unnecessary step where major equipment types are converted to component counts, which are in turn used with per component emission factors to calculate emissions. EPA seeks comment on the approach of providing population count emission factors by major equipment.

> **Comment:** Although this revision will eliminate an unnecessary calculation step for many reporters, it also eliminates the option to use actual component counts per facility to calculate equipment leak emissions. 40 C.F.R. § 98.233(r)(2) currently allows both "Component Count Method 1" – counting major equipment; and "Component Count Method 2" – counting individual components. The option to use actual individual component counts to calculate emissions should be retained as it will provide more accurate emission estimates compared to using major equipment counts. Table W-1a

should include both emission factors per major equipment type and per component count to allow for either option to continue to be used.

Commenter 0393: We also do not support the elimination of component count Method 2 and ask EPA to allow the use of actual component counts.

Commenter 0394: **Actual Component Counts**

Williams opposes the removal of the current option for owners / operators to perform actual equipment component counts in the gathering and boosting segment to calculate fugitive GHG emissions. The number of components per piece of major equipment (e.g., separators) is not an absolute count and varies according to equipment make, model, and design. For this reason, an actual count would be more accurate than a major equipment count.

Commenter 0398: Onshore Petroleum and Natural Gas Production and Onshore Petroleum and Natural Gas Gathering and Boosting Population Count Method. EPA proposes to replace component EFs with major equipment EFs. Overall, we think this will lead to significant overestimation of emissions as larger equipment EFs are not representative of individual leaking components.

Action Requested: We request EPA maintain the component EFs.

Commenter 0402: Equipment Leaks

Method 3 – Default Population Emission Factors

The proposed population emission factor approach should be revised to improve accuracy of emission factors and component counts, while allowing more flexibility for reporters.

…

The Industry Trades do not support the elimination of component count method 2 and request that EPA allow the use of actual component counts if it is subject to a state regulatory program that requires component counts.

Response 2: As noted in the response to Comment 1 of this section, we are finalizing the default major-equipment based emission factors from the Rutherford et al. (2021) study, as proposed. As stated in the TSD, the Rutherford study compiled leak screening and measurement data across multiple studies, providing a robust sample size (about 3,700 measurements across standardized component and equipment designations) and the study employed a bootstrap resampling statistical approach improving the representation of the inherent variability of equipment leaks in the developed emission factors. The representativeness of the Rutherford et al. (2021) study data is expected to result in more accurate emissions quantification than the existing factors or other reviewed publicly available studies from which population count emission factors could be derived (*e.g.*, Pacsi et al. (2019) and Zimmerle et al. (2020)) – all of which had smaller sample sizes than the Rutherford study.

In addition to the increased accuracy from the revisions to the emission factors themselves, we expect that providing emission factors based on the count of major equipment rather than the count of components to improve accuracy in the reported emissions. Under the existing requirements, the vast majority of reporters (*i.e.*, > 90%) estimate the number of components using component calculation method 1. This component calculation method provides default component counts per major equipment type (*e.g.*, 8 valves per separator), whereby reporters must count their major equipment to then estimate the component counts to which they apply the existing default component population count emission factors to estimate emissions. During our annual verification of these reported activity data (*i.e.*, estimated component counts) and resulting emissions, we typically find numerous errors in the reported components counts. With the major equipment-based emission factors, there will no longer be a need to estimate the component counts as they major equipment counts can be used directly with the final emission factors and we thereby expect fewer errors in the calculation and estimation of emissions.

Even though we expect the shift from component to major equipment activity data to result in fewer errors, we examined the Rutherford et al. (2021) study to determine if there was sufficient data to develop component-level emission factor such that we could provide a component-level approach using the same study data. We determined that there is not sufficient data to provide this approach using the Rutherford study. Therefore, we are not including default component-level population emission factors in the final rule.

Commenter: MiQ
Comment Number: EPA-HQ-OAR-2023-0234-0392
Page(s): 5

Comment 3: Population emission factors for onshore production facilities

MiQ Comments: MiQ applauds EPA on utilizing updated and synthesized data, including Rutherford et. al, to base population emission factors. Through preliminary analysis, it appears that these updated emission factors will lead to an increase in an operator's reported emissions simply due to the calculation methodology changes. This could lead to more operators beginning to perform leak inspections following 98.234(a) through (c) earlier than they are required to in NSPS OOOOc emission guidelines, which would lead to quicker emission reductions and operators reporting based on less generic methodologies.

Response 3: The EPA acknowledges the commenter's support of the proposed revisions. The EPA is finalizing these amendments as proposed.

Commenter: CrownQuest Operating
Comment Number: EPA-HQ-OAR-2023-0234-0393
Page(s): 279

Comment 4: It seems the EPA claims that reporters consistently under report estimated components. There are actual component counts based off type and size of equipment. The data is there, and the EPA should use it to derive realistic component counts rather than using cherry picked emission factors.

Response 4: This comment seems to be related to statements concerning errors identified with respect to reporters estimating component counts when using the existing component calculation method 1 (which uses the reported count of major equipment with default counts of components per major equipment type). As described in the preamble to the final rule, the vast majority of reporters utilize calculation method 1 rather than calculation method 2 which requires the reporting of actual component counts. In the preamble and TSD for the final rule, we noted that there are calculation errors each year by reporting facilities when estimating the counts of components using component calculation method 1 – sometimes the errors over- or under- report the number of components that would otherwise be estimated by the method.

As noted, very few reporters report emissions based on actual component counts. Furthermore, the existing subpart W methods do not provide measurements for components found leaking, so it is not possible to derive emission factors with the data currently reported to subpart W. In order to derive default population emission factors we would need component counts, measured emission rates, and population of components surveyed.

We maintain that the emission factors we have proposed and are finalizing are not "cherry picked", rather they are based on a published, peer-reviewed study that synthesized data from multiple studies.

Commenter: Endeavor Energy Resources, L.P.
Comment Number: EPA-HQ-OAR-2023-0234-0381
Page(s): 18

Comment 5: EPA Should Reconsider the Proposed Revisions to Calculation Methods for Several Emission Sources.

Equipment Leaks by Population Count

Endeavor supports EPA's proposed method of assigning a leak rate on a per-major-equipment basis rather than a per-component basis. This proposed change would eliminate the needless step (and additional burden) of estimating the number of components. However, it appears that EPA's emission factors are similarly based on the Zimmerle et al. (2020) and Pacsi et al. (2019) studies referenced above, and thus are subject to the same critiques and flaws and should not form the basis for revised emission factors. Endeavor therefore encourages EPA to provide additional support for this proposed change in order to comply with the IRA and APA.

Response 5: The EPA acknowledges the commenter's support of the major equipment-based default population emission factors. The EPA is finalizing these amendments as proposed. The default population emission factors provided for onshore production and natural gas gathering and boosting in the proposed and final rule are based on the Rutherford et al. (2021) study.

The default leaker emission factors provided for onshore production and natural gas gathering and boosting in the final rule are based on the combination of data from the Zimmerle et al. (2020) and Pacsi et al. (2019) studies. Comments and responses regarding the default leaker emission factors can be found in Section 17 of this document.

Commenter: Michigan Oil and Gas Association (MOGA)
Comment Number: EPA-HQ-OAR-2023-0234-0298
Page(s): 2

Commenter: Lambda Energy Resources
Comment Number: EPA-HQ-OAR-2023-0234-0405
Page(s): 1-2

Comment 6:

Commenter 0298: 1. Department of Energy (DOE) Marginal Well Study:

MOGA reviewed all documents posted to the Docket Documents. As a shareholder in the DOE study, MOGA constituents were surprised to find the EPA is not considering the results of DOE study finalized in 2022. The results of the DOE clarified the differences in potential emissions from marginal wells vs. non-marginal wells in various oil and gas producing regions throughout the United States. MOGA was also concerned that more than a million dollars of taxpayer money was allocated to the study. MOGA recommends including the results of the DOE with proposed emission factors proposed in revisions to Subpart W.

Commenter 0405: For operators that must comply with these rules it may be impractical to gather direct measurement leak data from all their equipment which makes equipment leaks by population count emission factors (EFs) found in Table W-1E essential. Although there are new studies that EPA is proposing to use to adjust emission factors (increase) we wonder why the Department of Energy (DOE) marginal well study is not being used to produce more accurate leak factors. This study spanned many basins across the country and cost both taxpayers and industry a lot of money to produce. EPA should use the data collected because it is current (kicked off in 2019) and comprises actual emission data gathered as opposed to studies that use estimates. We believe that if the DOE study were included in the emission factors calculations, reporters would report emissions more accurately than the current proposed rules and would certainly be more accurate than simply splitting the country into two halves, East or West, as the current EFs do. Also, in the event that an organization decides that it is practical to develop a way to collect actual emissions, the process to implement the method should be streamlined. A third option to report accurate emissions that should be considered is to allow in-house or third-party engineering studies. This too would need a streamlined approval process so reporters could integrate the manner of data collection to their program in a timely manner.

Response 6: We did not propose and are not finalizing separate default population emission factors for marginal wells in this rulemaking. We are aware of several studies including the DOE marginal well study, Omara et al. (2016), Omara et al. (2022), Rella et al. (2015), Brantley et al. (2014) and Rutherford et al. (2021), which we may evaluate for the purposes of providing default population emission factors for marginal wells in a future rulemaking. While the DOE study report was finalized in 2022, the underlying metadata were not made available for review until April 2023 on the NETL's Energy Data eXchange (EDX). The EPA has undertaken an initial review of these underlying data to review and understand the data collected by the study. In this initial review of the underlying data, we have tried to determine whether it is possible and/or appropriate to further disaggregate the data to develop marginal well specific population factors (*e.g.*, by well type, age, depth). We have also begun to assess whether the NETL data could be combined with other study data of marginal well emissions to potentially provide a more robust and comprehensive dataset. We are also conducting analyses to determine whether there is increased accuracy, consistent with the objectives of CAA section 136(h), in developing a separate set of default population emission factors using the data from one or more of the available studies. At this time, we are continuing our review of the available literature and may consider such information for a future rulemaking, which would provide the opportunity for public comment and review of the calculations used to derive a proposed revised population emission factor specific to marginal wells.

Regarding the request for a third option to allow in-house or third-party engineering studies, the commenter did not provide sufficient information on the nature of this approach to allow the EPA to assess its appropriateness for quantifying equipment leak emissions under Subpart W.

18.2 Natural Gas Distribution Emission Factors

Commenter: Atmos Energy Corporation
Comment Number: EPA-HQ-OAR-2023-0234-0406
Page(s): 7

Comment 1: Atmos Energy supports updating the pipeline main and services leak emission factors based updated data that is representative of industry.

Natural gas distribution companies currently quantify leak emissions from pipeline mains and services using emission factors outlined in the existing Subpart W regulations.[23] In the Proposed Rule, EPA is updating these emission factors based on a combination of data from two recent studies.[24] Atmos Energy supports these amendments and appreciates EPA's efforts to keep emission factors in line with current data.

Footnotes:

[23] See 40 C.F.R. § 98.233(r).

[24] 88 Fed. Reg. at 50, 352.

Response 1: The EPA acknowledges the commenter's support of the proposed revisions. The EPA is finalizing these amendments as proposed.

Commenter: Downstream Natural Gas Initiative
Comment Number: EPA-HQ-OAR-2023-0234-0396
Page(s): 7

Commenter: American Gas Association (AGA) and American Public Gas Association (APGA)
Comment Number: EPA-HQ-OAR-2023-0234-0418
Page(s): 10

Comment 2:

Commenter 0396: **Below Grade Stations**

EPA has proposed updating the emission factors for all below grade stations (T-D, M&R) to be the same regardless of inlet pressure. The change would consolidate the number of emission factors from six to two and reduce reporting burden. DSI agrees with this approach.

Commenter 0418: **The Associations support EPA's proposed methods of quantifying distribution segment equipment leaks via population count but offer additional recommendations for further improving the proposed methods.**

It is appropriate for EPA to use the Lamb Study to develop population emission factors for below-grade stations.

The current population emission factors for below-grade stations are based on the 1996 GRI/EPA Study, with T-D emission factors distinguished by station component and M&R station emission factors distinguished by inlet pressure. EPA is proposing to incorporate the Lamb Study data by establishing a single emission factor for both types of below-grade stations (T-Ds and M&Rs), without regard to inlet pressure. For the reasons discussed above, the Associations support the use of the Lamb Study for these emission factors because they would facilitate a more accurate reporting of distribution segment GHG emissions. Further, the Associations support the ancillary benefit of reduced reported data elements.[32]

Footnotes:

[32] The Associations note that, while a reduction in reporting burden is appreciated as a general matter, we support it in scenarios such as this one, where the accuracy of the emissions data is not inconsistent with the reduction in reporting elements. In contrast, we would not support a reduction in reportable elements just for the sake of reducing burden when they would also reduce accuracy—for example, if reporting obligations did not allow for identifying differences in pipe material where such differences have an impact on the estimated amount of GHG emissions.

Response 2: The EPA acknowledges the commenters' support of the proposed revisions. The EPA is finalizing these amendments as proposed.

Commenter: American Gas Association (AGA) and American Public Gas Association (APGA)
Comment Number: EPA-HQ-OAR-2023-0234-0418
Page(s): 10

Comment 3: The Associations support EPA's proposed methods of quantifying distribution segment equipment leaks via population count but offer additional recommendations for further improving the proposed methods.

EPA should provide an option for companies/utilities to develop their own emission factors, which would allow for even more accurate reporting and incentivize further reductions of GHG emissions from distribution mains, services, and below-grade stations.

With regard to default national emission factors, the Associations support EPA's proposed methodology based on the Lamb Study. However, we believe that EPA should also provide an option for companies/utilities to develop their own emission factors for distribution mains, services, and below-grade stations, as this would further facilitate improvement in the accuracy of reported emissions under Subpart W. In particular, we recommend that the Agency allow companies/utilities to use an emission factor developed via an LDC's survey of above-ground T-Ds to estimate emissions from below-grade stations. While emission factors based on direct measurement and top-down efforts like AMLD campaigns may be feasible for larger gas utilities, such a method may be beyond the resources of smaller gas utilities—especially those that are operated by municipalities. Allowing a utility to use its above-ground T-D emission factor for below-grade T-Ds and both above- and below-grade M&Rs is appropriate because leak rates are very low for both categories of stations.

Response 3: For below grade stations, it appears the commenter is requesting that we maintain the emission factor developed with the Lamb study and also provide an option for facilities to utilize the meter/regulator run population emission factors developed in accordance with section 98.233(q) for their below grade stations. Effectively, then we would be providing two population emission factors – one based on the Lamb study and the other based on company surveys which could include measurements depending on which of the options a natural gas distribution company is using for their leak survey emissions quantification. While the emissions from these stations are small relative to the overall GHG emissions for natural gas distribution facilities, the expected leak rates from the below grade and above grade stations are different. For example, in the Lamb et al. study, leak rates from below grade stations were an order of magnitude lower than above grade metering-regulating stations (reference Table 2). Because we are providing population emission factors derived from data for below grade stations, we disagree with the recommendation to provide an option for facilities to utilize a facility-specific emissions factor based on data from above grade stations as we do not think they would be as representative as the source-specific factors proposed. We are finalizing the below grade station default population emission factors, as proposed.

Relative to the request for facility-specific pipeline emission factor development, we are not finalizing an approach for pipeline mains and services to develop their own leaker or population emission factors. There is uncertainty in what methods we would include under such an approach. For example, the existing survey methods and quantification methods would require digging down and we have received adverse comment related to measurement methods which require digging down. Similarly, there are new technologies which would require further evaluation to determine whether they can at this time accurately detect and quantify equipment leaks emissions from pipeline mains and services. In considering a potential approach, aside from the survey and measurement methods, there is also uncertainty with respect to implementation including what would constitutes a complete leak survey, whether a multi-year survey cycle is appropriate, whether emission factors should be developed using the existing criteria (*i.e.*, pipeline material) or whether emission factors could be based on other criteria (*e.g.*, pipeline age). Due to this uncertainty, we are not finalizing an approach for pipelines to develop their own leaker or emission factors in this rulemaking, but we may consider this in a future rulemaking.

Commenter: American Gas Association (AGA) and American Public Gas Association (APGA)
Comment Number: EPA-HQ-OAR-2023-0234-0418
Page(s): 8

Commenter: Downstream Natural Gas Initiative
Comment Number: EPA-HQ-OAR-2023-0234-0396
Page(s): 1-2

Commenter: American Gas Association (AGA) and American Public Gas Association (APGA)
Comment Number: EPA-HQ-OAR-2023-0234-0418
Page(s): 8

Commenter: American Gas Association (AGA) and American Public Gas Association (APGA)
Comment Number: EPA-HQ-OAR-2023-0234-0418-A3 (Appendix B)
Page(s): 11-19

Comment 4: Commenter 0418: **The Associations support EPA's proposed methods of quantifying distribution segment equipment leaks via population count but offer additional recommendations for further improving the proposed methods.**

EPA is proposing to revise the distribution segment emission factors used to quantify equipment leaks via population count under Subpart W. As it applies to the distribution segment, the population count method currently uses (1) the count of equipment components, counted individually for each facility; (2) the Subpart W population emission factors in Table W-7; and (3) the time that the equipment was operational. EPA is proposing to update the population emission factors for pipeline mains and services, below-grade transmission-distribution ("T-D") transfer stations, and below-grade M&R stations in Table W-7 (and move these emission factors to Table W-5) using the results of newer study data.[25] Notably, the proposed population emission factors for distribution mains and services rely on direct flow measurements from the 2015 Lamb et al. study ("Lamb Study")[26] and do not incorporate leak frequency estimates from the 2020 Weller et al. study ("Weller Study")[27]—this is consistent with the approach that the Associations have previously urged EPA to adopt. The Associations also support EPA's proposal to incorporate data from the Lamb Study into the population emission factors for below-grade stations. However, the Associations encourage EPA to give owners and operators the option to develop site-specific or company/utility-specific emission factors, as this would further increase the accuracy of emissions reported under Subpart W.

Footnotes:

[25] Proposed Rule, 88 Fed. Reg. at 50,349–54.

[26] B.K. Lamb et al., Direct Measurements Show Decreasing Methane Emissions from Natural Gas Local Distribution Systems in the United States, 49 ENVIRON. SCI. TECHNOL. 8 at 5161–69 (Mar. 31, 2015), https://pubs.acs.org/ doi/10.1021/es505116p.

[27] Z.D. Weller et al., A National Estimate of Methane Leakage from Pipeline Mains in Natural Gas Local Distribution Systems, 54 ENVIRON. SCI. TECHNOL. 14 at 8491–9144 (June 10, 2020), https://pubs.acs.org/doi/full/ 10.1021/acs.est.0c00437.

Commenter 0396: **LAMB STUDY EMISSION FACTORS**

DSI agrees that Subpart W distribution main and service population emission factors should align with the emission factors currently used in EPA's Greenhouse Gas Inventory (GHGI). The GHGI emission factors for mains and services apply the leak rates from the Lamb et al. study (Lamb Study) and the leaks per mile rates from the 1996 GRI/EPA study. This approach reflects the best available science and aligns the distribution main quantification methodologies in Subpart W and GHGI, eliminating a longstanding inconsistency between the two EPA programs.

Application of the Weller Study leaks per mile rates for mains instead of the GRI/EPA study rates would lead to a significant divergence between the emission factors in the GHGI and Subpart W.

The proposed updates to distribution services use the Lamb Study leak rates and GRI/EPA study leaks per mile assumption, which would align the factors used in GHGI and Subpart W. DSI supports this approach for distribution services.

The application of the Weller Study results in an emission factor for protected steel mains that is higher than the emission factor for unprotected steel mains. This is inconsistent with gas utility experience, other studies measuring methane emissions from distribution mains, and EPA programs aimed at reducing methane emissions such as Methane Challenge. The emissions reduction programs of many gas utilities involve replacement of leak prone pipe (e.g., cast iron and unprotected steel) with modern materials (e.g., protected steel and plastic). These programs have received approval for rate recovery from state regulators on the basis that they improve safety and reliability and reduce emissions. The Weller Study assumptions would imply that the pipeline replacement programs approved by many states, and encouraged by EPA's Methane Challenge Program, are leading to increases in methane emissions.

DSI reiterates its support for alignment between the GHGI and Subpart W by using the proposed approach – using the leak rates from the Lamb et al. study (Lamb Study) and the leaks per mile rates from the 1996 GRI/EPA study.

Commenter 0418: **The Associations support EPA's proposed methods of quantifying distribution segment equipment leaks via population count but offer additional recommendations for further improving the proposed methods.**

It is appropriate for EPA to use the Lamb Study to develop population emission factors for distribution mains and services.

The Associations have identified several significant limitations to the Weller Study that preclude it from being a reasonable basis for natural gas distribution factors, as well as several reasons why EPA should adopt the proposed factors based on the Lamb Study. These attributes are summarized below and discussed in greater depth in the Associations' comments on the 2022 Proposal, which are enclosed as Appendix B. [28]

As to the Weller Study, although it had a larger sample size than the Lamb Study, it has key disadvantages, including that it: (1) did not distinguish between cathodically protected and cathodically unprotected steel pipe, which means that leak data for the more leak-prone cathodically unprotected pipe was arbitrarily combined with data for cathodically protected pipe; (2) assumed that all emissions were derived from gas main leaks, instead of distinguishing between distribution mains and service lines, which artificially inflated the leak factors for mains because their emissions were grouped in with those from services; (3) used AMLD methodology that, despite showing promise for the development of system-specific emission factors, is not precise enough to develop accurate emission factors for different types of pipe material; (4) was based on limited data from only four cities and did not distinguish between urban, suburban, and rural areas, which is insufficient geographic diversity for extrapolating the data to construct nationwide emission factors; (5) exhibited a high degree of uncertainty in correlating flow rate field results with flow rate control test results; (6) did not distinguish between biogenic and thermogenic sources of methane, thereby inflating emissions and leak rates from natural gas distribution systems; and (7) used minimal verification for leak locations by assuming that a leak indication within 40 meters of a distribution pipeline must be associated with the pipeline, instead of considering how wind direction or obstructions (e.g., trees, buildings) could affect the perceived location of a leak. It is particularly important for the population emission factors to be based on data that differentiates by cathodic protection because EPA's Methane Challenge Program incentivizes natural gas distribution companies and municipal utilities to replace unprotected steel pipe with cathodically protected steel pipe as a means to reduce leaks. Use of emission factors that do not recognize the lower methane emissions from protected steel would undermine this incentive.

The Associations support EPA's use of the Lamb Study to develop Subpart W population emission factors because the study is the best currently available basis for default national average emission factors for the distribution segment. Using the Lamb Study would improve the accuracy of reported distribution segment emissions for several reasons, including that the study: (1) reduced uncertainty through direct measurements by using a high-volume sampler methodology, which is an appropriate approach for measuring flow rates from leaks and developing emission factors for specific types of pipe materials; (2) was more geographically diverse, and therefore more representative of gas utilities across the country than the Weller Study, because it included nationwide data from thirteen cities across the country in different climates, population densities, and distribution system configurations; (3) verified leak locations before measurement by using standard, reliable leak detection methods to identify the exact area of a leak; and (4) verified pipe material and distinguished between cathodically protected and cathodically unprotected steel pipe, which was possible because the study authors worked with system operators to obtain site access, pipe asset and operations information, and direct viewing of pipes during excavations conducted for repair work. Furthermore, because the Lamb Study is already used in EPA's annual GHG Inventory, the study's use in population-based emission factors for gas distribution mains and services would promote consistency between Subpart W and the GHG Inventory.

The current population emission factors for distribution pipeline mains and services are based on information from a 1996 Gas Research Institute/EPA study ("GRI/EPA Study"),[29] with additional data on plastic mains sourced from a 2005 ICF analysis.[30] For the revised emission factors for mains and services, EPA is proposing to rely on leak rates from the Lamb Study and leak incidence data from the 1996 GRI/EPA Study.[31] The Associations request that EPA rely only on the Lamb Study to revise these emission factors, as the Lamb Study is more recent and therefore better accounts for the improved leak detection and repair ("LDAR") best practices applied by Association members in the years since the 1996 GRI/EPA Study. This, in turn, would make the distribution mains and services emission factors more accurate than what is currently proposed, which would align with Congress's directive to EPA in the IRA.

Footnotes:

[28] See AGA and APGA Comments on 2022 Proposal at 10–18 (Oct. 6, 2022), https://www.regulations.gov/comment/ EPA-HQ-OAR-2019-0424-0236 (enclosed as Appendix B).

[29] The 1996 GRI/EPA Study is presented in different volumes. The two that are relevant to Section G of the Associations' comments are: GRI/EPA, Methane Emissions from the Natural Gas Industry, Volume 9: Underground Pipelines, GRI–94/0257.2b, EPA–600/R–96–080i (June 1996), https://tinyurl.com/1996-GRI-EPA-vol9; GRI/EPA, Methane Emissions from the Natural Gas Industry, Volume 10: Metering and Pressure Regulating Stations in Natural Gas Transmission and Distribution, GRI–94/0257.27, EPA–600/R–96–080j (June 1996), https://tinyurl.com/1996- GRI-EPA-vol10.

[30] Fugitive Emissions from Plastic Pipe, Memorandum from H. Mallya and Z. Schaffer, ICF Consulting to L. Hanle and E. Scheehle, EPA (June 30, 2005), https://www.regulations.gov/document/EPA-HQ-OAR-2023-0234-0019.

[31] The Associations note that EPA did not explain why it proposes to rely on leak incidence data from the 1996 GRI/EPA Study instead of leak incidence data from the Lamb Study

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Commenter 0418, Appendix B: **EPA's Proposed Revisions to the Default Population-Based Emission Factors for Estimating Methane Leak Emissions from Natural Gas Distribution Protected and Unprotected Steel Mains Are Not Credible, Not Supported by the Record, and Would Undermine Efforts to Reduce Actual Emissions.**

The Weller Study Does Not Provide a Reasonable Basis for Gas Distribution Emission Factors.

EPA's proposal to blend the direct flow measurements from the Lamb Study[12] with the calculated leak frequency estimates from the Weller Study[13] yields results that are significantly inconsistent with all other previous studies. It is well-known from previous studies and experience that unprotected steel pipe has more leak emissions than modern cathodically protected steel. Both the 1996 GRI-EPA[14] study and Lamb Study demonstrate this emissions differential. Furthermore, EPA's voluntary Methane Challenge program incentivizes natural gas distribution companies or municipal utilities to replace unprotected steel pipe with cathodically protected steel pipe. EPA's Proposed Rule would undermine that incentive because it would establish a higher default emission factor for protected steel than for unprotected steel mains. *See* 87 Fed. Reg. at 36,981-82 (preamble) and proposed Table W-8, at 37,105 (1.2 scf/hr for unprotected steel mains vs. 2.3 scf/hr for protected steel mains).

EPA contends both studies have their advantages: the Lamb Study's advantage is its methodology – using direct measurements with a high-volume sampler, and, the Weller Study's advantage is its larger sample size. While the Weller study may have a larger sample size, numerous limitations preclude it from being used as a basis for revisions to the default emission factors for distribution mains. Simply stated, the Weller Study is not a reasonable basis for establishing national default emission factors.

First, and most importantly, the Weller Study conflated cathodically unprotected coated steel in the "coated (protected)" steel emission factor Category and did not verify pipe type, material, or cathodic protection. The Weller Study authors did not obtain information about or verify whether pipe was cathodically protected. As a result, no distinction between cathodically protected and unprotected steel pipe is made. This means leak data for *more leak-prone cathodically unprotected* (but coated) steel is arbitrarily combined in the "coated (protected)" category for calculating emission factors. The Weller Study authors failed to explain why their data indicated more leaks per mile for coated steel pipe than for bare steel pipe. This failure to distinguish cathodic protection is likely a large part of the answer to why the findings in the Weller Study are counterintuitive.

Steel pipe can be protected through cathodic protection and/or coating. Natural gas distribution pipeline operators annually report miles of steel pipe to the DOT PHMSA in four categories: cathodically protected coated pipe, cathodically protected uncoated pipe, coated steel pipe that is not cathodically protected and bare steel that is not cathodically protected. EPA's Subpart W default emission factors for steel pipe account for only two categories: protected and unprotected steel pipe, referring to steel pipe that is or is not cathodically protected.

The Weller Study also did not verify the type of pipe – distribution main or service line. The authors conceded they assumed all emissions to be caused by mains. As the authors explained: "We *assume that the leak indications and emissions observed in these surveys are derived from leaks in the gas mains … [a]lthough some of these leaks may arise from service lines or meter set assemblies…*"[15] As a result, main leak factors were inflated because emissions from services were not separated from the emissions assigned to distribution mains.

Verification of pipe material is important, as demonstrated in a recent study conducted by GTI for the California Air Resources Board (CARB) to develop California utility-specific emission factors for mains and service lines.[16] The CARB-GTI Study used a similar data collection and verification method as used in the Lamb Study. Field visits were conducted in the service territories of the three largest natural gas distribution utilities in California, using a high-volume sampler to measure flow rates at leak locations randomly selected from each utility's list of non-hazardous leaks, focusing on (cathodically) unprotected steel mains and services. As in the Lamb Study, pipe type, material and protection were verified.

> *"As part for the study, 78 leak sites were measured above ground. During the leak repairs by the utilities, about 1-3 years later, it was discovered that the original identifications of leak facility [pipe type] (mains vs services) or pipe material (plastic vs steel) were incorrectly classified 59% of the time. The facility and material were misclassified 40% and 31% of the time respectively."*[17]

The methodology of the CARB-GTI Study included an advanced statistical and probabilistic analysis on the leak data and the misclassifications to provide a representation of the average leak rates for underground distribution mains and services by pipe type, material, and protection.[18]

During the Lamb Study, the authors had access to utility pipe material information and were able to verify pipe material, cathodic protection, and location on the main or service line when the utility excavated the pipe after the measurements to conduct repairs. Conversely the authors in the Weller Study were not able to identify the true pipe material and type of leak that was detected (main or service; cathodically protected or not). The Weller Study evaluated four types of pipe material: "bare steel," cast iron, "coated steel," and plastic. Such a categorization is insufficient to draw conclusions from the resulting data about appropriate default emission factors for cathodically protected or unprotected steel pipe. Bare steel pipe is pipe that lacks a coating – but it may not lack cathodic protection. Coated steel may have a coating, but it may lack cathodic protection. *In other words, the Weller Study design at the outset did not actually attempt to provide emissions estimates for protected or unprotected steel pipe.*

In addition, in the Weller Study, other materials were aggregated with one of the other four categories. Copper pipe was included in the bare steel. Ductile iron was combined with cast iron.

This lack of proper pipe material characterization in the Weller Study design significantly undermines its value for determining emissions factors for protected and unprotected steel pipe.

Second, the "advanced mobile detection platform" (AMLD) methodology used in the Weller Study shows great promise for the development of system-specific emission factors, but it is not an appropriate tool for assessing emission factors for specific types of pipe material. There are now many tools in the methane detection and quantification toolbox, and it is important to pick the appropriate tool or mix of tools for the job at hand. AMLD can be quite useful when used to identify and fix medium and larger-volume non-hazardous leaks. As discussed later regarding company/utility-level system emissions quantification, AMLD can also be quite useful to quantify overall emissions from all leaks from a company's entire distribution system – when deployed with multiple passes of the mobile platform (whether by car, drone, airplane, or satellite) in conjunction with a robust, statistically valid sample of direct measurement data. However, it is not the best tool for quantifying emissions from individual leaks from specific types of sources, such as distribution mains made of different pipe materials.

The methodology used in the Weller Study was initially developed in field studies as a screening tool to assign distribution leak plume detections to approximate leak rate categories of very low (4 to 9 CH4 g/min.), low (10 to 36 g/min.), medium (37 to 182 g/min.) or high (>182 g/min.) for the purpose of prioritizing repairs for non-hazardous leaks that are relatively higher emitters.[19] Under DOT PHMSA pipeline safety regulations, 49 C.F.R. Part 192, natural gas distribution pipeline operators fix hazardous leaks immediately. For safety purposes, leaks that are currently non-hazardous leaks are scheduled for timely repair, and leaks that are determined to have no potential to become hazardous are either repaired within a longer timeframe or placed on a leak log and monitored. However, for purposes of reducing methane emissions to help minimize climate impacts, our members are interested in methods for identifying those non-hazardous leaks that have relatively higher emissions so that these leaks can be prioritized for repairs. Our members have found the methodology used in the Weller Study is useful for that purpose – to categorize non-hazardous leaks into approximate categories of small, medium, and larger emitters. However, our members have found that this methodology is not suited for measuring actual emission flow rates from specific leaks from specific pipe materials.

A field study conducted by NYSEARCH and a large group of natural gas utilities in 2015, with additional validation tests in late 2017 and 2018 compared the results of three AMLD technologies (including two types of cavity ring down spectrometers technologies[20] – one of which was used in the Weller Study – coupled with modeling) with direct measurements of over 300 leaks using a high volume sampler.[21] The goal of the NYSEARCH Study, co-funded by DOT PHMSA, "was to define a process for independent validation of mobile methane emissions measurement technologies."[22] The results showed AMLD – could quantify leaks within very broad ranges, which is useful as a general tool for prioritizing leaks, but for example, not to provide accurate emissions measurements for reporting or inventory purposes to develop emission factors for different pipe materials. "One of the conclusions…was that the technologies that were evaluated had a wide range of accuracy and precision…and] data analysis showed that accuracy of the predicted vs. actual flow rate indicated a 77% accuracy shown to within one order of magnitude."[23] Stated simply, the NYSEARCH Study demonstrates that the AMLD methodology is not as accurate as using high volume samplers to measure the flow rate of specific leaks from specific types of pipe materials.[24]

While AMLD is not the best tool for developing population-based emission factors for different types of pipe, the NYSEARCH Study[25] noted that a previous report indicated that with repeated passes, mobile technologies such as AMDL can be useful in quantifying overall system emissions:

> *"Adam Brandt et al (ii) have shown that more frequent surveys of gas systems even with less sensitive detection devices can substantially support methane emissions measurements. NYSEARCH data allows actual implementation of such an approach by defining quantitative uncertainties of mobile leak quantification systems in realistic conditions."*[26]

However, the level of frequent surveying suggested by Adam Brandt et al was not performed for the Weller Study.

Third, the Weller Study has limited data from only four cities, not the 13 cities from across the country in different geographic areas that are included in the Lamb Study. The results from those four cities were extrapolated to construct nationwide assumed emissions rates. This lack of geographic diversity can introduce significant bias. The study also did not consider differences between urban, suburban, and rural areas.

Fourth, the Weller Study exhibited a high degree of uncertainty. The Weller Study showed that the AMLD methodology was unable to document a high degree of correlation between field results and control test results. There were two to three orders of magnitude difference in flow rates between the author's predicted emission rates and confirmed actual emission rates during in-field validation studies. These validation studies were carried out using tracer-ratio methods, enclosure, and high-volume sample methods, and controlled metered releases.

Fifth, the Weller Study did not distinguish between biogenic and thermogenic sources of methane. This means the Weller Study may have included emissions from landfills, wetlands, sewers, and other biogenic sources rather than only leaks from the natural gas distribution systems, thereby inflating emissions and leak rates.[27]

Finally, the Weller emission factors derived from the Weller Study are unreliable because the Weller Study methodology used minimal verification for leak locations. During the field campaign, the authors assumed that a leak indication within 40 meters of a pipeline must be a leak associated with the distribution pipeline – considering the wind direction measured at the vehicle. The study design did not consider the possibility of a different wind direction at the actual location of the leak or the effect of obstructions (such as trees or structures) between the vehicle and the actual leak location. These are commonly encountered phenomena for leak detection in the natural gas distribution industry, particularly when using AMLD.

The Weller Study clearly does not provide a rational basis in the rulemaking record for EPA to revise its national default emission factors so that lower-emitting cathodically protected steel mains appear to emit more than cathodically unprotected steel gas distribution mains. Such a revision would undermine efforts to reduce actual emissions by making it appear – inaccurately – that replacing protected steel with unprotected steel would reduce emissions when the evidence shows the reverse is true.

To provide more accurate emissions reporting and to incentivize actual methane emission reductions, EPA should adopt the Lamb Study emission factors in the Subpart W Reporting Rule, as it did for the annual national GHG Inventory.

EPA has asked whether it should adopt the emission factors for gas distribution developed in the Lamb Study, which EPA already uses in the annual GHG Inventory, for reporting emissions with default emission factors under Subpart W. The Associations believe this is entirely appropriate because EPA already uses the Lamb Study emission factors in its annual GHG Inventory and because it is the best basis available at present for default national average emission factors.

First, the Lamb Study reduced uncertainty through direct measurements, using a high-volume sampler methodology, which is the appropriate approach for measuring flow rates from leaks and developing emission factors for specific types of pipe materials. The Lamb Study methodology involved delineating the parameters of a leak using standard leak detection technology, covering and sealing the leak area with a tarp, and connecting a high-volume sampler to measure the flow rate of the leak. This is a highly accurate method for measuring leak flow rates, as EPA has recognized by including it in a limited list of proposed direct emissions measurement methods.

Second, the Lamb Study included nationwide data from 13 cities across the country in different climates and with a variety of distribution system configurations more representative of gas utilities nationwide. The distribution systems studied were geographically diverse and included dense urban areas as well as suburban and rural areas. The Lamb Study database of 13 cities is clearly more representative than the Weller Study that only included four cities.

Third, the Lamb Study methodology verified leak locations. Unlike the Weller Study, the Lamb Study verified leak locations before measurement by using standard, reliable leak detection methods to identify the exact area of a leak. This further helped reduce uncertainties.

Fifth, the Lamb Study research team verified pipe material and distinguished between cathodically protected and cathodically unprotected steel pipe. Because operators assisted the authors of the Lamb Study in allowing site access, providing pipe asset and operations information, and following up on leak measurements by excavating the leak locations and conducting repairs, the authors were able to view the pipe, verify the pipe material and the presence or absence of cathodic protection, and report back to the research team. This prevented confusion between cathodically protected and unprotected steel pipe that is a weakness of the Weller Study.

For the foregoing reasons, The Associations urge EPA to adopt the Lamb Study emission factors and leak frequency data – which the agency has already adopted in the annual GHG Inventory –

as the new default population-based emission factors for gas distribution mains and services for Subpart W. This will promote consistency between Subpart W and the GHG Inventory and will improve the accuracy of reported emissions.

Footnotes:

[12] Direct Measurements Show Decreasing Methane Emissions from Natural Gas Local Distribution Systems in the United States | Environmental Science & Technology (acs.org), Lamb et al., *Environ. Sci. Technol.* 2015, 49, 8, 5161–5169, (hereinafter, Lamb Study).

[13] A National Estimate of Methane Leakage from Pipeline Mains in Natural Gas Local Distribution Systems | Environmental Science & Technology (acs.org), Weller et. Al, *Environ. Sci. Technol.* 2020, 54, 14, 8958–8967 (hereinafter, Weller Study).

[14] Harrison et al., GRI-EPA, "Methane emissions from the Natural Gas Industry" (June 1996) (hereinafter, 1996 GRI-EPA Study).

[15] Weller Study, Section 2.2, p. 8960.

[16] Ersoy, Adamo, "Quantifying Methane Emissions from Distribution Pipelines in California," Final Report (Sept. 2019) ("CARB-GTI Study").

[17] Id. p. 1. *See* also p. 13 and Appendix A.

[18] Id, at p. 1.

[19] Higher emitting leaks in the distribution context are typically orders of magnitude lower than the "super emitters" in upstream operations, such as from stuck dump valves on separation tanks. This is reflected in the relatively low percentage of emissions from gas distribution as compared to other sectors of the natural gas supply chain. For example, EPA's Inventory of GHG Emissions and Sinks (1990-2020) published in April 2022 indicates that emissions from gas distribution in the U.S. contributed only 8.4 % of emissions from the natural gas sector. *See* AGA's analysis in "Understanding the EPA GHG Inventory," p. 9, https://www.aga.org/research/reports/epaupdates-to-inventory-ghg/.

[20] The AMLD technologies evaluated in the NYSEARCH Study are described in D'Zurko and Mallia, "Measurement Technologies Look to Improve Methane Emissions," Pipeline & Gas Journal (Feb. 2018) at 55, https://pgjonline.com/magazine/2018/february-2018-vol-245-no-2/features/measurement-technologies-look-toimprove-methane-emissions.

[21] https://www.nysearch.org/white-papers/Validation-Methods-for-Methane-Emissions-Quantification-Technologies-Final.pdf (Oct. 2020) (hereinafter NYSEARCH Study).

[22] Id. P. 2.

[23] NYSEARCH Study, p. 1 referencing Figure 1.

[24] Id.

[25] NYSEARCH Study p. 5.

[26] Id at 5, quoting Chandler E. Kemp, Arvind P. Ravikumar, and Adam R. Brandt "Comparing Natural Gas Leakage Detection Technologies Using an Open-Source "Virtual Gas Field" Simulator" Environ. Sci. Technol. 2016, 50, 4546−4553.

[27] *See* Weller Study, section 2.2, p. 8960, noting that the authors "used the methane concentration data to develop NG leak indications consisting of the location of a potential leak and an estimate of its size. These data products were derived from the survey data using a set of data-processing algorithms, described in work of Weller et al. 2019." The reference in footnote 19 of the Weller Study leads to section 4.2 of the 2019 Weller et al. study, which states in paragraph 4 of section 4.2: "First, we do not distinguish between thermogenic and biogenic CH4 sources, but this capability could be added by analyzing both CH4 and ethane concentrations. There is no reference to using methane to ethane ratios in the Weller Study published in 2020.

Response 4: We acknowledge the comments related to the Weller et al. (2020) study and note that we have not maintained the use of these study data to inform the final subpart W pipeline mains and services emission factors.

For above grade transmission-distribution transfer stations, the existing rule provides for the use of default emission factors for quantifying component-level emissions. These emissions are then used to develop a meter/regulator run population emission factor. The meter/regulator run population emission factor is then applied to the above grade metering-regulating stations that are not required to be surveyed. We are finalizing, as proposed, to provide the ability for local gas distribution companies to use measurements to inform the component-level emissions at above grade transmission-distribution transfer stations and thus, inform the above grade metering-regulating station emission estimates. In this final rule we are providing the ability for local gas distribution companies to use facility-specific factors for above grade stations.

We considered providing an analogous option for the below grade stations to that which is available for the above grade stations. We did not propose and are not finalizing the measurement option for below grade stations in this rulemaking, but we may consider adding this approach in the future. The emissions from below grade stations are expected to be much lower than those from above grade stations and so the overall impact in terms of accuracy to facility-level estimates is expected to be minimal. We also note that providing additional options further complicates both the regulatory language and our ability to verify emissions. We are finalizing the default population emission factors for below grade stations based on the Lamb study, as proposed.

We have addressed the reasons for not finalizing a facility-specific emission factor development approach for pipeline mains and services in the response to Comment 3 in this section of this document.

We are also finalizing the default population emission factors for pipeline mains and services based on the combination of Lamb et al. and GRI/EPA, as proposed. Concerning the comments that EPA should base the population count emission factors on the Lamb study data only, we disagree. As described in the TSD for the final rulemaking, the GRI/EPA equivalent leak data was used because the Lamb study utilized the same method as GRI/EPA for determining the number of equivalent leaks and the resulting incident rate between the studies was similar. Further, using this combined dataset provides consistency with the GHGI.

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Comment 5:

Commenter 0412: Direct measurement is the only method with enough accuracy and specificity to enable effective methane emission abatement programs for gas distribution networks.

a. Emission factor-based emission estimates are inaccurate because of limited sampling.

Several scientific studies have shown that leak sizes vary on a large spectrum and that larger leaks dominate emissions across multiple gas asset families including distribution pipelines[1,2] . Measurements performed by Picarro on more than 4 million sources within distribution systems around the globe have confirmed this behavior (see Figure 1 below).

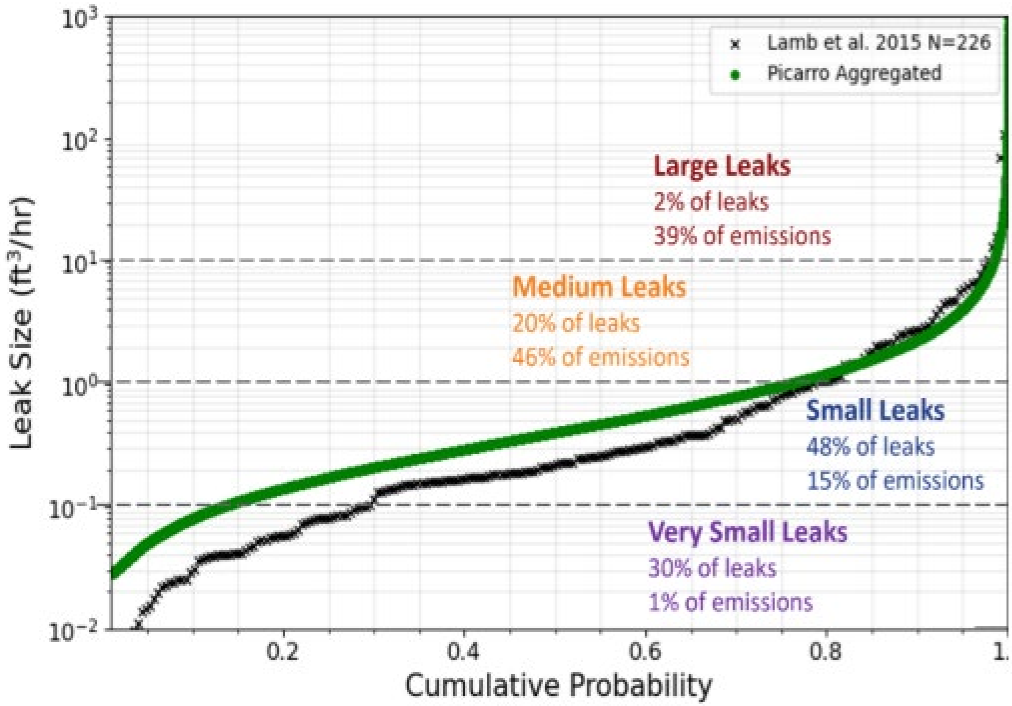
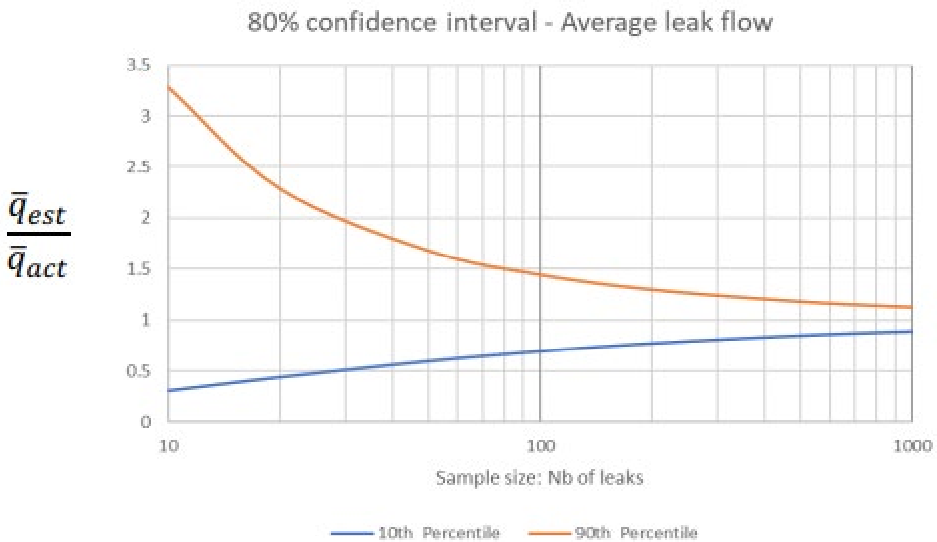


Figure 1: This chart displays the results of Brian Lamb's study along more than 4 million methane detections quantified by Picarro with its customers worldwide.

The extreme variation in leak sizes impedes accurate estimation of average flow rates using a constrained sample size. A lognormal distribution is generally considered an acceptable approximation of the distribution of leak sizes in a gas distribution network[3] . The lognormal curve can possibly under-estimate its fat-tail behavior, meaning that the true sampling uncertainty could be greater than what is currently depicted. The sampling uncertainty of a number of random measurements on a lognormal distribution is well represented by the Cox equation[4] :

$$ln(\bar{q}_{act}) = ln(\bar{q}_{est}) \pm z \cdot \sqrt{\frac{\sigma^2}{n} + \frac{\sigma^4}{2 \cdot (n-1)}}$$

Where q_{act} is the actual average flow rate, q_{est} is the average derived from the measurements, z is standard score corresponding to the confidence interval, s is the standard deviation of the log-normal distribution, and n the size of the sample. The chart below (Figure 2) displays the 80% confidence interval as a function of the sample size for the lognormal distribution fit on B. Lamb's empirical data (μ=-1.36, s=1.77). It shows that for a 50-measurement sample, the statistical uncertainty leads to the estimate average flow rate ranging from 0.6 to 1.7 times the actual value with 80% confidence.



Emission factors, such as the ones inferred from B. Lamb's study, are therefore highly uncertain because of the limited size of the measurement samples. Table 1 below shows this statistical uncertainty.

pipeline material	n	emission factor (g/min)
cast iron	14	0.90
unprotected steel	74	0.77
protected steel	31	1.21
plastic	23	0.33

Table 1: extracted from B. Lamb providing the size of the measurement sample (n) and the average flow rate for each sample (emission factor).

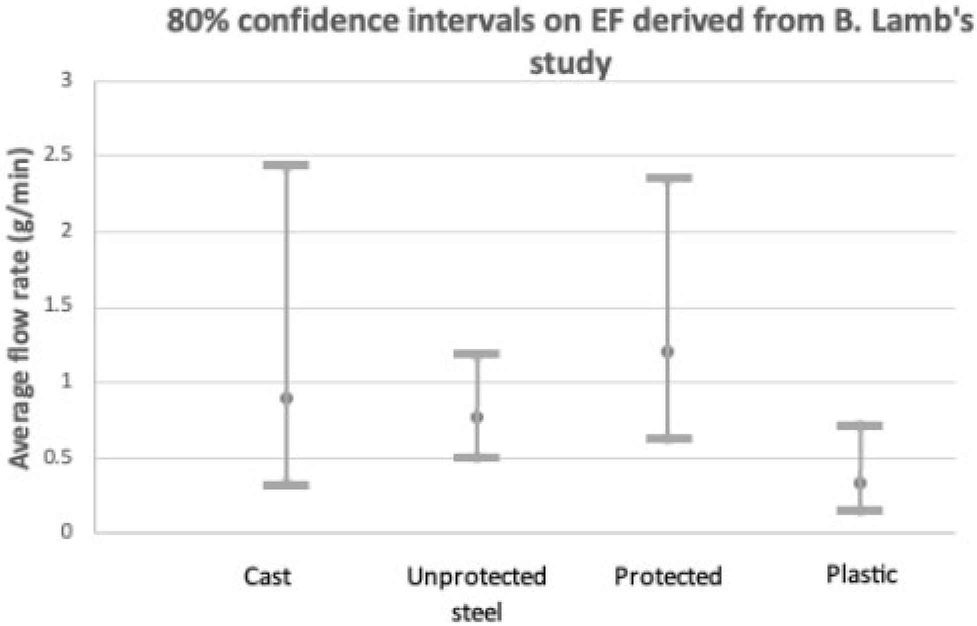


Figure 3: 80% confidence intervals for the emission factors derived from B. Lamb's study data.

Based on these data, the emission factor for cast iron pipelines has almost an order of magnitude of uncertainty with 80% confidence. Moreover, the differences between cast iron, unprotected steel and protected steel are also questionable since their confidence intervals overlap. The use of a unique emission factor across materials would likely be more representative and lead to better estimates. In conclusion, establishing meaningful emissions for specific distribution gas networks based on such emission factors is challenging.

b. Direct measurement of all leak detections leverages the large sample size to provide accurate emissions at the gas system level.

By contrast, direct measurement with AMLD systems estimates flow rates for every detection and then sums them all to quantify the overall emissions of a specific gas network. De facto, the sampling uncertainty is very tight (about 10% for 1,000 detections) or even null if these measurements are performed across the full network. In that case, the confidence interval defined in Figure 2 is the representation of the variability to expect from one reporting period to the other due to the stochastic nature of gas leaks. Therefore, the uncertainty of AMLD direct measurement-based emission calculations is limited to the leak quantification only.

Other investigators have studied AMLD quantification techniques.[5] For Picarro, the validation set include 430 controlled leaks and field tests as presented on Figure 4. The chart shows that quantification of a leak can be performed within an order of magnitude 80% of the time for flow rates spanning more than three orders of magnitude as observed on gas distribution networks. The data set is continuously expanded as new comparisons are made available.

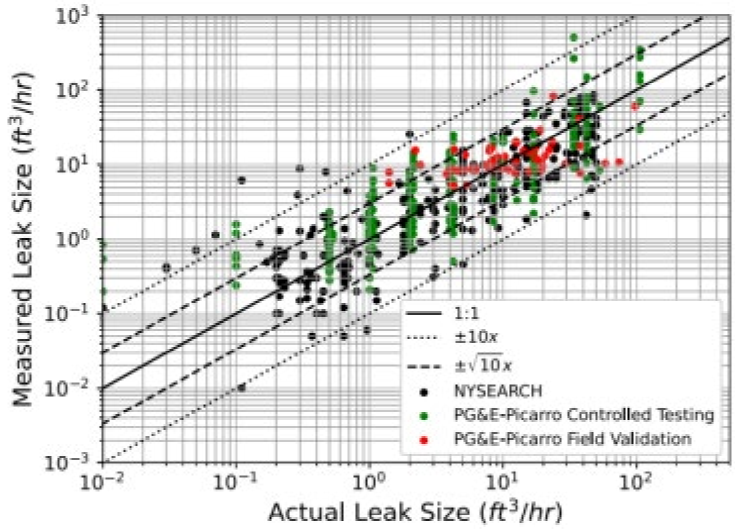


Figure 4: 1:1 comparison of actual and measured leak size using AMLD systems.

Picarro's quantification of each detection is substantially tighter than the results reported by Zachary Weller et al. using a model based only on methane concentration measurements[6]. This comparison demonstrates the value of accounting for atmospheric conditions such as wind and stability. We also noticed that Picarro's quantification models uncertainty was in line with the observations of Bradley Conrad et al for airborne systems on above-ground controlled releases covering flow rates ranging from 0.4 kg/h to 66 kg/h (i.e. 20 scfh to 3,400 scfh)[7]. Finally, AMLD leak quantification is substantially more accurate than the attempt to characterize leak size with traditional handheld detectors, as reported in D. Esroy "2019 Emission Factor Pilot Study" [3] . The accuracy of the quantification at the leak level being established, total emissions are calculated by integration over the gas networks. When doing so, one should account for the bias due to the interaction between the highly skewed leak size distribution and the fairly large and asymmetric uncertainty of leak flow rate measurements. In practice, when a leak is measured with a certain flow rate, there is a higher chance for the actual leak to be smaller rather than greater for the upper end if the distribution and the contrary for the lower end of the distribution. This bias can be addressed by a Bayesian inference as described in MacMullin and Rongere[8].

Applying this correction eliminates the bias of the measurements. The resulting uncertainty is then a random noise. Since a large number of independent measurements are made, the resulting uncertainty can be assessed using the confidence on their average:

$$\bar{q} \in \left[\bar{q}_m \cdot \left(1 - z \cdot \frac{\sigma}{\sqrt{n}}\right), \bar{q}_m \cdot \left(1 + z \cdot \frac{\sigma}{\sqrt{n}}\right)\right]$$

Where q is the actual average flow rate, q_m is the average derived from the measurements, z is standard score corresponding to the confidence interval, s is the standard deviation of the log-normal distribution and n is the size of the sample.

The current uncertainty of Picarro's AMLD quantification system expressed on the logarithm of the flow rate follows a normal distribution of parameters: μ= 0, s=0.95. For an 80% confidence interval, the measurement uncertainty can be drawn as a function of the number of leaks and compared to the sampling uncertainty (see Figure 5).

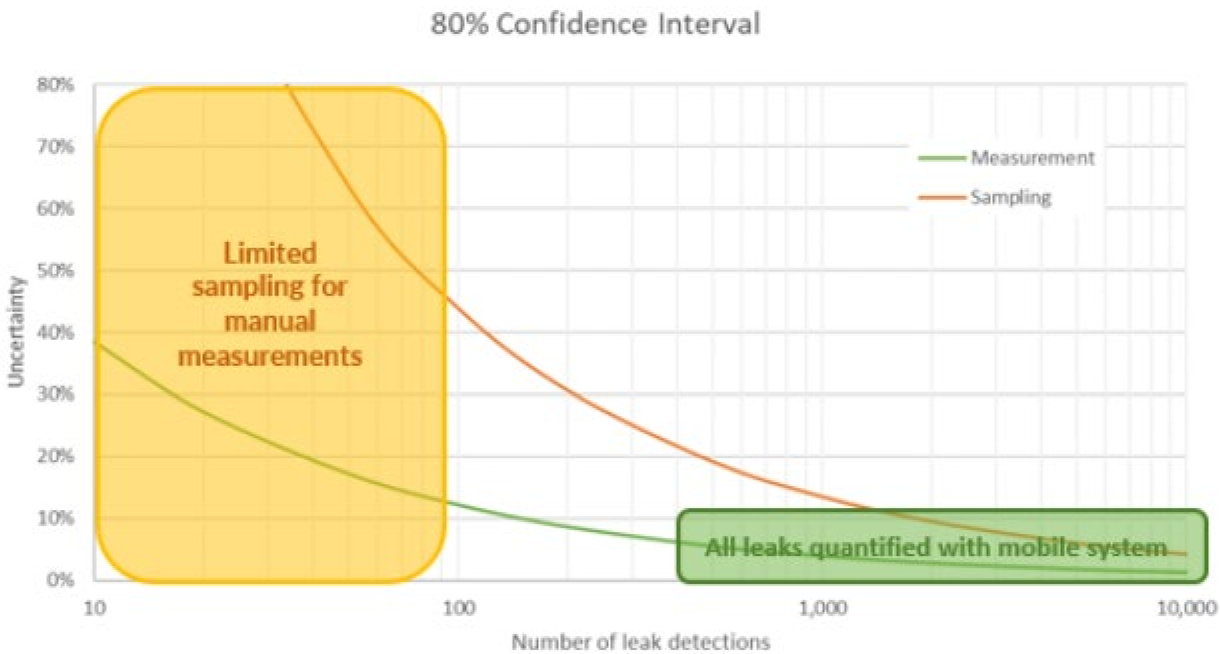


Figure 5: 80% Confidence uncertainty on the average value of flow rate from sampling and measurement in function of the sample size.

Several thousands of detections are typically quantified on a large distribution network, leading to a measurement uncertainty of less than 10% even if each measurement provides an estimate within an order of magnitude only. The measurement uncertainty of direct measurement is much less than the sampling uncertainty as observed by Matt Johnson et al.[9] using a Monte Carlo simulation.

In conclusion, direct measurement with AMLD systems provides substantially more accurate emission characterization than limited sampling used for emission factor-based calculations and should be the preferred method of emission computation and reporting.

c. The AMLD data collection process is independent of operators' practices.

PHMSA, in its recent NPRM, recognized that gas operators have inconsistent methodologies for foot survey leak detections, leading to broad variability in reporting[10]. Weller et al also mention this challenge in[11] as they attempted to reconcile vehicle-based methane detections and leak finding rates of utilities.

On the other hand, the AMLD data collection process is passive and fully automated with clear protocols that assure its accuracy independent of the workmanship and expertise of the leak surveyors. It provides a unique and easily auditable set of data that can be used by gas operators for a variety of purposes: leak detection and repair, emission calculations, reporting and abatement, resource optimization, integrity management, and pipeline replacement.

d. Direct measurement is the only method providing results specific enough to support effective emission abatement programs and assess their performance over time.

In addition to supporting emission reporting at the system level as described above, AMLD systems quantify every detection. The estimated flow rate can then be used to prioritize investigation and repair of the larger leaks in order to rapidly abate emissions without overwhelming the utility's resources, as shown by PG&E since 2018[12].

Footnotes:

[1] A. R. Brandt, G. A. Heath, D. Cooley, "Methane leaks from natural gas systems follow extreme distributions", Environmental Science & Technology 50 (2016) 12512–12520. https://pubs.acs.org/doi/epdf/10.1021/acs.est.6b04303

[2] B. K. Lamb, S. L. Edburg, T. W. Ferrara, T. Howard, M. R. Harrison, C. E. Kolb, A. Townsend-Small, W. Dyck, A. Possolo, J. R. Whetstone, "Direct measurements show decreasing methane emissions from natural gas local distribution systems in the United States", Environmental Science & Technology 49 302 (2015) 5161–5169. https://pubs.acs.org/doi/epdf/10.1021/es505116p

[3] D. Esroy "2019 Emission Factor Pilot Study" GTI Project 22509-3 Final Report August 2020

[4] U. Olsson "Confidence Intervals for the Mean of a LogNormal Distribution" Journal of Statistics Education Volume 13, Number 1 (2005)

[5] D'Zurko, D., Mallia, J., 2017. Nysearch Methane Emissions Technology Evaluation & Test Program, EPA 2017 Natural Gas STAR and Methane Challenge Annual Implementation Workshop, pp. 24–26.

[6] Zachary D. Weller, Duck Keun Yang, Joseph C. von Fischer "Sample size uncertainty. An open source algorithm to detect natural gas leaks from mobile methane survey data". PLoS ONE 14(2): e0212287. https://journals.plos.org/plosone/article?id=10.1371/journal.pone.0212287

[7] Bradley M. Conrad, David R. Tyner, Matthew R. Johnson "Robust probabilities of detection and quantification uncertainty for aerial methane detection: Examples for three airborne technologies", Remote Sensing of Environment 288 (2023) 113499. https://www.sciencedirect.com/science/article/pii/S0034425723000500

[8] Sean MacMullin, François-Xavier Rongere "Measurement-based emissions assessment and reduction through accelerated detection and repair of large leaks in a gas distribution network" Atmospheric Environment: X 17 (2023) 100201

Commenter 0412: **AMLD data collection does not require investigating or digging of leaks.**

AMLD systems automatically quantify leak emissions based on the data collected by the sensors carried by the vehicle: methane and ethane concentrations, wind direction and speed, GPS coordinates and additional information about the stability of the atmosphere. Specific details about the leak's location, the type of pipe it originates from, and the pipeline's material, are not required.

The method of emission calculation based on direct measurement proposed by Picarro considers and supports two paths:

- AMLD methane detections are followed by leak investigation to confirm the presence of a leak on a component of the operator's gas network.
- AMLD methane detections are directly used to calculate the emissions through a probabilistic model assigning the source to below-ground or above-ground natural gas assets or to third party sources.

For the second approach, the probabilistic model is validated based on the field data collected by the gas operator on a subset of the detections that are investigated. The "finding rate" provides the probability for an AMLD detection to be related to a below-ground or aboveground leak. This validation can be done within a specific gas network or across different gas networks.

As for the calculation of overall emissions as the aggregation of sources individually quantified by the AMLD, this method leverages the size of gas distribution networks and the large number of sources to assure a high level of accuracy at the system level while local detection attributions may be uncertain. Figure 6 below shows how the uncertainty associated with the probabilistic attribution of leaks to below-ground and above-ground gas assets varies in function of the number of detections.

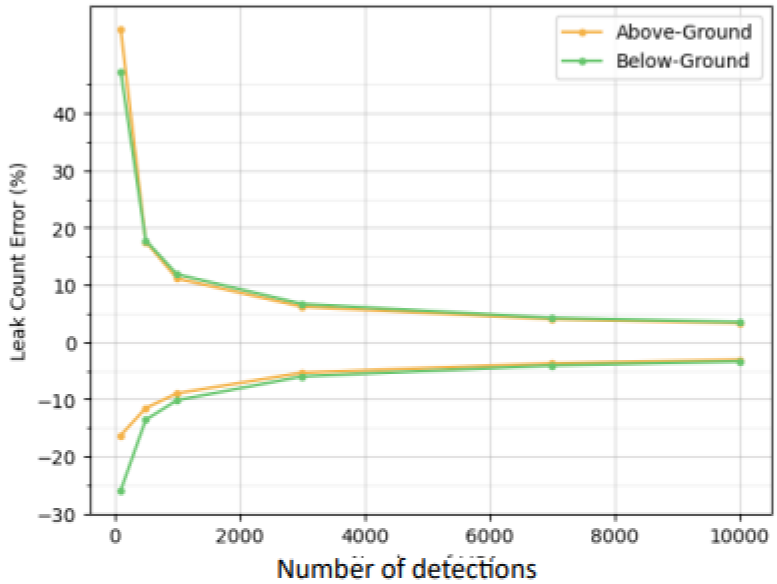


Figure 6: Leak count uncertainty (at 80% confidence) as the function of the number of methane detections.

This uncertainty is combined with the measurement uncertainty defined in §1.b to assess the overall accuracy of the measurement-based emissions calculations.

To be noted that the two paths described above can be used separately or in combination. For example, if the operator decides to investigate only but all detections greater than a defined flow rate threshold for accelerated repair as discussed above in §1.d. the first path with explicit assignment of detections to leaks will be applied to larger detections while the second path using the probabilistic assignment model will be used for the small detections that were not investigated. Here again, AMLD measurement-based emission calculation maximizes effectiveness by aligning closely with the characteristics of gas system leakage where a small number of larger leaks dominate overall emission justifying a focus effort on each of them while the contribution of the vast majority of sources, even altogether, is very marginal and for which a statistical approach is more effective.

On the other hand, emission-factor based calculations, since they are defined by specific attributes of gas assets such as type, material, vintage, construction methods, etc. require the association of each source with such assets. This cannot be achieved without digging out most of leak locations as reported by GTI during field studies for CARB in 2014 and 2015[13] and for the DOE in 2019[14]. This requirement of systematic excavation of leak locations to assign emissions to the right asset category is another key limitation of emission-factor based calculations.

Footnotes:

[13] D. Esroy, M. Adamo, K. Wiley "Quantifying Methane Emissions from Distribution Pipelines in California" GTI Project No. 22504 September 2019.

[14] C. Moore "Classification of Methane Emissions from Industrial Meters, Vintage vs Modern Plastic Pipe, and Plastic-lined Steel and Cast-Iron Pipe" GTI Project No. 22070 June 2019

Commenter 0412: **AMLD data collection is a cost-effective solution for more frequent leak survey needed to substantially reduce methane emissions without overwhelming operators' resources.**

Figure 7 demonstrates the importance of accelerating leak survey frequency to support substantial emission abatement of distribution networks. With a traditional survey frequency of 5 years, 80% of emissions come from unknown leaks. Accelerating the frequency to 3 years marginally improves the visibility of the network emissions with about 70% of emissions. Annual surveys reduce the operators' blind spot to less than 33% and therefore increase the effectiveness of their abatement programs as mentioned by A. Ravikumar[15] using their FEAST model.

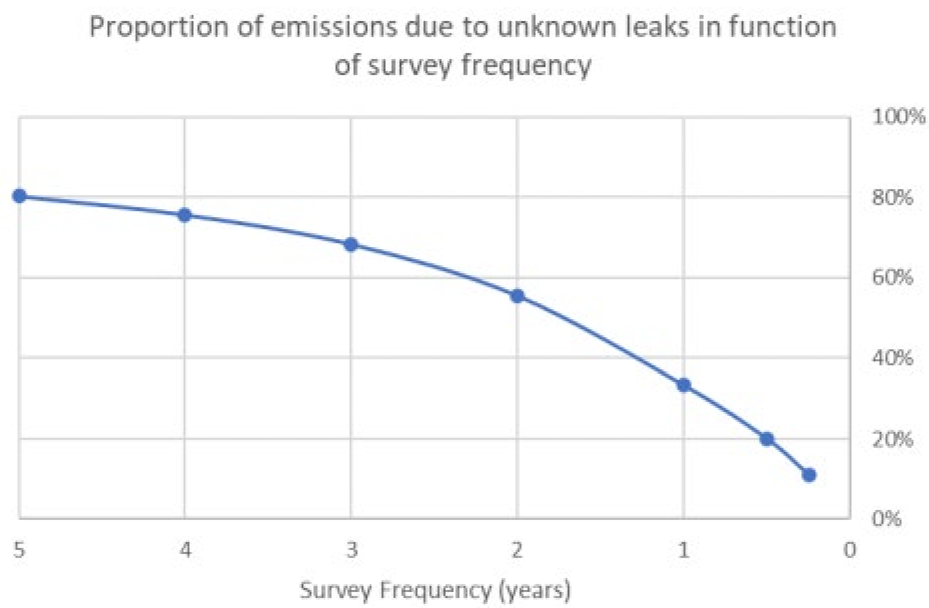


Fig 7: A simple calculation estimating the number of unknown leaks in a distribution system in function of the known leaks and the survey frequency shows that most of emissions are from unknown leaks unless the survey frequency is accelerated too annual or better.

However, scaling up gas operators' traditional leak surveys to an annual frequency or better would be ineffective in term of cost and resource allocation. AMLD data collection that is 5 to 10 times cheaper and faster than foot survey and provides flow rate quantification squarely supports this acceleration. The detections by the AMLD system can then be prioritized based on the potential leak size as discussed in §1.d or other criteria such as areas more prone to leakage before triggering the more time consuming investigation and repair operations.

Footnotes:

[15] Ravikumar, Arvind Ph.D. "FEAST-Based Evaluation of Methane Leak Detection and Repair Programs Using New Technologies." EPA Methane Detection Technology Workshop (August 24, 2021). https://www.epa.gov/controlling-air-pollution-oil-and-natural-gas-industry/epa-methane-detectiontechnologyworkshop. Day 2 at 1:33:50

Response 5: We did not propose and are not finalizing an option for reporters to use emissions quantification data from AMLD due to lack of the necessary information for implementation of this method under Subpart W and other concerns discussed below. While we are not finalizing this screening and quantification method in this rulemaking, we are undertaking research on and exploring options for using technology for this purpose and may consider these changes in a future rulemaking.

Specifically, in a future rulemaking, the EPA would need to establish detection limits for the AMLD method. We would need to understand and be able to characterize in the regulatory text the mechanism used to convert concentration values to mass flux. Many times, these methods are proprietary to the instrument vendor presenting challenges to the development of standards that can be uniformly applied by the regulated community. For example, there appears to be variability in the performance of different AMLD instruments and/or quantification techniques. Specifically, in the TSD for this rulemaking, we evaluated validation studies conducted by the authors of the Weller *et al.* 2020 study from two publications, "Vehicle-based methane surveys for finding natural gas leaks and estimating their size: Validation and Uncertainty" (Weller *et al.*, 2018) and "Vehicle-Based Identification of Location and Magnitude of Urban Natural Gas Pipeline Leaks" (von Fischer *et al.*, 2017). These studies compared the emission rate estimated from AMLD against those determined from other standard measurement methods including the tracer-ratio method, enclosure method, and controlled metered releases. As detailed in the TSD for this rulemaking, these validations showed a positive bias in leak size in the AMLD emission estimates particularly for smaller leaks. We also found in the Weller et al. 2018 study that the AMLD method tended to provide a fairly small range of leak estimates that correlate to a much wider range of actual mass emissions. When comparing the performance of similar validation tests for the Picarro device presented in Figure 4 of the comment, it appears the Picarro device and associated quantification techniques performed better than the instrument and methods presented in the Weller *et al.* 2018 validation study. However, any future rulemaking would need to specify consistent methods for emission quantification such that the expected performance and implementation of the AMLD method results in the same expected accuracy for all reporters electing to use it.

18.3 Gathering Pipeline Emission Factors

Commenter: GPA Midstream Association
Comment Number: EPA-HQ-OAR-2023-0234-0299
Page(s): 54-55, 92-93

Commenter: Carbon Mapper and RMI
Comment Number: EPA-HQ-OAR-2023-0234-0301
Page(s): 7-9

Comment 1: Commenter 0299: **EPA should reassess the development of revised gathering pipeline emission factors.**

EPA is proposing to change emission factors for gathering pipelines in Table W-1 based on the Lamb et al. (2015) study of distribution pipelines. In particular, the protected steel emission factor is proposed to nearly double from 0.47 to 0.93 scfh/mile.

For gathering pipelines, proposed emission factors are based on using the "Average Methane Leak Rate" from the Lamb Study in place of the GRI/EPA Study. We think EPA made two incorrect judgements when assessing the data. First, there is a significant increase in the mean leak rate due to only a few measured leaks. The three largest leaks measured in the Lamb Study (unprotected steel main, protected steel main, and cast-iron main leaks) accounted for 50 percent of the total leak rate, whereas 90 percent of the measured leaks were less than approximately 3 scfh. The three largest leaks are by far outliers, and significantly increase the average emission rates for the respective material. As an example, removal of the large, protected steel leak reduces the average leak rate and emission factor by approximately 60 percent.

Second, EPA only used leak data from distribution mains in the Lamb Study and excluded leak data from services noting that "the emission factors for gathering pipelines by pipeline material are based on the leak rates for distribution mains by pipeline material."[120] GPA does not support separating mains and services when identifying emission factors based on pipeline material. Gathering pipelines are not segregated like distribution pipelines and do not carry main or service designations. As such, it is not appropriate to represent gathering pipelines with only a portion of data collected on distribution pipelines from the Lamb Study. All leak measurement data for each pipeline material should be considered given the pipeline material is the corresponding factor when applying the results of the study on distribution pipelines to develop emission factors for gathering pipelines. Additionally, the Lamb Study notes, "it was not always possible to clearly define a main versus a service leak when the leak occurred at the junction between main and service." The uncertainty distinguishing between pipeline mains and services provides more support to analyze the leak measurements from pipeline mains and services together. When data from mains and services are assessed together, the average leak rate for protected steel drops by approximately 23 percent.

…

Proposed Change: EPA is proposing to change emission factors for gathering pipelines in Table W-1A based on the Lamb *et al* (2015) study of distribution pipelines. In particular, the protected steel emission factor is proposed to nearly double from 0.47 to 0.91 scf/hr/mile.

> **Comment**: For gathering pipelines, proposed emission factors are based on using the "Average Methane Leak Rate" from the Lamb Study in place of the GRI/EPA Study. We think EPA made two incorrect judgements when assessing the data. First, there is a significant increase in the mean leak rate due to only a few measured leaks. The three largest leaks measured in the Lamb Study (unprotected steel main, protected steel main, and cast iron main leaks) accounted for 50% of the total leak rate, whereas 90% of the measured leaks were less than approximately 3 scf/hr. The three largest leaks are by far outliers, and significantly increase the average emission rates for the respective material. As an example, removal of the large protected steel leak reduces the average leak rate and emission factor by ~60%.

Second, EPA only used leak data from distribution mains in the Lamb Study and excluded leak data from services, "[T]he emission factors for gathering pipelines by pipeline material are based on the leak rates for distribution mains by pipeline material."[29] GPA does not support separating mains and services when identifying emission factors based on pipeline material. Gathering pipelines are not segregated like distribution pipelines and do not carry main or service designations. As such, it's not appropriate to represent gathering pipelines with only a portion of data collected on distribution pipelines from the Lamb Study. All leak measurement data for each pipeline material should be considered given the pipeline material is the corresponding factor when applying the results of the study on distribution pipelines to develop emission factors for gathering pipelines. Additionally, the Lamb Study notes, "it was not always possible to clearly define a main versus a service leak when the leak occurred at the junction between main and service." The uncertainty distinguishing between pipeline mains and services provides more support to analyze the leak measurements from pipeline mains and services together. When data from mains and services are assessed together, the average leak rate for protected steel drops ~23%.

Further, EPA should consider the Pipeline and Hazardous Materials Safety Administration's ("PHMSA") leak detection and monitoring requirements for gathering and boosting. There should be an opportunity to align data on leaks as an alternative to using an emission factor. This would also align with the directive in the Inflation Reduction Act to report emissions based on empirical data, where available.

Footnotes:

[120] 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 at 108.

[29] TSD at 61.

Commenter 0301: **Increasing accuracy and scope of pipeline emissions covered by GHGRP**

…

If using an equivalent leak per mile metric, we recommend Lamb et al. (2015) [9] to reflect the state of aging pipeline infrastructure. Gas infrastructure, on average, is older than when this study was conducted and prone to an increased leak rate (Pipeline Replacement Background | PHMSA (dot.gov)). Using equivalent leak data from Lamb et al. (2015) would reflect the increase in equivalent leaks per mile from the aging nationwide natural gas system. Since the 1996 EPA/GRI Study estimated transmission emission factors "based on leak measurement data collected from distribution mains," data from Lamb (2015) should be applicable to transmission pipelines as well. Ultimately, these values should be replaced with leaker emission factors or direct measurement.

Footnotes:

[9] Lamb, B.K. et al. (2015). Direct Measurements Show Decreasing Methane Emissions from Natural Gas Local Distribution Systems in the United States.' Environ. Sci. Technol. 49, 5161–5169.

Response 1: The variability in the leak measurements observed in the Lamb *et al.* study is not unusual for equipment leak data. Generally, equipment leak data are highly variable and typically exhibit lognormal distribution. We find it appropriate to include all measured data points to ensure that the representation of such variability is included in the derived emission factors. Excluding the high emission rate events would bias the emission factor low because high emission rate events can and do occur. We also note that these high emission rate events are well below the threshold of 100 kg/hr for other large release events, so we cannot exclude these events from the average emission factor on the basis that they would be covered under the other large release event provisions. Therefore, we are maintaining the complete dataset when determining the final default population emission factors for gathering pipelines.

As noted in the preamble and TSD for this rule, the current subpart W population emission factors for gathering pipelines at facilities in the Onshore Petroleum and Natural Gas Gathering and Boosting industry segment are based on leak rates from natural gas distribution companies adjusted for methane content and soil oxidation of methane and gathering pipeline-specific activity data as provided in Volume 9 of the 1996 GRI/EPA study. The 1996 GRI/EPA study authors concluded that pipe use (*i.e.*, mains vs. services) was one of several factors that influenced leak rates and this is observed in both the 1996 GRI/EPA study as well as the Lamb *et al.* study, which demonstrate that leak rates are consistently higher from distribution mains than from distribution services. We note that distribution mains carry gas between metering and/or pressure regulating stations throughout the pipeline system, while services deliver gas to meters for end use, typically at much lower pressures. The difference in function as well as operating characteristics provide a distinction for the categories of distribution pipeline. As noted by the commenter, gathering pipelines are not characterized by main or service. From an operational perspective, however, the purpose of gathering pipelines more closely aligns with distribution mains rather than services. We expect that the use of service data would bias the emission factors low and not be representative of the emissions from gathering pipelines. Therefore, consistent with the use of the data by in the 1996 GRI/EPA study (*i.e.*, use of distribution mains data combined with gathering pipeline-specific data) in the development of the current gathering pipeline default population emission factors, we are maintaining the approach of combining distribution main leak rates from the Lamb *et al.* study with gathering pipeline-specific activity data from the 1996 GRI/EPA study.

Lastly, in reviewing the data reported to PHMSA in Form PHMSA F 7100.2-3 it is unclear how this data would be used as suggested by commenters. In the annual reporting form, gathering and boosting facilities report pipeline mileage and then separately report the total number of leaks eliminated or repaired during the calendar year by cause (*e.g.*, external corrosion, internal corrosion, construction, incorrect operations). Gathering and boosting facilities also report the number of known leaks at the end of the year that are scheduled for repair. The PHMSA data are informative for understanding overall leak rates for gathering pipelines (*i.e.*, the number of leaks on average per total mile of gathering pipeline). However, the reported data do not include the leak detection survey method utilized, leak quantification, or the pipeline materials associated with the leak which would be necessary to evaluate the appropriateness of potentially deriving default leaker or population emission factors for gathering pipelines.

Commenter: MiQ
Comment Number: EPA-HQ-OAR-2023-0234-0392
Page(s): 5

Commenter: Environmental Defense Fund, et al.
Comment Number: EPA-HQ-OAR-2023-0234-0413
Page(s): 43-47

Comment 2: Commenter 0392: Preamble III.Q-3 - Gathering pipeline emission factors: We are seeking comment on the EPA's decision not to use the Yu et al. study data in developing proposed population emission factors, including rationale supporting the EPA's decision or rationale for why this study should be used in developing proposed population emission factors. Additionally, we are seeking comments on whether there are other published studies the EPA should evaluate for potential use in developing revised emission factors for gathering pipelines.

MiQ Comments: We believe that EPA's decision to not use the study data in Yu et al. is erroneous and should be reconsidered. Current gathering pipeline emission factors are generally based on the 1996 GRI/EPA report assessment of distribution pipelines, which are arguably also not nationally representative and include zero data from actual gathering pipeline assets that are operated entirely differently than distribution pipelines. We agree that using Yu et al. alone to derive an updated national emissions factor will likely not result in nationally representative emission factors. All recent studies involving research around gathering pipeline emissions have been completed for specific regions or basins. Other studies that EPA should evaluate include Li et al. (2019)[2], focused on the Appalachian, San Juan and Piceance Basin and Zimmerle et al. (2017)[3] focused on gathering pipelines in the Fayetteville Shale.

Footnotes:

[2] Pekney, Natalie J, Li, Zhongju, Mundia-Howe, Mumbi, and Reeder, Matthew D. 2019. "Gathering Pipeline Methane Emissions in Appalachian/San Juan/Piceance Basin Using Unmanned Aerial Vehicle and Mobile Sampling". United States. https://www.osti.gov/servlets/purl/1604876.

[3] Zimmerle et al. "Gathering pipeline methane emissions in Fayetteville shale pipelines and scoping guidelines for future pipeline measurement campaigns." 2017. Elementa: Science of the Anthropocene. 1 January 2017. doi: https://doi.org/10.1525/elementa.258

Commenter 0413: **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.

Distribution and gathering pipelines are not interchangeable

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 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]

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 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 km1 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 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.

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.

<u>Replacement is not the only solution</u>

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.

Footnotes:

[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)

[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-transmissiongathering-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&disposit ion=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.

[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.

[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 Gas 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).

Response 2: As noted in Section III.Q of the preamble to the final rule and the response to Comment 1 in this section of this document, the EPA is finalizing population emission factors for gathering pipelines based on the Lamb *et. al* study, as proposed. The EPA undertook an initial review of the gathering pipeline studies cited by the commenters, including any supplemental information provided by the authors. While the studies do indicate the existence of additional data, it is not yet clear how the information would best be used for development of a nationwide emission factor. For example, Commenter 0413's assessment of the information presented in their Table 6 includes some of the questions that would need to be resolved for development of a nationwide emission factor (*e.g.*, why the derived emission factor for the Uinta basin is much greater than the other basins). We will continue to review available literature, including the studies cited by the commenter as well as any new studies that are released, and may consider such information for a future rulemaking, which would provide the opportunity for public comment and review of the calculations used to derive a proposed revised population emission factor for gathering pipelines.

Commenter: Kairos Aerospace
Comment Number: EPA-HQ-OAR-2023-0234-0240
Page(s): 14-16

Commenter: Carbon Mapper and RMI
Comment Number: EPA-HQ-OAR-2023-0234-0301
Page(s): 7-9

Commenter: MiQ
Comment Number: EPA-HQ-OAR-2023-0234-0392
Page(s): 5

Commenter: Bridger Photonics, Inc.
Comment Number: EPA-HQ-OAR-2023-0234-0407
Page(s): 8

Comment 3: Commenter 0240: Gathering Pipeline Emission Factors

EPA is requesting comment on the capabilities of today's commercial methane detection technologies to identify and measure emission specifically from gas gathering pipelines. Not only are aerial systems proven as effective methane detection tools, they have extensive records of field deployment within the gas pipeline industry, and particularly in the gathering segment in recent years. Kairos alone has surveyed over 500,000 miles of gas pipelines for the midstream industry, and has helped oil and gas industry clients eliminate 75 billion cubic feet of methane leaks from their systems.

The Kairos system is currently being used by midstream operators of all sizes to comply with the Type C annual leakage survey requirements contained within the PHMSA Mega Rule. Kairos has developed Operator Qualification protocols for our leakage survey work to ensure the highest possible standards of safety and quality are maintained. Aerial methane leak surveys, like that offered by Kairos, are highly effective, widely adopted by the industry, and remarkably cost-effective.

The capability of remote sensing technologies to measure gas pipeline emissions is also well-documented within the scientific literature. Both the Chen et al. and Sherwin et al. works referenced in Sections II. and III. of this comment letter examined the contribution of emissions from midstream assets.

The authors of Chen et al. found that of the 194 tonnes per hour (t/h) of observed methane emissions in that 2019 study of the New Mexico Permian Basin, 29 t/h was attributed to pipeline emissions, and 26 t/h was attributed to compressor stations, or 15% and 13% of total emissions, respectively. This amount of aircraft-identified emissions provides strong indication that remote sensing systems can be highly effective leak quantification tools.

We note that aerial methane leak detection services are deployed widely across the midstream industry today, and our technology routinely detects methane emissions from underground leaks. Using these measurement-based approaches to examine gas pipeline emissions would undoubtedly provide a better picture of emissions than EPA's proposed emission factor-based approach.

EPA also requests information on the possible scope and frequency of gas pipeline surveys. While we cannot speak to the full costs and benefits EPA must weigh to reach a decision here, we are able to offer this: from a scaling perspective, the measurement industry today already has the capacity to survey all the nation's 400,000 miles of gas gathering infrastructure on a yearly or even more frequent basis. In 2022, Kairos alone flew 163,728 miles of gas gathering lines, nearly half of the nation's entire gathering pipeline footprint. Again, Kairos is a leader in this industry but is far from the only company capable of surveying gas gathering pipelines, and the combined industry clearly has capacity today to regularly survey large swaths of our oil and gas infrastructure.

EPA also solicits comment on how to utilize the Yu et al. study mentioned in the Proposed Rule. EPA's proposal concludes that it will not use the study due in large part to its limited geographical scope. We question this assertion, because EPA is instead proposing to use a single emission factor that clearly will also be limited in its geographic scope. The very same reasoning that makes the Yu study unsuitable in EPA's eyes holds true for the premise that one emission factor can represent the nation's entire pipeline system.

There are other sources of information in the scientific literature that EPA could consider in its efforts to quantify pipeline emissions. For example, the Sherwin et al. study referenced earlier looked at pipeline emissions across 15 aerial campaigns covering multiple basins. The study found pipeline emissions range from 1% of total basin emissions in Carbon Mapper's 2021 DJ Basin campaign, to 33% of emissions in Carbon Mapper's 2020 San Joaquin Basin campaign. The Supplemental Information from Sherwin et al. is attached in Appendix A and the analysis of pipeline contributions is attached in Appendix B.

The wide variability in pipeline emissions makes clear that EPA's effort to create a single unifying national emission factor will likely be fruitless. A single emission factor would also create a static emission rate that would not be updated regularly, like you would have with a measurement-based approach. It would also penalize companies that are investing in emission reductions, since their emission factors wouldn't change even when they implement advanced leak detection programs. Instead, EPA should consider if the commercially available measurement systems on the market today could be utilized to better improve the Gas Pipeline reporting category.

References:

Chen, Y., Sherwin, E.D., Berman, E.S.F., Jones, B.B., Gordon, M.P., Wetherley, E.B., Kort, E.A., Brandt, A.R., 2022. Quantifying Regional Methane Emissions in the New Mexico Permian Basin with a Comprehensive Aerial Survey. Environ. Sci. Technol. 56, 4317–4323. https://doi.org/10.1021/acs.est.1c06458 (hereinafter, "Chen et al. 2022").

Sherwin, Evan, Yuanlei Chen, Arvind P. Ravikumar, and Adam R. Brandt, "Single-Blind Test of Airplane-Based Hyperspectral Methane Detection Via Controlled Releases," Elementa Science of the Anthropocene, 2021 ("Sherwin et al. 2021").

Commenter 0301: **Increasing accuracy and scope of pipeline emissions covered by GHGRP**

…

For gathering lines, EPA should use direct measurement screening surveys, ideally conducted at a weekly cadence, to ensure large leaks are captured from this source type and supplement bottom-up approaches. Studies find that gathering and transmission line emissions are dominated by super-emitting events. [8] Advanced technologies with high spatial and temporal coverage, such as aircraft and satellites, can facilitate weekly screening surveys at the 100 kg/hr level for pipelines. Remote sensing technologies are already used in this manner by some operators, and it is a safe, cost-effective tool to ensure fast identification and remediation of pipeline super-emitters.

Footnotes:

[8] Modeling Leak Detection and Repair Programs for Natural Gas Pipeline Infrastructure Using FEAST by Arvind P. Ravikumar et al. at UT Austin (August 2023) conducted FEAST modeling with an additional super-emitter distribution derived from Cusworth et al. 2021.

Commenter 0392: We do not believe that national emission factors based on pipeline type are the most accurate way to estimate methane emissions from gathering pipelines at an individual operator level. Although a number like this can be used as a baseline, for operators to be able to more accurately quantify emissions, measurement data from these assets must be used to both develop an estimate and assure that estimate is reasonable. Therefore, we propose that for operators of gathering pipeline sites they should be required to perform at least 1 annual leak detection survey on all of their gathering pipeline assets, and quantify emissions from detected sources using either the rate algorithm provided by the leak detection technology or engineering calculations using methodologies similar to orifice calculations.

Commenter 0407: **Allow operators to use direct measurements to report gathering pipeline emissions.**

The Proposed Rule relies entirely on emissions factors for reporting gathering line emission and lacks the option to use direct measurements to demonstrate reduced emissions. These leaker emission factors come from a limited dataset, may not be representative,[16] and are not company specific. We urge the EPA to give operators the option to use monitoring and measurement surveys to report these emission instead, as is generally allowed for other equipment leaks in the Proposed Rule. The EPA should harmonize gathering pipelines emissions reporting with other EPA and PHMSA provisions by allowing operators to use OOOOb compliant advanced technology, subpart W compliant monitoring and measurement methods, and suitable technologies used for proposed PHMSA gas pipeline leak screening requirements as the basis for emissions reporting.[17,18] Doing so would be inline with the IRA intention of allowing operators to submit empirical data to demonstrate their methane emissions.

We urge the EPA to allow operators to submit direct measurement data to demonstrate methane emissions from their natural gas gathering lines.

Footnotes

[16] "Methane Emissions from Natural Gas Gathering Pipelines in the Permian Basin". https://doi.org/10.1021/acs.estlett.2c00380.

[17] https://www.bridgerphotonics.com/sites/default/files/inline-files/230815_Bridger_Photonics_Comment_Letter_PHMSA_Gas_Pipeline_LDAR_NPRM.pdf

[18] 88 FR 31890

Response 3: See Section III.Q.3 of the preamble to the final rule for the EPA's response to this comment.

Commenter: EnerVest Operating, LLC
Comment Number: EPA-HQ-OAR-2023-0234-0229
Page(s): 4-5

Commenter: Independent Petroleum Association of America (IPAA)
Comment Number: EPA-HQ-OAR-2023-0234-0265
Page(s): 15

Commenter: Diversified Energy Company
Comment Number: EPA-HQ-OAR-2023-0234-0267
Page(s): 2, 4

Commenter: American Exploration and Production Council
Comment Number: EPA-HQ-OAR-2023-0234-0295
Page(s): 26

Commenter: GPA Midstream Association
Comment Number: EPA-HQ-OAR-2023-0234-0299
Page(s): 54-55

Commenter: Carbon Mapper and RMI
Comment Number: EPA-HQ-OAR-2023-0234-0301
Page(s): 7-9

Commenter: CrownQuest Operating
Comment Number: EPA-HQ-OAR-2023-0234-0393
Page(s): 291

Commenter: The Petroleum Alliance of Oklahoma
Comment Number: EPA-HQ-OAR-2023-0234-0398
Page(s): 18

Comment 4: Commenter 0229: Gathering Pipeline Emission Factors

- These pipelines are routinely inspected. Pipeline mileage alone accounts for a large portion of methane estimates in the gathering and boosting sector. Pipelines are inspected routinely, leaks are fixed, and emissions are eliminated. Only emissions found should be used for any waste tax calculation; not simply based upon miles of pipeline for which the vast majority are not leaking. We believe there should be a way to prove that there are no leaks, and where leaks are identified, the emissions be based on the leaks found. In essence, the agency has provided no manner for the company to address this potential issue and therefore has put companies in an unfair position to pay a waste tax where there is no waste.
- As noted in the proposed rule: "*The major finding of this study is that gathering pipelines have highly skewed emissions data distribution with very large leaks that only occur every few hundred miles. Finally, our assessment is that this study is geographically limited and are concerned that an emission factor derived with these study data may not*

be nationally representative. Additional discussion of the Yu et al. study, including population emission factors developed using study data as they compare to subpart W, is included in the subpart W TSD, available in the docket for this rulemaking (Docket Id. No. v). We are seeking comment on the EPA's decision not to use the Yu et al. study data in developing proposed population emission factors, including rationale supporting the EPA's decision or rationale for why this study should be used in developing proposed population emission factors. Additionally, we are seeking comments on whether there are other published studies the EPA should evaluate for potential use in developing revised emission factors for gathering pipelines."

- *Footnote: "GRI/EPA. Methane Emissions from the Natural Gas Industry, Volume 9: Underground Pipelines. Prepared for Gas Research Institute and U.S. Environmental Protection Agency National Risk Management Research Laboratory by L.M. Campbell, M.V. Campbell, and D.L. Epperson, Radian International LLC. GRI–94/0257.2b, EPA– 600/R–96–080i. June 1996. Available in the docket"*

- - As is indicated, pipeline leaks are easily detected through:
  - Regular inspection via ariel, easement riding and operator inspections. Arguably, these have lower detection limits based on the type of technology used.
  - Larger leaks can easily and quickly be determined by sudden drops in production. The pipeline can be isolated, and the volume of gas lost can easily be determined with great accuracy.

- We propose three methods of determining pipeline factors/credit for inspection:
  - Pipeline flyovers have a lower detection limit BUT do detect methane. If no leaks are found, then no emissions factor should be used for that segment and there should be no waste tax or emissions calculated
  - Similarly, when laser-based & acoustic based technology is employed while riding the pipeline easement, leaks are detected. If no leak is detected, then no waste tax or emission factor should be used; effectively 0.0. If a leak is found, then the actual leak can be measured, or an emission factor should be developed. This is currently allowed in the detection of fugitives, and we argue this should be the case for pipelines.
  - Finally, an OVA based emission factor should be developed to account for leaks detected in this manner.

Commenter 0265: Gathering and Boosting Emissions Factor Issues

A consistent criticism of the current emissions estimation process for gathering and boosting operations relates to its use of emissions factors based on the mileage of pipelines. These factors cannot be altered based on any operational actions other than changing the nature of the pipeline material or structure. These factors from 1996 are unchanged in this proposal despite studies showing that pipeline emissions are overestimated. The consequence of this failure will be to impose the harshest excess emissions tax on this essential component of the natural gas value chain without providing any plausible recourse to alter the emissions calculations. This inaction by EPA flies in the face of its mandate to make the Subpart W emissions estimate more accurate, more reflective of actual operations.

Pipelines are inspected routinely, leaks are fixed, and emissions are eliminated. Only actual emissions should be reported under Subpart W and used for any excess emissions tax calculation; not simply based upon miles of pipeline for which the vast majority are not leaking. There should be an option to demonstrate that emissions are being managed, to show that there are no leaks, or, where leaks are identified, the emissions be based on the leaks found.

Pipeline leaks are easily detected through regular inspection using airborne overflights, easement riding and operator inspections. Arguably, these have lower detection limits based on the type of technology used. Larger leaks can easily and quickly be determined by sudden drops in production. The pipeline can be isolated, and the volume of gas lost can easily be determined with great accuracy. Following are some options to determine pipeline factors and credit for inspection:

Pipeline flyovers have a lower detection limit but do detect methane. If no leaks are found, then no emissions factor should be used for that segment and there should be no excess emissions tax or emissions calculated.

Similarly, when laser-based and acoustic based technology is employed while riding the pipeline easement, leaks are detected. If no leak is detected, then no excess emissions tax or emission factor should be used. If a leak is found, then the actual leak can be measured or an emission factor should be developed. This is currently allowed in the detection of fugitives and a comparable approach for pipelines can be developed.

Commenter 0267: Specific Proposed Rules Which Stifle Technology or Disincentivize Emission Reduction

EPA Requested Comments on Methods to Quantify Emissions from Pipeline Leaks

As proposed, gathering lines, when surveyed for leaks using accepted technologies that meet the performance requirements of the existing Subpart W Monitoring and QA/QC requirements rules found at 40 CFR 98.234 or proposed detection thresholds for the current proposed Quad Ob rulemaking, would not benefit from any reported emission reduction. The default leak factors which are dated and not company-specific, would be used, and the reported emissions using default factors would be used as a basis for calculation of the methane tax under the MERP. This approach would both dis-incentivize voluntary surveys of gathering lines and not meet the IRA requirement of being empirically based.

A Leaker Emission Factor approach is appropriate for gathering pipelines surveyed according to schedules. EPA should use a scheme which mirrors the leaker factor approach and in doing so would meet the intention of the IRA by being empirically based.

Requested Action: Establish a leaker-factor approach for gathering lines.

Commenter 0295: **Gathering Pipelines**

AXPC has concerns that EPA continues to use an emission factor for gathering pipelines based on the material and miles of the pipe. Rather AXPC supports the use of EPA's leaker emission factor approach when the pipeline is surveyed using accepted technologies that meet the performance requirements of the existing Subpart W Monitoring and QA/QC requirements found at 40 CFR 98.234 or proposed detection thresholds for the current proposed OOOOb rulemaking. Making the standards performance-based, as outlined in the proposed OOOOb rulemaking, is important because it allows technology to advance without a cumbersome AMEL approval process.

EPA can use a scheme which mirrors the leaker emission factor approach for estimating emissions from leaks identified at facilities. Doing so would better meet the intention of the IRA to have emissions based off of empirical data. The absence of a leaker emission factor approach would dis-incentivize voluntary leak surveys because operators would not be able to report lower empirical emissions even on a system that is demonstrated to be leak free. Alternatively, EPA can propose a control efficiency that can be applied when pipeline surveys are being conducted. Although still not perfect for pipelines without emissions identified, it will incentivize the surveys to be conducted and get emissions reported closer to an actual value.

Commenter 0299: …Alternatively, at a minimum, operators should be able apply a control efficiency to the pipeline population emission calculation if pipeline monitoring surveys are conducted. This would also align with the directive in the Inflation Reduction Act to report emissions based on empirical data, where available.

Commenter 0301: **Increasing accuracy and scope of pipeline emissions covered by GHGRP**

…

EPA should develop leaker emission factors for all pipeline types over an equivalent leaks per mile metric to capitalize on leak survey data proposed by PHMSA. As proposed, pipeline and facility emission factors would be estimated per 40 CFR 98.233(r) without the use of any empirical data. Leak surveys conducted under proposed PHMSA regulations would not be utilized to their full potential. Including empirical data would ultimately be in greater alignment with IRA goals for GHGRP Subpart W, and we encourage EPA to develop leaker emission factors and ultimately move towards direct measurement consistent with proposed 40 CFR 98.233(q)(3). Note that information for transmission pipeline leaker emissions factors may be available from the California Air Resources Board (CARB) Natural Gas Leak Abatement efforts, which has collected engineering estimates of transmission pipeline leaks from operators since 2017.

At a minimum, EPA should align leak survey guidelines for pipelines with PHMSA and reference the American Gas Association's (AGA) 2022 ANSI-GPTC-Z380 standard for survey scope and frequency for gathering, and transmission and distribution pipelines for the application of leaker emission factors once developed. We support annual surveys of the entire pipeline system, in alignment with PHMSA, over a reduced frequency survey.

Commenter 0393: The burden to require operators to perform facility specific emission factors for each type of pipeline is egregious. This pipeline systems are complex and span over miles depending on the basin. It is our opinion that representative emission factors would be more than sufficient. Most of these pipelines are of similar pipe diameter size and have similar connections/metering setups at the facilities. We would like to comment on the language of "digging down". This phrase could result in large amounts of labor costs and become quite burdensome for the operator. With so much activity in the Permian Basin in the last several years, the number of physical pipelines has grown drastically. However, as stated in our other comments in this document, operators have already taken steps to mitigate these leaks. After all, operators have great incentive to keep the product in the pipeline. We believe that flyover surveying techniques are sufficient. We have implemented them internally with great success. If an application of a leaker emission factor is approved, we as that the EPA does their due diligence with data available, so the factors are realistic.

Commenter 0398: Gathering Pipeline Emission Factors. EPA seeks comment on the scope and frequency of leak detection surveys for gathering pipelines. The Pipeline and Hazardous Materials Safety Administration (PHMSA) recently concluded a rulemaking on Gas Pipeline Leak Detection and Repair (Docket No. PHMSA-2021- 0039). Differing or conflicting requirements between PHMSA and EPA will only create confusion and noncompliance for the regulated community.

Action Requested: We request EPA review and consider the comments submitted to PHMSA on its proposed rule (Docket No. PHMSA-2021-0039) and work with PHMSA to align requirements that avoid differing or conflicting requirements.

Response 4: Many of the comments included here request that the EPA develop a leaker factor approach for gathering pipelines. As discussed in sections III.C, III.P, and III.Q of the preamble, the EPA's ability to provide default emission factors for an emission source are dependent upon the availability of representative data. Generally, in order to develop leaker emission factors, a statistically robust sampling of the emission source that is specific to the survey and measurement method(s) would need to be available. Ideally, the results would provide metadata that could be independently reviewed and evaluated. The study would also ideally assess measurement method sensitivity and uncertainty. As discussed in the preamble and TSD for the final, emission factor development for the leaker method must include an evaluation of whether providing a survey method specific emission factor is appropriate. For example, in this final rule, the EPA is finalizing a separate emission factor set for equipment leaks screened using OGI versus Method 21.

At this time, we are not aware of gathering pipeline studies that provide the necessary data to develop nationally representative default leaker emission factors for any one of the existing subpart W survey methods (*i.e.*, Method 21, OGI, infrared laser beam illuminated instrument, acoustic leak device) using existing subpart W measurement methods for quantifying identified leaks (*i.e.*, high flow sampling, calibrated bags), let alone the variety of survey methods suggested by the commenters. As described in Sections III.C and III.Q of the preamble to the final rule, we evaluated the use of empirical methods (*e.g.*, aerial surveys) for surveying and quantifying emissions from pipelines including gathering pipelines and are not including these methods in this final rule for the reasons provided in the preamble.

We note that multiple commenters also requested that EPA align with the PHMSA monitoring programs. The PHMSA program for monitoring could provide a reasonable framework for surveying of gathering pipelines, but it does not specify survey technologies or require measurement, and thus quantification of emissions. Therefore, the survey results from the PHMSA program may not prove useful for GHGRP reporting because, at this time, there are not survey method specific leaker emission factors and/or measurement methods that do not require digging down for gathering pipelines. As noted elsewhere in this document, the current subpart W measurements methods would require digging down for pipelines and we received adverse comment related to their use for pipelines and after consideration of those comments, we are not providing them as measurement options for pipelines at this time.

Concerning the comment that facilities should be able to apply a control efficiency to their population count estimates when pipeline surveys are conducted, it is unclear how the commenter is suggesting a control efficiency would be developed and applied. Again, the control efficiency would be dependent on the survey method used (size of leaks that may be detected) and the survey frequency. We do not have adequate data at this time by which to develop and implement control efficiency factors of various survey methods and frequencies.

Commenter: Carbon Mapper and RMI
Comment Number: EPA-HQ-OAR-2023-0234-0301
Page(s): 7-9

Comment 5: Increasing accuracy and scope of pipeline emissions covered by GHGRP

There is a large gap in gathering pipeline emissions reporting, resulting in significant undercounting in the GHGRP. We recognize and support EPA's efforts to update gathering line emission factors and provide alternative ways for monitoring gathering lines using more empirical data. However, there are fundamental gaps regarding how gathering lines are regulated that are resulting in large amounts of undocumented emissions.

A report by Highwood Emissions demonstrates that there are an estimated 434,000 miles of gathering lines in the U.S., yet only ~32,000 miles, 7% of total gathering lines, are subject to federal leak survey requirements.[5] Our data shows that gathering lines are a larger source of basin-wide methane emissions than EPA assumes. A peer-reviewed study, Yu et al., 2022, used Carbon Mapper remote-sensing data to recalculate gathering line emission factors in the Permian Basin as up to "14-52 times higher than the U.S. Environmental Protection Agency's national estimate for gathering lines and 4-13 times higher than the highest estimate derived from a published ground-based survey of gathering lines."[6] Even while considering only leaks large enough to be detected by remote sensing technologies, pipeline emissions in the Permian were 40 times higher than the amount reported to GHGRP. Carbon Mapper has previously reported that these surveys of the Permian Basin pipelines contributed, on average, 23% (Low: 3%, High: 45%) of the total oil and gas emissions observed.[7]

Pipeline leaks can significantly increase the true emissions intensity of natural gas and negatively impact frontline communities exposed to unprocessed natural gas, which can contain hydrogen sulfide (H2S), volatile organic compounds (VOCs), hazardous air pollutants (HAPs), and other chemicals considered harmful to human health, per the EPA's Integrated Risk Information System (IRIS). Toxicology studies by the EPA have limited data regarding the effects of this chronic low-level exposure

EPA should work to close the gathering gap by adding gathering infrastructure to GHGRP reporting requirements. Gathering lines connecting upstream and midstream facilities are sometimes owned by smaller operators not subject to GHGRP requirements. However, their emissions could be tied to GHGRP reporting by upstream or midstream operators sending gas through these pipelines. In order to incentivize monitoring of these lines and overall emissions reductions, we suggest that EPA require emission events to be reported by either the upstream or midstream operators if detected leaks exceed "other large release event" thresholds. This would be congruent with emissions reporting from contracted services by operators reporting to GHGRP.

Footnotes:

[5] Strange et al., (2022). Technical Report: Leak detection methods for natural gas gathering, transmission, and distribution pipelines. Highwood Emissions Management. https://highwoodemissions.com/wp-content/uploads/2022/04/Highwood_Pipeline_Leak_Detection_2022.pdf

[6] Yu, J et al. (2022). Methane Emissions from Natural Gas Gathering Pipelines in the Permian Basin. Environmental Science & Technology Letters. 9 (11), 969-974. https://pubs.acs.org/doi/full/10.1021/acs.estlett.2c00380

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

Response 5: The EPA acknowledges this comment; however, this comment is outside the scope of this rulemaking, as we did not reopen and are not amending the G&B facility definition. Although implementation of CAA section 136(c) ("Waste Emissions Charge") is outside the scope of this rulemaking, the EPA notes that CAA section 136(d) defines the term "applicable facility" as a facility within the following industry segments as defined in subpart W: offshore petroleum and natural gas production, onshore petroleum and natural gas production, onshore natural gas processing, onshore gas transmission compression, underground natural gas storage, liquefied natural gas storage, liquefied natural gas import and export equipment, onshore petroleum and natural gas gathering and boosting, and onshore natural gas transmission pipeline. Thus, this approach is consistent with the existing facility definitions in subpart W referenced in CAA section 136 when the statutory provision was enacted.

Commenter: GPA Midstream Association
Comment Number: EPA-HQ-OAR-2023-0234-0299
Page(s): 54-55

Comment 6: EPA should reassess the development of revised gathering pipeline emission factors.

…

As noted in Comment 16, EPA should consider the PHMSA incident reporting requirements for pipelines. There should be an opportunity to align data on pipeline leaks as an alternative to using an emission factor. For example, if an operator conducts an annual survey of pipelines using advanced screening methods or equivalent methods, that pipeline mileage should be exempt from calculation under the population factors method. This helps to ensure that pipeline emissions are not double counted under both the "Equipment Leaks by Population Count" and "Other Large Release Event" source categories, which, as this rule is proposed, they likely would be.

…

Finally, as described in Comment 20, EPA must address how reporters are to determine if a pipeline leak exceeds the thresholds of 98.233(y)(1)(ii). In other words, EPA must describe how reporters are to determine if any given individual pipeline leak exceeds the emissions calculated under 98.233(r) *Equipment leaks by population count*.

Response 6: Please refer to the responses to Comment 4 in Section 3.3, Comment 1 in Section 3.4, and Comment 3 in Section 17.3 of this document.

19 Offshore Production

Commenter: Oceana
Comment Number: EPA-HQ-OAR-2023-0234-0391
Page(s): 5-6

Commenter: Environmental Defense Fund, et al.
Comment Number: EPA-HQ-OAR-2023-0234-0413
Page(s): 71-72

Comment 1: Commenter 0391: The changes proposed by the EPA to offshore reporting requirements are unlikely to close the gap between reported and actual emissions. The main change to reporting for offshore facilities is the requirement to report emissions from "other large release events." But as the Ayasse et al. study points out, the persistence rate from offshore facilities tends to be much higher than for onshore facilities,[19] meaning that large release events are less likely to be the cause of the shortfall in reporting.

The EPA also proposes to *allow* operators to fully recalculate their emissions for the current year using the most recent BOEM methods instead of simply adjusting for operating hours. The EPA says that this would improve data quality by relying on more empirical data, but if that is the case, then the agency needs to make this change mandatory. Otherwise, there is a strong chance that producers will only follow the new procedure if it benefits them financially (i.e., they predict the calculation would be lower than they would if they calculated their emissions by adjusting their operating hours).

Footnotes:

[19] Ayasse et al., at 5.

Commenter 0413: 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.

[W]e support some aspects of these changes—including additional reporting elements under the first reporting option…

…

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.

Response 1: See Section III.R.2 of the preamble to the final rule for the EPA's response to this comment.

Commenter: Oceana
Comment Number: EPA-HQ-OAR-2023-0234-0391
Page(s): 1, 2, 3-4

Commenter: Environmental Defense Fund, et al.
Comment Number: EPA-HQ-OAR-2023-0234-0413
Page(s): 70-72

Comment 2: Commenter 0391: By failing to adequately update offshore emissions reporting requirements, the Environmental Protection Agency ("EPA") is failing to meet its mandate under the Inflation Reduction Act to ensure that reporting under the Greenhouse Gas Reporting Program ("GHGRP") and calculations of the Waste Emissions Charge "are based on empirical data, . . . accurately reflect the total methane emissions and waste emission from the applicable facilities, and allow owners and operators of applicable facilities to submit empirical emissions data."[1] The EPA is ignoring this mandate by continuing to rely on the Bureau of Ocean Energy Management's ("BOEM") Outer Continental Shelf ("OCS") Emissions Inventory, which significantly undercounts methane emissions according to several studies.

Methane is a potent greenhouse gas released into the air during offshore drilling operations. Methane can be released accidentally through leaks or purposefully through venting or flaring. According to the International Energy Agency "[t]ackling methane emissions from oil and gas operations is one of the most important measures to limit near-term global warming."[2] To help avoid the worst of the climate crisis, the EPA must act decisively to strengthen this rule by ending its reliance on BOEM's OCS Emissions Inventory, include additional top-down and direct measurements for reporting and verification, and require offshore reporters to report additional information that will assist the EPA with verifying reported data.

…

Since Subpart W was first promulgated in 2010, the EPA has instructed offshore facilities to report in accordance with the data systems used for BOEM's OCS Emissions Inventory (the OCS Air Quality System, or its predecessor, the Gulfwide Offshore Activities Data System).[6]

BOEM OUTER CONTINENTAL SHELF AIR QUALITY SYSTEM INVENTORY

BOEM's regulations state that facilities must monitor emissions and submit the information to BOEM monthly,[7] but the regulations do not detail what information facilities must collect or how they must collect it. In practice, BOEM prepares an inventory of Gulfwide emissions every three years, to align with the EPA's three-year schedule for the National Emissions Inventory.[8] This inventory, referred to as the OCS Emissions Inventory, relies heavily on emissions factors for estimating emissions, but unlike the EPA, BOEM does not include the emissions factors in regulations. Instead, BOEM historically has only made the calculation methods public when they publish a study accompanying the inventory.

BOEM's OCS Emissions Inventory was last completed with data from 2021.[9] In 2023, BOEM completed a study on the inventory with several goals, including performing quality assurance and quality control of the inventory and conducting an emissions factor comparison between the 2017 and 2021 inventories and review the EPA's recommended emissions factors to ensure the inventory is based on the latest information.[10]

The next OCS AQS Inventory will be for 2023 data since the previous inventory was delayed by one year.

…

The EPA is making significant changes to the GHGRP for onshore reporters, but by relying on BOEM's OCS Emissions Inventory is leaving a significant gap in this update. While the EPA does propose one significant positive change to offshore reporting, which is to require reporting of emissions from "other large release events," this change is insufficient to close the gap in reported versus actual emissions found in several studies. The EPA should be applying the onshore reporting requirements to offshore facilities. If, however, the EPA believes that the onshore requirements would not translate well to offshore facilities, it must fully explain its reasoning and work with BOEM to update Subpart W to bring offshore requirements in line with the Inflation Reduction Act's mandate. The EPA must further update the requirements in the proposed rule to include top-down verification of reported data both offshore and offshore, and the EPA must include more requirements for direct measurement or work with BOEM and the Bureau of Safety and Environmental Enforcement ("BSEE") to require additional direct measurements, such as metering of vented and flared emissions at more facilities. The EPA must also include further requirements for verification of reported data from offshore producers by requiring producers to submit additional data reported to BOEM, such as the amount of flared and vented emissions for facilities that are required to install meters.

I. THE EPA'S PROPOSED CHANGES DO NOT MEET ITS MANDATE UNDER THE INFLATION REDUCTION ACT

By relying on BOEM's OCS Emissions Inventory for the reporting requirements for offshore facilities without a full assessment of the program's calculation methods, the EPA has failed to meet its mandate under the Inflation Reduction Act. The EPA must update the proposed rule to require the same reporting for onshore and offshore facilities or fully explain why it cannot do so. If the EPA believes it cannot finalize the same requirements offshore as it does onshore, the agency must work with BOEM to ensure that reporting requirements for offshore facilities meet the requirements of the Inflation Reduction Act.

In the Inflation Reduction Act, Congress mandated that the EPA achieve three goals with this rulemaking. The reporting of methane and calculation of the waste emissions charge must (1) be "based on empirical data"; (2) "accurately reflect the total methane emissions and waste emissions from applicable facilities"; and (3) "allow owners and operators of applicable facilities to submit empirical emissions data . . . to demonstrate the extent to which a charge . . . is owed." [13]

For purposes of the proposed rule, the EPA stated that empirical data means "data that are collected by conducting observations and experiments that could be used to accurately calculate emissions at a facility, including direct emissions measurements, monitoring of CH_4 emissions (e.g., leak surveys) or measurement of associated parameters (e.g., flow rate, pressure, etc.), and published data."[14]

To address the mandates of Congress, the EPA has proposed several significant changes to subpart W. The EPA proposes to add additional reporting categories for subpart W to address gaps in emissions. The EPA is also updating its calculation methodologies to improve the accuracy of reported emissions and requiring additional information from producers to improve verification of reported data.

Unfortunately, most of the changes the EPA is making are not being applied to offshore reporters. Instead, the EPA is violating Congress' mandates by relying on BOEM's OCS Emissions Inventory without any analysis as to whether BOEM's data achieves the goals of the Inflation Reduction Act. The EPA is proposing a handful of small changes to reporting for offshore facilities. The EPA is proposing to update the GHGRP regulations to reflect changes to BOEM and its regulations. The EPA is also proposing two changes for reporters in the years between OCS Emissions Inventories. First, the agency proposes to require reporters to submit two new data elements, (1) operating hours for the current year and (2) operating hours for the year of the OCS Emissions Inventory, in an effort to improve verification of reported data. Second, the agency proposes to provide an alternative to the current operating hours adjustment, which is simply to allow operators to fully recalculate their emissions for the current year using the most recent BOEM methods. The EPA expects that this option would improve data quality by relying on more empirical data.[15]

But the EPA's proposal faces a major flaw. The OCS Emissions Inventory has been found by several studies to undercount methane emissions. And the changes proposed by the EPA are unlikely to remedy the shortcoming.

Footnotes:

[1] 42 U.S.C. § 7436(h).

[2] INT'L ENERGY AGENCY, FINANCING REDUCTION IN OIL AND GAS METHANE EMISSIONS: A WORLD ENERGY OUTLOOK SPECIAL REPORT ON THE OIL AND GAS INDUSTRY AND COP28 (June 2023), https://www.iea.org/reports/financing-reductions-in-oil-and-gas-methane-emissions.

[6] Mandatory Reporting of Greenhouse Gases: Petroleum and Natural Gas Systems, 75 Fed. Reg. 74,458, 74,466 (Nov. 30, 2010).

[7] 30 C.F.R. § 550.303(k); 30 C.F.R. § 550.303(g).

[8] BUREAU OF OCEAN ENERGY MGMT., OUTER CONTINENTAL SHELF AIR QUALITY SYSTEM (OCS AQS): YEAR 2021 EMISSIONS INVENTORY QUALITY ASSURANCE/QUALITY CONTROL (QA/QC) STUDY 1 (March 2023), https://espis.boem.gov/Final%20Reports/BOEM_2023-023.pdf.

[9] *Id*.

[10] *Id*. at 2.

[13] 42 U.S.C. § 7436(h).

[14] 50,286.

[15] 50,354.

Commenter 0413: **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 underestimated. 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 CH4 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.

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 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.

Footnotes:

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-plumesusing-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.

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).

[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-plumesusing-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-fromspace/.

[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/studiesdevelopment-plan-2023-2024.

Response 2: The EPA thanks the commenters for their feedback. The EPA notes that the newly finalized reporting element in 40 CFR 98.236(s)(1), BOEM Facility ID(s), will create a definitive and direct crosswalk with BOEM's dataset, not only improving our verification of the data, but also creating a direct association of GHGRP facilities with all of the data that BOEM collects. Regarding revisions made to direct reporters to use BOEM methods to calculate emissions every year as the primary calculation method, please see Section III.R.2 of the preamble to the final rule for the EPA's response to this comment. The EPA also intends to continue to consider information discussed in these comments in future updates to the reporting rule.

Commenter: Offshore Operators Committee (OOC)
Comment Number: EPA-HQ-OAR-2023-0234-0409
Page(s): 6

Comment 3: Section/Paragraph Reference: §98.232(b)

Proposed Text: (b) For offshore petroleum and natural gas production, report CO_2, CH_4, and N_2O emissions from equipment leaks, vented emission, and flare emission source types as identified by Bureau of Ocean Energy Management (BOEM) in compliance with 30 CFR 550.302 through 304 and CO_2 and CH_4 emissions from other large release events. Offshore platforms do not need to report portable emissions.

Comment: OOC recommends the proposed regulatory text be modified as follows:

For offshore petroleum and natural gas production, report CO_2, CH_4, and N_2O emissions equipment leaks (fugitive sources as defined by Bureau of Ocean Energy Management (BOEM)), vented emission, and flare emission source types as identified by BOEM in compliance with 30 CFR 550.302 through 304 and CO2 and CH4 emissions from other large release events not otherwise accounted for in the source types listed above. Offshore platforms do not need to report portable emissions.

Rationale: The addition of "fugitive sources" aligns with BOEM's source descriptions and improves clarity for the regulated offshore community.

Additionally, see recommendations in [comment on 98.236(y)].

Response 3: See Section III.R.2 of the preamble to the final rule for the EPA's response to the comment regarding the addition of "fugitive sources." See the response to Comment 4 in Section 3.2 of this document for the EPA's response to comments on other large release events at offshore production facilities.

Commenter: Offshore Operators Committee (OOC)
Comment Number: EPA-HQ-OAR-2023-0234-0409
Page(s): 6-7

Comment 4: Section/Paragraph Reference: §98.233(s)(1)(i)

Proposed Text: (i) For any reporting year that does not coincide with a BOEM emissions inventory data collection year, report the most recent published BOEM emissions inventory data referenced in 30 CFR 550.302 through 550.304. Adjust emissions based on the operating time for the facility relative to the operating time in the most recent published BOEM emissions inventory data.

Comment: OOC recommends the proposed regulatory text be modified as follows:

(i) For any reporting year that does not coincide with a BOEM emissions inventory data collection year, report the most recent reported ~~published~~ BOEM emissions inventory data referenced in 30 CFR 550.302 through 550.304. Adjust emissions based on the operating time for the facility relative to the operating time in the most recent published BOEM emissions inventory data.

Rationale: The OOC agrees with and supports these requirements except that we recommend that EPA replace "published" with "reported" to avoid delays from BOEM issuing a published emissions report for offshore. The delay in BOEM publishing data has at times exceeded a year. BOEM's Air Quality System (AQS) reporting system has integrated QA/QC functions that assure data quality at the time of report submittal.

In addition, EPA allows the use of "reported" data for GHG reporting during BOEM reporting years. Therefore, this recommendation also increases consistency during BOEM non-reporting years.

Response 4: The EPA thanks the commenter for their suggestion. However, after revising the final text from proposal after consideration of other comments, the language that is being finalized no longer uses the phrasing in question.

Commenter: Offshore Operators Committee (OOC)
Comment Number: EPA-HQ-OAR-2023-0234-0409
Page(s): 1

Comment 5: The OOC appreciates EPA continuing to align with the Bureau of Ocean Energy Management (BOEM) methodology and reporting frameworks for the offshore sector. We look forward to working with the agency on the important issues included in our comments as the rule is developed, published, and finalized. OOC requests a meeting with EPA staff, after the comment period closes, to review the attached technical comments, and answer any clarifying questions the agency may have regarding the information provided here.

Response 5: The EPA thanks the commenter for their feedback.

Commenter: Offshore Operators Committee (OOC)
Comment Number: EPA-HQ-OAR-2023-0234-0409
Page(s): 5-6

Comment 6: Section/Paragraph Reference: §98.230(a)(1)

Proposed Text: This source category consists of the following industry segments:

(1) Offshore petroleum and natural gas production. Offshore petroleum and natural gas production is any platform structure, affixed temporarily or permanently to offshore submerged lands, that houses equipment to extract hydrocarbons from the ocean or lake floor and that processes and/or transfers such hydrocarbons to storage, transport vessels, or onshore. In addition, offshore production includes secondary platform structures connected to the platform structure via walkways, storage tanks associated with the platform structure and floating production and storage offloading equipment (FPSO). This source category does not include reporting of emissions from offshore drilling and exploration that is not conducted on production platforms.

Comment: OOC supports the current definition of "offshore facility" as written at the time the Inflation Reduction Act was passed.

Response 6: The EPA acknowledges the commenter's support of the proposed revisions.

Commenter: Oceana
Comment Number: EPA-HQ-OAR-2023-0234-0391
Page(s): 6

Comment 7: Regardless of whether the EPA relies on BOEM's OCS Emissions Inventory or sets its own emissions factors, it should look at all the data that facilities are required to report to BOEM and/or BSEE to determine if any of the data may be useful for verification of reports submitted under the GHGRP, such as the data from flare/vent meters. This kind of data can help ensure the accuracy of data submitted under the GHGRP, and the EPA must include it in its final rule.

Response 7: The EPA thanks the commenter for their feedback. We note that the newly finalized reporting element in 40 CFR 98.236(s)(1), BOEM Facility ID(s), will create a definitive and direct crosswalk with BOEM's dataset, not only improving our verification of the data, but also creating a direct association of GHGRP facilities with all of the data that BOEM collects. Beyond that, the EPA may consider this suggestion in future rulemaking updates.

20 Combustion Equipment

20.1 Clarifications of Calculation Methodology Applicability

Commenter: Alaska Oil and Gas Association (AOGA)
Comment Number: EPA-HQ-OAR-2023-0234-0241
Page(s): 2-3

Commenter: Marcellus Shale Coalition (MSC)
Comment Number: EPA-HQ-OAR-2023-0234-0275
Page(s): 5

Commenter: Williams Companies, Inc.
Comment Number: EPA-HQ-OAR-2023-0234-0394
Page(s): 13

Commenter: Downstream Natural Gas Initiative
Comment Number: EPA-HQ-OAR-2023-0234-0396
Page(s): 3-4

Commenter: Offshore Operators Committee (OOC)
Comment Number: EPA-HQ-OAR-2023-0234-0409
Page(s): 14

Comment 1: Commenter 0241: EPA should define "pipeline quality gas" for 40 C.F.R. 98.233(z).

Combustion emission units located within the Onshore Petroleum and Natural Gas Production and Onshore Petroleum and Natural Gas Gathering and Boosting sectors have the potential to use the 40 C.F.R. 98 Subpart C combustion calculation methodology if the fuel used meets certain criteria. The criteria are as follows from proposed 40 C.F.R. 98.233(z)(1):

(1) If a fuel combusted in the stationary or portable equipment meets the specifications of paragraph (z)(1)(i) of this section, then calculate emissions according to paragraph (z)(1)(ii) of this section.
(i) The fuel combusted in the stationary or portable equipment is listed in Table C-1 of subpart C of this part or is a blend in which all fuels are listed in Table C-1. If the fuel is natural gas or the blend contains natural gas, the natural gas must also meet the criteria f paragraphs (z)(1)(i)(A) and (B) of this section.
(A) the natural gas must be of pipeline quality specification.
(B) the natural gas must have a minimum higher heating value of 950 Btu per standard cubic foot.[1]

The first criterion (A) is that the natural gas must be of "pipeline quality specification." There is currently no definition of "pipeline quality specification" within Subpart W or Subpart A of Part 98. For clarity, that term should be defined.

AOGA proposes EPA adopt the following definition for "Pipeline Quality Natural Gas":

Pipeline Quality Natural Gas means a naturally occurring mixture or process derivative of hydrocarbon and non-hydrocarbon gases found in geologic formations beneath the earth's surface, of which its constituents include, but are not limited to, methane, heavier hydrocarbons and carbon dioxide. Pipeline quality natural gas must either be composed of at least 70 percent methane by volume or have a gross calorific value greater than 950 Btu per standard cubic foot.

This definition is based on the existing definitions of "Natural Gas" from 40 C.F.R. 98.238 and "Pipeline Natural Gas" from 40 C.F.R. 72.2, regulations which were developed for the Acid Rain Program.

The 40 C.F.R. 72.2 definition of "pipeline natural gas" is a long-standing definition within air regulations and a logical reference for these purposes. Adopting this definition would also obviate the need for the fuel specification criterion in proposed 40 C.F.R. 98.233(z)(2)(i). If a gas does not meet the specifications of pipeline quality natural gas, then it is necessarily field gas, and the operator would continue to calculate combustion emissions according to Subpart W methodology.

Footnote:

[1] Proposed 40 C.F.R. 98.233(z)(1)(i)(A) and (B).

<u>Commenter 0275</u>: Definitions

The MSC requests a clearer definition of pipeline-quality natural gas. The proposed rule would continue to allow engines combusting "pipeline quality" natural gas to use any Tier of Subpart C. However, the proposed rule states that for units burning fuel not of "pipeline quality" but meeting specific fuel quality conditions, the stationary combustion device may use Subpart C Tier 2 or higher. From the preamble (88 FR 50355):

"In particular, we are proposing that subpart C methodologies Tier 2 or higher may be used for fuel meeting the definition of "natural gas" in 40 CFR 98.238 if it has a minimum HHV of 950 Btu/scf, a maximum CO2 content of 1 percent by volume, and a minimum CH4 content of 85 percent by volume. We are not proposing to amend the existing provisions in 40 CFR 98.233(z)(1) that allow the use of any subpart C calculation methodology for natural gas of pipeline quality specification with a minimum HHV of 950 Btu/scf (other than the proposed clarifications noted earlier in this section)."

The MSC requests a definition of "pipeline-quality natural gas" and notes that the term is defined in other regulations, such as NSPS JJJJ, with a lower minimum methane content than the minimum methane content for non-pipeline quality natural gas in the proposed rule. As stated in 40 CFR Part 60 Subpart JJJJ § 60.4248:

"Pipeline-quality natural gas means a naturally occurring fluid mixture of hydrocarbons (e.g., methane, ethane, or propane) produced in geological formations beneath the Earth's surface that maintains a gaseous state at standard atmospheric temperature and pressure under ordinary conditions, and which is provided by a supplier through a pipeline. Pipeline-quality natural gas

must either be composed of at least 70 percent methane by volume or have a gross calorific value between 950 and 1,100 British thermal units per standard cubic foot."

The lower methane content proposed has many implications for reporters such as the use of Tier 2 methodology requiring periodic sampling. Therefore, it is suggested that the U.S. EPA specify what is and is not considered pipeline-quality natural gas for clarity and consistency in rule implementation. If there is a common understanding of what pipeline quality means in this context, the MSC requests a definition to improve regulatory certainty for reporters on the fuel sampling requirements.

Commenter 0394: Additionally, in its efforts to provide clarity around calculations for "field gas", the Proposed Rule creates some confusion regarding usage of Subpart C calculations reserved for pipeline quality gas. The proposed changes to 40 CFR § 98.233(z)(1) and new 40 CFR § 98.233(z)(2) confound industry's understanding of pipeline quality gas characteristics. Traditional interstate natural gas pipeline tariffs reference 1,150 Btu/scf as the expected maximum higher heating value (HHV) limit[32] with an acceptable CO2 content between 2% and 4%.[33] Rather than creating a new set of gas quality parameters in 40 CFR § 98.233(z)(2), Subpart W should simply define pipeline quality natural gas in 40 CFR § 98.238 and regulate reporters' usage of Subpart C calculations based on that definition. Natural gas not meeting that definition of pipeline quality gas should be required to utilize equations in Subpart W, 40 CFR § 98.233(z).

Williams proposes the following as a definition of pipeline quality natural gas that is broadly accepted in the industry: "pipeline quality natural gas" means (1) natural gas with a HHV between 950 and 1,150 Btu/scf, and (2) maximum CO2 content of 4%.

Footnotes:

[32] Natural gas with a HHV 1,150 Btu/scf tends to have a higher concentration of natural gas liquids that have a higher heat content and a lower CH4 content. The upper limit of 1,150 Btu/scf negates the need for the proposed minimum CH4 content (e.g. 85%) as it is an indirect and imprecise measure of maximum heat content.

[33] MICHELLE MICHOT FOSS, INTERSTATE NATURAL GAS – QUALITY SPECIFICATIONS & INTERCHANGEABILITY", CENTER FOR ENERGY ECONOMICS, UNIVERSITY OF TEXAS AT AUSTIN (December 2004).

Commenter 0396: EPA proposes the quantification and reporting of combustion slip from Subpart W facilities that currently report combustion emissions in Subpart C or Subpart W. In addition, EPA has proposed new methane slip estimation methods for Subpart W that are based on the quality of natural gas combusted. If gas is of pipeline quality and meets specific content requirements (HHV > 950 btu/scf, CH4 vol% minimum of 85%, and/or CO2 vol% maximum of 1%) then an operator may elect to utilize performance test data, manufacturer provided data or a default emission factor.

The distribution segment currently reports combustion emissions under Subpart W, and thus would be subject to this revision in the rule. To reduce any possible confusion, DSI requests that

EPA further define "pipeline quality", or specify that pipeline gas meeting the HHV, CH_4, and CO_2 content requirements noted above meets the definition of "pipeline quality".

Commenter 0409: **Section/Paragraph Reference:** GHGRP Technical Support Document; 14.2

Also reference section of preamble that discusses pipeline quality gas …

Proposed Text: "Stakeholders have expressed several concerns about these provisions, and one concern in particular is evaluated and analyzed in this TSD. Reporters have indicated in questions submitted to the GHGRP Help Desk that the term "pipeline quality" is not defined in Subpart W, but pipeline quality specifications vary across the U.S. depending on the requirements of the pipeline used to transport the gas."

Comment: OOC does not recommend using the term "pipeline quality gas" in any part of Subpart W for the reasons stated in the Technical Support Document. We support the continued use of the term "natural gas" in Tables C-1 and C-2. Table C-1 and Table C-2 reference natural gas only. These tables do not differentiate pipeline quality gas.

The definition of "Natural gas" in Subpart W reads "may be field quality, pipeline quality, or process gas". Therefore, the use of the term "natural gas" is appropriate.

Response 1: See Section III.S of the preamble to the final rule for the EPA's response to comments regarding a definition of pipeline quality natural gas.

Commenter: American Petroleum Institute et al. (Part 1 of 2)
Comment Number: EPA-HQ-OAR-2023-0234-0402
Page(s): 63

Comment 2: The Industry Trades appreciate that EPA intends to provide clarity on when reporters can use subpart C calculation methodologies instead of Subpart W, including defining the applicable gas quality. However, EPA has not provided sufficient information to justify the composition threshold of natural gas in determining between use of Subpart C or Subpart W calculation methodologies. EPA, in the TSD-W, concluded that the appropriate threshold criteria for use of subpart C includes a natural gas composition of 85% CH_4, but this threshold does not appear to represent any national or basin-wide average of the composition of fuel gas. EPA must provide additional information regarding the election of the 85% CH_4 composition threshold as a criteria for use of Subpart C methodologies.

Response 2: See Section III.S.1 of the preamble to the final rule for the EPA's response to this comment.

Commenter: CrownQuest Operating
Comment Number: EPA-HQ-OAR-2023-0234-0393
Page(s): 296

Comment 3: Changing the definition of "field gas" seems unnecessary. The language in the rule is not how field gas is used.

Response 3: The EPA did not propose and is not taking final action in this rule on revising a definition of "field gas." The commenter did not provide further details or rationale for their objection to the proposed revisions to 40 CFR 98.233(z)(1). The EPA is finalizing the revision of 40 CFR 98.233(z)(1) to remove the references to field gas and process vent gas and include only the characteristics for the fuels that can use subpart C methodologies, as proposed because relying on the fuel characteristics rather than the fuel name prevents confusion.

20.2 Methane Slip from Internal Combustion Equipment

Commenter: Public Hearing Transcript
Comment Number: EPA-HQ-OAR-2023-0234-0224
Page(s): 14 (Lisa Beal)

Commenter: INNIO Waukesha Gas Engines, Inc.
Comment Number: EPA-HQ-OAR-2023-0234-0343
Page(s): 4, 5-7

Commenter: Colorado Department of Public Health and Environment (CDPHE)
Comment Number: EPA-HQ-OAR-2023-0234-0373
Page(s): 4

Commenter: MiQ
Comment Number: EPA-HQ-OAR-2023-0234-0392
Page(s): 6-7

Comment 1: Commenter 0224: As an example, to estimate exhaust emissions, exhaust methane emissions from natural gas combustion, operators can use emission factors, company test data, or vendor data. INGAA also supports adding that flexibility to include measurement options at the operator's discretion.

Commenter 0343: INNIO's Waukesha is pleased that EPA recognizes default emission factors should be required where fuel quality varies.

…

In reference to language in section [ref. 50357] of the proposed ruling that discusses the three subpart W industry segments reporting combustion emissions into subpart W, INNIO's Waukesha agrees that there are several recent studies that have examined combustion emissions at Onshore Petroleum and Natural Gas Gathering and Boosting facilities demonstrating that a significant portion of emissions can result from unburned CH4 entrained in the exhaust of natural gas compressor engines (also referred to as "combustion slip" or "methane slip").

As the largest global manufacturer of rich-burn or stoichiometric natural gas-fueled internal combustion engines, and in response to EPA's request to resubmit relevant comments submitted in 2022, the content in italics below is a resubmission of INNIO's Waukesha comments regarding Proposed Rule – Revisions and Confidentiality Determinations for Data Elements Under the Greenhouse Gas Reporting Rule, Docket ID No. EPA-HQ-OAR-2019- 0424 as these comments remain relevant and now pertain to III. Proposed Amendments to Part 98, S. Combustion Equipment, 2. Methane Slip from Internal Combustion Equipment:

Comments submitted on October 5, 2022:

INNIO's Waukesha comments pertain specifically to EPA's proposed revisions to subpart W, outlined as follows:

- INNIO's Waukesha agrees with EPA's finding that there is methane combustion slip from all compressor engine types at oil and gas facilities throughout the natural gas supply chain, and that combustion slip is dependent on the type of engine, not the application.
- Current subpart W methodologies do not distinguish between rich-burn and lean-burn engines and are significantly underestimating methane emissions from natural gas combustion from compressor engines.
- INNIO's Waukesha supports EPA's proposal to use subpart W specific methane emission factors and combustion efficiency values by engine design class (e.g., 2- stroke lean-burn, 4-stroke lean-burn, 4-stroke rich-burn) in a proposed new Table W-9 and revised Equation 39-B. These proposed revisions to the subpart W methodology are more representative of operational emissions and would improve the accuracy of emissions data submitted to EPA. INNIO's Waukesha supports EPA's conclusion that the proposed approaches incorporate the best available data and emission factors. As shown in the table below, the proposed 4-stroke lean burn and 4-stroke rich burn emission factors are in good agreement with data taken in the INNIO's Waukesha engine laboratory under tightly controlled conditions with quality-controlled measurement systems.
- All engine original equipment manufacturers (OEMs) have their own proprietary tools to provide predicted performance information for equipment operating under site conditions. OEM tools allow producers and operators to apply for emission permits using the OEM provided data on criteria pollutant emissions. In addition to criteria pollutants, INNIO's Waukesha has provided CH4 emissions data since 2013 for currently manufactured engine models—and is the only engine OEM that provides CH4 emissions data. The process for obtaining emissions and performance data as inputs into the performance prediction tool involves months of running the engine in an engine test laboratory environment, under a range of speeds, loads, ambient temperature & humidity, simulated elevation, and fuel quality. The data needs continuous checking for data quality and completeness and is processed with Design of Experiments software to feed into INNIO's Waukesha engine performance prediction tool. The process is sufficiently time

consuming and costly that INNIO's Waukesha offers this for currently manufactured engines only.

- INNIO's Waukesha findings indicate the CH4 emissions from both its rich-burn and lean-burn models are within ±15% of the proposed emission factors as shown in Table 1 below.

Engine Type	*Table W-9 Emissions Factor (kg CH4/MMBtu)*	*INNIO's Waukesha EngCalc Calculated Emissions Factors (kg CH4/MMBtu)*	*% Difference*
4SLB	*0.522*	*0.469*	*-10%*
4SRB	*0.045*	*0.041*	*-10%*

As supported by the comments above submitted in 2022, INNIO's Waukesha agrees with EPA's proposed default equipment specific combustion efficiency as proposed to be provided in equations W-39A and W-39B for RICE that must be used to determine emissions using the subpart W calculation methodologies per existing 40 CFR 98.233 (z) (2) (proposed 40 CFR 98.233 (z) (3)) for the three subpart W industry segments reporting combustion emissions into subpart W (Onshore Petroleum and Natural Gas Production, Onshore Petroleum and Natural Gas Gathering and Boosting, and Natural Gas Distribution). INNIO's Waukesha agrees that the fuel types covered by methods in existing 40 CFR 98.233 (z)(2) (proposed 40 CFR 98.233 (z) (3)) are highly variable in composition over the course of the year.

…

INNIO's Waukesha acknowledges, agrees, and supports EPA's proposed ruling under 2. Methane Slip from Internal Combustion Equipment [ref. 50357] as follows:

- The equations for (z)(3)(iii) utilize default efficiency percentages, or factors, provided in Subpart W. These default emission factors, developed using data from Zimmerle et al. (2019), require the reporter to select the emission factor by equipment type (e.g., 2-stroke lean-burn, 4-stroke lean-burn, 4-stroke rich-burn, or GT).
- The proposed emission factors will be published in new proposed Table W-7. INNIO's Waukesha confirmed in 2022's comments (resubmitted above), that Table W-7 emission factors are within +/- 15% of INNIO's Waukesha OEM calculated factors.
- These emission factors are more representative of operational emissions and would significantly improve the accuracy of emissions data submitted to EPA.

<u>Commenter 0373</u>: CDPHE also provides the following technical comments and recommendations.

…

- For **combustion equipment (98.233(z))**, we support the EPA's proposal to extend the more-accurate methane slip emission factors to all internal combustion equipment, and not just those that are compressor-drivers (as was previously proposed in summer 2022). We believe these emission factors more accurately quantify methane emissions from engines and turbines.
- For **combustion equipment (98.233(z)),** we support the EPA's idea of developing requirements (see page 50356) for a standardized testing program for measuring methane emissions from engines. We also support the EPA's concept of placing reporting requirements for the results of performance tests conducted by engine and turbine manufacturers.

<u>Commenter 0392</u>: Updated methane emission factors for internal combustion equipment in Table W-7

MiQ comments: We applaud EPA's proposal to, at minimum, require operators to report methane emissions from internal combustion equipment consuming pipeline quality gas using emission factors that are based on actual data taken from specific types of internal combustion engines. This update is critical to more accurate operator-level reporting of methane emissions for operators with significant usage of internal combustion engines. We also applaud EPA's decision to limit the usage of these emission factors to the consumption of pipeline quality gas. This will ensure that these emission factors are used only in situations where they are representative of real operations.

98.233(z)(4)(i) & (ii): *(4) For each natural gas-fired reciprocating internal combustion engine or gas turbine calculating emissions according to paragraph (z)(1)(ii) or (z)(2)(ii) of this section, you must determine a CH4 emission factor (kg CH4/MMBtu) using one of the methods provided in paragraphs (z)(4)(i) through (iii) of this section. If you are required to or elect to use the method in paragraph (z)(4)(i) of this section, you must use the results of the performance test to determine the CH4 emission factor.*

> *(i) Conduct a performance test following the applicable procedures in § 98.234(i).*
>
> *(ii) Original equipment manufacturer information, which may include manufacturer specification sheets, emissions certification data, or other manufacturer data providing expected emission rates from the reciprocating internal combustion engine or gas turbine*

MiQ Comments: We applaud EPA's proposal to allow operators to use more specific methods of estimating methane emissions from their operations. The difference in methane emissions estimation method from combustion equipment will significantly increase reported emissions from operators especially in the gathering & boosting, and transmission & storage segments, potentially up to an order of magnitude. For an emission source of this materiality, we believe it's critical to allow the use of site-specific methods where available. These allowances will ensure that operators have a pathway to estimate emissions from their own test data or their own manufacturer, helping to further differentiate performance on an operator level.

Response 1: See Section III.S.2 of the preamble to the final rule for the EPA's response to these comments.

Commenter: CrownQuest Operating
Comment Number: EPA-HQ-OAR-2023-0234-0393
Page(s): 305

Comment 2: This seems like a "deaggregation" of equipment type to verify data instead of having a reasonable definition of "facility".

Response 2: The EPA is finalizing multiple methodologies to measure and report emissions to the GHGRP. These additional methodologies will require RICE and GT units that were previously aggregated with units using a single common methane emission factor to be aggregated by the revised methane emission factors, which vary by unit type (e.g., 2-stroke lean-burn, 4-stroke lean-burn, 4-stroke rich burn). Allowing only units of the same type to be aggregated with a single emission factor will increase the accuracy of emission calculations and will allow the EPA to more accurately verify the reported data.

Commenter: American Exploration and Production Council
Comment Number: EPA-HQ-OAR-2023-0234-0295
Page(s): 20

Comment 3: Finally, AXPC recommends that EPA consider allowing the use of company-average emission factors derived from direct measurement in cases where the same make/model units are installed at many facilities. This would preserve the accuracy of the derived emission factors while balancing the resource burden and cost of conducting site-specific measurements at multiple locations where the same units are being installed, operated, and maintained under comparable conditions.

Response 3: The addition of direct measurement and OEM data improve the granularity and accuracy of the reported emissions. These additional methodologies apply to engines and turbines using fuels described in 40 CFR 98.233(z)(1) or 98.233(z)(2). The use of performance testing has also been expanded to fuels described under 40 CFR 98.233(z)(3). Many reporters have the same make/model of engines and turbines across all their operating areas; however, these units operate under varying conditions with varying fuel compositions. Based on our assessment of these consideration, we are keeping the use of direct measure at the facility level and not allowing aggregation of all company engines and turbines into one company level factor. This ensures the derived direct measure emission factors are appropriate and applicable to the equipment operating under the same conditions.

Commenter: EnerVest Operating, LLC
Comment Number: EPA-HQ-OAR-2023-0234-0229
Page(s): 2

Commenter: Independent Petroleum Association of New Mexico (IPANM)
Comment Number: EPA-HQ-OAR-2023-0234-0337
Page(s): 11-12

Commenter: Gas Turbine Association (GTA)
Comment Number: EPA-HQ-OAR-2023-0234-0384
Page(s): 3

Commenter: Williams Companies, Inc.
Comment Number: EPA-HQ-OAR-2023-0234-0394
Page(s): 13

Comment 4: Commenter 0229: Engine Methane Emission Factors (Slippage from Combustion)

There are currently re-proposed emission factors (TABLE W–7 TO SUBPART W OF PART 98—DEFAULT METHANE EMISSION FACTORS FOR INTERNAL COMBUSTION EQUIPMENT) for classes of engines:

- 4-Stroke Rich Burn Engines
- 4-Stroke Lean Burn Engines
- 2-Stroke Lean Burn Engines
- Gas Turbines

While we acknowledge that, due to combustion characteristics, varying concentrations of methane will be present in each type, the only existing recourse for determining methane is via emission factors for each engine.

- In addition to the proposed factors, we would like the option to use both; proposed factors or empirically measured (e.g. ASTM 6348-3 Standard Test Method for Determination of Gaseous Compounds by Extractive Direct Interface Fourier Transform Infrared (FTIR) Spectroscopy) as an alternative to empirically prove engine emission methane slip.
- As a large majority of engines are already tested for formaldehyde, we already have methane present in the dataset on a dry basis. Via the use of portable mass flow fuel meters or if possible, orifice plates, to measure fuel & thermodynamic software to determine true horsepower, operators would have sufficient data to determine emission factors of methane.
- An added advantage is that operators would be able to detect difficult-to-monitor problems such as improper pre-chamber ignition and non-complete combustion in the cylinder. The overall effect would result in cleaner burning engines as maintenance could be performed.

Commenter 0337: **40 CFR § 98.233(z) Combustion**

The Proposed Rule in § 98.233(z)(4)(i) and § 98.234(i), states performance test data can be used to calculate methane emissions from combustion provided that EPA Method 18, EPA Method 320 or ASTM D6348–12 are used. Many compressor engines are currently being tested in accordance with the requirements of 40 CFR 60 - Subpart JJJJ, and according to Table 2 of that subpart, VOC must be measured using "Methods 25A and 18 of 40 CFR part 60, appendices A–6 and A–7, Method 25A with the use of a hydrocarbon cutter as described in 40 CFR 1065.265, Method 18 of 40 CFR part 60, appendix A–6, Method 320 of 40 CFR part 63, appendix A, or ASTM Method D6348–03."

To allow for continuity in testing procedures currently in place and allowed by both the EPA and state agencies, it is requested that the hydrocarbon cutter method referenced in Table 2 and as described in 40 CFR § 1065.265 be added to the methods in § 98.234(i) to be used to measure and calculate methane emissions. Allowing this method would decrease any burden related to operators having to change test methods to comply with the proposed requirements of Subpart W.

We recommend § 98.234(i) be revised to read:

"(i) You must use any of the applicable methods described in paragraphs (j)(1) through (4) of this section to conduct a performance test to determine the concentration of CH4 in the exhaust gas. This concentration must be used to develop a CH4 emission factor (kg/ MMBtu) for estimating combustion slip from reciprocating internal combustion engines or gas turbines as specified in § 98.233(z)(4). Each performance test must be conducted within 10 percent of 100 percent peak load. You may not conduct performance tests during period of startup, shutdown or malfunction. You must conduct three separate test runs for each performance test. Each test run must be conducted within 10 percent of 100 percent peak (or the highest achievable) load and last at least 1 hour.

(1) EPA Method 18, Volatile Organic Compounds by Gas Chromatography in appendix A–6 to part 60 of this chapter.

(2) EPA Method 320, Measurement of Vapor Phase Organic and Inorganic Emissions by Extractive Fourier Transform Infrared (FTIR) Spectroscopy in appendix A to part 63 of this chapter

(3) ASTM D6348–12 Standard Test Method for Determination of Gaseous Compounds by Extractive Direct Interface Fourier Transform Infrared (FTIR) Spectroscopy (incorporated by reference, see § 98.7).

(4) 40 CFR 1065.265 Use of Flame Ionization Detector (FID) for Nonmethane cutter (incorporated by reference in Table 2 of 40 CFR 60 - Subpart JJJJ)."

Commenter 0384: **Emissions Factors from OEMs and Compliance Testing**

GTA strongly supports the inclusion of OEM (Original Equipment Manufacturer) data and source testing as a basis for emissions factors in this proposal. GTA recommends inclusion of Method 25A in addition to the allowable test methods for methane listed in §98.234.

Commenter 0394: Williams supports the ability for a reporter to use a performance (stack) test to establish a methane slip emission factor, as well as the option of using OEM data to calculate methane slip.[34] The EPA should also allow the recurring stack emissions testing commonly conducted for NSPS JJJJ and NSPS ZZZZ testing be used for methane slip performance testing as well.

Footnote:

[34] Proposed Rule, 88 Fed. Reg. at 50,356.

Response 4: See Section III.S.2 of the preamble to the final rule for the EPA's response to these comments.

Commenter: Alaska Oil and Gas Association (AOGA)
Comment Number: EPA-HQ-OAR-2023-0234-0241
Page(s): 2

Commenter: Gas Turbine Association (GTA)
Comment Number: EPA-HQ-OAR-2023-0234-0384
Page(s): 2

Comment 5: Commenter 0241: Destruction Efficiency for Turbine Compressor-Drivers.

AOGA previously commented (October 6, 2022) that natural gas turbines were not evaluated in determining the destruction efficiency for compressor drivers to determine volumetric emissions from those combustion sources. AOGA appreciates and supports the incorporated destruction efficiency for turbine compressor drivers of 0.999 (variable ?) within equations W-39A and W-39B of this proposed rule.

Commenter 0384: **Retain Turbine CH4 Default Emissions Factor of 0.001 kg CH4/MMBtu**

Gas turbines achieve combustion efficiency approaching 100% with very low levels of Unburned Hydrocarbons (UHC). When firing natural gas, the emissions are commonly measured at levels of less than 1 ppmv and are often reported as undetectable when measured during baseload gas turbine operation. Methane (CH4) emissions from a gas turbine would be a constituent of these UHC emissions.

The proposed emissions factor in Table W-7 of 0.004 kg CH4/MMBtu equates to approximately 7 ppmv at the gas turbine exhaust exit. This value is much higher than the emissions from a gas turbine firing natural gas fuel. Typical results from compliance tests at base load are generally less than 1 ppmv of UHC (THC) emissions, of which 50-90% may be attributed to CH4, based on typical pipeline gas having about 90% CH_4 content. Therefore, GTA recommends that the 0.001 kg CH_4/MMBtu (HHV) emissions factor for natural gas be retained as this level is an accurate and conservative representation of actual CH_4 emissions, corresponding to about 2.4 ppmv UHC (~2.2 ppmv CH_4).

Response 5: The EPA acknowledges the commenter's support for incorporating a destruction efficiency of 0.999 for turbine compressors burning fuels described in 40 CFR 98.234 (z)(3) and electing to use equations W-39A and W-39B. We do not agree with retaining the default emission factor of 0.001 kg CH_4/MMBtu. After reviewing the data supplied in the subpart W TSD, available in the docket for this rulemaking, Docket Id. No. EPA-HQ-OAR-2023-0234, the emission factor of 0.004 kg CH_4/MMBtu more accurately describes the emissions for the fuels outlined in sections 40 CFR 98.234(z)(1) or (2). We have increased flexibility for GT emission calculations by allowing the use of OEM and direct measurement. These methodologies will allow reporters additional versatility if the default emission factors do not accurately estimate their emissions.

Commenter: GPA Midstream Association
Comment Number: EPA-HQ-OAR-2023-0234-0299
Page(s): 60

Commenter: INNIO Waukesha Gas Engines, Inc.
Comment Number: EPA-HQ-OAR-2023-0234-0343
Page(s): 4-5

Commenter: Truck & Engine Manufacturers Association (EMA)
Comment Number: EPA-HQ-OAR-2023-0234-0352
Page(s): 5

Commenter: Interstate Natural Gas Association of America (INGAA)
Comment Number: EPA-HQ-OAR-2023-0234-0387
Page(s): 6-7

Comment 6: Commenter 0299: **GPA supports EPA's proposed option allowing reporters to use OEM data to calculate and report methane slip emissions for RICE and natural gas turbine engines.**

A review of methane emissions data from engine specification sheets published by leading OEMs of RICE and natural gas turbine engines indicates that OEM equipment specification sheet data are consistent with EPA's methane emissions factors presented in Table W-7, which are in turn based on stack test data compiled and critically reviewed by various research organizations, universities, and institutions.

A review of engine specification sheets published by Caterpillar for its line of four-stroke lean-burn ("4SLB") RICE shows that methane slip emissions from these engines are estimated to range from 0.429 to 0.740 kilograms of methane per million British thermal unit ("kg

CH4/mmBtu") depending on an engine's horsepower rating and number of cylinders. A prevalent 4SLB natural gas compressor engine, the Caterpillar 3516B, has an emissions rate of 0.429 kg CH4/mmBtu at 100 percent load. These data are consistent with 0.522 kg CH4/mmBtu, EPA's emission factor for 4SLB engines presented in Table W-7 of the Rule.

Additionally, a review of engine specification sheets published by Waukesha for its line of four-stroke rich-burn ("4SRB") RICE shows that methane emissions from these engines are estimated to range from 0.041 to 0.062 kg CH4/mmBtu depending on the engine's horsepower rating and number of cylinders. A prevalent 4SRB natural gas compressor engine, the Waukesha L7042GSI, has an emissions rate of 0.041 kg CH4/mmBtu at 100 percent load. These data are consistent with 0.045 kg CH4/mmBtu, EPA's emission factor for 4SRB engines presented in Table W-7 of the Rule.

Collectively, methane emissions data from these leading OEMs of natural gas compressor engines support the concept that OEM specification data can be used by reporters to reliably estimate and report actual methane slip emissions for GHG inventory purposes.

Commenter 0343: In response to EPA seeking comments on whether OEM data is representative of field conditions, INNIO's Waukesha has concerns in two related areas: **data quality or completeness**, and the **availability of OEM data**. INNIO's Waukesha has provided CH4 emissions data since 2013 for currently manufactured engine models and is the only engine OEM that readily provides CH4 emissions data. As stated in 2022 submitted comments (and resubmitted below), the process for obtaining emissions and performance data as inputs into the engine performance prediction tool involves months of running the engine in an engine test laboratory environment, under a range of speeds, loads, ambient temperature & humidity, simulated elevation, and fuel quality. The data needs continuous checking for **data quality and completeness** and is processed with Design of Experiments software to feed into INNIO's Waukesha engine performance prediction tool.

As stated in 2022 comments (and resubmitted below), equipment used in the natural gas industry is robustly designed for long life so while EPA seeks comments on whether OEM data is "representative" of field conditions, INNIO's Waukesha has larger concerns regarding the **availability** of OEM data for all engine makes and models currently in operation throughout all relevant reporting segments. Many engines currently in operation may have been manufactured by an OEM that has ceased business operations more than 30 years ago (e.g. Enterprise, Dresser Rand, Ingersoll Rand, Worthington, and Clark).

EPA is considering proposing requirements for the OEM supplied data including defining a standardized testing program for engine families like those that underly the emissions certification process for the engine NSPS in 40 CFR part 60 subparts IIII and JJJJ (e.g., Parts 1054 and 1065). INNIO's Waukesha does not support defining a standardized testing program for engine families like those that underly the emissions certification process for NSPS in 40 CFR part 60 subparts IIII and JJJJ. Almost no stationary engines are certified, due to state and local emission requirements that are more stringent than NSPS in 40 CFR part 60 subpart JJJJ. OEM data is typically "not to exceed" since the engines are emissions compliance tested on a routine basis for the **life** of the engine. Further, it would be difficult to develop a manufacturer testing program given the potential for inconsistent fuel quality/composition across all testing programs and protocols.

Commenter 0352: **EPA Should Not Use this Rulemaking to Regulate Manufacturer Testing of Stationary Engines.**

EPA should not add new requirements for engine-manufacturer testing of engine families in this rulemaking. Such testing is outside the scope of this rule, presents issues and complications EPA has not addressed in this rulemaking, imposes costs EPA has not evaluated here, and focuses disproportionally on certified engines. EPA's current proposals to use existing OEM data and emission factors (in Table W-7) are sufficient. No additional manufacturing testing program is needed. EPA's proposal is nested under "S. Combustion Equipment, 2. Methane Slip from Internal Combustion Equipment." 88 Fed. Reg. at 50,356-57. EPA states:

[W]e are considering proposing requirements for the OEM supplied data including defining a standardized testing program for engine families similar to those that underly the emissions certification process for the engine NSPS in 40 CFR part 60 subparts IIII and JJJJ (e.g., Parts 1054 and 1065). These programs define the number of engines in a family that are required to be tested as a number (e.g., 30) or a percentage of engines produced in a year. The programs also define the methods for testing the engines (including engine load, test duration, etc.) as well as deterioration factors for adjusting for the degradation of performance that is expected over time. Alternatively, we are considering that manufacturers perform the same type of testing incorporated in proposed 40 CFR 98.234(i) for a certain number of engines in an engine family. We are seeking comments on these considerations including how the manufacturer testing program should be structured and more specifically: how many engines should be tested in an engine family; under what load(s) should the engines be tested; what testing methods should be used; what is the appropriate duration of the test; and whether a deterioration factor be included to account for degradation of performance over time. We are also considering whether to add reporting requirements for the results of performance tests conducted by manufacturers.

88 Fed. Reg. at 50,356-57.

This NPRM is not the appropriate place to conduct such an evaluation. EPA has not adequately announced its intention to adopt a new testing and reporting program for engine manufacturers. RICE manufacturers are not listed as an affected industry in the NPRM. The costs and benefits of regulating RICE manufacturing are not addressed in the NPRM or the accompanying documents in the regulatory docket.[2] EPA has not proposed to amend the NSPS, nor has it notified engine manufacturers of this issue so as to begin a conversation around amending the NSPS.

EMA and its member companies stand ready to work with the Agency to provide real-world solutions. In order to do so, we must first understand the real-world problem EPA is trying to address. EPA's assessment is that combustion slip methane emissions are a small percent of overall emissions from the petroleum and natural gas systems source categories. 88 Fed. Reg. at 50,358 ("If the amendments to combustion slip discussed in section III.S.2 of this preamble are finalized, the reported CH4 emissions from combustion are expected to increase, but we estimate the increase in total CH4 emissions from combustion devices at facilities subject to subpart W would be less than 5 percent.”). It is unclear what impact an additional OEM testing program would yield to augment the accuracy of current information. At present, this portion of the NPRM appears without a sufficient basis.

EPA should not include a new OEM testing program in this rulemaking. If EPA seeks further comment on such a program, EMA and its members welcome the opportunity to discuss the objectives of such a program and how it could be designed to prevent unintended outcomes or inconsistencies with current stationary source rules.

Footnote:

[2] EPA determined that this rulemaking is subject with CAA 307(d), which requires that the factual data on which the proposed rule is based be placed into the regulatory docket at the time of proposal, not after. 42 U.S.C. § 7607(d)(3).

Commenter 0387: EPA request for feedback on OEM data

The Proposed Rule preamble solicits feedback on criteria associated with OEM EFs[11],

“…seeking comment on whether OEM data is expected to be representative of field conditions. Further, we are considering proposing requirements for the OEM supplied data…”

INGAA member experience indicates that OEMs and third-party technology providers use standard test methods and develop technically sound EFs, ensuring that EFs / emissions data presented in engine specification sheets or other documentation are representative. Since the EFs may be guarantees, there may be a margin included which results in an EF nominally higher than expected emissions – e.g., EF includes a margin to address uncertainty, and would thus provide a conservatively high emission estimate.

Regarding related criteria or OEM requirements, these EFs should not be encumbered with additional requirements or burden within Subpart W, and the information stipulated in§98.223(z)(4)(ii) quoted above is adequate for exhaust methane EFs. No further requirements should be imposed on OEMs or third-party service providers regarding exhaust methane EFs.

Footnote:

[11] 88 Fed. Reg 50,356.

Response 6: The EPA acknowledges commenters concern with adding further regulation and testing standards on OEMs. We agree with the commenters to allow the use of OEM data and limit their applicability to RICE and GT’s combusting fuels outlined in sections 98.233(z)(1) or (2). Regulation of OEM testing procedures through subpart W is currently beyond the scope of the GHGRP and at this time will not be included in the final rule.

Commenter: CrownQuest Operating
Comment Number: EPA-HQ-OAR-2023-0234-0393
Page(s): 299, 302

Comment 7: The study being referenced is the Zimmerle study that references compressor stations but does not include smaller compressors that would be used at well sites. The smaller compressors are very common across the basin. It would be wise of the EPA to allow operators to use measured data to determine factors for these smaller engines. The natural gas emission calculations seem complicated for no reason.

…

Operators should be allowed to use OEM supplied data or utilize the already required JJJJ testing results to calculate an emission factor.

Response 7: Portable and stationary RICE and GT units outlined in section 40 CFR 98.233 (z) choose their emission measurement methodology by fuel type regardless of engine size. Units that combust fuels described in 40 CFR 98.233(z)(1) and (z)(2) can use performance testing, OEM data, or default emission factors. The use of performance testing was also finalized for units that combust fuels described in 40 CFR 98.233(z)(3).

Commenter: Marcellus Shale Coalition (MSC)
Comment Number: EPA-HQ-OAR-2023-0234-0275
Page(s): 21

Commenter: GPA Midstream Association
Comment Number: EPA-HQ-OAR-2023-0234-0299
Page(s): 59

Commenter: CrownQuest Operating
Comment Number: EPA-HQ-OAR-2023-0234-0393
Page(s): 302

Comment 8: Commenter 0275: Combustion Sources

The MSC supports the use of performance test data and manufacturer data to calculate methane emissions from internal combustion engine and turbine combustion. The MSC requests clarification that performance test data must be used if a performance test is completed during the reporting year (i.e., reporters are not required to use performance tests from historical performance testing that may have occurred more than ten years ago).

Commenter 0299: **EPA should allow for annual performance testing results instead of a one-time performance test for methane slip.**

EPA proposed a one-time performance test to establish a methane slip emission factor for engines and turbines.[137] Many of the engines and turbines, however, are already subject to annual performance testing under federal or state rules that utilize the same methodology required under the proposed rule. EPA should make clear that the operator may use the most recent performance test data to establish the methane slip emission rate since it would provide the best data and reflect current emissions. As engine and turbine technology evolves, there may be additional ancillary equipment added to an engine or turbine that may improve its emissions, and EPA should allow the operator to establish a new emission rate. This suggestion is consistent with section II.B and C of the preamble while not placing an additional burden on operators that are already completing these performance tests to comply with existing standards and regulatory requirements.

Footnote:

[137] Id. at 50,356.

Commenter 0393: EPA is proposing engine tests like JJJJ, this is duplicative as they are already required.

Response 8: See Section III.S.2 of the preamble to the final rule for the EPA's response to these comments.

Commenter: American Exploration and Production Council
Comment Number: EPA-HQ-OAR-2023-0234-0295
Page(s): 20

Commenter: GPA Midstream Association
Comment Number: EPA-HQ-OAR-2023-0234-0299
Page(s): 59

Commenter: Antero Midstream Corporation
Comment Number: EPA-HQ-OAR-2023-0234-0338
Page(s): 2-4

Commenter: Ascent Resources, LLC
Comment Number: EPA-HQ-OAR-2023-0234-0339
Page(s): 4

Commenter: Marathon Oil Company
Comment Number: EPA-HQ-OAR-2023-0234-0378
Page(s): 3-4

Commenter: Williams Companies, Inc.
Comment Number: EPA-HQ-OAR-2023-0234-0394
Page(s): 13

Commenter: Range Resources Corporation
Comment Number: EPA-HQ-OAR-2023-0234-0397
Page(s): 11-12

Commenter: The Petroleum Alliance of Oklahoma
Comment Number: EPA-HQ-OAR-2023-0234-0398
Page(s): 18-19

Commenter: Western Energy Alliance
Comment Number: EPA-HQ-OAR-2023-0234-0399
Page(s): 9

Commenter: American Petroleum Institute et al. (Part 1 of 2)
Comment Number: EPA-HQ-OAR-2023-0234-0402
Page(s): 64-65

Comment 9: Commenter 0295: AXPC supports EPA's general approach to addressing methane slip from all reciprocating engine and gas turbine sources (regardless of whether they drive compressors or not) and is in favor of a hierarchy of calculation methodologies that include the use of direct measurement or OEM data where available. To that end, AXPC recommends that EPA extend that same approach incorporating empirical data to combustion sources that are not burning pipeline quality natural gas, such that direct measurement or OEM data (provided that it takes into account site-specific gas quality considerations) could be used in lieu of the proposed combustion efficiency factors in Equations W-39A and W-39B. This would increase the accuracy of these emissions calculations. In cases where direct measurement and OEM data are not available, AXPC agrees that the use of emission factors should be allowed and supports the use of unique emission factors for each combustion equipment/burn type.

Commenter 0299: **The use of stack testing results for engines and natural gas turbines should not be restricted to units that use pipeline-quality fuel.**

Stack testing results for engines and natural gas turbines that use non-pipeline quality fuel should also be allowed to determine methane slip emissions. EPA noted in the preamble that "fuel types covered by the methods in existing 98.233(z)(2) (proposed 98.233(z)(3)) are expected to be highly variable in composition over the course of the year, such that a one-time performance test or OEM data are not expected to be representative of the annual emissions." [136] GPA suggests if an annual performance test is already required for the engine or turbine under another applicable federal standard (e.g., NSPS Subpart JJJJ or NSPS Subpart KKKK), or if the operator voluntarily performs an annual performance test, EPA should allow the results of those tests to be used to determine a methane slip emission factor. While there may be variability in the gas composition, an annual schedule of performance testing will account for changes in gas composition from year to year. This rationale is supported by engine and turbine testing requirements under both NSPS and NESHAP compliance programs.

Additionally, using annual stack data would be consistent with section II.B and C of the proposal's preamble. Annual performance testing results provide additional empirical data to report emissions more accurately and would improve verification and transparency of the data since the tests would follow strict EPA reference methods. EPA should include the option to allow an operator to utilize annual performance testing results for any fuel quality.

Footnote:

[136] Id. at 50,357

Commenter 0338: **EPA should allow operators of reciprocating internal combustion engines and gas turbines to determine emissions through direct measurement using a performance test if the operator can demonstrate limited fuel composition variability---*even where the methane content of the fuel is less than 85%.***

EPA proposes a default equipment-specific combustion efficiency that must be used by operators to calculate emissions from reciprocating internal combustion engines (RICE) and gas turbines (GT) when that equipment utilizes fuel with a methane content less than 85%. See 88 Fed. Reg. at 50,355-57, 50,410-11 (proposed 40 C.F.R. § 98.233(z)(3)). The Proposed Rule would not allow operators of these engines to determine emissions through direct measurement using a performance test. Id. at 50,357. We understand that EPA's rationale is that fuels with a methane content of less than 85% "are expected to be highly variable in composition over the course of the year, such that a one-time performance test are not expected to be representative of the annual emissions." Id. However, Antero's own empirical data, gathered through a review of its extensive operations, does not support this assumption.

Antero has reviewed nineteen of its different compressor stations that have compressor engines operating on fuel with a methane content less than 85%. Out of 115 fuel-gas analyses, over a three-year period, the average percent change in methane content is only 1.0% with a minimum change of 0.008% and a maximum change of 4.0%. Exhibit 1 summarizes the results of the quarterly fuel analyses for each of the compressor stations over that three-year period. The data shows the methane content of the fuel for each compressor station, each quarter, and the subsequent year-to-year variability.

Antero's empirical data demonstrates that fuel composition variability is not correlated to a threshold of methane content and that facilities within the natural gas gathering and boosting industry segment have more consistent gas compositions than EPA assumes. Many sources, as shown by Antero's data, have low to negligible fuel composition variability.

EPA should adopt a mechanism for operators to demonstrate limited fuel composition variability to allow emissions reporting through direct measurement using a performance test.

If, after reviewing Antero's data, EPA is still concerned about fuel composition variability, Antero would propose incorporation of some mechanism through which operators of RICE and GT, utilizing fuel with a methane content of less than 85%, can demonstrate limited fuel composition variability, and in exchange elect to determine emissions through direct measurement using a performance test. For example, EPA could require quarterly fuel gas sampling and submission of that data alongside annual emissions reports for relevant facilities.

This will provide EPA with a mechanism to verify the empirical data submitted by the facility confirms the facility's fuel composition has not varied beyond some negligible amount, such as 5% over the course of the calendar year.

To accomplish this, EPA could adopt a provision in proposed§ 98.233(z)(3) that would allow operators to utilize the performance-testing procedures in § 98.233(z)(2)(ii), and through cross-reference§ 98.233(z)(4)(i), measure and report emissions from natural gas-fired RICE and GT if facility-specific data demonstrates the facility's fuel composition varies less than the amount proposed above. This is important to Antero and likely important to many operators in the Appalachian Basin utilizing similar fuel types for purposes of operating RICE and GT. Perfonnance test data will ensure that our emissions reporting is as accurate as possible, and in doing so, align with the principled directives of the Act (which explicitly requires that reporting under Subpart W is "based on empirical data, … accurately reflect[s] the total methane emissions and waste emissions from the applicable facilities, and allow[s] owners and operators of applicable facilities to submit empirical emissions data." 42 U.S.C. § 7436(h)).[1]

EXHIBIT 1

CH4 mol% Fuel Gas Analysis

Compressor Station	2020 Q1	2020 Q2	2020 Q3	2020 Q4	2021 Q1	2021 Q2	2021 Q3	2021 Q4	2022 Q1	2022 Q2	2022 Q3	2022 Q4	2020 Max % Difference	2021 Max % Difference	2022 Max % Difference
A	77.95				79.14	79.00	79.01		78.01	78.01	79.00		--	0.2%	1.3%
B	75.50		76.68				75.37		76.24		75.57		1.6%	--	0.9%
C	76.85		75.88				76.07		76.44				1.3%	--	--
D	80.31				79.95		80.27				79.84		--	0.4%	--
E	80.77				82.09		82.71		78.12				--	0.8%	--
F	78.98	77.55	78.68		79.52				79.01		78.87		1.8%	--	0.2%
G			74.83		75.24		75.43		76.24		75.69		--	0.3%	0.7%
H			74.84		75.45	74.85	75.97				77.10		--	1.5%	--
I	78.17	78.49	78.52			78.40					74.48		0.5%	--	--
J	84.23	83.30	82.94	83.12			83.31		83.46		83.09		1.5%	--	0.4%
K	78.05		80.13	79.94	80.23		80.29		80.53	80.34	79.88		2.6%	0.1%	0.8%
L	80.57	81.67	80.45	80.78	81.16		80.40		78.78		80.38		1.5%	0.9%	2.0%
M	78.13	78.20	80.47		82.55		80.80		82.11		81.47		3.0%	2.1%	0.8%
N	80.04	80.48	80.34		81.06	81.15	81.09		81.14		81.12		0.5%	0.1%	0.0%
O	77.36	78.91	80.51		80.19		80.36		80.38		80.07		4.0%	0.2%	0.4%
P			78.12		75.49				78.07		78.10		--	--	0.0%
Q	78.90	79.30	79.10	78.95		79.61	79.34		78.21	79.13	77.39	79.29	0.5%	0.3%	2.4%
R	79.61		78.50		79.56		79.56				78.91		1.4%	0.0%	--
S	76.58		77.58		77.11		77.05		77.67		77.33		1.3%	0.1%	0.4%
												Average % Difference	1.6%	0.5%	0.8%
														Overall Average % Difference	1.0%

Footnote:

[1]As an administrative agency, EPA must act within the bounds of, and consistent with, the direction provided by Congress. E.g., Nat '/ Fed'n of lndep. Bus. v. Dep 't of Lab., Occupational Safety & Health Admin., 142 S. Ct. 661 , 665 (2022).

Commenter 0339: The EPA should allow for the use of methane emissions factors determined through 98.233(z)(4) for fuels that meet the requirements of 98.233(z)(3)(i). This will allow for the use of measured emissions factors, in the case of performance testing, to be used to estimate methane emissions from reciprocating internal combustion engines and gas turbines across all fuel specifications in 98.233(z). The EPA's stated expectation that fuel composition is "highly variable" over the course of the year is not explained adequately and is not true for Ascent's operations.

Commenter 0378: Marathon Oil supports EPA' s general approach to addressing methane slip from all reciprocating engine and gas turbine sources and is in favor of a hierarchy of calculation methodologies that include the use of direct measurement or original equipment manufacturer (OEM) data where available. To that end, Marathon Oil recommends that EPA extend that same approach to combustion sources that are not burning pipeline quality natural gas, such that direct measurement or OEM data (provided that it takes into account site-specific gas quality considerations) could be used in lieu of the proposed combustion efficiency factors in Equations W-39A and W-39B. The inability for a company to demonstrate a reduction in slip emissions in their reported inventory and thus reduce its waste emissions charge will disincentivize the deployment of emerging technology that may significantly reduce emissions from this source category. In cases where direct measurement and OEM data are not available or emission sources are small, Marathon Oil agrees that the use of emission factors should be allowed and supports the use of unique emission factors for each combustion equipment/bum type. Finally, Marathon Oil recommends that EPA consider allowing the use of company-average emission factors derived from direct measurement in cases where the same make/model units are installed at many facilities. This would minimize the cost of conducting site-specific measurements at multiple locations where the same units are being installed, operated and maintained under comparable conditions.

Commenter 0394: Williams disagrees with limiting the performance testing option to units fueled by pipeline quality gas and suggests the option should also be allowed for units fueled by non-pipeline quality gas. To encourage reporters to measure data, the EPA should consider adding language specifying reports must use the most recent performance test and update the emission factor to coincide with the best data available.

Commenter 0397: **Operators should be allowed to use stack testing to measure combustion emissions even if the gas methane content is less than 85% as long as gas analysis is conducted quarterly.**

Under proposed 40 C.F.R. § 98.233(z), operators must calculate carbon dioxide, methane, and nitrous oxide combustion-related emissions from stationary or portable equipment using different methodologies depending on the type of fuel being combusted. 88. Fed. Reg. at 50354-56. Under proposed 40 C.F.R. § 98.233(z)(2), an operator may use stack testing to measure emissions from units combusting field gas as long as the gas has a methane content of at least 85%. 88. Fed. Reg. at 50355. The rationale appears to be that gases with methane content greater than 85% have less variability than gases with a lower methane content. However, operators conducting quarterly gas analysis are able to monitor the methane content of gases to ensure there is no substantial variability. An operator can ensure that its emissions reporting based on stack testing accounts for the fuel quality that is observed in the field through gas composition analyses.

Therefore, EPA should clarify that an operator may use stack testing to perform emissions measurement on its combustion devices for fuel with a methane content of less than 85% as long as quarterly gas analyses are performed and incorporated into the emissions analysis.

Commenter 0398: Methane Slip from Internal Combustion Equipment. EPA is proposing default equipment specific combustion efficiency (proposed to be provided in equations W– 39A and W–39B) for RICE and GT that must be used to determine emissions using the subpart W calculation methodologies per existing 40 CFR 98.233(z)(2) (proposed 40 CFR 98.233(z)(3)). The default combustion efficiency would account for methane slip and be combined with fuel composition to calculate emissions. EPA is not proposing to provide options for reporters to conduct performance tests or use original equipment manufacturer (OEM) data for such RICE and GT. EPA states that fuel types covered by the methods in existing 40 CFR 98.233(z)(2) (proposed 40 CFR 98.233(z)(3)) are expected to be highly variable in composition over the course of the year, such that a one-time performance test or OEM data are not expected to be representative of the annual emissions.

This is not the case. Many of these engines are located at or near wells where the gas composition does not change. We think that field measurement testing of these engines can provide the most accurate information, and the collection of this data could align with other air emission testing requirements.

Action Requested: We request EPA allow reporters to conduct performance testing of these engines as it can provide the most accurate emission information. Additionally, reporters should be allowed to develop representative EFs for similar types of equipment and fuel types.

Commenter 0399: For combustion emissions from compressors within Subpart C, EPA provides three options for capturing methane slip for engines: 1) using direct engine testing, 2) OEM data; 3) default combustion efficiency factors. However, for reporting under subpart W, only the third option is available. Even under subpart C which has more options, those options are only available for equipment at a facility with a natural gas stream of 85% or higher of methane. There is also no justification for a distinction between subpart C and subpart W, as direct engine testing and OEM data should be just as appropriate for gas streams at lower methane concentrations, and for non-subpart C facilities. … If EPA does not allow for this change, given the default values are much higher than data from OEM and direct engine testing, reporting will once again artificially increase, contrary to the IRA's accuracy directive for the methane fee assessment.

Commenter 0402: **Direct measurement and the use of default equipment-specific destruction efficiencies should be allowed regardless of fuel type, and EPA should allow for control efficiencies from emerging technologies.**

The Industry Trades agree with the agency that the default combustion efficiency for incomplete combustion or "methane slip" should be updated. However, it is important to note that the changes to methane combustion slip emission factors are expected to result in one of the largest changes to reported methane emissions, and EPA should allow the use of performance tests to determine methane slip factors regardless of fuel type. This would critically incentivize investments in technologies to reduce methane slip and would meet the objective of using empirical data. However, EPA should include these revisions under Subpart C instead of under Subpart W.

EPA's basis for exclusively using default equipment-specific destruction efficiencies, when the fuel does not meet at least 950 btu/scf, and contains less than 1% CO2 and at least 85% methane by volume is flawed. We recognize that EPA tried to simplify the performance test requirement to a one-time performance test, and as such did not propose to allow performance testing because fuel types "are expected to be highly variable in composition over the course of the year, such that a one-time performance test or OEM data are not expected to be representative of the annual emissions." The Industry Trades make two comments on this assertion. First, operator experience indicates that field gas is not significantly variable year over year and EPA does not provide data to support its assertion. Second, EPA does not explain why the range of any expected variability would result in a change in combustion slip. Third, and most importantly, reporters commonly conduct performance testing on engines to meet NSPS JJJJ/NESHAP ZZZZ or state regulatory requirements. As such, EPA should allow reporters to use those results regardless of the fuel gas type, as well as the default equipment-specific combustion efficiency for reciprocating internal combustion engines (RICE) and gas turbines (GT), as long as the performance test results are only applied to sites with similar fuel gas quality.

To further emphasize the importance of allowing performance test data from any RICE or GT, the Zimmerle study cited by EPA is representative for natural gas compressor stations, but it does not include any smaller engines likely to be found in an upstream environment. Allowing directly measured data will both provide EPA with additional details regarding methane slip related to the smaller engines, and it will allow operators to use empirical data as aligned with EPA's intent. Critically, this will also incentivize operational improvements to reduce methane slip from natural gas combustion. This also clears up the proposed discrepancy where EPA proposes to mandate incorporation of performance test results for some RICE and GTs, but prohibits the use of performance test results for others. Ultimately, there is no reason EPA should not allow operators to use results from periodic performance tests conducted per EPA reference methods regardless of fuel quality.

The table below summarizes the distribution of combustion efficiencies calculated from member-provided performance tests:

Horsepower	Count	Minimum Combustion Efficiency	Mean Combustion Efficiency	Median Combustion Efficiency	Maximum Combustion Efficiency
> 500 hp	76	96.16%	98.29%	99.46%	99.46%
< 500 hp	57	98.29%	99.58%	99.99%	99.99%

The above data is based on performance tests using engine horsepower, load, break-specific fuel consumption, the average grams of methane per horsepower-hour over three test runs, and the methane concentration of fuel gas. The combustion efficiencies were derived by dividing the stack test mass of methane by the mass of methane consumed in the fuel gas. The results show that minimum stack test combustion efficiency for engines greater than 500 horsepower is on par with EPA's equipment-specific default combustion efficiency for 4 stroke lean burn engines; while the combustion efficiency for engines less than 500 horsepower is greater than EPA's equipment-specific combustion efficiency for the same engine type. The data illustrates how smaller engines typically have favorable combustion efficiencies given they have smaller cylinder bores. The Industry Trades believe that allowing operators to develop horsepower-specific destruction efficiencies based on performance tests would lead to more accuracy while meeting EPA's intent to measure combustion slip from internal combustion units.

Response 9: We are finalizing the option of using OEM data for only RICE and GT using fuel with compositions described in 40 CFR 98.233(z)(1) or (2). OEM data is typically measured in a laboratory environment that simulates field operating conditions and various fuel compositions. The EPA acknowledges that fuel variability for fuels described under 40 CFR 98.233(z)(3) doesn't significantly differ annually from fuels described under 40 CFR 98.233(z)(2); however, there's a concern that applying OEM data to all fuels compositions could potentially fall outside the confidence interval for OEM data, resulting in inaccurate emission calculations. Given this concern, the EPA determined that the best course of action for fuels in 40 CFR 98.233(z)(3) is to allow performance testing. This approach ensures more accurate and reliable emission calculations by accounting for the specific characteristics of these fuel compostions. See Section III.S.2 of the preamble to the final rule for the EPA's response to comments regarding allowing performance testing to fuels not described in 40 CFR 98.233(z)(1) or (2).

Commenter: Truck & Engine Manufacturers Association (EMA)
Comment Number: EPA-HQ-OAR-2023-0234-0352
Page(s): 4

Comment 10: CAA § 136(h) Is Satisfied with Manufacturer Data, Emission Factors, and Source Testing.

The requirements of CAA § 136(h) are met by EPA's proposal to allow manufacturer data, emission factors, or source testing for quantifying combustion slip emissions. See 88 Fed. Reg. at 50,356 (proposing to allow use of OEM data, default emission factors or direct measurement to quantify and report combustion slip). The statutory text requires that methane reporting be based on empirical data. Manufacturer data are empirical and can cover a variety of fuels, from field gas 4 to pipeline-quality natural gas. EPA has conducted additional work to update the emission factors in Table W-7. And direct measurement at the source is clearly observed data. Therefore, these three options satisfy the empirical criterion required by Congress. Additionally, they meet EPA's expressed interest in minimizing the burden of reporting requirements.

CAA § 136(h) was recently added by Section 60113 of the Inflation Reduction Act of 2022 ("IRA"), and it reads:

REPORTING.—Not later than 2 years after the date of enactment of this section, the Administrator shall revise the requirements of subpart W of part 98 of title 40, Code of Federal Regulations, to ensure the reporting under such subpart, and calculation of charges under subsections (e) and (f) of this section, are based on empirical data, including data collected pursuant to subsection (a)(4), accurately reflect the total methane emissions and waste emissions from the applicable facilities, and allow owners and operators of applicable facilities to submit empirical emissions data, in a manner to be prescribed by the Administrator, to demonstrate the extent to which a charge under subsection (c) is owed.

42 U.S.C. § 7436(h).

EPA's proposed definition of "empirical data" is "data that are collected by observation and experiment." 88 Fed. Reg. at 50,286. Dictionary.com distinguishes empirical evidence, which is from experience or experiment, from "abstract principles or theory." EPA states that, for this rulemaking, "the EPA interprets empirical data to mean data that are collected by conducting observations and experiments that could be used to accurately calculate emissions at a facility, including direct emissions measurements, monitoring of CH_4 emissions (e.g., leak surveys) or measurement of associated parameters (e.g., flow rate, pressure, etc.), and published data." 88 Fed. Reg. at 50,286.

EPA's proposal to use manufacturer data and emission factors is sufficient, under the circumstances here, to meet EPA's legal obligations to base calculations on empirical data.

Response 10: The EPA acknowledges the commenter's support for the proposed use of manufacturer data and emission factors.

Commenter: GPA Midstream Association
Comment Number: EPA-HQ-OAR-2023-0234-0299
Page(s): 60

Commenter: Arkansas Independent Producers and Royalty Owners (AIPRO)
Comment Number: EPA-HQ-OAR-2023-0234-0382
Page(s): 14

Commenter: Chesapeake Energy Corporation
Comment Number: EPA-HQ-OAR-2023-0234-0400
Page(s): 16

Commenter: American Petroleum Institute et al. (Part 1 of 2)
Comment Number: EPA-HQ-OAR-2023-0234-0402
Page(s): 65-66

Commenter: American Gas Association (AGA) and American Public Gas Association (APGA)
Comment Number: EPA-HQ-OAR-2023-0234-0418
Page(s): 16

Comment 11: Commenter 0299: **EPA should account for combustion exhaust control in emission calculations.**

GPA emphasizes that operators are actively pursuing emission reduction methods, such as considering options to capture and prevent the release of combustion exhaust. However, the current proposed rule overlooks the ability for reporters to account for these innovative emissions control measures. EPA should modify combustion emission calculations to enable reporters to accurately represent novel emission control approaches and incentivize all potential emission reduction. This allowance directly aligns with the goal of the Inflation Reduction Act and incentivizes absolute emission reductions.

Commenter 0382: At a minimum, if EPA insists on including this emissions source under proposed Subpart W revisions, AIPRO encourages EPA to amend the proposed requirements in a manner that allows reporters that choose to install developing methane slip control technologies to include emissions reductions from the controls in their reported emissions. Failure to do so will disincentivize reporters from installing these costly control technologies.

Commenter 0400: **EPA should ensure that its Final Rule includes flexible, cost-effective methods for measuring emissions from methane slip, flares, and stuck dump valves.**

EPA's Proposed Rule revises existing methodologies for measuring emissions from combustion engines to account for methane slip.[58] Under the proposal, operators would be able to choose from three different methodologies to calculate methane slip emissions, including "measurement using a performance test, the use of OEM data, or the use of default emission factors."[59]

Chesapeake supports inclusion of a broad range of methods for reporting methane slip emissions. EPA's Final Rule should continue to permit operators to use emission factors, vendor spec sheets, or emission test reports. Chesapeake also encourages EPA to expand these methods to include a provision permitting operators to rely on catalyst vendor guarantees to reflect emission reductions. Such a provision would further the goals of CAA Section 136(a), which seeks to encourage innovative emission reductions, by preserving flexibility for operators as new technology is developed.

Footnotes:

[58] 88 Fed. Reg. at 50,356.

[59] Id.

Commenter 0402: **Direct measurement and the use of default equipment-specific destruction efficiencies should be allowed regardless of fuel type, and EPA should allow for control efficiencies from emerging technologies.**

…

EPA should also allow for flexibility to incorporate methane controls as new technologies are being developed to control methane emissions from RICE. The Industry Trades recommend that EPA add a methane control efficiency parameter to Equation W-39B to allow for flexibility of incorporating a control efficiency to enable reporters to report methane slip more accurately when methane control technologies emerge and are demonstrated to be effective.

Allowing for the use of additional approaches to calculate methane slip from compressor engines would further support technology development. For example, the Department of Energy is currently in year two of funding for the ARPA-E REMEDY program (REMEDY | arpa-e.energy.gov) that has a stated goal of developing technical solutions to achieve 99.5% methane conversion in natural gas fired lean burn engines. If technology development from this 3-year, $35 million research program is successful, the ability to use updated values in methane emissions reporting could help to drive greater adoption of new technologies in operations.

Commenter 0418: The Associations request that EPA incorporate additional flexibilities and clarifications into the Subpart W requirements for combustion equipment emissions.

The GHGRP currently requires facilities in certain segments, including the distribution segment, to report combustion emissions under Subpart W. With regard to those segments, EPA is proposing to revise the methodologies for determining combustion emissions from reciprocating internal combustion engines (“RICE”) and gas turbines (“GT”) to better account for combustion slip.[47] The Associations ask EPA to make the combustion slip quantification more flexible and, as a general matter, to provide further clarification on the applicability of 40 C.F.R. § 98.233(z).

For distribution sector RICE and GT that meet the criteria in current 40 C.F.R. § 98.233(z)(1) (e.g., units that combust one or more of the fuels listed in Table C-1 to Part 98), EPA is proposing to allow reporters to select from three options to quantify emissions from combustion slip: (1) a CH4 emission factor based on direct measurement via a performance test, (2) a CH4 emission factor based on original equipment manufacturer (“OEM”) data, or (3) a default CH4 emission factor. To use a performance test emission factor, a facility would have to conduct a performance test pursuant to the criteria in proposed 40 C.F.R. § 98.234(i).[48] Facilities that use the default would select the appropriate emission factor by equipment type (2-stroke or 4-stroke lean-burn, 4-stroke rich-burn, or GT) provided in new Table W-7.[49] For distribution sector RICE and GT that meet the criteria in current 40 C.F.R. § 98.233(z)(2) (e.g., units that combust field gas or process vent gas), reporters would be required to use a default equipment-specific combustion efficiency that would account for methane slip and be combined with fuel composition to calculate emissions.[50]

With regard to the proposed combustion slip emissions quantification methods, the Associations ask EPA to consider whether these procedures can benefit from additional flexibility. For example, Association members note that OEM data may not include methane emissions, whereas third-party service providers that work with a facility’s RICE or GTs may have the requisite methane data for developing emission factors.[51] We also request that alternate forms of performance testing that are already required under other regulatory programs, such as permit conditions for RICE-driven compressors that are not EPA certified, be deemed allowable bases for developing a CH4 emission factor. These flexibilities would reduce the administrative burden on covered facilities while maintaining reporting accuracy. More generally, the Associations request that EPA provide more clarity regarding which combustion equipment emissions are subject to Subpart W reporting. For example, it is unclear from Subpart W whether emergency generator emissions are reportable. Such emissions are explicitly exempt from Subpart C reporting[52] and the Associations believe Subpart W should contain the same clearly phrased exemption. Subpart W is similarly unclear about whether emissions flared from RICE or GTs are reportable as combustion emissions. While Subpart W as a whole could benefit from reorganization to make its requirements clearer to regulated entities, the Subpart W reporting obligations for combustion emissions are particularly unclear.

Footnotes:

[47] Id. at 50,356–59. Combustion slip (also called "methane slip") occurs when unburned CH4 is entrained in the exhaust of natural gas-fired engines.

[48] The Associations have identified an apparent typographical error in the proposed regulatory text: proposed 40 C.F.R. § 98.234(i) references "paragraphs (j)(1) through (3) of this section," but there is no paragraph (j) in that section. We believe the text should refer to "paragraphs (i)(1) through (3) of this section."

[49] This refers to a new table that would be numbered W-7 if the Proposed Rule is finalized. EPA is proposing to modify and renumber existing Table W-7 as Table W-5.

[50] EPA is proposing the following default combustion efficiencies by equipment type: 2-stroke lean-burn RICE (0.953), 4-stroke lean-burn RICE (0.962), 4-stroke rich-burn RICE (0.997), GTs (0.999). See Proposed Rule, 88 Fed. Reg. at 50,411 (equations W-39A and W-39B).

[51] The Associations concur in INGAA's comments on the issue of OEM and service-provider emission factors.

[52] See 40 C.F.R. § 98.30(b)(2) ("This source category does not include . . . [e]mergency generators and emergency equipment, as defined in § 98.6.").}

Response 11: The EPA has included the option for performance testing for all natural gas fuel types in RICE and GT (See Section III.S.2 of the preamble to the final rule). We do not agree with including catalyst vendor guarantees or modifications to the default emission factors or default combustion efficiencies. At this time we have concerns that modifications to the default emission factors or combustion efficiencies would not be consistent with using empirical data and potentially decrease the accuracy of emissions under various operating conditions. The option of direct measurement for all natural gas fuel sources allows reporters to incorporate any third-party emission reduction equipment and report emission based on emission factors derived directly from empirical data under their operating conditions. Commenter 0418 provided a footnote about a typographical error in the regulatory text 40 CFR 98.234. This error has been corrected in the final regulatory text.

Commenter: Interstate Natural Gas Association of America (INGAA)
Comment Number: EPA-HQ-OAR-2023-0234-0387
Page(s): 6

Comment 12: OEM or *third-party service* provider EFs should be allowed

Since existing T&S engines often include after-market technology from third party service providers, such as low emission combustion (LEC) technology to reduce NOx emissions, it is imperative that Subpart W allow service provider EFs in addition to OEM EFs. For example, OEM EFs may not be available for methane or may not be appropriate if the engine includes technology upgrades provided by after-market companies. To address this, INGAA recommends using the term "third-party service provider" (or similar terminology defined by EPA), and §93.233(z)(4)(ii) of the Proposed Rule should be revised to state:

"(ii) Original equipment manufacturer **or third-party service provider** information, which may include ~~manufacturer~~ specification sheets, emissions certification data, or other ~~manufacturer~~ data providing expected emission rates from the reciprocating internal combustion engine or gas turbine."

Response 12: The finalized regulation has allowed the use of OEM data for RICE and GT that combust fuels that meet specifications in 98.233(z)(1) or 98.233(z)(2). OEM data is completed under a controlled environment with specific fuel types. We are not introducing or finalizing additional regulations for OEM data in this regulation. In future amendments we may explore standardizing OEM testing procedures at which time we may investigate allowing additional third-party data. The EPA is finalizing the use of performance testing for units combusting fuels that meet specifications in 98.233(z)(3). This will allow reporters using third-party or after-market technology to verify the reduction in emissions.

Commenter: Offshore Operators Committee (OOC)
Comment Number: EPA-HQ-OAR-2023-0234-0409
Page(s): 4-5, 14

Comment 13: Section/Paragraph Reference: §98.33(c)(1), §98.33(c)(1)(i), §98.33(c)(1)(ii), §98.33(c)(2), §98.33(c)(4)

Proposed Text: Where: *** EF = Fuel-specific default emission factor for CH4or N2O, from Table C–2 of this subpart (kg CH4 or N2O per mmBtu), except for natural gas-fired reciprocating internal combustion engines and gas turbines at facilities subject to subpart W of this part, which must use a CH4 emission factor determined in accordance with §98.233(z)(4).

Comment: The proposed text appears in 5 paragraphs in the proposed rule.

OOC recommends that the proposed text be modified as follows:

EF = Fuel-specific default emission factor for CH_4 or N_2O, from Table C–2 of this subpart, original equipment manufacturer information or performance test data (kg CH_4 or N_2O per mmBtu), except for natural gas-fired reciprocating internal combustion engines and gas turbines at facilities subject to §98.233(z) in subpart W~~ of this part~~, which must use a CH4 emission factor determined in accordance with §98.233(z)(4).

Rationale: Alternative emission factors may be available for certain equipment from the equipment manufacturer or from equipment testing. If those factors are available, the regulated community should have the option of using those emission factors.

We are also clarifying that the requirement to use §98.233(z)(4) does not apply to offshore facilities located on the U.S. Outer Continental Shelf (OCS).

…

Section/Paragraph Reference: Footnote to Table C-2

Proposed Text: Reporters subject to subpart W of this part may only use the default CH4 emission factor for natural gas-fired combustion units that are not reciprocating internal combustion engines or gas turbines. For natural gas-fired reciprocating internal combustion engines or gas turbines, at facilities subject to subpart W of this part, reporters must use a CH4 emission factor determined in accordance with §98.233(z)(4).

Comment: Reporters subject to §98.233(z) in subpart W ~~of this part~~ may only use the default CH4 emission factor for natural gas-fired combustion units that are not reciprocating internal combustion engines or gas turbines. For natural gas-fired reciprocating internal combustion engines or gas turbines, at facilities subject to §98.233(z) in subpart W ~~of this part~~, reporters must use a CH4 emission factor determined in accordance with §98.233(z)(4).

Rationale: We are clarifying that the requirement to use §98.233(z)(4) does not apply to offshore facilities located on the U.S. OCS.

Response 13: The EPA is finalizing the revisions as proposed. The EPA does not agree with the addition of §98.233(z) to the footnote in Table C-2 or to the "EF" equation term described in §98.33(c)(1), §98.33(c)(1)(i), §98.33(c)(1)(ii), §98.33(c)(2), and §98.33(c)(4). To clarify, the provisions described in §98.233(z)(4) were intended to apply to RICE or gas turbine combustion units at facilities subject to subpart W, both facilities subject to §98.233(z) of subpart W and facilities subject to subpart W but reporting combustion emissions under subpart C. We believe the final language accurately communicates this intent. Additionally, we do not agree with adding "original equipment manufacturer information or performance test data" to the "EF" equation term definition in §98.33(c)(1), §98.33(c)(1)(i), §98.33(c)(1)(ii), §98.33(c)(2), and §98.33(c)(4). This change in the equation term definition would allow the use of OEM and performance testing for combustion devices in source categories/industries other than Petroleum and Natural Gas Systems that calculate combustion emissions using subpart C, which is outside the scope of this rulemaking. The final revisions are only intended to allow equipment that is

RICE or GT at facilities subject to subpart W and required to determine a CH_4 emission factor in accordance with 98.234(z)(4) to use the additional methodologies.

Commenter: Truck & Engine Manufacturers Association (EMA)
Comment Number: EPA-HQ-OAR-2023-0234-0352
Page(s): 3-4

Comment 14: EPA Should Clarify the Limited Nature of Crankcase Ventilation Emissions and Combustion Slip Measurements.

In any final rule, EPA should remove any ambiguity regarding reciprocating internal combustion engines ("RICE"). The NPRM addresses crankcase ventilation emissions and combustion slip in the context of petroleum and natural gas systems. The NPRM does not, and should not, purport to address these issues beyond the petroleum and natural gas systems source category. As such, any language implying that the crankcase ventilation or combustion slip issues apply beyond the petroleum and natural gas systems source category should be removed or edited.

…

Later in the preamble, EPA confuses the issue by speaking generally of combustion slip:

> In this rulemaking, we are continuing to propose the quantification and reporting of combustion slip from subpart W facilities that currently report combustion emissions in subpart C or subpart W. However, in consideration of the comments received on the 2022 Proposed Rule and the directives under CAA 136(h), we are broadening the applicability of the combustion slip quantification and reporting methods to all RICE and GT and additionally providing three methods for quantifying slip including default emission factors or combustion efficiencies, OEM data, or direct measurement. …
>
> [W]hile the recent studies are focused on the Onshore Petroleum and Natural Gas Gathering and Boosting industry segment, the EPA's literature review found the presence of combustion slip in different industry segments, so it appears that combustion slip is dependent on the type of internal combustion equipment and not the application (i.e., we expect combustion slip from RICE or GT regardless of the industry segment). We also considered that other EPA programs such as AP–42: Compilation of Air Pollutant Emissions Factors; 40 CFR part 60, subpart JJJJ; and 40 CFR part 63, subpart ZZZZ consider emissions from internal combustion equipment (i.e., RICE or GT) irrespective of their use to drive a compressor or the industry segment in which the engine operates. Therefore, consistent with section II.A of this preamble, we are proposing to revise the methodologies for determining combustion emissions from RICE and GT, including those that drive compressors, to account for combustion slip.

88 Fed. Reg. at 50,356 (emphasis added).

The language is ambiguous regarding whether this action addresses RICE and GT in any context or solely in oil and gas sources. Such an action would be beyond the scope of the notice EPA has provided and the analysis EPA has conducted. EPA has failed to provide notice that engine manufacturers should address a rulemaking positioned solely for the oil and gas sector. Before any such action could be taken, a new notice with a genuine opportunity to comment must be provided. Further discussion and analysis of impacts, costs, benefits, and unintended consequences must be taken before making a source category-wide determination for RICE and GT, particularly in a rule that is not advertised as targeting those source categories. EPA itself acknowledges it is basing this conclusion on the appearance of cross-industry consistency, even though the recent studies relied upon focused on the oil and gas sector. And as noted above, EPA explicitly evaluated costs and burdens only from petroleum and natural gas industry segments.

EPA should remove any ambiguous language and clarify that the only changes for RICE are with respect to the relevant, specific oil and gas sources outlined in Subpart W.

Response 14: The EPA acknowledges the commenter's concern about the applicability of the proposed changes. Subpart W is only relevant to the petroleum and natural gas industry.

Commenter: GPA Midstream Association
Comment Number: EPA-HQ-OAR-2023-0234-0299
Page(s): 95, 96

Comment 15: Proposed Change: EPA is proposing three methane emission factors in Table W-9 (or three combustion efficiencies in Equation W-29) from reciprocating engines that drive compressors: two-stroke lean-burn, four-stroke lean-burn, and four-stroke rich-burn.

> **Comment**: GPA does not oppose the proposed emission factors/combustion efficiencies. However, the proposal does not provide an opportunity for reporters to reduce emissions from this source and account for those reductions in their reports. The combustion calculations should allow reporters to use the emission factors in Table W-9 *or* use OEM (original equipment manufacturer) specific emission factors *or* use stack test data *or* apply a percent reduction to the Table W-9emission factors based on other data. Operators, engine manufacturers, and engine catalyst manufacturers are rapidly working to develop technologies to minimize methane slip. Allowing use of OEM specific factors, or stack test data, or a control percentage applied to the emissions incentivizes reporters to reduce methane slip, and by extension incentivizes engine and catalyst manufacturers to develop low methane emissions technology for both new and existing engines (with, for example, upgrade kits). EPA must not stifle innovations that are currently under development to reduce methane emitted to the atmosphere. If reporters cannot account for improvements in engine methane emissions, then improvements are much, much less likely to happen. Because this is an area of developing innovation, EPA should allow reporters to use the calculation method that is most representative of emissions, whether that be Table W-9 factors, OEM factors, stack test data, or control percentages applied to Table W-9 factors. With the confluence of possible SEC reporting, methane fees, ESG reporting, responsibly sourced gas certifications, and other driving forces for methane

> emission reductions, EPA must allow reporters to accurately reflect their emissions using a variety of means to calculate emissions. Especially for significant sources of methane emissions, like engine slip, the time for allowing flexibility in calculations is now, not a future rulemaking. The request also aligns with the directives in the Inflation Reduction Act to pursue reported emissions based on empirical data.

…

Proposed Change: EPA is proposing new methane emission factors for two-stroke lean-burn, four-stroke lean-burn, and four-stroke rich-burn reciprocating engines. However, throughout the preamble and proposed rule text, EPA uses the inaccurate and broad terminology of “compressor drivers” to refer to these engines.

> **Comment**: In addition to engines, midstream operators commonly use turbines as compressor drivers. EPA is not proposing new methane emission factors for turbines. Therefore, EPA must replace the term “compressor drivers” with “compressor driver-engines” (or something similar) throughout the preamble and rule text, including in both Subparts C and W, to clarify that turbines are not included.

Response 15: These comments were included as an attachment to the commenter’s letter, but they are comments on the 2022 GHGRP Proposal, which are not relevant to this final rule. The commenter also submitted comments on the 2023 Subpart W Proposal related to this issue, included earlier in this section and responded to by the EPA there.

20.3 Other Calculation Methodology Clarifications

Commenter: GPA Midstream Association
Comment Number: EPA-HQ-OAR-2023-0234-0299
Page(s): 17

Comment 1: The following is a list of substantive proposed changes that GPA expressly supports.

…

- The option to use engineering estimates based on best available data to determine the fuel gas composition, while maintaining the option for reporters to use 98.233(u)(2) [98.233(z)(3)(ii)(B)];
- Allowing calculations and reporting for groups of combustion unit types using the same fuel type and method for determining the CH4 emission factor;

Response 1: The EPA acknowledges the commenter’s support of the proposed revisions. The EPA is finalizing these amendments as proposed.

Commenter: Ascent Resources, LLC
Comment Number: EPA-HQ-OAR-2023-0234-0339
Page(s): 3

Comment 2: Combustion emissions calculated under 98.233(z) of Subpart W for onshore production include multiple units across a broad facility (represented by the AAPG basin). The EPA should clarify whether the HHV from gas composition samples used to develop basin-average compositions in 98.233(u)(2)(i) can be used to meet the HHV sampling requirements specified in 98.34(a)(2)(i) referenced by the Tier II calculation methodology in Subpart C. Ascent believes that a basin-level average HHV can be representative of the fuel combusted across multiple units in the basin.

Response 2: The provisions in 40 CFR 98.233(z)(1)(ii) and 40 CFR 98.233(z)(2)(ii) require the use of subpart C to calculate emissions. The subpart C HHV sampling requirements at 40 CFR 98.34(a)(1) require that all fuel samples be taken at a location in the fuel handling system that provides a sample representative of the fuel combusted. The subpart C HHV sampling frequency requirements at 40 CFR 98.34(a)(2)(i) require semiannual sampling and analysis, with consecutive samples taken at least four months apart. An average basin-level HHV based on an average basin-level composition cannot be used in cases in which the sampling performed for purposes of 40 CFR 98.233(u)(2)(i) does not meet the HHV sampling requirements at 40 CFR 98.34(a)(1) and (a)(2)(i).

Commenter: CrownQuest Operating
Comment Number: EPA-HQ-OAR-2023-0234-0393
Page(s): 308

Comment 3: If allowing for best available engineering estimations for gas composition, EPA should allow this universally throughout all estimations.

Response 3: Where estimation is part of a calculation method in subpart W, the rule specifies that reporters should use engineering estimates based on best available data, or it specifies another appropriate procedure for estimation. The EPA is not finalizing additional amendments or changes from proposal based on consideration of this comment.

Commenter: GPA Midstream Association
Comment Number: EPA-HQ-OAR-2023-0234-0299
Page(s): 95

Comment 4: Proposed Change: EPA is clarifying that emissions may be calculated in 40 C.F.R. § 98.233(z)(3)(ii) for groups of combustion units. However, if any of the combustion units downstream of this shared measurement point are natural gas-driven compressor drivers, the volumes of fuel for those units would have to be separated from the total before emissions are calculated to account for the differences in combustion efficiency.

> **Comment**: EPA should allow grouping of natural gas-driven compressor driver engines if they are of the same class. First, at a G&B station, most fuel combustion equipment are compressor drivers, with possibly one or two small heaters. Second, it takes considerable work to apportion fuel use to each piece of equipment. One must use actual station fuel use, individual equipment heat rate, and individual equipment actual run hours to properly apportion fuel use, and the calculations accordingly must be performed using a mix of station-wide operating data (fuel use), equipment properties (heat rate), and equipment operating data (run hours). This is difficult to automate. However, if a station consists of, for example, three 4 stroke-rich burn engines, and a heater less than 5 MMbtu/hr, the reporter should be able to simply use the station fuel use and the 4-stroke rich-burn methane emission factor and combustion efficiency. This would dramatically reduce burden and provide the same emissions data.

Response 4: The final provisions in 40 CFR 98.233(z) require that a CH_4 emission factor must be determined for each reciprocating internal combustion engine or gas turbine that combusts natural gas. However, for reciprocating internal combustion engines or gas turbines, reporting of emissions and activity data under 40 CFR 98.236(z) is grouped by type of combustion unit, well-pad ID, and type of fuel, type of equipment (e.g., reciprocating 2-stroke-lean burn), method used to determine the CH_4 emission factor, and value of the CH_4 emission factor. For the example provided by the commenter, the emissions from the three 4 stroke-rich burn engines would be reported together if the default CH_4 emission factor applies to all three. If the emission factor is different for any the three engines, the emissions would need to be reported separately by emission factor, and the reporter would need to determine the quantity of fuel combusted in the engine(s) and calculate emissions accordingly; this approach ensures that emissions are calculated accurately based on empirical data.

20.4 Location of Reporting Requirements for Combustion Equipment

Commenter: Anonymous
Comment Number: EPA-HQ-OAR-2023-0234-0183
Page(s): 1

Commenter: GPA Midstream Association
Comment Number: EPA-HQ-OAR-2023-0234-0299
Page(s): 2, 56-59, 94-95

Commenter: INNIO Waukesha Gas Engines, Inc.
Comment Number: EPA-HQ-OAR-2023-0234-0343
Page(s): 3-4

Commenter: INNIO Waukesha Gas Engines, Inc.
Comment Number: EPA-HQ-OAR-2023-0234-0343
Page(s): 7-9

Commenter: Colorado Department of Public Health and Environment (CDPHE)
Comment Number: EPA-HQ-OAR-2023-0234-0373
Page(s): 4

Commenter: Arkansas Independent Producers and Royalty Owners (AIPRO)
Comment Number: EPA-HQ-OAR-2023-0234-0382
Page(s): 14

Commenter: Gas Turbine Association (GTA)
Comment Number: EPA-HQ-OAR-2023-0234-0384
Page(s): 2

Commenter: Williams Companies, Inc.
Comment Number: EPA-HQ-OAR-2023-0234-0394
Page(s): 12-13

Commenter: The Petroleum Alliance of Oklahoma
Comment Number: EPA-HQ-OAR-2023-0234-0398
Page(s): 18

Commenter: Western Energy Alliance
Comment Number: EPA-HQ-OAR-2023-0234-0399
Page(s): 9-10

Commenter: American Petroleum Institute et al. (Part 1 of 2)
Comment Number: EPA-HQ-OAR-2023-0234-0402
Page(s): 6

Commenter: American Petroleum Institute et al. (Part 1 of 2)
Comment Number: EPA-HQ-OAR-2023-0234-0402
Page(s): 63-64

Comment 1: Commenter 0183: The definition of "waste emissions" in the proposed rule is inconsistent with the general definition of "waste gas" in subpart C of part 98, which includes any gas that is combusted or oxidized. The proposed rule should clarify whether emissions from combustion or oxidation of waste gases are considered waste emissions or not, and how they should be reported.

Commenter 0299: More extensive comments are provided in this letter, but to highlight our key areas of concern the following summary is provided:

- **Reporting of Combustion Emissions** – EPA has inexplicably retained reporting of combustion emissions under Subpart W while all other industries report these exact same emissions under Subpart C.

…

Methane emissions resulting from combustion are not "waste emissions" for purposes of section 136 of the CAA and should not be subject to the waste emissions fee.

In the preamble to the proposed rule, EPA appropriately distinguishes between "total [methane] emissions" and "waste emissions."[123] This distinction recognizes that not all methane emissions are "waste emissions"—such as any emissions resulting from the operation of equipment intended to actually perform a beneficial function—and should not be included in the definition of methane emissions for purposes of the waste emissions charge. Examples of the types of beneficial functions that should be excluded are methane emissions that result from utilizing natural gas as fuel for engines driving compressors or generators.[124]

The text of the Inflation Reduction Act, as codified in section 136 of the CAA, supports this distinction as well. Specifically, section 136(a)(3)(B) clearly distinguishes between emissions that result from beneficial use and waste emissions, as it provides funding for "improving and deploying industrial equipment and processes that reduce methane and other greenhouse gas emissions and waste."[125] Section 136(a)(3)(C) also makes this distinction, providing funding for "supporting innovation in reducing methane and other greenhouse gas emissions and waste from petroleum and natural gas systems."[126]

The Bureau of Land Management also recognizes this distinction. In a recent proposed rule, the Bureau explicitly specified that waste is associated with venting, flaring, and leakage.[127] Emissions resulting from stationary combustion are fundamentally different. Rather than being "wasted," gas at those sources is used to fuel critical energy infrastructure. Congress knew how to address methane emissions from beneficial uses and how to address waste emissions, and it did both of those things in the Inflation Reduction Act.[128] Further, Congress made clear that the methane fee provision was intended to apply to waste emissions only.

The distinction between methane emissions resulting from beneficial uses and waste emissions also makes sense because it recognizes that the majority of combustion exhaust methane emissions result from industry reducing criteria pollutant emissions such as NOx and CO by switching combustion engines to lean-burn technologies. Methane emissions are inherent to a low-NOx/low-CO combustion process and lack any current feasible or practical means of control. State gas capture programs such as those in New Mexico[129] and North Dakota[130] recognize this and deem gas used for combustion as beneficial use. These state gas capture programs do not count fuel gas or fuel gas combustion products against gas capture target requirements and certainly do not deem it waste.

While EPA certainly implies in the proposed rule that there is a distinction between methane emissions resulting from combustion and waste emissions, it should explicitly make this distinction in the final rule.

The only appropriate subpart for reporting combustion emissions is Subpart C, not Subpart W.

In the proposed rule, EPA asks whether combustion emissions for petroleum and natural gas systems should be moved exclusively to Subpart W.[131] GPA strongly believes that all combustion emissions for petroleum and natural gas systems should be reported under Subpart C. Every other industry reports its combustion emissions under Subpart C (addressing General Stationary Fuel Combustion Sources), while the petroleum and natural gas industry has historically been arbitrarily split between Subparts C and W. This has never made good sense, and GPA urges EPA to place all combustion emissions for petroleum and natural gas systems into Subpart C, which would bring the industry in line with other industries. There is no difference between combustion emissions from other industries and those from the petroleum and natural gas industry. Therefore, treating the petroleum and natural gas industry differently is arbitrary and capricious. In the event that EPA nevertheless decides to move forward with placing combustion emissions for the industry into Subpart W (which GPA urges EPA not to do), then GPA believes that combustion emissions should not be considered "waste" emissions subject to the Methane Fee. GPA's reasons for these recommendations are discussed in further detail below.

In the Inflation Reduction Act, Congress applied the waste emissions charge to an "applicable facility that reports more than 25,000 metric tons of carbon dioxide equivalent of greenhouse gases emitted per year *pursuant to subpart W*."[132] Although many emissions from sources covered by Subpart W could reasonably be deemed to be waste emissions and thus subject to the waste emissions fee, methane emissions from combustion sources are a true outlier because they are not, in fact, "wasted." As such, they should not be subject to reporting under Subpart W. Instead, the most appropriate way to address this issue is to revise Subpart W to redirect stationary combustion emissions to Subpart C. As described below, such action would be consistent with the intent behind CAA section 136, and it would rectify a longstanding discrepancy with Subpart W.

Subpart W was originally promulgated on November 30, 2010, with the express intent to add requirements for facilities that contain petroleum and natural gas systems to report equipment leaks and vented GHG emissions under the GHGRP. EPA later amended Subpart W on October 22, 2015, to include the addition of calculation methods and reporting requirements for GHG emissions from gathering and boosting facilities, completions and workovers of oil wells with hydraulic fracturing, and blowdowns of natural gas transmission pipelines between compressor stations. Stationary combustion emissions are not equipment leaks or vented emissions and as such would be more appropriately reported under Subpart C.

It would also be arbitrary and capricious for EPA to continue requiring the reporting of stationary combustion emissions under Subpart W for the onshore petroleum and natural gas production, onshore petroleum and natural gas gathering and boosting, and natural gas distribution segments when all other segments of the petroleum and natural gas industry and *all other industries with fuel combustion emissions* report under Subpart C.[133] The GPA Comments on the 2022 Proposed Rule also addressed this issue.[134]

EPA seeks comment "on amending subpart W to specify that all industry segments would be required to report their combustion emissions, including CH4, under subpart W."[135] EPA claims that "the increase in total CH4 emissions from combustion devices at facilities subject to subpart W would be less than 5 percent." As an initial matter, the change in combustion emissions reported under Subpart W is irrelevant when determining where these emissions should be reported. Even if it were relevant, GPA was unable to find support for this claim. It is difficult to imagine that this is the case, especially considering the proposed changes to RICE emission factors.

For the reasons stated here and for the reasons stated in the GPA Comments on the 2022 Proposed Rule, EPA should revise Subpart W to move combustion sources for *all* industry sources to Subpart C. If EPA is unwilling to move these emissions to Subpart C, however, GPA recommends that EPA make explicit in the final rule that natural gas used for stationary combustion is a beneficial use that is not subject to the waste emissions charge (or that the methane emissions that result from the combustion of the natural gas are deemed as unavoidably lost and thus not subject to the charge).

…

Proposed Change: Some Petroleum and Natural Gas industry segments calculate and report fuel combustion emissions under Subpart C (which is proposed to reference Subpart W emission factors for certain sources). Other Petroleum and Natural Gas industry segments calculate and report emissions under Subpart W, except for some equipment for which emissions are calculated under Subpart C (which is proposed to reference Subpart W emission factors for certain sources) but are still reported under Subpart W.

> **Comment**: The elaborate structure dividing reporting requirements for similar type sources and processes among Subparts C and W has long been a source of confusion, administrative difficulty, and cost for affected facilities. For reporting consistency and to improve transparency, GPA requests that EPA consolidate combustion source calculation and reporting (40 C.F.R. §§ 98.233(z) and 98.236(z)) for all Petroleum and Natural Gas Systems segments under Subpart C – General Stationary Fuel Combustion Sources.
>
> As currently structured, Subpart W requires the Production segment, Gathering & Boosting segment, and the Distribution segment to calculate and report their combustion emissions under Subpart W. All other segments of the industry calculate and report combustion emissions under Subpart C (40 C.F.R. § 98.232(k)). This includes the majority of the segments in the industry: onshore natural gas processing, onshore natural gas transmission compression, underground natural gas storage, liquefied natural gas ("LNG") storage, LNG import and export equipment, onshore natural gas transmission pipelines.
>
> It has never been clear why EPA would treat the Production, Gathering & Boosting, and Distribution segments differently than the other industry segments in this regard—the source of the emissions, combustion, is the same. GPA has commented to EPA in previous rulemaking proceedings addressing Subpart W that the Agency's unusual approach with respect to these facilities, inconsistently piecing together combustion-related emission reporting requirements across various subparts, lacks a clear rationale or precedent.[31] Indeed, because Subpart C is proposed to reference Subpart W emission factors for certain sources, and Subpart W will continue to reference Subpart C calculation methods for certain sources, the utility of housing combustion emission requirements under two different subparts will not only remain unclear and confusing but become more so.

Further this complex system with its many cross-references creates multiple and unnecessary opportunities for mistakes in the regulatory text itself, future agency guidance, and for companies attempting to implement the rule. As noted in the Federal Plain Language Guidelines, "There are several ways to deal with cross-references. The best is to organize your material so you can ***eliminate the need for cross-references*.**"[32]

These issues are especially complex for companies that must report under the conflicting reporting regimes for different facility types that are treated differently under Subpart C and Subpart W, and the costs of maintaining separate systems for such facilities are not insignificant.

As EPA has previously explained, the purpose of Subpart W was to require the calculation and reporting of vented, fugitive, and flare combustion emissions, while "stationary combustion emissions are included in Subpart C."[33] Without providing a straightforward rationale for failing to adhere to that basic practice by including some combustion emissions in Subpart W, EPA has acted arbitrarily. An agency's basic obligation under the law is to assess the relevant facts and provide a reasoned rationale for its choice of action. As the D.C. Circuit has explained, agencies must "consider[] the relevant factors and articulate[] a rational connection between the facts and its choices."[34] Although it is permissible for an agency to make a decision that contradicts an earlier approach to a similar situation, when so doing, it must "supply a reasoned analysis for the change."[35] On the other hand, when an agency treats similarly situated parties differently, taking conflicting approaches based on the same or similar data, "[s]uch inconsistent treatment is the hallmark of arbitrary agency action," and requires further explanation from EPA.[36]

Here, the approach EPA has taken with respect to Production, Gathering & Boosting, and Distribution differs from and conflicts with the approach taken for other segments in the natural gas industry. The unusual division of reporting for these segments also differs from EPA's approach under other subparts of the GHGRP. EPA has supplied no clear rationale, and none is obvious.

Under these circumstances, the appropriate course of action is for EPA to move all combustion reporting under Subpart C. That would also allow EPA to streamline data aggregation and reporting for the annual Inventory of US GHG Emissions and Sinks and for other consumers of the reported data. Moving all combustion requirements to Subpart C could be accomplished by "lifting and shifting" regulatory text related to calculations, monitoring, and reporting from Subpart W to Subpart C. GPA is not proposing any changes to existing requirements related to combustion or sector threshold determinations.

Footnotes:

[123] *See, e.g.*, 88 Fed. Reg. at 50,286 (noting CAA section 136 requires Subpart W "accurately reflect the total [methane] emissions and waste emissions from the applicable facilities") (emphasis added); id. at 50,288 (noting proposed revisions to Subpart W "would ensure that the

reporting under subpart W accurately reflects the total [methane] emissions *and* waste emissions as required by CAA section 136(h)") (emphasis added); see also CAA § 136(h), 42 U.S.C. § 7436(h) (noting that revisions to Subpart W must ensure data reported "accurately reflect the total methane emissions *and* waste emissions from the applicable facilities") (emphasis added).

[124] These emissions are often colloquially referred to as "methane slip." This term and "combustion exhaust methane emissions" are meant to be used interchangeably throughout these comments.

[125] CAA § 136(a)(3)(B), 42 U.S.C. § 7436(a)(3)(B) (emphasis added).

[126] *Id*. § 136(a)(3)(C), 42 U.S.C. § 7436(a)(3)(C) (emphasis added).

[127] 87 Fed. Reg. 73,588 (Nov. 30, 2022).

[128] *See, e.g., Hamdan v. Rumsfeld*, 548 U.S. 557, 578 (2006) ("A familiar principle of statutory construction … is that a negative inference may be drawn from the exclusion of language from one statutory provision that is included in other provisions of the same statute.").

[129] New Mexico Administrative Code § 19.15.28.8.F(3)(a).

[130] North Dakota Industrial Commission Order 24665(4)(b).

[131] 88 Fed. Reg. at 50,358.

[132] CAA § 136(c), 42 U.S.C. § 7436(c) (emphasis added).

[133] Industries that report combustion emission under Subpart C include: Subpart D Electricity Generation, Subpart E Adipic Acid Production, Subpart F Aluminum Production, Subpart G Ammonia Manufacturing, Subpart H Cement Production, Subpart I Electronics Manufacturing, Subpart K Ferroalloy Production, Subpart L Fluorinated Gas Production, Subpart N Glass Production, Subpart O HCFC-22 Production And HFC-23 Destruction, Subpart P Hydrogen Production, Subpart Q Iron And Steel Production, Subpart R Lead Production, Subpart S Lime Manufacturing, Subpart T Magnesium Production, Subpart U Miscellaneous Uses Of Carbonate, Subpart V Nitric Acid Production, Subpart X Petrochemical Production, Subpart Y Petroleum Refineries, Subpart Z Phosphoric Acid Production, Subpart AA Pulp And Paper Manufacturing, Subpart BB Silicon Carbide Production, Subpart CC Soda Ash Manufacturing, Subpart DD Electrical Transmission And Distribution Equipment Use, Subpart EE Titanium Dioxide Production, Subpart FF Underground Coal Mines, Subpart GG Zinc Production, Subpart HH Municipal Solid Waste Landfills, Subpart II Industrial Wastewater Treatment, Subpart SS Electrical Equipment Manufacture Or Refurbishment, and Subpart TT Industrial Waste Landfills.

[134] GPA Comments on 2022 Proposed Rule at 25.

[135] 88 Fed. Reg. at 50,358.}

[31] *See* Gas Processors Association, Comments on Greenhouse Gas Reporting Rule: 2015 Revisions and Confidentiality Determinations for Petroleum and Natural Gas Systems; Proposed Rule (Docket EPA-HQ-OAR-2014-0831) at 24-26, 34 (Feb. 24, 2015).

[32] Federal Plain Language Guidelines at 83 (emphasis in original) (May 2011)

[33] 69 Fed. Reg. 18,576, 18,611, 18,614 (Apr. 12, 2010).

[34] *Nat. Res. Def. Council, Inc. v. EPA*, 194 F.3d 130, 136 (D.C. Cir. 1999).

[35] *Jicarilla Apache Nation v. DOI*, 613 F.3d 1112, 1119 (D.C. Cir. 2010).

[36] *Catawba Cnty., NC v. EPA*, 571 F.3d 20, 51 (D.C. Cir. 2009).

Commenter 0343: **Proposed Amendments to Part 98**

Combustion Equipment

Methane Slip from Internal Combustion Equipment

INNIO's Waukesha recognizes the requirements put upon the EPA by the passage of the Inflation Reduction Act (IRA) and commends the work done to ensure reporting under subpart W and corresponding waste emissions charges are based on empirical data, accurately reflecting the total CH4 emissions and waste emissions from the applicable facilities to demonstrate the extent to which a charge is owed under CAA section 136(h).

EPA's proposal allows for multiple calculation methods for GHG pollutants based on the natural gas quality for the Onshore Petroleum and Natural Gas Production, Natural Gas Gathering and Boosting, and the Natural Gas Distribution industry segments. For example, RICE combusting natural gas that qualify to determine emissions using subpart C calculation methodologies per 40 CFR 98.233(z)(1) and proposed new 98.233(z)(2) would have three options in proposed 40 CFR 98.233(z)(4) to quantify emissions from combustion slip including direct measurement using a performance test, the use of OEM data, or the use of default emission factors.

In general, INNIO's Waukesha agrees that proposing three options including performance testing, use of OEM data and or use of default emission factors adequately satisfies the CAA section 136(h) **empirical data requirements**; however, to fully comply with the **accuracy** component of the CAA section 136(h) requirements, INNIO's Waukesha proposes that all industry segment report combustion emissions, including CH4, under subpart W, as proposed in EPA's 2022 ruling. See additional comments referencing section [ref. 50358] below.

…

Proposed Amendments to Part 98 S. Combustion Equipment 5. Location of Reporting Requirements for Combustion Equipment

In reference to section 5. Location of Reporting Requirements for Combustion Equipment [ref. 50358], INNIO's Waukesha does not support EPA's approach to consider allowing all industry segments that currently report into subpart C to continue to use subpart C calculation methodologies as they currently use. When the IRA established a waste emission charge for methane from applicable facilities that report more than 25,000 metric tons of CO2 equivalent per year to the Greenhouse Gas Reporting Program (GHGRP) petroleum and natural gas systems source category (GHGRP subpart W) that exceed statutorily specified waste emissions thresholds, there were nine types of facilities (listed 1-9 below) specifically identified that would be subject to the charge.

If six of these facilities or segments are exempt through continued reporting into subpart C, it puts the entire MERP burden on three industry segments (1,3,9) as shown below.

1. Onshore Petroleum and Natural Gas Production
2. Offshore Petroleum and Natural Gas Production
3. Onshore Petroleum and Natural Gas Gathering and Boosting
4. Onshore Natural Gas Processing
5. Onshore Natural Gas Transmission Compression
6. Underground Natural Gas Storage
7. Liquefied Natural Gas Import and Export Equipment
8. Liquefied Natural Gas Storage
9. Natural Gas Distribution

The MERP program commits $1.55 billion in grants, rebates, and loans to help reduce methane emissions from certain petroleum and natural gas systems. In July 2023, EPA in conjunction with DOE and NETL released a notice of intent announcing the first in a series of funding opportunities. INNIO's Waukesha position is that the MERP funding model is potentially in jeopardy if only three segments, Onshore Petroleum and Natural Gas Production, Onshore Petroleum and Natural Gas Gathering and Boosting and Natural Gas Distribution become burdened with 100% of the waste emission charge fees.

EPA states that using RY2021 data for combustion sources, it was determined that requiring combustion emissions from all oil and gas be reported to subpart W rather than subpart C would increase total subpart W CH4 emissions between one and five percent, depending on if the amendments to combustion slip discussed in Section III.S.2 of the preamble are finalized. INNIO's Waukesha would like to confirm that these calculations are using previous subpart W factors (0.095 kg/mmBtu for 4SLB/4SRB) and subpart C (0.001 kg/mmBtu) or proposed factors (0.658 kg/mmBtu for 2SLB, 0.522 kg/mmBtu for 4SLB, 0.045 kg/mmBtu for 4SRB, and 0.004 kg/mmBtu for turbines) as the difference would likely have a material impact on the projected contribution of each of these sectors on the overall methane inventory. Based on these assumptions, the contribution of methane emissions from engine/turbine combustion reporting into subpart C is undercounted by 4 to 658 times given the difference between current and proposed emission factors.

Per Figure 2 in the EPA's 2011-2021 Greenhouse Gas Reporting Program Industrial Profile: Petroleum and Natural Gas Systems3 (epa.gov), methane from segments Onshore Petroleum and

Natural Gas Production, Onshore Petroleum and Natural Gas Gathering and Boosting, and Natural Gas Distribution above account for over 87% of total inventory. This assumes the utilization of current emission factors that (based on proposed emission factors) undercount methane from combustion emissions across virtually all sectors. Figure 3 of the same profile document shows that combustion emissions (CO2e) from sectors proposed to remain in subpart C account for approximately 48% of total combustion CO2e emissions. It stands to reason, that the methane emissions associated with those combustion sources is significantly undercounted and would account for more than 13% of total methane emissions. The monetary impact of having all segments report under Subpart W is unclear, but for sectors such as natural gas transmission compression, it is suspected that reporting under W would not have a material financial impact, as volumes moved are high (due to low pressure ratios) and the methane emission threshold is 2x that of non-production (0.11% vs. 0.05%). However, the purpose of the GHGRP is not monetary, but to simply account for and report GHG emissions. INNIO's Waukesha supports any action that provides the most accurate estimations of different emissions sources.

According to EPA's "Overview of Greenhouse Gases," in 2021, CH4 accounted for 12% of all U.S. GHG emissions from human activities, with natural gas and petroleum systems identified as the second largest source of CH4 in the U.S. INNIO's Waukesha questions if purposely eliminating any CH4 emissions from the MERP reporting mechanism is in alignment with the 2030 Greenhouse Gas Pollution Reduction Target, announced on April 22, 2021, which states a target of "a 50-52% reduction in U.S. greenhouse gas (GHG) pollution from 2005 levels in 2030".

As stated earlier in these comments, INNIO's Waukesha agrees with EPA's **2022** proposed approach, "in an analogous amendment for the reporters in the other subpart W industry segments that calculate and report combustion emissions under subpart C, we (EPA) are proposing that they also use subpart W-specific emission factors rather than the emission factors in Table C-2."

Footnote:

3 https://www.epa.gov/system/files/documents/2022-10/subpart_w_2021_sector_profile.pdf

<u>Commenter 0373</u>: For **combustion equipment (98.233(z))** (as prompted on page 50358), we believe it is appropriate for all oil and gas industry segments (i.e., Onshore Natural Gas Processing, Onshore Natural Gas Transmission Compression, Underground Natural Gas Storage, LNG Storage, LNG Import/Export Equipment, and Offshore Petroleum and Natural Gas Production) to be required to report their combustion emissions under Subpart W rather than Subpart C. Subpart W more accurately reflects methane and other GHG emissions from combustion equipment, particularly from engines. Combustion equipment operated in the above-listed segments does not materially differ in operation nor emissions profile from the equipment in the Onshore Production Production / Gathering & Boosting / Distribution segments that already are required to report under Subpart W. Further, this would remove exclusions for certain equipment (e.g., external combustion equipment with a rated heat capacity of less than 5 MMBtu/hr, and internal combustion equipment with a rated heat capacity of less than 1

MMBtu/hr). These steps to improve accuracy are warranted by the directives in the IRA and Section 136 of the Clean Air Act.

Commenter 0382: f. Methane Slip from Internal Combustion Equipment:

i. AIPRO strongly objects to the proposed revisions to Subpart W related to calculating methane slip from RICE and GT. Methane slip emissions from combustion are not waste emissions, they are an unavoidable result of the beneficial use of fuel. Accordingly, it is unnecessary and inappropriate to require reporters to report these emissions under Subpart W which will be used to determine methane taxes under the waste emissions provisions of the IRA…again these are non-waste emissions. AIPRO specifically incorporates by reference the comments submitted by API related to combustion emissions and methane slip from RICE and GT. Further, AIRPO strongly encourages EPA to remove all combustion emissions reporting requirements from Subpart W and continue to require these emissions to be reported under Subpart C.

Commenter 0384: **Comment #2 All Combustion Emissions Should Be Calculated in Subpart C**

Stationary combustion emissions calculations already established in Subpart C should also be applied to stationary combustion sources from the oil and gas sector. Subpart W calculations and reporting methodology should be exclusive to fugitive and vented emissions. Combustion emissions calculations currently in Subpart W should be relocated to Subpart C. The separation of combustion emissions and fugitive/vented emissions will simplify and clarify the purposes and calculation methods of both subparts.

Commenter 0394: F. Combustion Equipment

Williams recommends all combustion emissions in the Petroleum and Natural Gas Sector be reported in Subpart C – General Stationary Fuel Combustion Sources. All other Industrial Sectors in EPA's Greenhouse Gas Reporting Program exclusively use Subpart C to report their combustion emissions. Combustion emissions that result from the beneficial use of fuel for energy are a consequence of consumption and should not be considered in the Inflation Reduction Act of 2022 (Section 136) as a waste via Subpart W reporting

Commenter 0398: Clarifications of Calculation Methodology Applicability. EPA is proposing to revise 40 CFR 98.233(z)(1) to remove the references to field gas and process vent gas and include only the characteristics for the fuels that can use subpart C methodologies.

This proposal does not streamline or remove potential confusion among reporters as some combustion information will continue to be reported under subpart C and other information will be reported under Subpart W. Also, placing all combustion calculation methodologies in subpart C would reduce confusion and streamline the reporting process.

Action Requested: We request EPA move all subpart W combustion requirements into subpart C.

Commenter 0399: For combustion emissions from compressors within Subpart C, EPA provides three options for capturing methane slip for engines: 1) using direct engine testing, 2) OEM data; 3) default combustion efficiency factors. However, for reporting under subpart W, only the third option is available. Even under subpart C which has more options, those options are only available for equipment at a facility with a natural gas stream of 85% or higher of methane. There is also no justification for a distinction between subpart C and subpart W, as direct engine testing and OEM data should be just as appropriate for gas streams at lower methane concentrations, and for non-subpart C facilities.

The simplest way to accomplish this would be for EPA to move all combustion calculations into Subpart C to both simplify reporting and remove arbitrary distinctions that split oil and gas combustion emissions across multiple subparts. If EPA does not allow for this change, given the default values are much higher than data from OEM and direct engine testing, reporting will once again artificially increase, contrary to the IRA's accuracy directive for the methane fee assessment.

Recommendation: EPA should combine combustion emissions into Subpart C to make combustion emission reporting consistent.

Commenter 0402: We urge EPA to seek true alignment and harmonization with other federal regulatory requirements, particularly the NSPS OOOOb and EG OOOOc "Methane Rules" and the GHGRP itself. Below are a few examples that are articulated in our comments:

…

- Combustion emissions for all oil and gas segments should be reported under Subpart C, which is the subpart under which *all other industries* report fuel combustion emissions.

…

3.12 Reporting Combustion Sources in Subpart C versus Subpart W

Emissions from natural gas combustion are *not* waste emissions that should be subject to the methane fee but are a result of the end use of natural gas within the value chain; emissions should be reported under Subpart C and not under Subpart W and excluded from methane fee calculations.

…

As the Industry Trades previously commented during the June 2022 proposal, EPA should move all combustion calculations and reporting requirements from Subpart W to Subpart C to conform with the structure of the rule for other industries reported under the GHGRP. This would eliminate the current and proposed confusing structure that splits oil and gas combustion emissions across multiple subparts and references back and forth between the two subparts.

EPA seeks comment on "amending Subpart W to specify that all industry segments would be required to report their combustion emissions, including CH4, under Subpart W to more accurately reflect the total CH4 emissions from such facilities within the emissions reported under Subpart W." EPA asserts that Section 136(h) of the CAA specifies that EPA must "revise the requirements of subpart W…. [to] accurately reflect **the total CH4 emissions and waste emissions** from the applicable facilities and allow owners and operators of applicable facilities to submit empirical emissions data, in a manner to be prescribed by the Administrator, **to demonstrate the extent to which a charge under subsection (c) is owed**" (emphasis added). Methane slip emissions from combustion are *not* waste emissions that are subject to the methane fee but are a result of the end use of natural gas within the value chain. Therefore, such emissions should be reported under Subpart C and not under Subpart W and excluded from methane fee calculations, when they are defined under future EPA rulemaking.

The IRA includes several statements that clarify the definitions of waste with regards to methane emissions within the rule. The IRA includes provisions for exemptions based on regulatory compliance with new source performance standards and state-level implementation of existing source rules that are equivalent or greater in emissions reductions to EPA's November 2021 Methane Rule framework. Neither the 2021 Methane Rule Framework nor the subsequent December 2022 proposal for NSPS OOOOb and EG OOOOc include source performance standards for methane slip from compressor engines. While not directly applicable to the methane fee, Section 50263 of the IRA clarifies that royalties on all extracted methane emissions on Federal lands and the Outer Continental Shelf have a stated exception for "gas used or consumed within the area of the lease, unit, or communitized area", which clearly would exempt the routine use of fuel gas, and associated methane slip emissions, from such royalty calculations. Considering these statutory provisions of the IRA, methane slip from compressor engines should not be included within the emission calculation framework for Subpart W and the eventual methane fee calculations that EPA will define at a later date.

Response 1: See Section III.S.3 of the preamble to the final rule, regarding the EPA explaining that this rule does not change the existing provisions that specify the subparts under which combustion emissions are reported.

Commenters stated that the use of separate terms of "total [methane] emissions" and "waste emissions" in CAA section 136 indicates that not all methane emissions are "waste emissions" and suggested EPA should clarify that methane emissions resulting from the operation of equipment intended to perform a beneficial function are not "waste emissions." Other comments asked the EPA to clarify the difference between "waste emissions" and "waste gas." We note that "waste emissions" are the amount of "total methane emissions" from the facility that exceed the waste emission threshold for a WEC applicable facility, while "waste gas" is gas that is combusted or oxidized without thermal recovery. In subpart W, a flare is defined as "a combustion device, whether at ground level or elevated, that uses an open or closed flame to combust waste gases without energy recovery." Therefore, any waste gas that is combusted or oxidized would be reported with subpart W flare emissions for that facility and would be considered part of the total facility emissions. The corresponding emissions from that facility that exceed the WEC threshold after any applicable exceptions, or "waste emissions," would be subject to the WEC charges.

20.5 Other Applicability Clarifications

Commenter: Interstate Natural Gas Association of America (INGAA)
Comment Number: EPA-HQ-OAR-2023-0234-0387
Page(s): 7

Comment 1: §93.233(z) title should be revised to clearly reflect segments addressed

§93.233(z) currently addresses select segments (i.e., upstream, distribution) and is titled accordingly. However, the Proposed Rule section added to address exhaust methane emissions more broadly addresses Subpart W segments including T&S, so the section title should be revised for clarity. INGAA recommends the following revision:

"(z) ~~Onshore petroleum and natural gas production, onshore petroleum and natural gas gathering and boosting, and n~~**N**atural gas ~~distribution~~ combustion emissions"

Response 1: See Section III.S.1 of the preamble to the final rule for the EPA's response to this comment.

Commenter: INNIO Waukesha Gas Engines, Inc.
Comment Number: EPA-HQ-OAR-2023-0234-0343
Page(s): 9-10

Comment 2: September 7th Webinar - Open Topic and Question: Do dual fuel (DF) engines report into subpart W and if not, where are these methane emissions reported? See background information and open question below.

To reduce fuel costs and lower emissions, the unconventional well development industry is investing in dual fuel (DF) engines and DF conversion kits to power directional drilling rigs and hydraulic fracturing engines. A 2017 study titled, "Greenhouse Gas Emission and Fuel Efficiency of In-Use High Horsepower Diesel, Dual Fuel and Natural Gas Engines for Unconventional Well Development"[2] published by Johnson et al. collected data focusing on in-use emissions of engines servicing the unconventional well development industry to explain the impact from current and newly applied technologies.

Findings from this study show methane losses from DF engines significantly contributing to GHG profiles. The average CH_4 loss rate during DF operation was 14.3% for steady state drilling operation. The GHG emissions of DF operation were 1.65 times higher than dedicated natural gas (DNG) and 2.2 times higher than diesel only (DO). Of these GHG emissions, over 47% were due to exhaust CH_4 and just over 2% were due to CH_4 from the crankcase of DF engines.

INNIO's Waukesha expects that emissions and engine counts from drilling operations are included in the operator's Onshore Petroleum and Natural Gas Production section of the annual subpart W report. As DF engines would be subject to the large engine category of the rule, fuel volumes are required to calculate emissions. Subpart W addresses fuel blends so it would be the operator's responsibility to report emissions based on the type of fuels blended.

As these engines utilize diesel and natural gas for combustion, INNIO's Waukesha expects that the diesel combustion contribution will utilize Table C-1 emission factors and the natural gas combustion contribution would follow the proposed or perhaps newly calculated emission factors based on the quality of the natural gas being utilized for the blend.

With this background information, INNIO's Waukesha requests for the EPA to provide a clarifying response to the question posed during the September 7th webinar as shown below:

Do Diesel engines that have supplemental fuel flow of natural gas (Dynamic Gas Blending) or more generically, dual fuel (DF) engines used in drilling and fracking, report into subpart W? If not, where are those methane emissions reported?

Footnote:

[2] Greenhouse gas emissions and fuel efficiency of in-use high horsepower diesel, dual fuel, and natural gas engines for unconventional well development; Author: Derek R. Johnson, Robert Heltzel, Andrew C. Nix, Nigel Clark, Mahdi Darzi; Publication: Applied Energy; Publisher: Elsevier; Date: 15 November 2017

Response 2: The EPA agrees with the commenter that it appears these units would be subject to reporting under the GHGRP. If the combustion units are part of a facility with respect to onshore petroleum and natural gas production, onshore petroleum and natural gas production, or natural gas distribution, then any combustion units that meet the applicability criteria would calculate and report emissions under subpart W. The commenter indicates the concern is use of these engines in unconventional well development, which would be the Onshore Petroleum and Natural Gas Production industry segment. Per 40 CFR 98.232(c)(22), the units that must calculate emissions according to 40 CFR 98.233(z) include stationary or portable fuel combustion equipment that cannot move on roadways under its own power and drive train. Stationary or portable equipment are the following equipment, which are integral to the extraction, processing, or movement of oil or natural gas: well drilling and completion equipment, workover equipment, natural gas dehydrators, natural gas compressors, electrical generators, steam boilers, and process heaters. These applicability criteria are not dependent on the type of fuel combusted.

If the reporter determines that the engine meets these applicability criteria, then the calculation methodology used depends on the fuels combusted. If the fuel combusted in the stationary or portable equipment is listed in Table C-1 of subpart C or is a blend in which all fuels are listed in Table C-1, emissions can be calculated using any Tier listed in subpart C of this part. If the fuel is natural gas that is not pipeline quality but has a higher heating value between 950 and 1,100 Btu/scf and at least 70 percent CH_4, either as the only fuel or in a blend in which the only other fuels are those listed in Table C-1, emissions can be calculated using Tier 2, Tier 3 or Tier 4 listed in subpart C of this part. Emissions from other fuels are calculated using the methods in 40 CFR 98.233(z)(3). Note that if the combustion unit is a reciprocating internal combustion engine or gas turbine that combusts natural gas, the requirements cited above include combustion slip emissions; see Section III.S.2 of the preamble to the final rule and Section 20.2 of this document for details on those calculation methods.

Commenter: Truck & Engine Manufacturers Association (EMA)
Comment Number: EPA-HQ-OAR-2023-0234-0352
Page(s): 2

Comment 3: EPA Should Ensure Consistency with Existing Regulations and Procedures

EMA agrees that the scope of the Notice of Proposed Rulemaking ("NPRM") and any final revised Greenhouse Gas Reporting Rule (40 CFR Part 98, Subpart W) is limited to petroleum and natural gas systems. EPA should emphasize this fact in the final rule to ensure no inconsistency between the Greenhouse Gas Reporting Rule, on the one hand, and stationary reciprocating internal combustion engine ("RICE") regulations under Clean Air Act ("CAA") Section 111, on the other. *See* 40 C.F.R. Part 60, Subparts IIII and JJJJ.

The NPRM states in several places that the rules therein regulate one source category: petroleum and natural gas systems. *See, e.g.*, 88 Fed. Reg. at 50,282, 50,283, 50,333, 50,369. EPA provides the following examples of affected facilities: pipeline transportation of natural gas, natural gas distribution facilities, crude petroleum extraction, and natural gas extraction. 88 Fed. Reg. at 50,283. EPA states that the impact of the NPRM would be to "amend requirements that apply to the petroleum and natural gas systems source category of the Greenhouse Gas Reporting Rule consistent with CAA section 136(h) …." 88 Fed. Reg. at 50,369. In addition, EPA assessed the incremental burden of the rule by looking at petroleum and natural gas industry segments *only*. 88 Fed. Reg. at 50,370 (Table 7—Total Incremental Burden By Industry Segment and Reporter); Assessment of Burden Impacts for Proposed Greenhouse Gas Reporting Rule Revisions for Petroleum and Natural Gas Systems, Docket Id. No. EPA-HQ-OAR-2023-0234-0165 at 6 (listing only petroleum and natural gas industry segments regarding crankcase venting and combustion slip emissions); *id.* at 14 (listing costs only for petroleum and natural gas industry segments). Indeed, none of EPA's documents address any impact on engine manufacturers.

The underlying statutory authority is limited to petroleum and natural gas systems as well. The Greenhouse Gas Reporting Rule is based on EPA's authority under CAA § 114, and EPA has issued rules for distinct source categories in 40 C.F.R. Part 98. Subpart W specifically addresses petroleum and natural gas sources. Section 60113 of the Inflation Reduction Act of 2022 ("IRA") added CAA § 136, which is titled, "Methane emissions and waste reduction incentive program for petroleum and natural gas systems." CAA § 136(d) defines "applicable facility" as all of the industry segments in subpart W, excluding natural gas distribution. The nine segments included in "applicable facility" are "offshore petroleum and natural gas production, onshore petroleum and natural gas production, onshore natural gas processing, onshore gas transmission compression, underground natural gas storage, liquefied natural gas storage, liquefied natural gas import and export equipment, onshore petroleum and natural gas gathering and boosting, and onshore natural gas transmission pipeline." 88 Fed. Reg. at 50,286. Thus, the lists in CAA § 136(d) and Subpart W are all petroleum and natural gas source categories.

EMA agrees with these numerous statements on scope and requests confirmation that the NPRM is not intended nor will be used to alter general stationary engine requirements. To that end, we have identified specific portions of the NPRM that could be misinterpreted or misapplied to affect stationary engine manufacturers.

Response 3: All of the final amendments to subpart C for methane slip clearly specify that those amendments apply only to "natural gas-fired reciprocating internal combustion engines or gas turbines at facilities subject to subpart W of this part." These provisions are not applicable to stationary engines at facilities that are not subject to subpart W. See Section III.S.2 of the preamble to the final rule and Section 20.2 of this document for more information regarding the amendments related to methane slip.

Commenter: GPA Midstream Association
Comment Number: EPA-HQ-OAR-2023-0234-0299
Page(s): 105

Comment 4: Appendix A

Table of changes GPA supports as proposed.

Subpart	Citation	Change
…		
W	98.238	Definition of "Routed to combustion"

Response 4: The EPA acknowledges the commenter's support of the proposed revisions. The EPA is finalizing these amendments as proposed.

21 Leak Detection and Measurement Methods

Commenter: Taxpayers for Common Sense (TCS)
Comment Number: EPA-HQ-OAR-2023-0234-0351
Page(s): 5

Comment 1: Gas Emitted Through Leakage

Natural gas is also routinely lost through leaking. On federal lands, oil and gas operators are not required to check for leaks or detect fugitive emissions, even as leaks and fugitive losses are common throughout the oil and gas production process.[11] The proposed rule seeks to improve monitoring and reporting of methane leakage in the oil and gas industry. Among other changes, the rule would mandate that any leak detected by an acoustic leak detection device be reported, as opposed to the current threshold of 3.1 standard cubic feet per hour or greater. TCS supports stringent requirements for reporting GHG leaks…

Footnote:

[11] Alvarez et al., "Assessment of methane emissions from the U.S. oil and gas supply chain," *Science*, July 13, 2018. https://www.science.org/doi/10.1126/science.aar7204

Response 1: The EPA acknowledges the commenter's support of the proposed revisions. The EPA is finalizing these amendments as proposed.

Commenter: Range Resources Corporation
Comment Number: EPA-HQ-OAR-2023-0234-0397
Page(s): 12-14

Commenter: The Petroleum Alliance of Oklahoma
Comment Number: EPA-HQ-OAR-2023-0234-0398
Page(s): 19

Comment 2: Commenter 0397: **EPA should allow operators to rely on manufacturer information when reporting high volume analyzer measurements.**

EPA is proposing revisions to the high volume sampler methods for identifying flow measurements. 88 Fed. Reg. at 50359. One of the proposed revisions would change how operators assess the capacity limits of a high volume sampler. EPA argues that the current regulations only require an operator to operate a high volume sampler to measure emissions with the capacity of the instrument but does not state how an operator is to determine the capacity of the instrument. So, EPA proposes that the capacity of the instrument be considered 70% of the device's maximum rates sampling rate. The Proposed Rule states:

Based on our review of reported high volume sampler measurements, we found that 2 to 5 percent of high volume sampler measurements for all types of compressor sources (for both centrifugal and reciprocating compressors) are likely at or beyond the expected capacity limits of the high volume sampler instrument. Considering actual sampling rates, gas collection efficiencies near the sampling rates, and reported CH_4 quantitation limits relative to maximum sampling rates, we determined that whole gas flow rates exceeding 70 percent of the device's maximum rated sampling rate is an indication that the device will not accurately quantify the volumetric emissions, which we deem to exceed the capacity of the device. 88 Fed. Reg. at 50359.

Range has been unable to identify any support for this statement in the technical information supporting this proposed rulemaking. Range believes that the manufacturer information accompanying high volume analyzers provides sufficient information to ensure that it is operating its high volume analyzer within the proper capacity limits. Manufacturers provide information regarding the maximum flow rate that a high volume analyzer accommodate as well as the minimum and maximum measurable leak rates as shown in the below example for a SemTech High-Flow 2.[3]

SPECIFICATIONS	
Total Flow Rate*	5-30 CFM (Upper limit dependent on accessories)
Measurable Leak Rate*	0.0005 to 25 CFM
Accuracy	<5% of full scale or 20% of point, whichever is lower
Dimensions (W x D x H) Electronics and Gas Module	12 x 12.0 x 3.5 in. (30 x 30 x 8.75 cm)
Dimensions (W x D x H) Handheld Unit w/o extension	24 x 7.5 x 10.5 in. (61 x 19 x 12.7 cm)
Weight (Electronic and Gas Module)^	18.1 lbs. (8.2 kg.)
Weight (Handheld Unit)	< 5.5 lbs. (<2.5 kg.)
Data transmission	WIFI

*Inlet restrictions on the HI-FLOW 2 handheld sampling unit will reduce the maximum achievable flow.
^Weight assuming full battery pack installed for 8+ hours of continuous operation.

Footnote:

[3] SemTech, SemTech Hi-Flow 2: Accurate Quantification of Fugitive Emissions, available at: https://sensors-inc.com/Portals/0/brochures/SEMTECH_HI-FLOW_2_Tech_Sheet.pdf.

Commenter 0398: High Volume Sampler. EPA is proposing to add a paragraph at 40 CFR 98.234(d)(5) to clarify how to assess the capacity limits of a high-volume sampler. EPA states that it has determined that whole gas flow rates exceeding 70 percent of the device's maximum rated sampling rate is an indication that the device will not accurately quantify the volumetric emissions, which EPA deems to exceed the capacity of the device.

It is unclear how EPA assessed high-volume samplers to determine that 70 percent is the correct threshold. Manufacturers design and test their products to make this determination, and OEM data should be adequate for reporters to use to determine the limits of the device. We question how EPA determined its data is better than manufacturer's data or that EPA's data should apply in all situations.

Action Requested: We request EPA allow reporters to use OEM data to determine the maximum rated threshold of high-volume sampling devices. If EPA maintains its 70 percent threshold, at a minimum, it must provide more details on how it analyzed each high-volume sampler that shows that the 70 percent threshold is appropriate for all samplers in all scenarios.

Response 2: In the specifications provided by one of the commenters, it is clear that one cannot rely solely on the measurable flow rate range provided by the manufacturer. Clearly the maximum measurable flow rate of 25 cfm is tied to the configuration that allows a maximum flow rate of 30 cfm. If different configurations are used where the sampling rate is not 30 cfm, the device would become saturated and "pegged" at much lower flows, so reliance on the reported measurable flow rate would not be appropriate. Also, the manufacturer suggests the measurable flow rate is 83 percent (25/30) of the maximum sampling rate. Because high volume samplers are typically designed specifically for methane detection, if the inlet stream is 80 percent methane, the upper quantitation limit of measured methane flow would likely be closer to 20 CFM or 67 percent of the maximum rated flow rate. This is consistent with what we have observed in our review. For example, the Bacharach high volume sampler includes the following technical specifications (see figure below, taken from https://www.mybacharach.com/wp-content/uploads/2020/06/0055-9017-Rev-7.pdf).

TABLE 1-1. TECHNICAL SPECIFICATIONS

Specification	Description
Information Displayed	• Date and Time • Battery voltage • Leak rate in cfm • Sampling flow rate in cfm • Leak concentration in ppm or % by volume • Background gas concentration in ppm or % by volume • Percent difference between leak rate measurements #1 and #2
Display	8 line by 20 character LCD
Pushbutton Controls	**I/O ↵** (Enter) **v** (Down Arrow) **^** (Up Arrow) **ESC** (Escape)
Communication	Three DB9 connectors providing serial data transfer at 115200 baud to a personal computer, or other peripheral device
Measured Values	• Sampling flow rate • Battery voltage • Sample gas concentration • Background gas concentration
Calculated Values	Leak concentration corrected for background gas level Leak rate Percent difference between leak rate measurements #1 and #2
Measurable Leak Rate	0.05 to 8.00 SCFM (1.42 to 226 LPM) 0.05 to 6.00 SCFM (1.42 to 170 LPM)
Accuracy	Calculated Leak Rate: ±10% of reading by volume methane
Temperature	Operating: 0 to 50 °C (32 to 122 °F) Storage: –40 to 60 °C (–40 to 140 °F)
Humidity	5 to 95% RH (non-condensing)
Sampling Flow Rate	Maximum.................................. 10.5 SCFM (297 LPM) at full battery charge Operating Flow Points................ Initial flow ≈ 10 SCFM (283 LPM). Second flow ≈ 8 SCFM (226 LPM). (The second flow rate is approximately 75% of the initial flow) Measurement Method................ Differential pressure across restriction Accuracy.................................... ±5% of reading
Natural Gas Sensor	Detection Method...................... Catalytic oxidation / Thermal conductivity Range: Catalytic oxidation.......... 0 to 5% by volume methane Range: Thermal conductivity ..... 5 to 100% by volume methane Accuracy.................................... ±5% of reading or 0.02 % methane, whichever is greater

The maximum sampling rate of this device is 10.5 scfm, so 8 scfm measurable flow rate is 76 percent of the maximum flow rate. Also note that the natural gas sensor specifications are specific to methane. When accounting for methane concentration of less than 100 percent, it is likely that measured methane rates over 70 percent of the maximum sampling rate of 10.5 scfm are indicative of leak rates that are at or in excess of the upper quantitation limit of the instrument. Hetek high volume samplers show more limited detection limits, presumably because they based their measurable flow rates on the Stage 2 sampling rate (see figure below; taken from https://www.hetek.com/wp-content/uploads/2022/01/6.42-Hetek-Flow-Sampler-Brochure-1.pdf). At stage 2 sampling rate of 75 percent of maximum, the measurement limit is approximately 5/6.75 or 74 percent of the sampling rate. However, the reported maximum measurement range is only 55 percent of the maximum blower flow rate of 9 cfm.

TECHNICAL SPECIFICATIONS

Specification	Value
Display Information	• Date and Time • Battery Level • Sample Concentration • Background Concentration • Blower flow rate • Difference between 2 stages • Leak Temperature • Quantified Leak Rate
Display Screen Size	3-inch LCD Display
User Controls	4 Pushbutton keys: ESCAPE; ↑ (up arrow); ↓ (down arrow); ENTER
Data Output	Data log file and Calibration log file (.CSV format)
Memory	800 records for Data; 1000 records for Calibration
Communication	USB cable from Hetek Flow Sampler to a digital device
Measured Values	• Blower Flow Rate • Battery Level • Sample Gas Concentration • Background Concentration
Calculated Values	• Quantified Leak (Stages 1 and 2) – CFM or LPM • Difference between stage 1 and stage 2 (Automatic and Manual)
Humidity	0 – 95% relative humidity (non-condensing)
Operating Temperature	- 20°C to 40°C (-4°F to 104°F)
Storage Temperature	- 20°C to 45°C (-4°F to 113°F); - 40°C to 90°C (without battery)
Blower Flow Rate	Maximum ≈ up to 9.0 CFM (255 LPM) at full battery charge Stage 2 is 70 – 80% of the flow rate of Stage 1
Sensor	Catalytic Oxidation Mode: 0 to 5% by volume methane Thermal Conductivity Mode: 5 to 100% by volume methane
Leak Measurement	1.5 – 140 LPM (0.052 – 5.0 CFM) : Automatic 2-Stage & Manual 2-Stage 0.5 – 140 LPM (0.017 – 5.0 CFM) : Manual 1-Stage
Battery	Standard Quantity: Two (2) with every Hetek Flow Sampler 4.8 V Nickel-Cadmium Rechargeable Battery Run Time: 5 hours (per battery) | Recharge Time: 12 hours
Weight	Enclosure and Display : 19.90 lbs (9.05 kgs)
Dimensions	Enclosure: 12" L x 16" H x 7.5" D (30.48 cm L x 40.64 cm H x 19.05 cm D)
Flow Measurement	Differential pressure across orifice
Accuracy	Sensor: ± 5% | Flow Rate: ±5% | Calculated Leak Rate: ±10%

After considering these comments, we maintain measurements exceeding 70 percent of rated sampling rates are indicative of leaks that are at the high volume sampler's quantitation limit.

Commenter: Range Resources Corporation
Comment Number: EPA-HQ-OAR-2023-0234-0397
Page(s): 12-14

Comment 3: Range has developed methods to appropriately measure the extent of emissions through the use of a high volume analyzer. For example, Range uses OGI in combination with a high volume analyzer. Because a high volume analyzer collects (i.e., captures) the emissions, OGI can be used to ensure that the high volume analyzer is collecting all of the emissions in its vicinity. EPA should clarify that an operator using OGI to ensure that a high volume analyzer is capturing all emissions may rely on the manufacturer's information on capacity limitations when reporting emissions.

Response 3: See Section III.T of the preamble to the final rule for the response to this comment.

Commenter: Public Hearing Transcript
Comment Number: EPA-HQ-OAR-2023-0234-0224
Page(s): 20 (Antoinette Reyes)

Comment 4: Then lastly, please … consider updating the EPA's Method 21 to a process that is less susceptible to human error.

Response 4: EPA Method 21 is a well demonstrated and widely adopted equipment leak screening protocol. EPA Method 21 specifies instrumentation requirements (*e.g.*, response time) as well as requirements for source surveys. The source survey requirements include component level (*e.g.*, valves) positioning of the instrument probe as well as durations for which detected leakage must be surveyed (*i.e.*, two times to instrument response time). These detailed requirements for instrumentation and the procedures for how to use the instruments are designed to ensure consistency and accuracy for all facilities utilizing the method to successfully detect equipment leaks. Furthermore, the EPA did not propose and is not finalizing changes to EPA Method 21, Determination of Volatile Organic Compound Leaks, in this rulemaking. EPA Method 21 is a test method that has been codified in the Code of Federal Regulations (CFR), so any changes to the method would need to be proposed so that all stakeholders required to use EPA Method 21 would have a chance to provide comments on the changes to the method.

22 Industry Segment-Specific Throughput Quantity Reporting

22.1 Throughput Information for the Future Implementation of the Waste Emissions Charge

22.1.1 General Comments

Commenter: GPA Midstream Association
Comment Number: EPA-HQ-OAR-2023-0234-0299
Page(s): 60-61

Comment 1: The requirement to use a flow meter to determine quantities sent to sale or through the facility is not workable for hydrocarbon liquids.

EPA proposes that:

Each facility must report the information specified in paragraphs (aa)(1) through (11) of this section, for each applicable industry segment, determined using a flow meter that meets the requirements of 98.234(b) for quantities that are sent to sale or through the facility and determined by using best available data for other quantities [98.236(aa)].

98.234(b) is limited to “flow meters, composition analyzers and pressure gauges,” and as such, this proposal is not workable for hydrocarbon liquid throughputs. Liquid throughputs are not always (or even commonly) measured with flow meters but are instead usually determined by truck loading tickets. To address this issue, EPA must expand the allowable methods to measure liquid sales/throughputs.

Response 1: See Section III.U of the preamble for the response to this comment.

Commenter: Environmental Defense Fund, et al.
Comment Number: EPA-HQ-OAR-2023-0234-0413
Page(s): 72-73

Comment 2: 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 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.

Response 2: The EPA acknowledges the commenter’s support of the proposed revisions. The EPA is finalizing these amendments as proposed.

22.1.2 Onshore Petroleum and Natural Gas Production and Offshore Petroleum and Natural Gas Production

Commenter: Western Energy Alliance
Comment Number: EPA-HQ-OAR-2023-0234-0399
Page(s): 14

Commenter: American Petroleum Institute et al. (Part 1 of 2)
Comment Number: EPA-HQ-OAR-2023-0234-0402
Page(s): 72-73

Commenter: Offshore Operators Committee (OOC)
Comment Number: EPA-HQ-OAR-2023-0234-0409
Page(s): 8-9

Comment 1: Commenter 0399: *Condensate*

The proposal requires companies to separate condensate from oil production reporting. Not only would this be inconsistent from field to field and operator to operator, but is also not feasible for most upstream facilities as the two are typically sold as one volume. The requirement to separate condensate from oil reporting should be removed.

Commenter 0402: Administrative Recommendations

Streamline Existing Reporting Forms to Reduce Duplicative Reporting and Reduce Unnecessary Submittal Errors

Due to the proposed requirement to report information on a more granular basis, the Industry Trades recommend the following streamlining efforts to reduce duplicative reporting, and to reduce the possibility of administrative error.

…

Miscellaneous Topics

Reporting condensate separate from other hydrocarbon products will be challenging due to where and how it is separated.

Commenter 0409: **Section/Paragraph Reference:** §98.236(aa)(2) and (ii) (iii)

Proposed Text: (ii) The quantity of crude oil produced from producing wells that is sent to sale in the calendar year, in barrels. (iii) The quantity of condensate produced from producing wells that is sent to sale in the calendar year, in barrels.

Comment: OOC recommends the proposed regulatory text be modified as follows:

(ii) The total quantity of ~~crude~~ oil produced from producing wells that is sent to sale in the calendar year, in barrels. ~~(iii) The quantity of condensate produced from producing wells that is sent to sale in the calendar year, in barrels.~~

Rationale: To be consistent with the Inflation Reduction Act (IRA) and BSEE reporting, OOC proposes for oil and condensate volumes to have combined reporting. Oil and condensate production is sent onshore via single combined pipelines.

The IRA does not differentiate between oil, condensate, and natural gas. BSEE does not differentiate between oil, condensate, and natural gas. Offshore operators report offshore production as either oil or natural gas.

In addition, Subpart A defines "sales oil" as produced crude oil or condensate measured at the production lease automatic custody transfer (LACT) meter or custody transfer tank gauge. LACT meters are installed on an offshore platform to measure the volume of oil sent to the pipeline. They do not measure oil or condensate separately.

Response 1: See Section III.U of the preamble for the response to this comment.

Commenter: Environmental Defense Fund, et al.
Comment Number: EPA-HQ-OAR-2023-0234-0413
Page(s): 72-73

Comment 2: 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]

Footnote:

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

Response 2: See Section III.U of the preamble for the response to comments regarding the reporting of crude oil and condensate.

Regarding the comment that EPA should retain the existing reporting elements in addition to the proposed new data elements, the commenter did not specify the reporting elements to which they were referring. However, the EPA specified in the preamble to the 2023 Subpart W proposal that most of the proposed revisions were for consistency in language rather than any expected difference in the volumes to be reported or the interpretation of the terms. As explained in Section III.U of the preamble to the final rule, the EPA is not finalizing the separate reporting of crude oil and condensate. The throughput reporting for Offshore Petroleum and Natural Gas reporting is another area in which the EPA indicated the proposed reporting elements were expected to differ from the current reporting requirements, and the EPA requested comment on whether to add the proposed throughputs as new data elements or continue to retain the existing reporting elements, along with rationale for maintaining the existing reporting elements. The commenter indicated that the EPA should add the new reporting elements and retain the existing reporting elements "to allow direct comparison of the impacts of the proposed change in requirements." However, the rationale did not explain how the existing data elements would be used if they were retained, beyond noting the ability to compare how the existing data elements are interpreted compared to the new data elements. The commenter also did not explain how they expected the proposed new data elements to differ from the existing reporting elements, and the EPA does not believe it would be appropriate to require reporters to report potentially duplicative data elements just to confirm whether reporters do consider them to be the same information. Therefore, the EPA is finalizing as proposed the revision of 40 CFR 98.23(aa)(2)(i) and (ii) rather than retaining the elements for gas handled and oil and condensate handled and then adding separate new data elements for the quantities sent to sales.

Commenter: Encino Energy (EAP Ohio, LLC)
Comment Number: EPA-HQ-OAR-2023-0234-0408
Page(s): 3-4

Commenter: Offshore Operators Committee (OOC)
Comment Number: EPA-HQ-OAR-2023-0234-0409
Page(s): 9-10

Comment 3: Commenter 0408: EAP Ohio, LLC askes EPA to treat the proposed rule more like an accounting framework than an NSPS OOOOb/c enforcement document.

…

Extra data requested for Onshore Petroleum and Natural Gas Production well-pad with a well that was permanently shut-in and plugged is duplicative reporting and unnecessary.

For each Onshore Petroleum and Natural Gas Production well-pad with a well that was permanently shut-in and plugged the EPA is proposing to require reporting of the total quantities of natural gas, crude oil, and condensate produced that was sent to sale in the reporting year for the well. Companies are already required to report production data from wells under other agency programs every year (e.g. Ohio Revised Code 1509.11). The production information is available to the public and the EPA. EAP Ohio, LLC asks the EPA to remove the requirement to report total volumes the year the wells were plugged since the information is available elsewhere as needed by the agency.

Commenter 0409: **Section/Paragraph Reference:** §98.236(aa)(2) and (vi), (v), (vi)

Proposed Text: (iv) For each well permanently shut- in and plugged during the calendar year, the quantity of natural gas produced that is sent to sale in the calendar year, in thousand standard cubic feet.

(v) For each well permanently shut-in and plugged during the calendar year, the quantity of crude oil produced that is sent to sale in the calendar year, in barrels.

(vi) For each well permanently shut- in and plugged during the calendar year, the quantity of condensate produced that is sent to sale in the calendar year, in barrels.

Comment: OOC recommends the proposed regulatory text be removed as follows:

~~(iv) For each well permanently shut- in and plugged during the calendar year, the quantity of natural gas produced that is sent to sale in the calendar year, in thousand standard cubic feet.~~

~~(v) For each well permanently shut-in and plugged during the calendar year, the quantity of crude oil produced that is sent to sale in the calendar year, in barrels.~~

~~(vi) For each well permanently shut-in and plugged during the calendar year, the quantity of condensate produced that is sent to sale in the calendar year, in barrels.~~

Rationale: Prior to permanently shutting in and plugging a well, production of oil or gas will be reported as a part of total sales which includes multiple wells producing on an offshore platform. Once a well is plugged, production ceases for that well, but production continues for others which would continue to be reported as total sales. Therefore, these requirements are unnecessary and overly burdensome.

Response 3: The EPA disagrees with the commenters that these requirements are unnecessary, as they are intended for consistency with and implementation of CAA section 136. We note that, under the WEC proposal, these throughputs would be used in the proposed methods to calculate emissions for the exemption for each well permanently shut-in and plugged. The EPA is finalizing the requirements to report, for each well permanently shut-in and plugged, the quantity of natural gas produced that is sent to sale in the calendar year and the quantity of oil and condensate that is sent to sale in the calendar year, in 40 CFR 98.236(aa)(2)(iii) and (iv), respectively (proposed as 40 CFR 98.236(aa)(2)(iv) and (v), respectively).

As explained in Section III.U of the preamble to the final rule, the EPA is not finalizing the separate reporting of crude oil and condensate. Therefore, the EPA is not finalizing the requirement proposed in 40 CFR 98.236(aa)(2)(vi) to report the quantity of condensate produced that is sent to sale in the calendar year.

Commenter: The Petroleum Alliance of Oklahoma
Comment Number: EPA-HQ-OAR-2023-0234-0398
Page(s): 10, 19-20

Commenter: Encino Energy (EAP Ohio, LLC)
Comment Number: EPA-HQ-OAR-2023-0234-0408
Page(s): 3-4

Comment 4: Commenter 0398: **Reporting for the Onshore Petroleum and Natural Gas Production and Onshore Petroleum and Natural Gas Gathering and Boosting Industry Segments**

For each Onshore Petroleum and Natural Gas Production well-pad with a well that was permanently shut-in and plugged, EPA is proposing to require reporting of the total quantities of natural gas, crude oil and condensate produced that is sent to sale in the reporting year for the wells on that well-pad. EPA states this information is anticipated to be useful in the future evaluation of the plugged well provisions of CAA section 136(f)(7).

However, EPA provides no details on how producing well production on a well-pad with a permanently shut-in and plugged well would be useful or informative for future plugged well provisions. If EPA wants such production information for each well on a well-pad, it should contact the appropriate state agency that maintains that data. EPA must explain and justify the need for such data.

Action Requested: We request EPA remove the requirement from the rule to report the total quantities of natural gas, crude oil and condensate produced that is sent to sale in the reporting year for other wells on that well-pad that contains a permanently shut-in and plugged well. At a minimum, if EPA proceeds ahead with this requirement, it must justify the need and use of this information.

…

Industry Segment-Specific Throughput Quantity Reporting

EPA proposes reporters provide additional throughput data elements to provide separate, well-level reporting of throughputs associated with wells in the Onshore Petroleum and Natural Gas Production and Offshore Petroleum and Natural Gas Production industry segments that are permanently shut-in and plugged. EPA provides no justification as to why it needs production information for producing wells at a facility that also has permanently shut-in or plugged wells.

Action Requested: See our comments in II.D. above

Commenter 0408:

EAP Ohio, LLC askes EPA to treat the proposed rule more like an accounting framework than an NSPS OOOOb/c enforcement document.

…

Extra data requested for Onshore Petroleum and Natural Gas Production well-pad with a well that was permanently shut-in and plugged is duplicative reporting and unnecessary.

For each Onshore Petroleum and Natural Gas Production well-pad with a well that was permanently shut-in and plugged, the EPA is proposing to require reporting of the total quantities of natural gas, crude oil, and condensate produced that is sent to sale in the reporting year for the wells on that well-pad. Other wells on the pad may have production which is irrelevant to the production of the plugged well due to the possibility of different completions techniques or time drilled. EAP Ohio, LLC asks the EPA to remove the requirement to report total pad production volumes the year the well was plugged, since the information is irrelevant.

Response 4: See Section III.U of the preamble for the EPA's response to this comment.

Commenter: Environmental Defense Fund, et al.
Comment Number: EPA-HQ-OAR-2023-0234-0413
Page(s): 48-49

Comment 5: 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 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.

Footnotes:

[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

[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.

Response 5: The EPA appreciates the commenter's support for the proposed amendments and is finalizing amendments as described in Section III.U of the preamble to the final rule.

Regarding additional data elements that the commenter asserted are needed for implementation of CAA section 136, the EPA recently published a proposed rule to implement CAA section 136(c), "Waste Emissions Charge," or "WEC," on January 26, 2024 (89 FR 5318). Several of the commenter's suggestions were considered and, where appropriate, included in the provisions of that proposal. In particular, the WEC proposal included proposed provisions regarding documentation of when a well is plugged, identification of the regulations (state, local, and federal) stipulating requirements that were applicable to the closure of the well, and how reporters calculate the emissions that may be exempted from WEC when a well is plugged. As part of the WEC proposal, the EPA sought comment on these provisions under that separate rulemaking. Therefore, the EPA is not finalizing any other amendments to subpart W as a result of consideration of this comment at this time, as they are outside the scope of this rulemaking.

22.1.3 Onshore Petroleum and Natural Gas Gathering and Boosting

Commenter: Environmental Defense Fund, et al.
Comment Number: EPA-HQ-OAR-2023-0234-0413
Page(s): 73

Comment 1: 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.

Response 1: The EPA acknowledges the commenter's support of the proposed revisions. The EPA is finalizing these amendments with slight changes from proposal, as detailed in Section III.U of the preamble to the final rule.

Commenter: GPA Midstream Association
Comment Number: EPA-HQ-OAR-2023-0234-0299
Page(s): 61

Comment 2: Additional changes are needed to properly account for gathering and boosting throughput.

EPA's proposed changes to the gathering and boosting throughput reporting requirements are an improvement upon the current rule. Two additional changes, however, are needed. First, the term "downstream endpoint" is too narrow because gas sometimes exits the gathering system to an "upstream" location, such as when some gas goes back to upstream producers for various uses. Second, as GPA noted to EPA in both the GPA Comments on Methane Emissions Reduction Program and the GPA Comments on the 2022 Proposed Rule, it is critical for gathering and boosting segment reporters to account for gas that flows through multiple compressor stations in series within the same basin.[138] The proposed language is closer to directly accounting for this, but still falls short of clarity on this important point. As a result, GPA proposes the following changes be made:

> *98.236(aa)(10)(ii) The quantity of natural gas transported through the facility to a downstream endpoint or to another industry segment such as a natural gas processing facility, a natural gas transmission pipeline, a natural gas distribution pipeline, a storage facility, or another gathering and boosting site or facility in the calendar year, in thousand standard cubic feet.*
>
> *98.236(aa)(10)(iv) The quantity of all hydrocarbon liquids transported to a downstream endpoint or to another industry segment such as a natural gas processing facility, a natural gas transmission pipeline, a natural gas distribution pipeline, a storage facility, or another gathering and boosting site or facility in the calendar year, in barrels.*

Footnote:

[138] GPA Comments on Methane Emissions Reduction Program at 6; GPA Comments on 2022 Proposed Rule at 31.

Response 2: See Section III.U of the preamble for the EPA's response to this comment.

Commenter: GPA Midstream Association
Comment Number: EPA-HQ-OAR-2023-0234-0299
Page(s): 12-13, 100-101

Comment 3: EPA needs to consider revising the definition of "facility" to align with the Inflation Reduction Act.

EPA needs to consider the interaction between the Inflation Reduction Act, the GHGRP, and proposed NSPS OOOOb ("NSPS OOOOb") and proposed Emission Guideline OOOOc ("EG OOOOc"). [18] All of these programs involve a definition of "facility" that differs in scope from, and that do not necessarily align with, the public's common understanding of that word. In NSPS OOOOb and EG OOOOc, the "affected facility" is an individual piece of equipment (or group of equipment) such as all the natural gas-driven pneumatic controllers at a gas plant. In the GHGRP, a Subpart W "facility" includes all emissions of the same type (e.g., all gathering and boosting sources) within a basin. A basin is a large geographical area spanning many counties and sometimes multiple states. Neither of these definitions work in the context of the Inflation Reduction Act, nor are they consistent with the general understanding of the word "facility."

The Inflation Reduction Act states that "the term 'applicable facility' means a facility within the following industry segments…."[19] GPA suggests that EPA use the simplest interpretation of the term, which is that a "facility" is a single site, and not specific pieces of equipment within that site or the aggregation of hundreds of sites within a geographical area. GPA believes that this is a straightforward approach that bridges the gap between how the term is used in NSPS OOOOb and EG OOOOc and how the term is used in Subpart W. As the Supreme Court has noted, it is a "fundamental principle of statutory construction (and, indeed, of language itself) that the meaning of a word cannot be determined in isolation but must be drawn from the context in which it is used."[20]

To illustrate this point, current Subpart W requirements address throughput differently depending on each industry segment. This has significant ramifications for implementation of the waste charge provisions of the Inflation Reduction Act, particularly if "facility" is not defined specifically for purposes of the waste emission charge. For instance, under current Subpart W requirements, the gas through each transmission compressor station is reported on a per-transmission-compressor-station basis (98.236(aa)(4)(i)). This accounts for the same gas moving through multiple compressor stations. But then just upstream of transmission, Subpart W requires reporting only of the volumes into and out of a gathering and boosting basin (98.233(aa)(10)(i)-(iv)).[21] Reporting throughput at the gathering and boosting basin boundaries does not adequately capture "intra-basin" movement (e.g., natural gas that moves through multiple gathering and boosting compressor stations within a single basin). Because emissions generated from a facility are a function of the facility throughput, this is a significant disparity. EPA should address this disparity by modifying or adding Subpart W throughput reporting elements for gathering and boosting that allow reporters to align with other industry segments and reflect true facility throughput for assessment against the waste charge.[22] EPA has proposed additional reporting requirements for each "gathering and boosting site located in the facility," meaning each gathering compressor station, centralized oil production site, gathering pipeline, or other fence-line site.[23] In addition to the identification data that EPA has proposed be reported, throughput data should be reported per site as well. The overall throughput for the gathering and boosting "facility" should be revised to be equal to the sum of all individual "site" throughputs. Comment 85 provides additional comment on the definition of the term throughput.

…

Proposed Change: EPA is proposing to add, as reporting element, the count of compressor stations within a basin to facilitate better understanding of G&B operations [98.236(aa)(10)(v)], at the request of GPA Midstream.

> **Comment**: Reporting element 98.236(aa)(10)(ii)—"The quantity of gas transported to a natural gas processing facility, a natural gas transmission pipeline, a natural gas distribution pipeline, or another gathering and boosting facility in the calendar year, in thousand standard cubic feet"—is collected to assess basin throughput. However, this throughput metric only captures gas at the boundaries of a G&B basin and does not adequately capture gas movement within a basin. For example, it is not uncommon for gas to travel through multiple compressor stations in series on its way to a gas plant. However, with the current throughput definition, this gas movement is only captured once – at the gas plant. Just as understanding the number of gathering and booster stations in a basin is critical for data analysis, understanding gas flow through gathering and boosting stations as it truly moves within a basin is critical. We suggest that EPA include in this data element any gas volume that moves through a gathering and boosting station that is not otherwise captured by the existing definition.
>
> **Suggested text**: *98.236 (aa)(10)(ii) The quantity of gas transported to a natural gas processing facility, a natural gas transmission pipeline, a natural gas distribution pipeline, or another gathering and boosting facility in the calendar year, in thousand standard cubic feet. <u>This quantity should also include volume transported from one gathering and boosting station to another gathering and boosting station within the basin that is not otherwise accounted for.</u>*

Footnotes:

[18] EPA proposed NSPS OOOOb and EG OOOOc under section 111(b) and section 111(d), respectively, of the CAA. See 87 Fed. Reg. 74,702 (Dec. 6, 2022) (supplemental proposed rule); 86 Fed. Reg. 63,110 (Nov. 15, 2021) (partial proposed rule). NSPS OOOOb would apply to new, modified, and reconstructed sources in the oil and gas source category, while EG OOOOc sets forth guidelines for state plans that, once adopted and approved, will apply to existing sources within that category.

[19] Pub. L. No. 117-169, § 30114 (adding new CAA § 136).

[20] Deal v. United States, 508 U.S. 129, 132 (1993).

[21] In this proposal, EPA improves the throughput reporting requirements, but the changes fall short of clearly accounting for intra-basin throughput.

[22] See GPA Comments on 2022 Proposed Rule; GPA, Comments on EPA's Request for Information on the "Methane Emissions Reduction Program" at 6 (Jan. 18, 2023), Doc. ID No. EPA-HQ-OAR-2022-0875-0054 ("GPA Comments on Methane Emissions Reduction Program") (attached hereto as Attachment B and incorporated by reference).

[23] Proposed 40 C.F.R. § 98.236(aa)(10)(v).

Response 3: The commenter's reference to the language in the Inflation Reduction Act (specifically, CAA section 136(d)) was not complete. The full text is "For purposes of this section, the term `applicable facility' means a facility within the following industry segments, *as defined in subpart W of part 98 of title 40, Code of Federal Regulations*:" (emphasis added). At the time that Congress drafted CAA section 136, the current definitions of "facility" already existed in Subpart W. The EPA thus is acting consistent with the text of CAA section 136.

The commenter also requested that the EPA require the throughput for each gathering and boosting site and that the total basin throughputs should be the sum of the throughputs for each gathering and boosting site. However, a sum of individual site throughputs that include natural gas transported between compressor stations that are part of the same "facility with respect to onshore petroleum and natural gas gathering and boosting" would not be consistent with the throughput in CAA section 136(f)(2), which is the "natural gas sent to sale from or through such facility." As noted in Section III.U.3 of the preamble to the final rule, the finalized quantity of natural gas reported in 40 CFR 98.236(aa)(10)(ii) is the quantity of natural gas transported from the facility regardless of endpoint (the proposal limited the quantity to the quantity of natural gas transported downstream).

22.2 Onshore Natural Gas Processing and Natural Gas Distribution Throughputs Also Reported Under Subpart NN

Commenter: GPA Midstream Association
Comment Number: EPA-HQ-OAR-2023-0234-0299
Page(s): 17

Commenter: Chesapeake Energy Corporation
Comment Number: EPA-HQ-OAR-2023-0234-0400
Page(s): 5

Commenter: Environmental Defense Fund, et al.
Comment Number: EPA-HQ-OAR-2023-0234-0413
Page(s): 73

Commenter: American Gas Association (AGA) and American Public Gas Association (APGA)
Comment Number: EPA-HQ-OAR-2023-0234-0418
Page(s): 21

Comment 1: Commenter 0299: The following is a list of substantive proposed changes that GPA expressly supports.

…

- Streamlining reporting of hydrocarbon liquid throughputs under Subparts W and NN [98.236(aa)(3)];

Commenter 0400: **The Proposed Rule should retain provisions seeking to remove duplicative or unnecessary reporting.**

EPA's Proposed Rule seeks to eliminate duplicative elements from Subpart W. Specifically, EPA is proposing to remove certain data elements that are analogous to elements in Subpart NN, as well as certain reporting elements unique to Subpart W that "require additional burden to estimate" but "have not been used for the EPA's analyses." [13] This proposal will help limit compliance burdens for Natural Gas Distribution companies and prevent unnecessary expenditures on top of existing requirements.

Chesapeake supports EPA's acknowledgement that reporting obligations should not be overly burdensome without accompanying emissions benefits. Chesapeake strongly encourages EPA to more broadly assess the cost-effectiveness of its proposed requirements in order to tailor reporting methodologies to the specific equipment and unique circumstances involved, considering available data, compliance burdens, and emissions benefits.

Footnote:

[13] 88 Fed. Reg. at 50,362.

Commenter 0413: 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.

Commenter 0418: **The Associations support the removal of certain throughput reporting elements from Subpart W that are duplicative of Subpart NN.**

According to the Proposed Rule, there are no LDCs that report under Subpart W that do not also report under Subpart NN of the GHGRP. [69] EPA has determined that Subpart W contains several throughput reporting requirements that are duplicative of data elements in Subpart NN. To eliminate reporting redundancies and reduce burden—and because Subpart NN has been in effect for LDCs longer than Subpart W's throughput requirements—EPA is proposing to remove certain data elements from Subpart W and retain the analogous requirements in Subpart NN. Specifically, the Proposed Rule would eliminate the Subpart W requirement for LDCs to report the quantities of natural gas (1) received at all custody transfer stations, (2) withdrawn from in-system storage, (3) added to in-system storage, and (4) delivered to end users. EPA also is proposing to remove the requirement to report the volume of natural gas used for operational purposes and the volume of stolen natural gas, as EPA has not used these elements for its analyses of Subpart W data. The Associations support the proposed removal of these Subpart W throughput reporting requirements for the distribution segment for the reasons set out in the preamble to the Proposed Rule.[70]

Footnotes:

[69] Proposed Rule, 88 Fed. Reg. at 50,362.

[70] *See id*. at 50,361–63.

Response 1: The EPA acknowledges the commenters' support of the proposed revisions. The EPA is finalizing these amendments as proposed.

Regarding Commenter 0413's question on whether and how the volume of natural gas used for operational purposes and natural gas stolen are used by stakeholders aside from the EPA, we do not have information regarding the uses of this information once it is published. However, as we indicated in the preamble to the 2023 Subpart W Proposal, these data elements have not been used for the EPA's analyses of the subpart W data, and at this time we do not expect they will be used in analyses for potential future policy decisions under the provisions of the CAA.

22.3 Onshore Natural Gas Transmission Pipeline Storage Throughputs

Commenter: Environmental Defense Fund, et al.
Comment Number: EPA-HQ-OAR-2023-0234-0413
Page(s): 73

Comment 1: 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.

Response 1: The EPA acknowledges the commenter's support of the proposed revisions. The EPA is finalizing these amendments as proposed.

23 Measurement Approaches

23.1 Satellite Measurements

Commenter: Public Hearing Transcript
Comment Number: EPA-HQ-OAR-2023-0234-0224
Page(s): 40 (Kayley Shoup)

Comment 1: A recent incident in the Permian underlines why you must take full advantage of the technology at your fingertips by incorporating measurement data, but why it's crucial that it also goes hand in hand with implementing strict guardrails for self-reporting at all sites as green washing from major oil companies becomes the norm. In 2021, Exxon announced that it would be working with an independent certifier to certify that the natural gas produced at their Poker Lake facilities is responsibly sourced. These sites are right outside of Carlsbad, and I knew that they would get way too much credit for cleaning up a few sites while continuing to pollute the air that I and my family breathe. Fast forward to March 2022. A NASA satellite caught a large emission event just miles out of Carlsbad. This emission event was not reported to the state of New Mexico as is required. No one knew of it, and never would know of it, if it wasn't for that satellite. And as I'm sure you might have guessed, Exxon's XTO was responsible for this unreported event. As your agency finalizes these rules, it is crucial that your regulations take into account the fact that the companies that knowingly got us into this mess of fossil fuel climate change will not be the ones to save us, and they are still as dishonest as ever.

Response 1: The EPA thanks the commenter for the background on satellite usage to detect a large emissions source. In this final rule, we are adding a new emissions source, referred to as "other large release events," to capture abnormal emission events that are not accurately accounted for using existing methods in subpart W. For our discussion on the addition of this new emission source and alignment with EPA's Super Emitter Program, see Section III.B of the preamble to the final rule. With respect to the commenter's request that there are strict guardrails for self-reporting, we note that facilities are required to calculate emissions using methodologies that are specified at 40 CFR Part 98 for reporting their emissions. The EPA also conducts a robust, multi-step data verification process for all information reported under subpart W to ensure reported data are accurate, complete, and consistent. The EPA will be developing additional processes to verify data reported under the new requirements in this final rule. We note that under a separate rulemaking, the EPA plans to address additional verification of subpart W reporting, including any potential use of third-party verification, as it relates to and under the waste emissions charge (WEC) rule. Stakeholders should review the proposed WEC rule for additional information.

Commenter: CrownQuest Operating
Comment Number: EPA-HQ-OAR-2023-0234-0393
Page(s): 35

Comment 2: The EPA is using the Pandey study to define ranges of top-down satellite detection limits; however, this study does not elaborate on detection limits, nor does it sufficiently define anything besides potential methodology for similar large methane releases in the future.

Response 2: The Pandey study was cited in the proposed rule as example of current satellite capabilities. This study was not used to develop definitions in the proposed or final rule.

23.2 Other Aerial Measurements

Commenter: Bridger Photonics, Inc.
Comment Number: EPA-HQ-OAR-2023-0234-0407
Page(s): 7

Comment 1: Recommendation 4: Create a pathway to approve and update methods for developing measurement-based methane emissions inventories.

The following discussion illustrates how Gas Mapping LiDAR technology achieves the necessary technology/technology deployment performance metrics:

Detection Sensitivity. Bridger's GML technology is capable of detecting methane emissions to below 1 kg/h with 90% probability of detecting emissions. Independent third-party studies find GML to be ~30x more sensitive than the nearest alternative commercial airborne (i.e. scalable) solution.[14] Furthermore, Bridger's detection sensitivity model determines detection sensitivity performance on a site-by-site (or better) basis, allowing undetected emissions to be accurately estimated based on site-specific detection probabilities for a given emission rate and the count of emissions detected at that rate.

Quantification Accuracy. To achieve an accurate aggregate emissions inventory, the systematic error in quantifying emission rates must be low. The primary sources contributing to quantification bias are instrument bias, processing bias, and wind speed bias. Bridger's internal calibration and flight-testing procedures applied to each GML sensor remove quantification bias to <10%. Bridger uses established low-bias wind sources (e.g. NOAA's HRRR), supplemented by gas plume shape characteristics, to remove wind-based quantification bias. Bridger's aggregate quantification uncertainty (including all bias sources) for a single sensor has been rigorously confirmed to be below 10% by independent third parties when NOAA's HRRR wind source is used.[15] Bridger's quantification uncertainty model is used to further remove bias from aggregate measurements and to characterize instrument quantification confidence intervals.

Resilience Towards Systematic Errors. Bridger's GML technology uses a birds-eye aerial vantage point to prevent systematically missed sources (which could otherwise occur for sources elevated off the ground, like combustion stacks or tanks). Bridger also audits the spatial coverage of its scanning lasers. Because GML uses laser light rather than sunlight as its light source, GML has the deployment flexibility to sample at any time of day and remove uncertainty from intraday emissions variation.

Equipment Attribution. The correct attribution of emission sources to equipment in an inventory critically enables strategic and intelligent reduction strategies. Poor spatial resolution and lack of accurate equipment inventories can lead to systematic errors in emission source attribution. Bridger's machine learning algorithms to automatically detect and label equipment. Bridger combines this capability with high spatial resolution gas imagery to confidently attribute emission sources. This allows statistical filtering of the emissions inventory data.

Inventory Assessment Validation. Bridger validates the deployment of GML technology within inventory development frameworks to ensure inventory assessments are consistent and reproducible. Replicate scans of infrastructure sample sets at different points in time and under different environmental conditions (but without operator intervention between scans) are used to determine the variance in calculated total emissions between scans and evaluate if the variance aligns with the expected uncertainty. In addition, scans spaced over longer time periods are used to assess the impact of seasonal emissions variation.

As the EPA develops the final rule, Bridger will continue to inform the EPA on suitable requirements for approving inventory assessment frameworks and measurement technologies.

We urge the EPA to provide an approval pathway for frameworks and technologies to be used to develop regional and facility-level measurement-based methane emissions inventories for subpart W reporting. This would provide confidence and transparency for reporting and open the door for emissions assessment methods to be continually improved.

Footnotes:

[14] "Robust probabilities of detection and quantification uncertainty for aerial methane detection: Examples for three airborne technologies". https://doi.org/10.1016/j.rse.2023.113499

[15] "Single-blind determination of methane detection limits and quantification accuracy using aircraft-based LiDAR". https://doi.org/10.1525/elementa.2022.00080

Response 1: Thank you for the information on Gas Mapping LiDAR. As discussed in Section II.B of the preamble to the final rule, this final rule does not include a general provision to incorporate the use of advanced measurement approaches for sources at this time and instead specifically allows its use in certain appropriate cases, including for large release events. However, the Agency recognizes that these technologies, and approaches for using these technologies for long-term quantification of emissions from oil and natural gas operations, are evolving rapidly. Historically, the Greenhouse Gas Reporting Rule has been revised to incorporate the latest data, updated scientific knowledge or additional measurement methods and EPA intends to continue to evaluate the appropriateness of additional updates. The EPA is actively reviewing relevant peer-reviewed literature and pilot programs and in advance of future rulemaking, the EPA intends to initiate a request for information, workshop, or white paper to further solicit feedback on the use of advanced measurement data and methods in subpart W.

Commenter: CrownQuest Operating
Comment Number: EPA-HQ-OAR-2023-0234-0393
Page(s): 39

Comment 2: In reference to the Duren, et al. study

This study, from the beginning, has some flaws. First off it was done in California from 2016-2018, you cannot cherry pick certain studies in a specific area and try to blanket that study across the country and across all basins. Formation characteristics, production profiles, equipment, etc vary too much to do that. The study also includes airborne imaging with a spectrometer for manure-management and waste-management sectors. We are in the oil and gas sector. "The largest methane emitters in California are a subset of landfills, which exhibit persistent anomalous activity. Methane-point source emissions in California are dominated by landfills, followed by dairies …" Again, Subpart W pertains to the oil and gas sector. This study does not pertain to the oil and gas industry.

Response 2: The Duren, *et al.* study was cited in the proposed rule as a source of information on satellite capabilities with respect to methane detection and quantification and was not used to characterize the oil and gas sector.

Commenter: CrownQuest Operating
Comment Number: EPA-HQ-OAR-2023-0234-0393
Page(s): 78

Comment 3: We support the addition of the introduction of advanced technologies in the proposed NSPS OOOOb and EG OOOOc, specifically the use of the aerial LiDAR flyover technology. This technology allows the operator to cover many more sites in a day compared to boots on the ground OGI surveys. In turn this would allow the operator to identify more leaks quickly and address those leaks in a timelier manner.

Through The Environmental Partnership companies have been taking action to reduce emissions with the use of flyover technology. Through the technology using a methane specific light detection and ranging (LiDAR) instrument mounted on a low flying fixed wing aircraft, operators can cover a wide area of coverage in a much smaller amount of time. Companies in the partnership have flown in eight basins (Permian, DJ, Bakken, Marcellus, Anadarko, Eagleford, Haynesville and Powder River), surveying over 10,000 sites. The Partnership is able to survey complex sites which enables us to get a deeper understanding of emissions across our assets. These flyovers provide a couple of things: the opportunity to deploy and understand the capabilities of new aerial detection technology and the ability to advance our understanding of methane emission profiles, which includes source identification and rates. These flyovers provided an aerial snapshot in time of methane emissions with high enough resolution to attribute the emissions to a single piece of equipment in the field.

This LiDAR technology uses laser technology to measure either distance at the presence of gas. By utilizing lasers to v=create 3D topographic or gas concentration imagery of the surveyed environment. Both uses for LiDAR can be performed using either pulses of laser light or laser light that stays on all the time. We can use continuous wave LiDAR to measure both solid surfaces and gases. The sensitivity for the production sector is great. 3 kg/hr with a >90% probability of detection. Multiple studies are available that back the technologies detection capabilities:

- "Robust probabilities of detection and quantification uncertainty for aerial methane detection: Examples for three airborne technologies"

Conrad, Tyner & Johnson

- Single-blind determination of methane detection limits and quantification accuracy using aircraft-based LiDAR"

Bell, Rutherford, Brandt, Sherwin, Vaughn & Zimmerle

- Single-blind determination of methane detection limits and quantification accuracy using aircraft-based LiDAR"

Bell, Rutherford, Brandt, Sherwin, Vaughn & Zimmerle

As mentioned before, this technology provides a strong detection sensitivity with the production sector of 3 kg/hr with >90% probability of detection. This emission rate detection sensitivity is unmatched for aerial methane detection.

Response 3: We acknowledge the commenters support for LiDAR technology. As discussed in Section II.B of the preamble to the final rule, this final rule does not include a general provision to incorporate the use of advanced measurement approaches for sources at this time and instead specifically allows its use in certain appropriate cases, including for large release events. However, the Agency recognizes that these technologies, and approaches for using these technologies for long-term quantification of emissions from oil and natural gas operations, are evolving rapidly. Historically, the Greenhouse Gas Reporting Rule has been revised to incorporate the latest data, updated scientific knowledge or additional measurement methods and EPA intends to continue to evaluate the appropriateness of additional updates. The EPA is actively reviewing relevant peer-reviewed literature and pilot programs and in advance of future rulemaking, the EPA intends to initiate a request for information, workshop, or white paper to further solicit feedback on the use of advanced measurement data and methods in subpart W.

Commenter: CrownQuest Operating
Comment Number: EPA-HQ-OAR-2023-0234-0393
Page(s): 78

Comment 4: No matter the detection technology, there will be conditions under which it will perform better and conditions where it will perform worse. We ask the EPA to require that the specified detection sensitivity be achieved under "typical" conditions for which the alternative work practice is applied.

We also ask the EPA to set a detection sensitivity performance standard of 10 kg/hr (as proposed) with a required >50% probability of detection under typical conditions where the alternative work practice is applied.

The EPA solicited feedback on the alternative work practice consisting of a bi-monthly aerial scan frequency IN ADDITION to annual OGI surveys. There has been extensive modeling done to predict the efficiency of using different scan frequencies, these model predictions vary widely depending on many factors and assumptions. It is our opinion that insufficient experimental data exists regarding scan frequency to guide and inform. With this uncertainty in modeling, and the financial, operational, and logistical burden for a ramp up to bi-monthly scanning, we urge the EPA to keep semiannual scan frequency in the final rule.

The EPA solicited feedback on the possibility of using a "matrix" to aerial scanning, where poor detection sensitivity could be subbed for increased scanning frequency, or where better detection sensitivity could be subbed for lower scanning frequency. It is of our opinion that there is insufficient data that exists regarding scan frequency for a matrix approach. For this, we ask the EPA to only allow a matrix approach that subs detection sensitivity for scan frequency if detection of 75% of emissions will be achieved.

…

Limit OGI follow up requirements:

The EPA's proposed rule says that an emission source identified by an aerial scan must be investigated with ground crews and repaired in the case of fugitive emissions. However, some number of detected emissions are linked with normal operating process emissions rather than fugitive emissions, so no repair action is required because of the detection. We ask the EPA to not require OGI-follow up visits to equipment that corresponds to emission sources that have previously been identified as normal operating process emissions if the emission rate is within the permitted range for said equipment and the equipment is scanned during the scheduled OGI scan.

Allowing aerial scans in lieu of OGI on a per scan basis:

The EPA is proposing " …the option to comply with this alternative fugitive emissions standard instead of the proposed ground based OGI surveys …" We fully support this alternative option in general. However, we ask the EPA to provide sufficient flexibility in the alternative work practice to allow for aerial/OGI swaps on a per-scan basis due to certain wind/weather conditions.

Regarding the affected category of fugitive emissions components timeline in the proposed rule, the EPA compliance timeline is 60 days. The EPA must realize that this is not realistic due to the current supply chain issues. The API polled its members across 11 basins in the country to provide what we are seeing as far as lead times go for equipment. The average time for fugitive emissions components is 18 months. We ask that the EPA please take this into consideration in the final rule.

Response 4: These comments appear to be on the proposed NSPS OOOOb and EG OOOOc rule and not this proposed rule. Therefore, this comment is out of scope for this rulemaking.

Commenter: Kairos Aerospace
Comment Number: EPA-HQ-OAR-2023-0234-0240
Page(s): 6-8

Comment 5: High-Quality Measurement Technology is Commercially Available, Widespread, and Low Cost

The oil and gas infrastructure subject to Subpart W is often spread over large spatial areas and geographic locations. Infrastructure often spiderwebs across major producing basins, with pipelines connecting individual well sites all the way to the major gas gathering and processing infrastructure used to transport that gas to market. Many of these oil and gas producing regions span tens of thousands of square miles. Oftentimes these facilities and pipelines are remote and difficult to access, crossing rugged terrain and located many hours from the closest company field office. Because of these challenges, ground-based leak detection on these systems is a daunting, costly, and personnel-intensive task.

By contrast, remote sensing leak detection surveys deploy highly engineered scientific instruments across vast areas that would take a ground crew months to survey. Within hours or days, remote sensing surveys pinpoint emission source locations with high precision, facilitating targeted, critical repair. Aerial systems, like the one used by Kairos, have been rigorously tested and subjected to independent, blinded evaluation of their performance. In the case of Kairos, leading experts at Stanford University conducted multiple days of blinded, controlled testing of the Kairos aerial leak detection platform and published the results in the peer-reviewed scientific literature[10,11] . These testing results show Kairos technology achieving 90% probability of detection of emissions of 8.9 kilograms per hour. To put it simply, aerial systems like the ones used by Kairos have been thoroughly tested and have a demonstrated track record of performance.

Not only are aerial systems proven and effective methane detection tools, they have extensive records of field deployment within the oil and gas industry. Kairos alone has surveyed over 710,000 active wells and 500,000 miles of gas pipelines for the oil and gas industry, and has helped clients eliminate 75 billion cubic feet of methane leaks from their systems. And while we are a leader in the methane detection industry, we are certainly not the only company capable of delivering high quality methane measurement products to a variety of industry clients at scale.

Kairos operates 18 aerial methane leak detection units in the field today, each one capable of surveying over 250 sq miles per day. Combined, we have the capability to survey thousands of square miles for methane emissions across multiple oil and gas basins simultaneously each week. Figure 2 below illustrates the Kairos Aerospace data collection process.

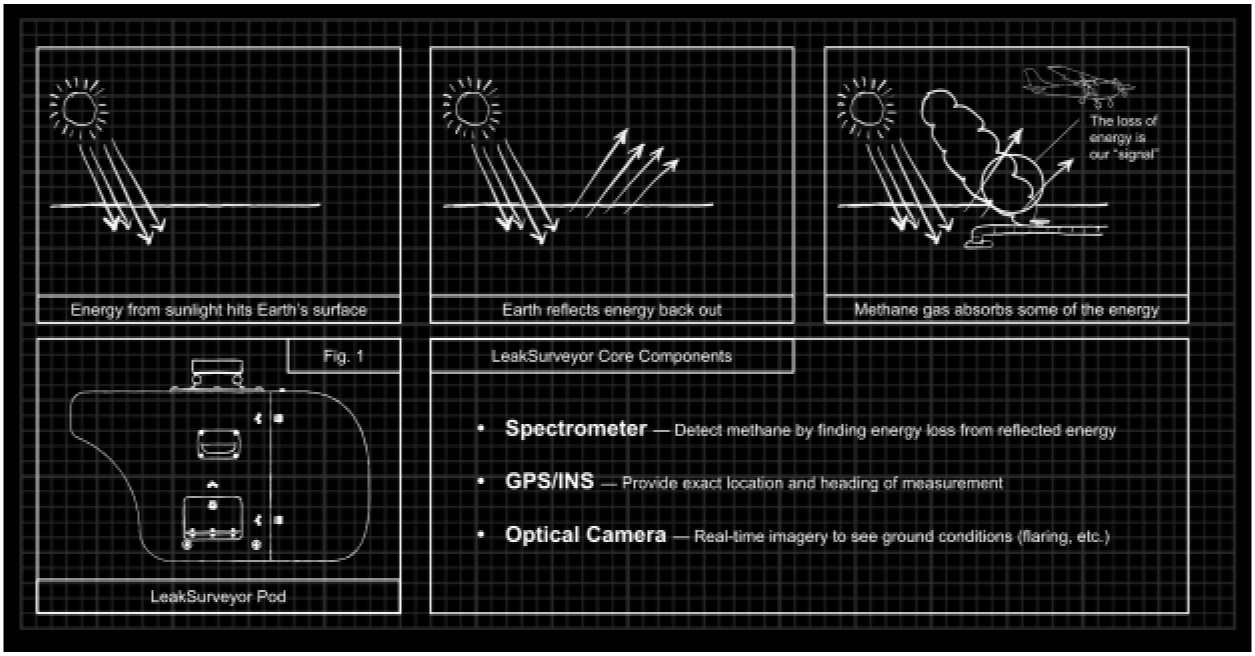


Figure 2: Conceptual diagram of the LeakSurveyor™ instrument capturing data in the field.

Our combination of methane detection, precise geolocation that can feed into operators' in-house mapping tools, and optical data allows the operator to determine the location and likely source of the methane plume while providing important contextual information about ground activity that might be contributing to emissions (e.g. well maintenance).

Kairos technology can detect emissions at the facility level and sometimes down to the equipment group level. For example, Figure 3 shows three confirmed leaks at a Kairos client's facility. In the image, there are three clearly visible, distinct plumes from a single facility.

Figure 3: Three confirmed leaks observed at a compressor station facility in the Permian Basin.

Footnotes:

[10] Sherwin, Evan, Yuanlei Chen, Arvind P. Ravikumar, and Adam R. Brandt, "Single-Blind Test of Airplane-Based Hyperspectral Methane Detection Via Controlled Releases," Elementa Science of the Anthropocene, 2021 ("Sherwin et al. 2021").

[11] El Abbadi, S.H., Chen, Z., Burdeau, P.M., Rutherford, J.S., Chen, Y., Zhang, Z., Sherwin, E.D. and Brandt, A.R., "Comprehensive evaluation of aircraft-based methane sensing for greenhouse gas mitigation" 2023 (In Revision).

Response 5: We appreciate the example and information on field deployed aerial survey technology. As discussed in Section II.B of the preamble to the final rule, this final rule does not include a general provision to incorporate the use of advanced measurement approaches for sources at this time and instead specifically allows its use in certain appropriate cases, including for large release events. However, the Agency recognizes that these technologies, and approaches for using these technologies for long-term quantification of emissions from oil and natural gas operations, are evolving rapidly. Historically, the Greenhouse Gas Reporting Rule has been revised to incorporate the latest data, updated scientific knowledge or additional measurement methods and the EPA intends to continue to evaluate the appropriateness of additional updates. The EPA is actively reviewing relevant peer-reviewed literature and pilot programs and in advance of future rulemaking, the EPA intends to initiate a request for information, workshop, or white paper to further solicit feedback on the use of advanced measurement data and methods in subpart W. For our discussion specifically related to the use of aerial technology for the quantification of pipeline leaks, see Section III. C.1 of the preamble to the final rule.

23.3 Continuous Monitoring Systems

Commenter: Public Hearing Transcript
Comment Number: EPA-HQ-OAR-2023-0234-0224
Page(s): 12-13 (Alice Lu), 17 (Luke Metzger), 17 (Luke Metzger)**,** 20 (Antoinette Reyes), 21 (Cheyenne Branscum), 26-27 (Arthur Gershkoff), 33 (Margeret Bell), 42 (Glenn Wikle), 44 (Shanna Edberg)

Commenter: Sensirion Connected Solutions
Comment Number: EPA-HQ-OAR-2023-0234-0293
Page(s): 2

Commenter: Project Canary, PBC
Comment Number: EPA-HQ-OAR-2023-0234-0348
Page(s): 18

Comment 1: Commenter 0224: The EPA should also require continuous optical gas imaging or OGI for all affected facilities with required reporting of data from OGI inspections necessitated by EPA's forthcoming methane rule. Stationary OGI is a very simple process of surveying the facility with a specialized infrared camera that shows gas leaks on a screen. This would allow for more frequent and accurate data that could help catch super emitter incidents more quickly.

…

We also urge the EPA to strengthen the final rule, including by … requiring continuous optical gas imaging for all affected facilities …

…

We also urge the EPA to strengthen the final rule, including by integrating top-down basin-level measurement data such as from continuous air monitoring …

…

Please consider … supporting stationary continuous optical gas imaging for leak detection.

…

We have the technology, for example, for continuous measurement for affected facilities, and we can do that, and I am not sure why we're not where there is so much at stake, and I would love to see that changed.

…

Extraction wells and processing facilities should be monitored frequently for leaks, ideally using optical leak detection equipment that also provides quantification data. If possible, continuous 24-hour per day monitoring by mounted fixed-position optical leak detection monitors to detect leaks and quantify leakage flow rates may provide more accurate data. It may be possible to combine such equipment with computerized hardware and software that can capture leak characteristics in real time, and alert staff who monitor settings to act promptly to initiate procedures to seal a leak.

…

However, we're dealing with the oil and gas industry which always has and always will put profits before the planet, and public health. Therefore, think we're well past relying on company reported data to help address and reduce methane emissions. Therefore, I would recommend that the EPA further strengthen Subpart W by requiring continuous optical gas imaging for all affected facilities. This simple, readily available, easy to use noninvasive technology would result in more frequent and accurate data and help catch emissions data for super emitter incidents.

…

[R]equire optical gas imaging as we've heard about from so many people. It's faster and more reliable than the original proposal.

…

We recommend requiring approaches like continuous optical gas imaging and continuous aerial monitoring to ensure more frequent and accurate data and to catch emissions data for super emitter incidents …

Commenter 0293: **Summary of Principal Comments**

…

b. Continuous monitoring can play a compelling role in monitoring, detecting, and quantifying methane emissions in the oil and natural gas industry. Both remote sensing and continuous monitoring technologies have their benefits, and both will play a critical role in determining what the true emissions are at a given site.

Commenter 0348: Continuous monitors are also well suited for conducting site-level quantified emissions estimates. Continuous monitoring technologies have very granular temporal resolution, and when combined with robust and technically sound quantification methodologies, can provide site-specific, accurate emissions values for a facility. This data can be reconciled with bottoms-up inventories and other top-down methodologies, to more accurately inform the GHG emissions inventory. Reconciliation protocols, such as OGMP2.0 and GTI Veritas, can serve as models for EPA to develop a specific Subpart W protocol for reconciliation of bottoms-up and top-down inventories. Colorado is also evaluating these models.

Response 1: We acknowledge the commenters' support for continuous monitoring. As discussed in Section II.B of the preamble to the final rule, this final rule does not include a general provision to incorporate the use of advanced measurement approaches for sources at this time and instead specifically allows its use in certain appropriate cases, including for large release events. However, the Agency recognizes that these technologies, and approaches for using these technologies for long-term quantification of emissions from oil and natural gas operations, are evolving rapidly. Historically, the Greenhouse Gas Reporting Rule has been revised to incorporate the latest data, updated scientific knowledge or additional measurement methods and EPA intends to continue to evaluate the appropriateness of additional updates. In advance of future rulemaking, the EPA is reviewing relevant peer reviewed papers and pilot programs to explore future incorporation of different continuous monitoring solutions and methods in subpart W.

Commenter: Public Hearing Transcript
Comment Number: EPA-HQ-OAR-2023-0234-0224
Page(s): 42 (Glenn Wikle)

Commenter: David Allen
Comment Number: EPA-HQ-OAR-2023-0234-0243
Page(s): 3

Commenter: David Allen
Comment Number: EPA-HQ-OAR-2023-0234-0243
Page(s): 4

Commenter: Clean Connect AI Inc.
Comment Number: EPA-HQ-OAR-2023-0234-0266
Page(s): 2-7

Commenter: SENSIA Solutions S.L.
Comment Number: EPA-HQ-OAR-2023-0234-0279
Page(s): 2

Commenter: Sensirion Connected Solutions
Comment Number: EPA-HQ-OAR-2023-0234-0293
Page(s): 4-7

Commenter: Konica Minolta Sensing Americas, Inc.
Comment Number: EPA-HQ-OAR-2023-0234-0340
Page(s): 1-8

Commenter: Honeywell International Inc.
Comment Number: EPA-HQ-OAR-2023-0234-0375
Page(s): 11-17

Commenter: LongPath Technologies, Inc.
Comment Number: EPA-HQ-OAR-2023-0234-0410
Page(s): 13-22

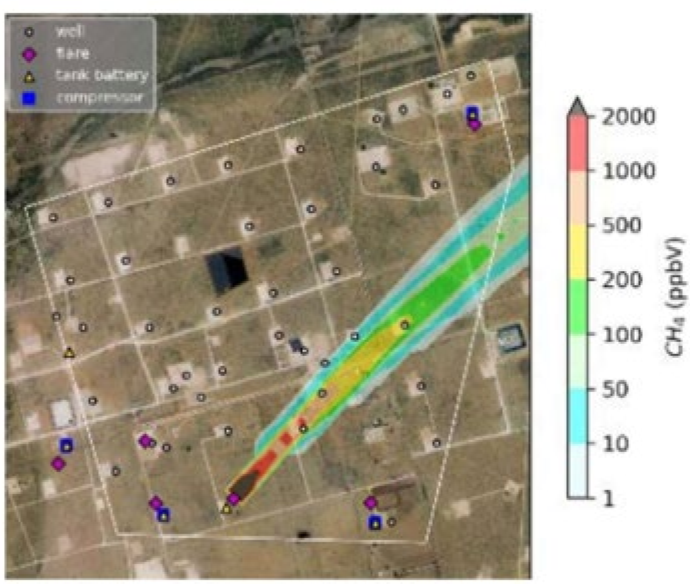
Comment 2: Commenter 0224: … require fence line air monitors to track methane emissions for facilities that are required to report emissions or experience a super emitter event …

Commenter 0243: **Monitoring Network Design**

The sensitivity, number and location of sensors required, in a shared network of fixed sensors, depends on the magnitude of the emission rate that is to be detected. The initial design of the network was based on dispersion modeling of emissions from each site in the test region. When multiple sources were present on a site (e.g., tanks and flares), each source was modeled individually.

Atmospheric dispersion simulations were used to determine how long it would take a network to detect emissions for various emission magnitudes, sensor densities and sensor locations. Analyses of the dispersion simulations were initially conducted to determine how many monitors would be required to be able to detect emissions of 10 kg/hr within a week (Chen, et al., 2022). For the purposes of this comment, these analyses were extended for detecting emissions of 100 kg/hr (Chen, et al, 2023a,b)

For the conditions in the Permian Basin, simulations indicate that less than one continuous monitor per site is capable of consistently detecting emissions in the range of 100 kg/hr within an average of less than one day of the onset of emissions.



Case study of dispersion modeling used to determine the number, location and sensitivity of sensors required in the Project Astra network; snapshot of one minute in the multi-week simulation shows concentration enhancements 2 m above ground level generated by 10 kg/hr emissions from one site.

Commenter 0243: Methane Sensor/Monitor Characterization and Testing

Project Astra is developing an innovative sensor network that is harnessing advances in methane sensing technologies, data sharing, and data analytics to provide near-continuous methane emissions monitoring across oil and gas facilities in the Permian Basin. Through mid-2023, the project has three had phases: a sensor inter-comparison which tested sensor technology to find out which existing sensing technologies were suitable for this application under real-world operating conditions, development of digital simulations of methane emission rates and dispersion to design the network and develop data analytics, and a pilot demonstration of the network.

The sensor testing has been completed. Seven solar-powered methane sensing systems with remote communication capabilities were tested for nine months at a production site in the Permian Basin oil and gas production region in west Texas. The test site is shown below. Sensor performance was evaluated using single blind certified gas challenges and by comparison with a continuously operated quantum cascade tunable infrared laser differential absorption spectrometer (QC-TILDAS) sensing system. Dispersion modelling was used to estimate concentrations that would need to be detected to identify continuous and intermittent emissions.

A detailed description of the sensor inter-comparison is available on the Project Astra web site maintained by the University of Texas, which conducted the inter-comparison (http://dept.ceer.utexas.edu/ceer/astra/). The results have also been published as a preprint (Torres, et al., 2022). These initial results focused on evaluating the detection of emissions with rates in the range of 5-10 kg/hr, but these analyses have also been extended to assess the ability of sparser networks of sensors to detect emission rates of 100 kg/hr, the emission rate threshold proposed by EPA for large release events (Chen, et al, 2023a,b).

Four sensor systems (Aeris, Canary, Quanta3 and Scientific Aviation) demonstrated sufficient precision to detect emissions of 5-100+ kg/hr under the meteorological conditions found in the Permian Basin, had one minute or better temporal resolution, and had data capture rates >80%, during 9 months of testing.

Based on these results, Project Astra has deployed sensing systems in the pilot phase of the project. The first sensors were deployed in early 2022.

Sensor inter-comparison test site

Commenter 0266: OGI+AI - A New Category of Direct Emission Measurement

OGI (optical gas instrumentation) “cameras” are considered by EPA to be the best system of emission reduction (BSER) according to the new OOOO b/c rules.

When you combine continuous-OGI with artificial intelligence (AI), you get an entirely new category of advanced technology to detect & quantify VOC & methane gasses that we call OGI+AI.

Continuous-OGI camera technology PLUS AI are making rapid improvements–exceeding Moore’s law. We contend and can prove that OGI+AI qualifies and fulfills the EPA’s definition of direct emissions measurement.

In addition, Subpart W recognizes ProMax (version 5 or above) as a valid measurement method #3: Engineering calculations (site-specific).

We have successfully combined OGI+AI, ProMax 6, with other direct measurement devices on operators’ sites. This measurement method 2, “combination of measurement and engineering calculations,” is an extremely powerful way to accurately measure emissions.

How we measure leaks at the component level

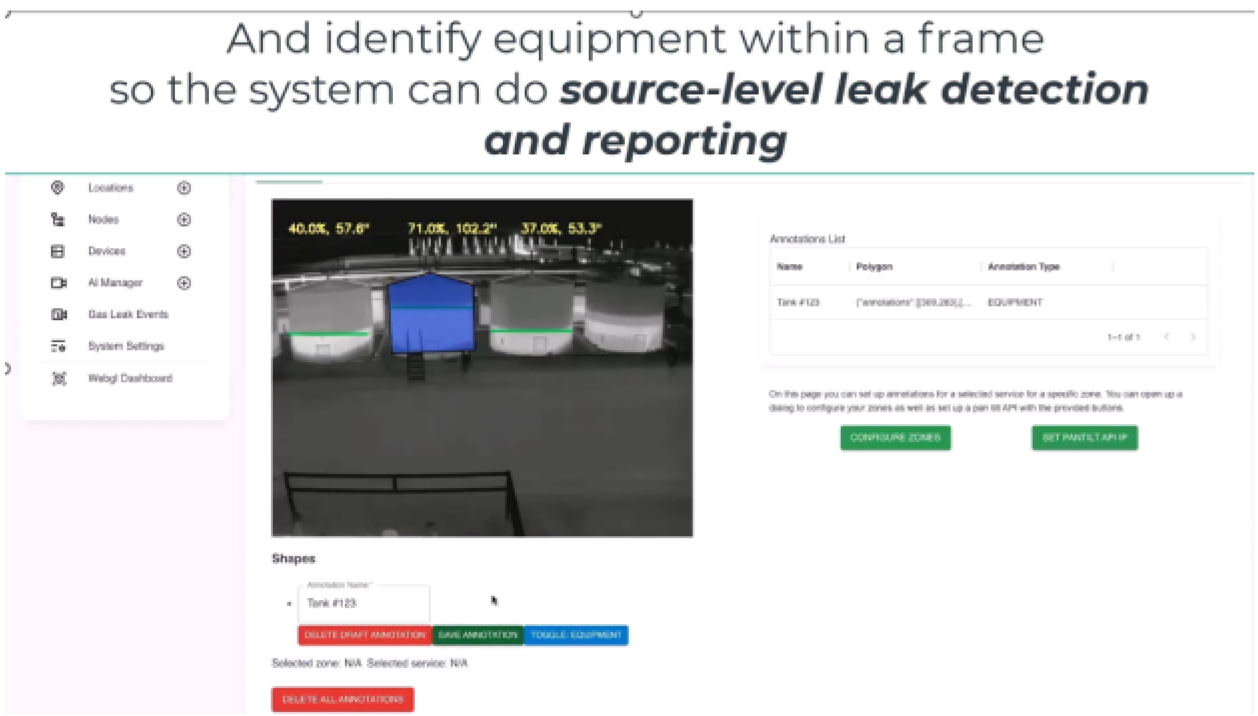


Figure 1: Configuring OGI+AI tour stops & component-level identification

CleanConnect.ai OGI+AI Setup

1. We use digital twins to properly place the OGI camera tower and camera height. Continuous-OGI camera placement is important so that we cover all equipment groups. NOTE: We are government-approved to detect leaks at 100m (200m diameter).
2. We allow the operator to configure OGI camera tour stops. These are operator-defined, and are designed to view/detect every equipment group. Pan, tilt, zoom can be set at each tour stop.
3. If there are multiple sources in the OGI camera field of view, we allow the operator to identify individual equipment or components, so when we detect a leak, we can associate it with that component, equipment, and.or equipment group.
4. IIoT meter devices are associated with the site setup. We are reading IIoT telemetry data in real-time
5. We associate that IIoT meter data with the site-specific ProMax v6 model. ProMax v6 data integration feature allows us to integrate with the IIoT meter data so that the ProMax (process model) is "live," allowing us to get real time mass balance, system-wide gas emission losses, throughput and much more. In addition, a site-specific ProMax model has all of the calculations used in Subpart W for the various equipment groups built-in. NOTE: ProMax is mentioned in Subpart W 26 times and is considered a valid measurement methodology

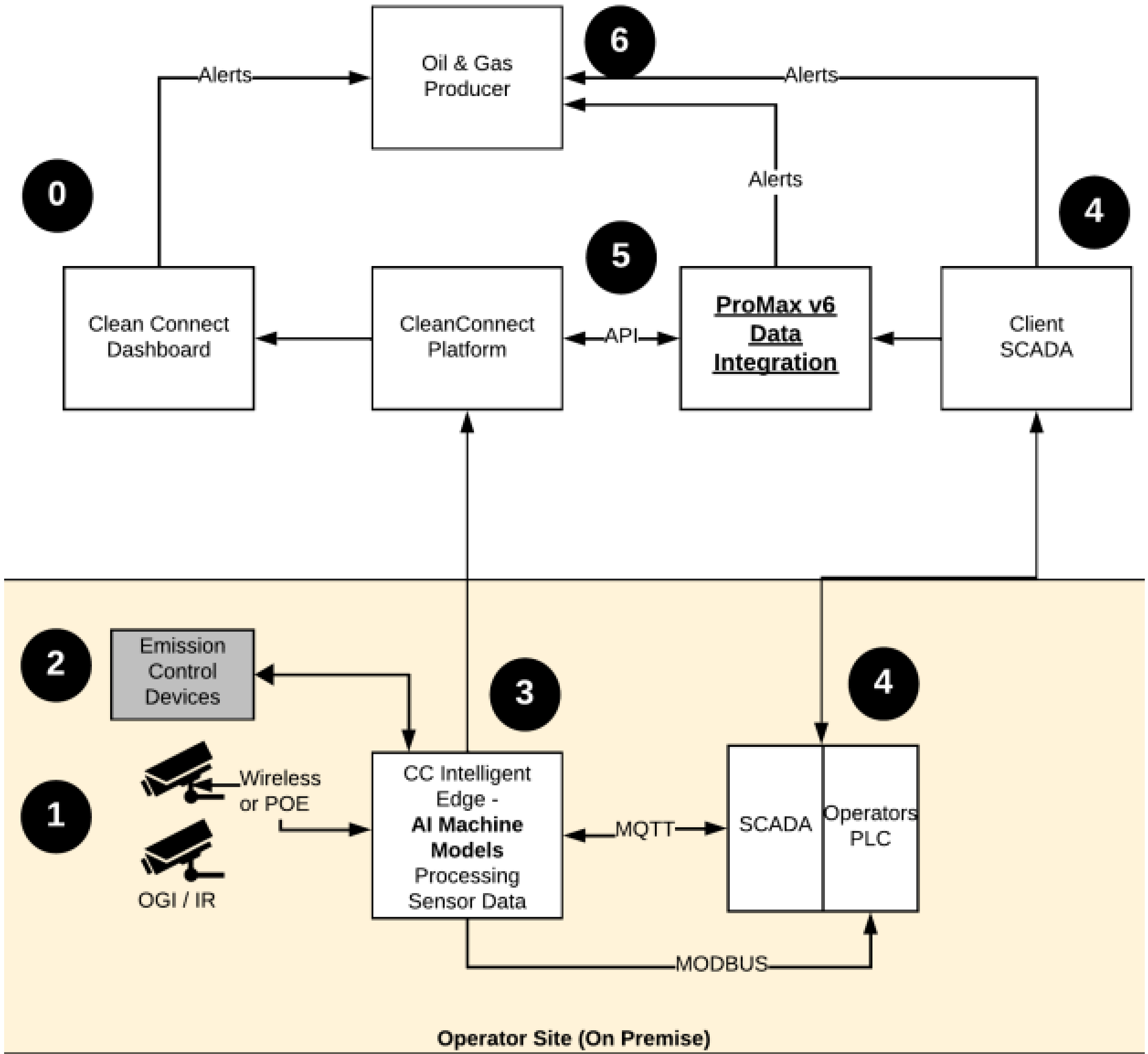


Figure 2: Clean Connect OGI+AI Architecture

Continuous Gas Leak Monitoring (refer to Figure 2)

- Setup (0) (see Setup above) is performed one-time on the Clean Connect dashboard.
- The OGI cameras (1) go on their tour (see setup).
- Raw OGI footage is sent to the edge computing device (3) for processing.
- The edge compute processes the inference computer vision models
- Detection & quantification is done on the edge
- Clean Connect is integrated with the operator's SCADA system (4)

- We also can read live IIoT emission control devices (2), such as VRU, BMS controllers, and other emission control devices telemetry data and send those to the AI edge computer (3). This also helps in our quantification models.
- IIoT telemetry data is sent from SCADA (4) to Clean Connect's instance of ProMax v6 (5).
- Clean Connect compares the OGI+AI quantification to the mass balance from ProMax (5)
- Leak detections, quantifications, and all supporting data are sent to the cloud (5)
- All detection/quantification alerts are sent to the operator (6) for diagnosis, repair. NOTE: Clean Connect has a built-in LDAR workflow, so operators can diagnose, issue repair tickets, and record repair
- The OGI cameras (1) will verify any repairs on their next tour

Fugitive Gas Leak Example:

Methane Gas Detection & Quantification

- Methane-only camera
- Thief hatch opening
- The mean leak rate starts high
  - **Start 38,000 scf/hr**
- As the pressure decreases, the quantification decreases
  - **End 3,000 scf/hr**
- 100 feet
- 12:30 pm

In this blind testing result, an operator opened the thief hatch. The camera immediately identified the fugitive emission and began quantifying. The near real-time video shows the leak-rate quantification at around 38,000 scf/hour and, as the pressure is relieved in the tank, the quantification is measured a few minutes later at around 3,000 scf/hour leak rate.

In this example, we are able to accurately determine the source, leak flow rate, total size of emission, and duration of the fugitive emission. We were also able to verify the repair and log everything with our OGI+AI system.

In addition to accurately detecting the source-level emissions measurement (with live OGI+AI video to prove it), we also reconciled the fugitive emission size with the live mass-balance loss using ProMax 6 integrated with onsite IIoT direct measurement devices. This methodology is an accurate component level emission measurement method with low uncertainty and it continues to rapidly improve as we train the computer vision models with millions of production videos, IIoT data, ProMax 6, and other direct measurement devices.

Benefits of Using OGI+AI for Direct Measurement:

- Safety. We can continuously monitor & measure emissions remotely, without putting onsite personnel at risk. This includes: ? Tank-level monitoring ? Gas leak monitoring ? Liquid leak monitoring ? Flame & smoke monitoring ? Flare monitoring ? Combustion efficiency monitoring ? And more.
- Real-time Speed. Our monitoring is real-time, so we use OGI+AI to assist operators to detect, diagnose, repair, verify, and report within minutes.
- Accuracy. By integrating all available direct measurement devices & site-specific process modeling (i.e. ProMax), we can achieve increasing accuracy. In addition, using machine learning, we can identify IIoT devices that are not calibrated and notify the operator to calibrate the meter.
- Granularity. We get real-time detection & measurement at the equipment group, equipment, and/or component level. This allows us to detect the source, measure the duration, and quantify fugitive emissions.
- Near real-time mass balance reconciliation with our OGI+AI quantified leak detection system. This works because we get ProMax data in the same time-series sequence.
- Speciating the gas stream. By integrating ProMax 6 with the OGI+AI system, we can understand the percent of methane in the stream (vs. other constituents). This allows us to calculate methane intensity, GHG intensity, or any other required calculations.
- Non-fugitive emissions. The Subpart W formulas are built into the site-specific ProMax model. Therefore, we can keep track of non-fugitive and permitted emissions in addition to fugitive emissions. In addition, we are working with various equipment manufacturers to pull in real-time IIoT telemetry data.
- Near real-time GHG/Methane Intensity calculations. Because we're continually monitoring throughput and emissions, we can provide site-level GHG/methane intensity calculations in near real-time.

We strongly suggest that EPA recognize OGI+AI and its ability to combine OGI, AI-computer vision, direct measurement devices from equipment manufacturers, ProMax v6 w/data integration, and machine learning. OGI+AI is a dramatic advancement in direct emissions measurement.

If EPA moves forward with their own Alt-AIMM type program (as suggested in the upcoming OOOOb), each advanced technology vendor will have an opportunity to prove their detection & measurement claims.

In the meantime, please allow operators to use advanced OGI+AI and other advanced technology to fulfill their obligations to direct emissions measurement under Subpart W.

It does not make any sense for EPA to bet against AI, when the evidence of its rapid acceptance and improvement is already impacting every industry as of this date, and will continue to make rapid progress. Every OGI camera manufacturer is combining AI with their OGI cameras, so OGI+AI is readily available in the marketplace.

To not recognize OGI+AI as a possible measurement method, would make Subpart W obsolete before it's even published.

Commenter 0279: Alternative Top-Down Facility-Level Approach: Imaging-Based Continuous Monitoring

Addressing the EPA's call for comments welcoming alternative top-down facility-level approaches, automated OGI solutions mounted from high viewpoint masts on programed tours can provide a powerful facility-level continuous monitoring solution for emissions. Through monitoring potential emissions sources from a plant around the clock, more realistic site-level emissions measurements can be achieved than with periodic flyovers or other intermittent checks. Based on SENSIA's experience, the benefits of this approach are:

- More frequent measurements mean higher aggregated emissions data accuracy
- Analysis of emissions trends over time mean valuable insights for identifying root causes
- Inventory of unpredictable, fugitive emissions
- Raising awareness of emissions through its visualization
- Activity factors vs. emissions factors correlation
- Granularity components emissions
- OGI continuous monitoring leads to more evidence and transparent emissions records

For an efficient implementation of such as kind of systems, two key factors must be considered:

- Minimum Detectable Leak Rate of the OGI with distance. A continuous monitoring system must be designed considering a range of detection typically larger than a handheld OGI, where most of the cases are a few meters. For such ranges of dozens of meters, the Minimum Detectable Leak Rate will depend on the observation distance, and it has to be determined.
- Detection and Quantification Automation: A continuous monitoring OGI must operate automatically, as a sensor, both detection and quantification must be done by the system without human supervision to warrant traceability of the measurement

Commenter 0293: **Latest advancements in continuous monitoring technology**

While the overall system performance of any continuous monitoring solution is driven mainly by the underlying sensor technology as well as the applied mass quantification models, mass adoption across operators and basins is only achievable if total cost of ownership are comparable to today's traditional work practices such as Method21 or periodic Optical Gas Imaging (OGI) cameras.

SCS took all those requirements into account to develop a solution including the deployed methane sensor technology that is finetuned to the specific needs of the oil and gas industry and those of the use case “continuous methane emissions monitoring via fixed-point sensor networks” itself.

Consequentially, Nubo Sphere’s next generation methane sensor, based on a laser spectroscopy working principle, will be a key enabler for the fixed-point sensor market. The proprietary sensor technology has been miniaturized to provide a low-power and low-cost yet very robust and long-term stable alternative over commonly used metal-oxide sensors. This enables remote operation over the lifetime of the sensor node which is specified to be 6 years under typical environmental conditions across the US. While the sensor technology in itself already comes at a much-reduced price, compared to already commercially available high-end sensors using a similar working principle, the system is there is also neither maintenance required nor in-field calibrations. The sensor node has been designed to be easy and fast to install and upgradable, to make total costs of ownership meet those of quarterly OGI inspections as calculated by EPA in the appendices of the proposed supplemental of NSPS oooob and EG ooooc. This allows even small operators or low producing facilities to deploy the technology and spread throughout more of a basin.

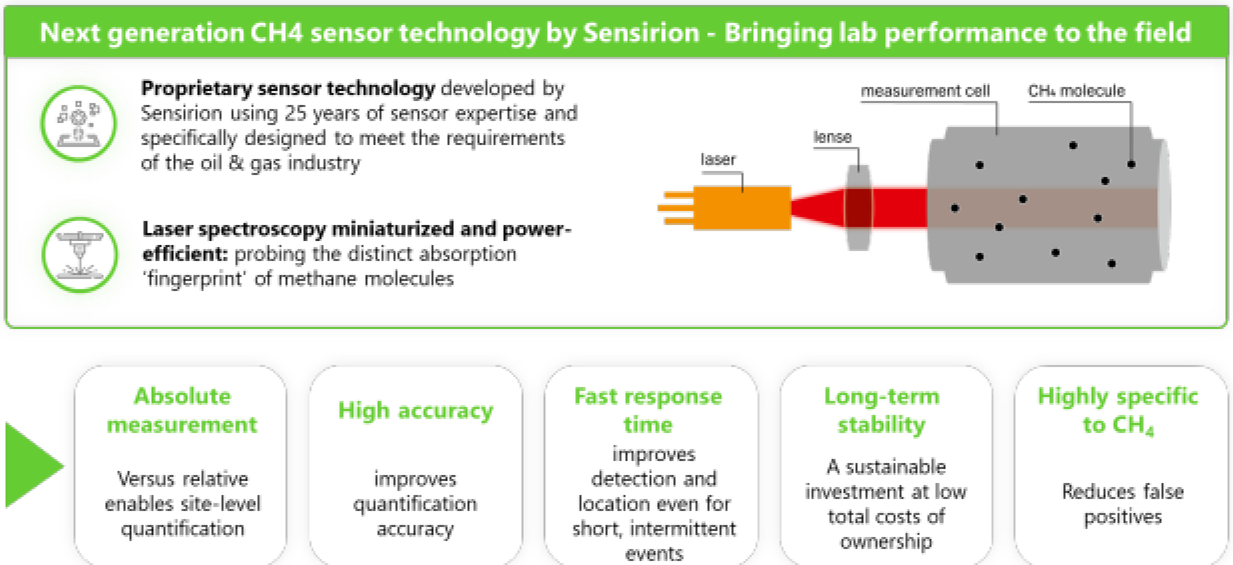
What is in it for oil and gas operators:

- A fast and reliable detection and localization accuracy of a large range of emission ranges from single g/h up to super-emitters of 100 kg/h and more which improves operational efficiency by providing 24/7 actional insights, and
- a quantification accuracy which allows to estimate total site-level emissions for regulatory reporting and reconciliation purposes with bottom-up estimates.
- Or as an international oil company recently put it: “early detection of unexpected and intermittent emissions sources, long-term quantification of potentially variable emissions, and assurance of absence of methane emissions above a certain threshold.”

What’s in it for the EPA:

- by enabling operators to use continuous monitoring as part of the advanced technology suite, mass adoption of low-cost, yet high performance solutions such as Nubo Sphere will drive emissions reduction and adherence to regulatory requirements such as the super emitter program within the Inflation Reduction Act;
- without imposing high costs on the oil and gas industry, and
- finally falling in line with state, and other leading regulatory compliances that have adopted the usage of continuous monitoring systems for both leak detection and repair (LDAR) and site-level emissions quantification, such as Colorado who recently empowered their local operators to file their annual greenhouse gas emissions reports using measurement informed inventories produced by advanced technologies including continuous monitors. SCS is prominent in the Colorado region and supportive of this standard to replicate nationwide, and hopefully, across multiple continents.

Picture 4 provides a short summary of the said above:



Picture 4: Key features and their value for operators of Sensirion's next generation methane sensor technology

The above-described sensor characteristics play a crucial role in the ability to develop a high precision mass quantification model. SCS's current model accounts for atmospheric conditions (such as wind speeds, topography, temperature, humidity), facility obstacles, and different emission sources.

SCS consistently tests and is dedicated iterating improvements of the mass quantification model through controlled-release testing environments as well as real-world deployments where operators realize the benefit of alternative technologies into their voluntary greenhouse gas (GHG) reduction commitments such as MiQ, Trustwell, OGMP 2.0 or other RSG-related compliance initiatives. SCS helps contribute and push test campaigns with exemplary institutions such as Colorado State University, the Colorado School of Mines, the University of Texas, and Stanford University along with operator sponsored tests such as the QMRV protocol through Cheniere Energy or the National Gas Institute Foundation (NGIF) in Canada alongside Tourmaline. The resulting performance continues to demonstrate significant improvements of the mass quantification model and the value of continuous monitoring soluontis such as Nubo Sphere that will further data quality for operators. All updates to the mass quantification model are then pushed via over the air firmware updates to the existing installed base constantly improving systems' performance in the field.

Recent proof for Nubo Sphere's performance can be found here and in the attached, soon also to be published by Colorado State University in the course of their ADED 2023 test campaign.

Commenter 0340: **Description of QOGI Technology**

Our quantification is a technology that displays the result as shown in Figure 1, by specifying the gas area to be estimated with 4 points, and inputting the gas type, shooting distance and temperature as shown in Figure 2. Quantifiable distance range is from 4 ft to 328 ft. The estimated result is the average over a 5 second period of recorded image and updates every 5 seconds. The minimum video length for quantification is 7 seconds.

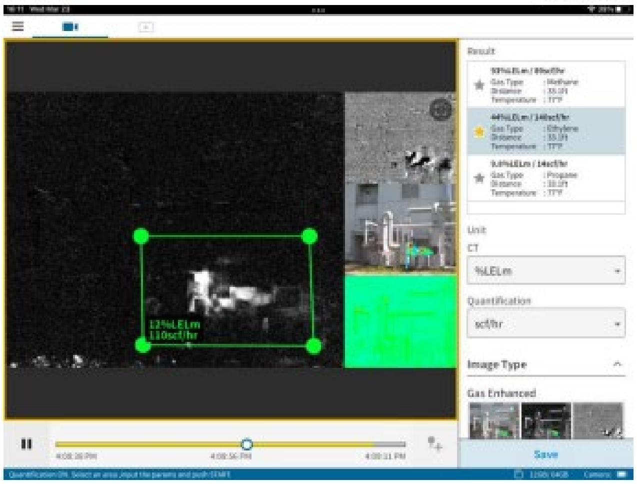


Figure 1. Results display screen

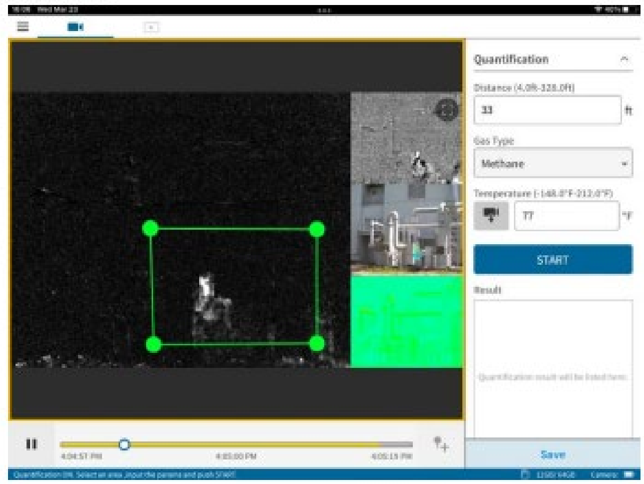


Figure 2. Information input screen

The technology consists of two estimation techniques: a) gas concentration length and b) gas flow velocity. By calculating the amount of gas from a) gas concentration length, and the passage time of gas from b) gas flow velocity, a gas flow rate per unit time is estimated. A schematic diagram is shown in Figure 3. Wind measurement is unnecessary as the gas flow velocity is estimated by tracking the gas movement from the images. A patent has been applied for this method. [1]

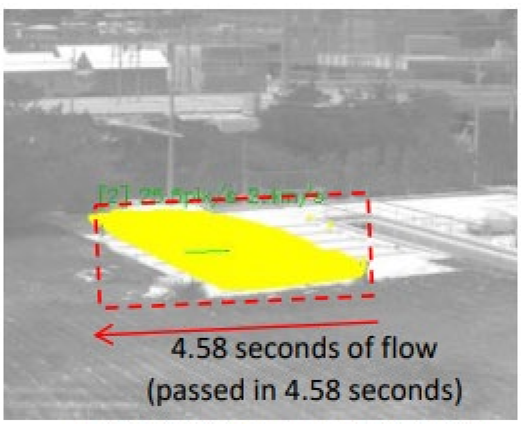


Figure 3. Gas flow rate estimation

Gas concentration length can be theoretically calculated by considering the gas temperature, the background temperature in the presence of gas and the background temperature without gas. The gas temperature is assumed to be the ambient temperature input by the user. Furthermore, the background temperature in the presence of gas and without gas are estimated from time-series changes in the infrared images taken as shown in Figure 4. Please see the patent for more details.2

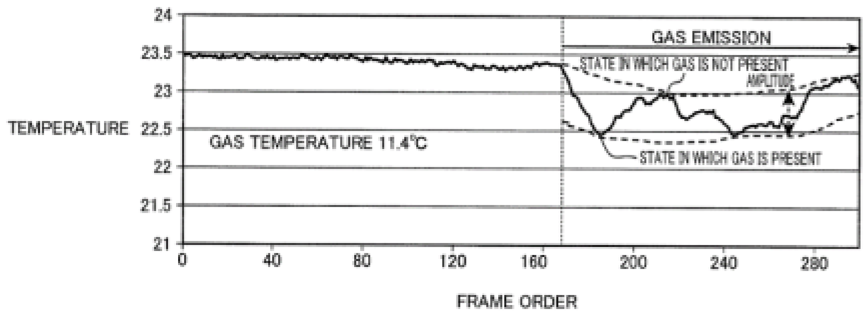


Figure 4. Estimation method of gas concentration length

Analyzing the gas pixels within the specified area alleviates the effects of noise and provides for a higher level of accurate quantification. Also, for backgrounds with low noise, turning on the Image Stabilization function of the camera will optimize the quantification image as shown in Figure 5. This makes it possible to quantify the flow rate with high accuracy even with handheld photography. The method of Image Stabilization utilizes the fact that there is a correlation between changes in direction and changes in time, and can perform optimization with high accuracy. Please see the patent for more details. 3

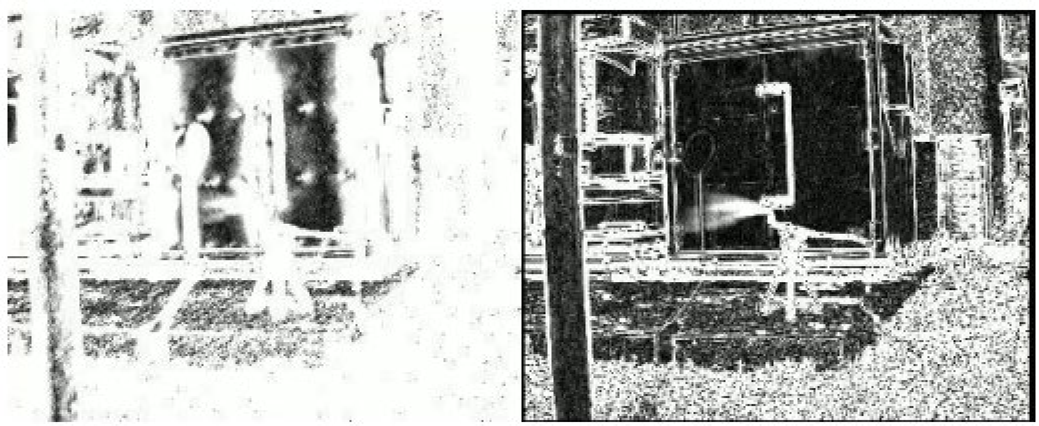


Figure 5. Image Stabilization OFF (left) / ON (right)

Since gas plumes and noise in the image can be differentiated by the camera operator, backgrounds and areas can be selected while avoiding noise, and the amount of gas is quantified with high accuracy. For example, it is difficult to determine whether clouds become noise in a visible image, but in processed images as shown in Figure 6 and 7, it is easy to understand the presence of noise and its level along with gas.

Figure 6. Case where clouds do not become noise

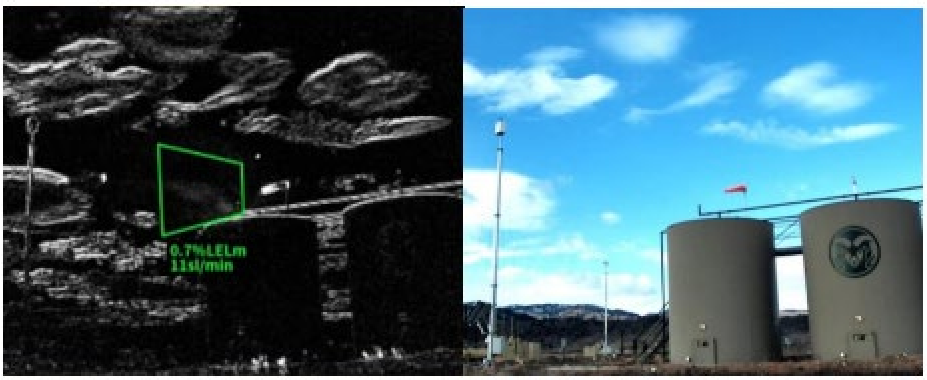


Figure 7. Case where clouds become noise

The processed images used as the basis for quantification, as shown in Figure 8, visualize the temporal changes caused by the fluctuation of gas due to the wind, based on the time-series changes in the infrared images taken. This allows for the visualization of the concentration of the gas and the noise level.4

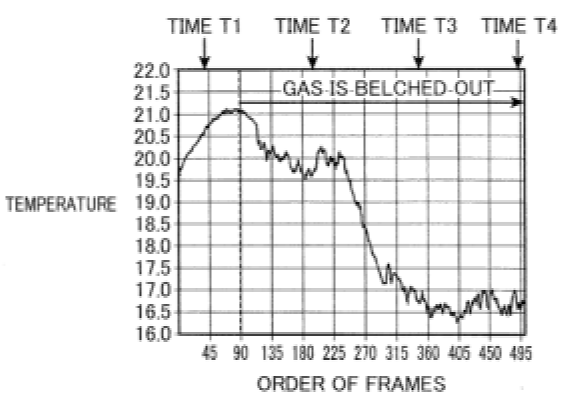
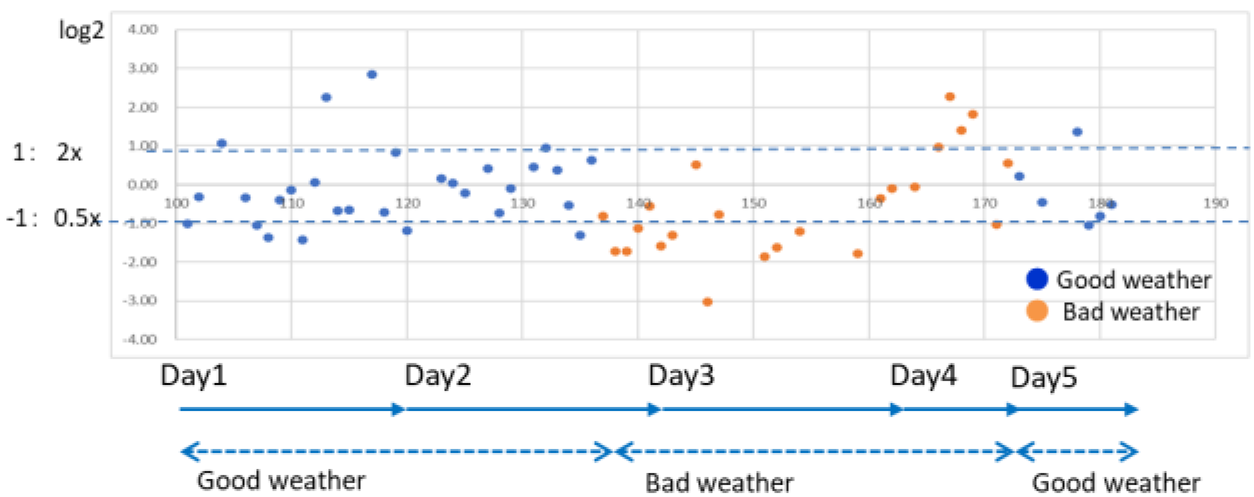


Figure 8. Principle of gas image and noise highlighting

Gas concentration length can be displayed in 5 units of volumetric flow rates (sl/min, scc/min, scc/sec, scf/min and scf/hr) and 4 units of mass flow rates (g/min, g/hr, mg/sec, lb/hr). The volume flow rate is prefixed with “s” (standard). This indicates that the standard conditions (70°F, 1atm) defined by CGA (Compressed Gas Association) are used as the standard conditions required for conversion of volumetric flow rates and mass flow rates.

Field Evaluation Results

Konica Minolta participated in Colorado State University (CSU)'s Advancing Development of Emissions Detection (ADED) project and conducted an evaluation of the leak detection and quantification technology at the University's Methane Emissions Technology Evaluation Center (METEC) facility. It was a blind test to identify the leak source and measure the amount of emissions. The final version of the data is still to be confirmed by CSU and the final results are subject to change. However, if we extract only the data that can be confirmed by both parties, the results are shown in Figure 9, with 56% overall and 69% during good weather in the range of half to double the actual flow rate. In that trial, the sky was intentionally used as the background this time to ensure a sufficient temperature difference (?t) between the gas and the background. But it is confirmed through the trial it was not always possible when the weather was bad. Therefore, there is a possibility of further improvement in the numbers depending on how it is used, such as considering the equipment as a background.



	% within 0.5-2x
Overall	56%
Good weather only	69%

Figure 9. METEC ADED trial results (preliminary)

Konica Minolta also confirmed correlation with existing quantification technology through field tests at partner facilities. 21 intentional emissions were quantified using a QOGI camera and the results were compared with a high volume sampling technology as specified in 40 CFR 98.234(d). In order to eliminate arbitrariness, the median value of the output results of the QOGI camera was adopted. As a result, 81% of the quantified values were in the range of half to double the High Flow Sampler values, and the correlation coefficient was 0.8557 as shown in Figure 10. The individual test results are shown in Figure 11.

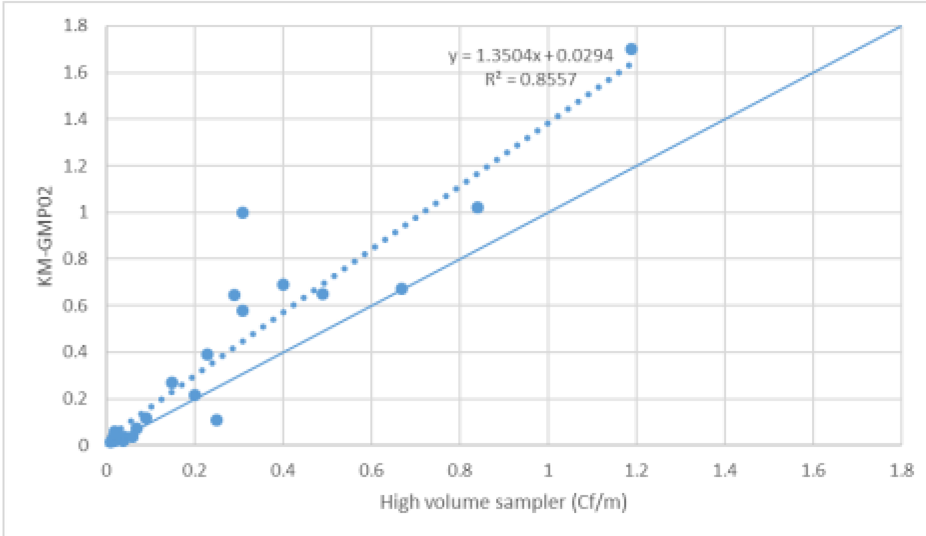


Figure 10. Correlation diagram between QOGI camera and high volume sampling

Test No.	Unit	1	2	3	4	5	6	7	8	9	10	11	12	13	14	15	16	17	18	19	20	21
Quantified 1	Scfm	0.0071	0.16	0.028	0.0035	0.0071	0.18	0.43	0.046	0.11	0.21	0.0035	0.06	0.16	0.43	0.5	0.018	0.035	0.25	0.7	0.41	0.025
Quantified 2	Scfm	0.021	0.2	0.032	0.0071	0.0071	0.55	0.55	0.085	0.18	0.24	0.0071	0.071	0.18	0.47	0.54	0.021	0.057	0.37	0.75	0.47	0.042
Quantified 3	Scfm	0.021	0.2	0.032	0.011	0.014	0.66	0.6	0.088	0.38	0.24	0.011	0.071	0.21	0.49	0.59	0.021	0.057	0.38	0.84	0.97	0.042
Quantified 4	Scfm	0.025	0.3	0.039	0.014	0.021	0.92	0.67	0.099	0.63	0.3	0.011	0.11	0.22	0.67	0.61	0.028	0.06	0.69	1.2	1.5	0.057
Quantified 5	Scfm	0.025	0.35	0.067	0.018	0.021	1	0.67	0.12	0.66	0.31	0.014	0.12	0.3	0.8	0.64	0.035	0.067	0.69	1.9	1.9	0.057
Quantified 6	Scfm	0.035	0.38	0.1	0.018	0.025	1	0.73	0.14	0.7	0.4	0.018	0.12	0.37	1.1	0.64		0.078	0.7	2.5	2.4	0.074
Quantified 7	Scfm	0.039	0.4		0.067	0.032	1.1	0.76	0.17	0.76		0.018	0.13			0.65		0.088	0.72		2.7	0.11
Quantified 8	Scfm	0.053	0.41		0.092	0.042	1.1	0.85	0.19	1		0.021	0.14			0.67		0.099	0.72		3	0.12
Quantified 9	Scfm	0.057	0.42			0.042	1.1	0.94				0.021				0.67		0.1	2.2			0.44
Quantified 10	Scfm	0.071	0.54			0.046	1.4					0.025				0.72		0.14				
Quantified 11	Scfm	0.078	0.6			0.049	2.3					0.025				0.89						
Quantified 12	Scfm		0.95			0.078						0.035				0.9						
Quantified 13	Scfm											0.035				1.36						
Quantified 14	Scfm											0.053										
Quantified 15	Scfm											0.063										
Quantified 16	Scfm											0.15										
Median	Scfm	0.035	0.390	0.036	0.016	0.029	1.000	0.670	0.110	0.645	0.270	0.021	0.115	0.215	0.580	0.650	0.021	0.073	0.690	1.020	1.700	0.057
High Flow	Cfm	0.040	0.230	0.060	0.010	0.040	0.310	0.670	0.250	0.290	0.150	0.020	0.090	0.200	0.310	0.490	0.039	0.070	0.400	0.840	1.190	0.020
Quantification /High Flow		87.5	169.6	59.2	160.0	71.3	322.6	100.0	43.8	222.4	180.0	105.0	127.8	107.5	187.1	132.7	53.8	103.6	172.5	121.4	142.9	285.0
Within 0.5-2x		YES	YES	YES	YES	YES	NO	YES	NO	NO	YES	YES	YES	YES	YES	YES	YES	YES	YES	YES	YES	NO
																			% within 0.5-2x			81%

Figure 11. Individual test results

The lowest emission (test #4) was measured by the high volume sampling at 0.01 cfm, which was quantified by the QOGI camera at 0.016 scfm (i.e. +0.006 cfm error) as shown in Figure 12. And the highest emission in this test was 1.19 cfm and the quantified result was 1.70 scfm, but the QOGI camera is able to quantify emissions even above 10 scfm.

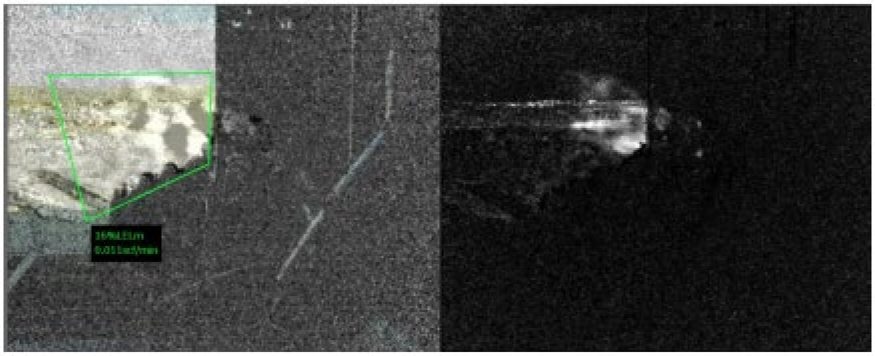


Figure 12. Images of the lowest emission (test #4)

Further Applications

QOGI cameras also make it possible to quantify emissions that are difficult to measure with existing technology, such as leaks from sources at high elevations, in narrow gaps in equipment, or in areas that are dangerous to access. Figure 13 shows an example of quantified emissions from the top of the tank, and Figure 14 shows quantified emissions from a compressor engine. Our method of quantification, allows for gas measurement of confined spaces and difficult to monitor areas, allowing for a better understanding of the intensity of an emissions leak.

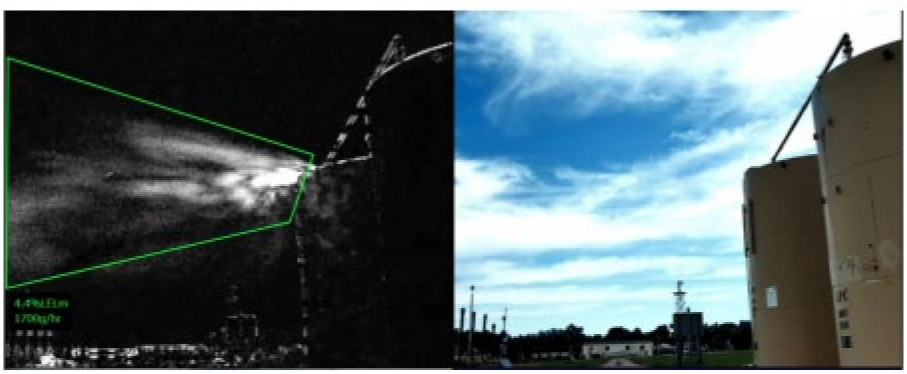


Figure 13. Quantified emissions from the top of the tank

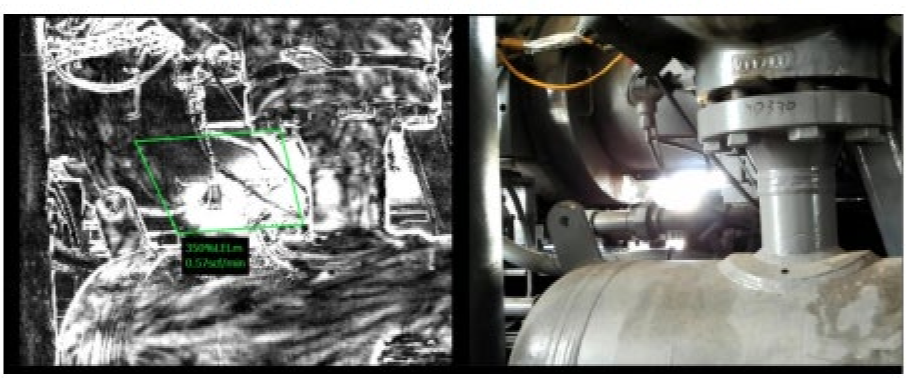


Figure 14. Quantified emissions near the compressor engine

Conclusion

In summary, taking into consideration the points made in this comment, we urge the EPA to consider the QOGI camera as one of the direct measurement methods for gas emissions to encourage emissions reductions based on facts and data.

Footnotes:

[1] "US20220034742 - GAS FLOW RATE ESTIMATION DEVICE, GAS FLOW RATE ESTIMATION METHOD, AND GAS FLOW RATE ESTIMATION PROGRAM" https://patentscope.wipo.int/search/en/detail.jsf?docId=US349429229&_fid=WO2020110411

[2] "US20180364185 - GAS CONCENTRATION-THICKNESS PRODUCT MEASUREMENT DEVICE, GAS CONCENTRATIONTHICKNESS PRODUCT MEASUREMENT METHOD, AND COMPUTER-READABLE RECORDING MEDIUM HAVING GAS CONCENTRATION-THICKNESS PRODUCT MEASUREMENT PROGRAM RECORDED THEREON" https://patentscope.wipo.int/search/ja/detail.jsf?docId=US235210241&_fid=WO2017104607

[3] PATENT 6838605 https://patentscope2.wipo.int/search/ja/detail.jsf?docId=WO2017179510&_cid=JP2-LIB8A7-90072-1

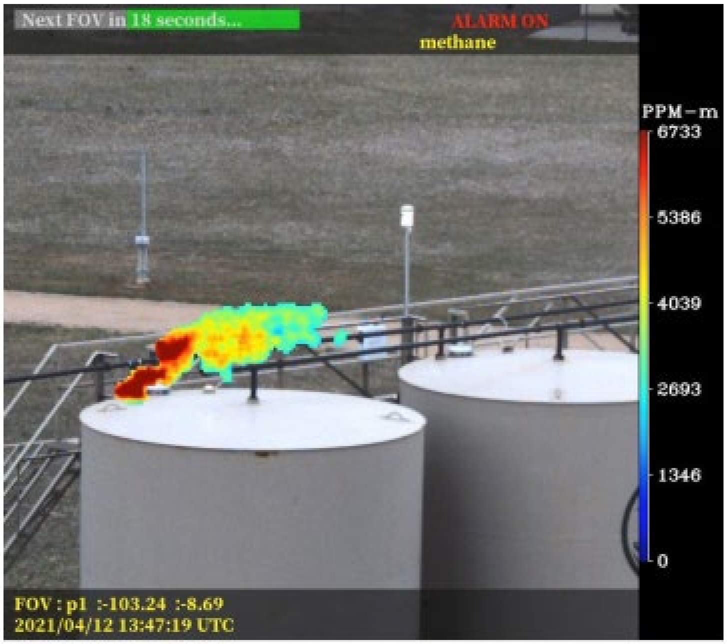
[4] PATENT US10145788 https://patentscope2.wipo.int/search/en/detail.jsf?docId=WO2017073430&_cid=JP2-LIBJ15-83875-1

<u>Commenter 0375</u>: *Honeywell's Advanced Continuous Monitoring Technologies, Including Honeywell's Rebellion™ Cameras and Signal Scout™ Sensors For Reporting on Emissions From Various Sources, Are Capable of Providing Component-Level and Site-Level Emissions Monitoring and Measurement that Would Enable More Accurate Emissions Accounting*

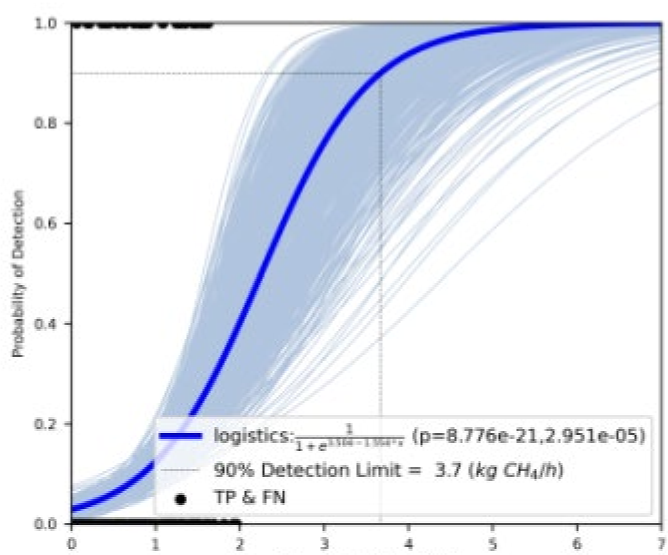
1. Honeywell's Rebellion™ GCI cameras

The Rebellion™ Gas Cloud Imaging (GCI) system is deployed at oil and gas facilities across the U.S. for continuous monitoring of gas leaks. The technology is part of an established class of continuous monitoring technologies that use continuous OGI cameras (C-OGI) to detect, visualize and quantify methane emissions. It utilizes hyperspectral infrared gas imaging technology to identify and alarm when leaks occur and provides a live video transmission to visually display and verify the plausibility of any gas leaks in real time. The Rebellion™ GCI cameras come in two versions, a GCI-Standard designed for extended areas and large sites with a range of 1,700 meters and a Mini GCI designed for congested areas and small sites with a range of 100 meters. Both GCI camera models provide an easy-to-interpret colored video, which shows the gas type, location, plume direction, size, and concentration. The hyperspectral sensor is a critical component of the system, as it can identify the optical fingerprint of the gas cloud— thus making it possible to differentiate from common "false alarm" molecules that can arise from steam or water vapor and detect a wide range of gases, including methane and typical flammable hydrocarbons. An example of a customer installation is shown in the image below:

The Rebellion™ GCI system can provide a site level screening at a frequency of typically less than 10 minutes. This is performed by deploying the system at an elevated position at a facility with a line-of-site that covers all equipment under surveillance. Third party test data determine the maximum range at which the camera can detect leaks within a certain rate of probability. As long as the equipment under surveillance is less than this distance, the GCI system will be able to alarm when a leak is present. The system comes with a pan and tilt motor that allows the camera to move across the facility to screen for leaks from any of the equipment in a similar fashion to an OGI inspector. It is completely automated and continuously scans the entire facility 24/7. During the presence of a gas leak, the Rebellion™ GCI provides video of the gas plume similar to those obtained utilizing the "gold standard" optical gas imaging (OGI) camera. An example frame from one of the videos is shown below for comparison purposes with published OGI images.



The Rebellion™ GCI camera has been tested through customer pilots and test facilities as well as academic research centers such as Colorado State University's METEC facility. At the METEC facilities, detection probability curves for this technology were determined through an extended test campaign as shown in the figure below and found to have a 90% probability of detection of a leak with a < 4 kg/hr rate at distances of less than 100 meters from the camera.



However, unlike periodic screenings, the Rebellion™ GCI camera has the ability to detect gas leaks within minutes of a leak occurring (at the same leak detection threshold) rather than waiting for a monthly inspection. Furthermore, unlike handheld OGI surveys, Rebellion™ cameras do not depend on extensive operator experience to provide a particular leak detection rate. A recent study indicated that OGI surveyor experience significantly impacts the leak detection rate of handheld OGI surveys.[9]

2. Honeywell's Signal Scout™ technology

The Honeywell Emission Management Solution, comprising of Honeywell Versatilis™ Signal Scout™ detectors, Gateway and Anemometer, has been installed at several plants. The methane concentrations detected by the Signal Scout™ detectors are correlated with wind speed and wind direction data to triangulate the leak location and to quantify the leak size. Analyzing the data in real time with the Honeywell Emission Management Software provides an opportunity to correlate emissions with process steps, and hence to optimize efficiencies and emissions control.

Signal Scout™ detectors have no wires and their installation is extremely simple (e.g., using a screw mount, magnet mount, or pole mount). They are aerodynamically shaped to optimize methane detections in 360-degree wind directions. Signal Scout™ detectors communicate wirelessly to a gateway that forwards the detection data to the analysis software. Most importantly, the Signal Scout™ detectors are fully certified to be used in explosion hazardous areas, which allows them to be placed in the middle of the action, right at the process unit. This is in contrast to fenceline monitoring systems, with detectors positioned further away from the equipment.

Because the detectors are placed so close to the equipment, the Emission Management Software is able to deliver a fast response and precise leak localization. It presents the leaks on a real time basis on a zoomable map to make it easy for the operator to take action. The near-real-time analytics allow operators to further investigate which process actions are causing the emissions and assess ways to optimize those processes. Operational results showed a 100% match with the site logs of short-duration large emissions, and also revealed many smaller emissions that plant operation teams were not yet aware of, both of which are important to identify in order to achieve emissions reductions.

The Honeywell Emission Management system is being tested at METEC to objectively provide the system's detection limits at a 90% probability of detection. With optimal positioning of the Signal Scout™ detectors, the Honeywell Emission Management system is able to detect and quantify leaks well below 1 kg/h.

3. Honeywell's Emission Management Solution System can provide prompt leak detection of low-level emissions, which is beneficial to efforts to improve the accuracy of the emissions inventory.

Continuous monitoring systems can provide faster leak detection than periodic surveys, as leak detection times range from 20 minutes to several hours. The faster the detection time, the better the continuous monitoring system can be used to correlate the emission with process events.

Because Honeywell Versatilis™ Signal Scout™ detectors can be placed in the hazardous areas of a facility, allowing for placement of the detectors very close to the potential emitters, the Honeywell Emission Management Solution system has demonstrated some of the shortest detection times, down to 20 minutes. This is much faster than current fenceline monitoring systems, because the probability of detection decreases rapidly with distance. At large distances, a strong and steady wind aligned exactly from the leak to the detector is required to reach a fenceline mounted detection system. When detectors are placed closer to potential emission sources, faster detection times result as the weather and the wind are far less critical. In addition, having sensors located closer to potential emission sources leads to much more accurate localization of emissions once detected. While fenceline monitoring systems typically only report site-emission totals, Honeywell's Signal Scout™ detectors allow for reporting emissions per process unit, and potentially emissions per specific identifiable equipment components.

Moreover, continuous monitoring systems can provide the equivalent or better sensitivity as permitted periodic leak detection monitoring system, depending on the configuration and location of the sensors. The level of sensitivity required of the sensors will depend on the distance between the sensor and the emission. For instance, the sensor of a fenceline monitoring system put at 100 meter distance needs to be much more sensitive than a hazardous location-approved sensor placed amidst the process unit at 10 meter distance, as the concentration of methane quadratically decreases with distance. Honeywell's Versatilis™ Signal Scout™ can detect methane down to a 50 ppm concentration, which translates to the ability to detect a leak of 100 liter/hour when Signal Scout™ are positioned at distances less than 10 meters. For example, a fenceline monitoring system able to detect down to 5 ppm (a factor of 10 more sensitive), placed at 100 meter distance (a factor of 10 further away, so a factor of 100 less methane concentration to be detected) is still a factor of 10 less sensitive than Signal Scout™. In evaluating such continuous monitoring systems, the key metrics are True Positive percentage and Probability of Detection, that will show the threshold emission rate above which leaks can be detected with a 90% probability.

Footnotes:

[9] Daniel Zimmerle, Timothy Vaughn, Clay Bell, Kristine Bennett, Parik Deshmukh, and Eben Thoma, Detection Limits of Optical Gas Imaging for Natural Gas Leak Detection in Realistic Controlled Conditions, Environmental Science & Technology 2020 54(18) 11506-11514, available at: https://pubs.acs.org/doi/10.1021/acs.est.0c01285.

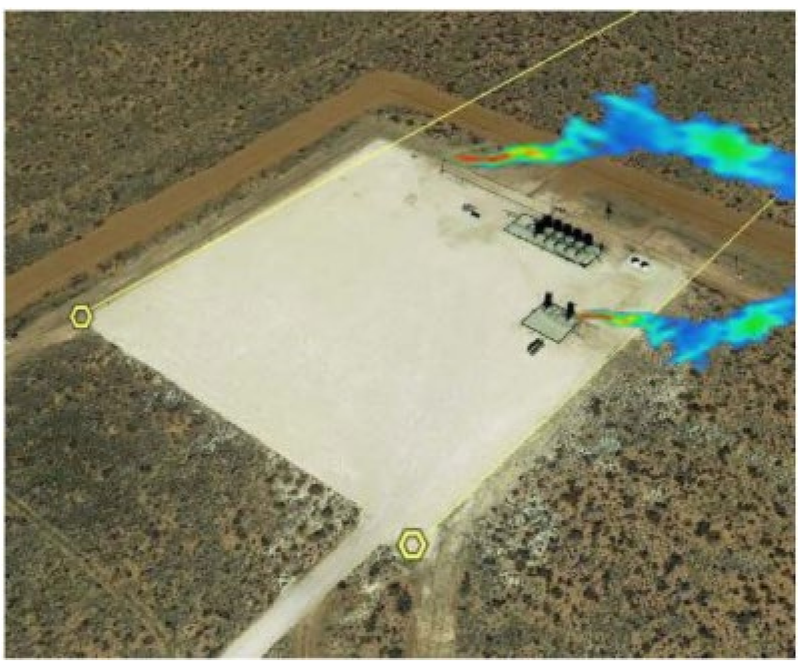
Commenter 0410: **LongPath continuous monitoring system detailed overview**

The Long Path monitoring system is a continuous line sensor system (C. Line Sensor or C. Open-Path Sensor). The Long Path system is capable of continuously monitoring multiple facilities (monitored areas) via a single installation of a centralized tower from which laser light is generated. The Long Path system employs a rigorous system of quality control checks to ensure incoming data is valid. With this data, the Long Path system is capable of accurately quantifying emission rates in the order of minutes with a detection and quantification level of down to 0.06 kg/hr. Depending on the system configuration, operator specifications for alarming, and wind conditions, the time-to-detect of emission from leak start to operator alert can be as low as minutes.

Open-path, laser-based measurements rely on a light source that is sent through the open atmosphere. Continuous Open-Path Sensors measure path-integrated concentrations (total concentration of molecules along the laser path), so that the laser detection sensitivity is specified in units of mixing ratio* path length (ppm*m). Measures of precision are related to the signal-to-noise ratio of a given measurement, so they can be variable through time.

The length of the beam cutting through the atmosphere can be between 1 meter and several thousand meters long, and the beam can be very narrow to roughly .2 min diameter (depending upon distance from the light source), collectively giving rise to the effective dimensions of the C. Open-Path Sensor as a horizontally-oriented, integrated column.

Atmospheric concentration measurements collected over the open path are coupled to an atmospheric model and methane source sizing/localization inversion framework[17]. Similar to other continuous monitoring systems based, for example, on point sensors arrayed in a fenceline pattern around a monitored area (C. Point Sensor Systems), Long Path positions laser beams to create a geofence around each monitored area and "waits" for the wind to blow plumes across the sensor. In this sense, LongPath is a passive sensor. The sensor geometry for LongPath is not a single point in space, but, instead, an integrated line (pathway) through space between the telescope head and the retroreflective mirror (and back). In the image below, yellow laser beams act as a trip-wire geofence to catch all emissions originating from the monitored pad.

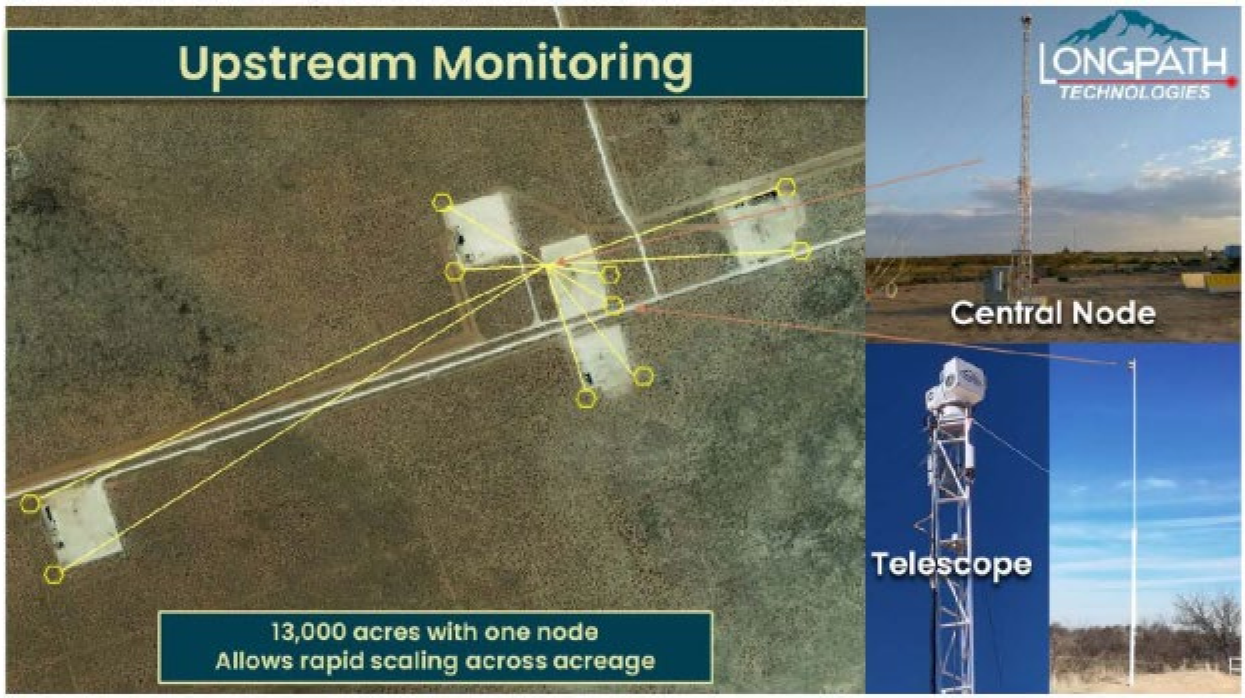


This full fenceline attribute results in high spatial coverage of the monitored area with each reading that is taken, under a wide range of wind directions.

With this system, LongPath has demonstrated in single-blind testing and field testing the ability to detect, locate, and size methane sources from individual facilities down to flow rates less than 0.1 kg/hr over large regions.[18, 19, 20]

Sensors and components

The Long Path system is composed of a small tower and Long Path's laser spectrometer and computing and control systems at a central node. A telescope emits the laser light and receives (detects) the reflected, return laser light. Reflective mirrors are installed on or near each monitored area and return emitted laser light to the transceiver.



The figure above shows the Long Path System deployment. A central node is shown in the center of the starburst pattern in the left-hand panel. In that panel, yellow lines indicate the geometry of eye-safe and invisible laser light that travels between the telescope (located at the central node location) and passive mirror) located in and around monitored areas (shown with yellow hexagons).

LongPath technology operation

The laser spectrometer produces and detects eye-safe laser light continuously through time (data rate of hundreds of millions per second). Sites and facilities around the central node may be eligible monitored areas, with many sites monitored with one node in a networked fashion. Alternatively, a single site may be monitored with a smaller central node.

Data logging and processing of concentration and emission rate data occurs locally on a computer chip co-located with the laser spectrometer in the field. Data is securely transferred to a cloud server via communications on the tower. All information relevant for emission rates (emission rate data, auxiliary information of interest to Long Path or the customer, and QAQC data) is transferred, and emission rate data is provided in real-time to the end user (e.g., customer) via secure cloud transfer, along with customized alerting mechanisms for emissions requiring operator mitigation.

Quantification method and localization method

Long Path Technologies provides quantitative, continuous methane emissions monitoring using long-range open path laser concentration measurements and local micrometeorological measurements coupled to an atmospheric inversion.[21,22]

Emissions are quantified and localized at the site-level, equipment group or equipment unit. Combination with other process data can provide component-level quantification.

Calibration and maintenance requirements

Calibration: Long Path laser systems do not require any instrument calibration or on-site visits for tuning.

Manufacturer information and Technology Maturity

LongPath was founded in 2017. LongPath is headquartered in Boulder, Colorado. All hardware is manufactured in-house at the Boulder facility by Long Path personnel.

The Long Path continuous monitoring system is commercially available worldwide.

Description of Long Path field deployments and controlled release testing

Long Path Technologies' continuous monitoring equipment is currently operating in the field on hundreds of upstream and midstream oil and gas facilities (well pads, tank batteries, and compressor stations) with dozens of operators (E&Ps). Here, we will provide a brief history of how Long Path arrived at this stage of commercialization, including extensive validation testing in 3rd-party single-blind tests at METEC, blinded field trials with operators, and independently verified (e.g., by field teams and production data) detection and quantification of leaks.

Long Path Technologies was launched from an ARPA-E MONITOR program[22] award to the University of Colorado, Boulder, NIST (National Institute of Standards and Technology) and the Cooperative Institute for Research in Environmental Sciences (CIRES; a partnership between CU-Boulder and the National Oceanic and Atmospheric Administration (NOAA)) in 2014 to develop a reduced-cost open-path laser system for methane monitoring.

At the start of MONITOR, the spectrometer system (based on Nobel prize-winning technology) was a laboratory system that had only recently been demonstrated for measuring methane over open atmospheric paths[23]. ARPA-E MONITOR funded the team to ruggedize, weatherize, miniaturize and automate the system, and develop and implement novel algorithms to accurately characterize methane emissions with the data. The team's ARPA-E MONITOR successes resulted in an additional "Plus Up" award to continue developing the technology and begin engaging with industrial partners. In late 2017, the spin-out venture, Long Path Technologies Inc., was launched to offer methane monitoring as a service to the oil and gas industry.

Throughout 2014 - 2018, the team performed multiple early-stage controlled release field trials at the NOAA Boulder Atmospheric Observatory, the NOAA Table Mountain Test Facility, and the NOAA Platteville Atmospheric Observatory. At each location, the team performed sensitivity testing of the system, using small, controlled methane releases. The Platteville Observatory is situated within extensive oil and gas production in the Denver Julesburg Basin, which allowed the team to validate methods for correctly identifying and quantifying even small emission rates against rapidly varying levels of ambient atmospheric methane concentrations. The team published results in the peer-reviewed literature, ensuring the highest standards of quality and validation were demonstrated[24, 25].

LongPath also underwent extensive ARPA-E MONITOR verification testing at the METEC (Methane Emissions Technology Evaluation Center) test facility operated by the Colorado State University in Fort Collins, Colorado. The following description of testing is from the team's 2019 peer-reviewed publication[26]: "The METEC facility has three pads built to simulate those found in natural gas production. Pads 1 and 2 are 10 m x 10 m with a wellhead, separator, and storage tank located on each. Pad 3 is 60 m x 10 m, and has a 10 m x 10 m wellhead battery on the north end with three wellheads, a 10 m x 10 m separator battery in the middle with two separators, and a 10 x 10 m tank battery on the south end with two storage tanks. All equipment is plumbed to allow testers to remotely activate natural gas leaks, at known flow rates, at a variety of points on the equipment. Prior to testing, we were informed by METEC that methane leak rates could vary from Oto any value. The composition of gas emitted was that of natural gas, and we reported rates of methane emissions. We examined the system's capabilities for pad-level or battery-level as well as equipment-level emissions monitoring."

The method was tested in two different "rounds": "R1" and "R2". During R1 tests, emission rates were continuous (sustained, or persistent emissions) and from a single leak point. During R2 tests, the emissions included multiple leak point locations (occurring simultaneously), and variable, intermittent emission rates (non-steady rates). The METEC testers chose a maximum limit for emissions that was equal to 5x the target emission rate of the ARPA-E program target (6 scfh). Compared to more recent estimates of emission rates from fugitive sources, [27, 28] these targets are extremely low and below the typical detection limits of most other commercial monitoring systems (e.g., aircraft, satellite and most other ground-based sensors). The Long Path system was able to accurately detect and quantify these very small emission rates.

We summarize the results of the R1 and R2 tests here and note that the results of both are extensively documented in a publicly available documents and peer-reviewed publications:

R1 Test Results: Alden, C. B., Coburn, S., Wright, R. J., et al. (2019). Single-blind quantification of natural gas leaks from 1 km distance using frequency combs. Environmental Science & Technology, 53(5), 2908-2917. https://doi.org/10.1021/acs.est.8b06259

R2 Test Results: Coburn, S., Alden, C. B., Wright, R., et al. (2020). Long distance continuous methane emissions monitoring with dual frequency comb spectroscopy: deployment and blind testing in complex emissions scenarios. https://arxiv.org/abs/2009.10853

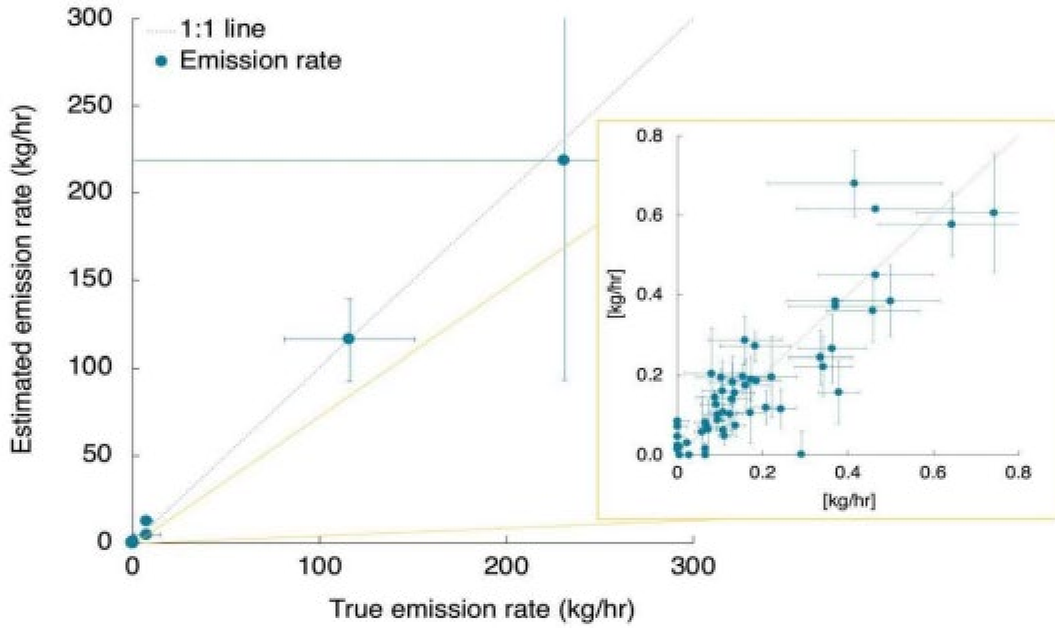
In the R1 tests, the system had a 100% success rate in detecting the presence and absence of leaks. There were no "false positives" (the incorrect reporting of emissions when there were none) or "false negatives" (the incorrect reporting of no emissions when there were emissions). Quantification for individual emission rate readings was within 27%.

In the R2 tests, the system had a 100% success rate in detecting the presence and absence of leaks greater than 5 scfh. For reference, 5 scfh is less than the allowable emissions for a single pneumatic valve. Early studies suggested that 90% of total emissions from oil and gas come from leaks that are at least 27 times larger than 5 scfh[29], although that is likely an underestimate based on newer studies. Quantification of individual emission rate readings was within 40%, including for multiple, very low-rate intermittent emissions occurring at once. Individual reading accuracy for single, steady sources was within 21%.[30]

In 2020, Long Path began long-term commercial continuous monitoring of customer sites in the Permian (both Midland and Delaware), Anadarko, and Denver Julesburg Basins. During these commercial field deployments, Long Path performed blinded tests of controlled releases with various customers. The importance of blinded field tests is that they fill in areas that METEC testing cannot provide: 1) detection and quantification of emissions on large and complex facilities, 2) detection and quantification of large emission rates, 3) detection and quantification of tall emission sources, and 4) localization of emissions on large, complex facilities.

Complex facilities: Long Path monitors large, multi-well pads and tank batteries and compressor stations. Blinded field testing of controlled emissions at these sites, as well as accurate detection and quantification of real fugitive emissions during monitoring, have confirmed Long Path's suitability for monitoring large and complex pads.

Large emission rates: In blinded field trials, Long Path has detected and quantified large emission rates, between 400 -12,500 scfh (10 - 300 Mcfd), or roughly 10 - 300 times larger than the rates tested at METEC. These tests verify that there is no bias in quantification at larger emission rates, or across a full range of expected emissions. Long Path has also had field verification of large emission quantified rates from fugitive events; rates were corroborated, for example, by comparison of gas loss rates to percentage reductions in well-site production data.



The figure above shows quantification of all blind-tested emission rates, including high rates, intermittent emissions and multiple simultaneous emissions. The dotted line shows the 1:1 line.

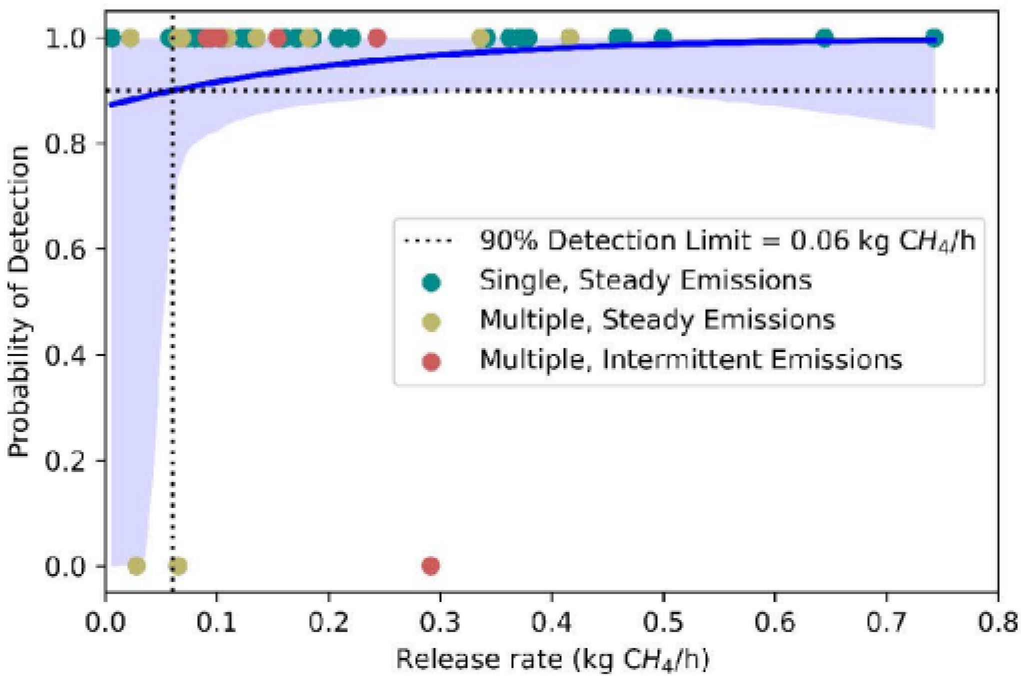
Tall leak points: Long Path consistently, correctly identifies fugitive emissions from unlit and malfunctioning flares, which can be 60-80' tall. In a controlled, blinded field trial, Long Path correctly detected a flare emission and accurately quantified the rate. Long Path has also accurately identified fugitive emissions from large compressors, indicating verified ability to detect and quantify heated (buoyant) plumes.

Localization on larger facilities: Finally, Long Path has demonstrated the ability, in blind trials with customers, as well as in field verification of monitoring data, to accurately localize emissions to the correct area of the pad.

In addition to the above blinded tests in the controlled MET EC setting and field demonstrations at production facilities and compressor stations, Long Path has performed long-term measurements at an underground natural gas storage facility (midstream). This year-long campaign included cross-validation of results with repeat aircraft mass balance measurements, as well as cross-validation of emissions variation with changes in operations according to logs maintained by the site manager. In this study, it was demonstrated that, while the independent Long Path (ground-based) and aircraft-based methods found the same statistical distribution of emissions (or size and range of routine emission rates), only the Long Path continuous monitoring consistently identified high-emitting outlier events. These top 10% of the largest emissions events accounted for a vast proportion (40%) of total emissions from the site and were not able to be documented by aircraft flyovers because of the short duration and infrequent cadence (monthly) of the aircraft flights, compared with the continuous (3-hourly) measurements. That work was published in a peer-reviewed journal[31].

Probability of detection

Long Path's minimum detection level (MDL), or probability of detection value, is calculated using only 3rd party (METEC) blind test data as shown above. That detection level is 0.06 kg/hr, as shown in the figure below.



Quantification precision/bias

As is described in the relevant publications, field trials have demonstrated that there is no bias in the quantified emission rate. Adding in the high emission rate events described above, we confirm the lack of bias across the range of tested emission rates from O kg/hr to 231 kg/hr. For all field trials, including those on large operating production sites and compressor stations (predominantly in the Permian Basin), the mean and standard deviation of the difference (Long Path minus Truth} between the "True" (typically the true rates themselves suffer high uncertainties, particularly in field tests) and Long Path measured rates is -0.19 ± 1.79 kg/hr.

Localization precision/bias

As is demonstrated in the publications and field trials above, Long Path has a 80-90% success rate for localizing to the equipment unit or group, with a 100% success rate in correctly determining the emitting pad or site.

Peer-reviewed publications and papers that demonstrate the method

Rieker, G. B., Giorgetta, F. R., Swann, W. C., et al., (2014). Frequency-comb-based remote sensing of greenhouse gases over kilometer air paths. Optica, 1, 290-298.

https://doi.org/10.1364/OPTICA.1.000290: This publication demonstrates proof-of-concept open-path sensor atmospheric measurements of greenhouse gases with a dual frequency comb spectrometer.

Coddington, I., Newbury, N., and Swann, W. (2016). Dual-comb spectroscopy. Optica, 3, 414-426. https://doi.org/10.1364/OPTICA.3.000414: This publication describes dual frequency comb spectroscopy, an open-path sensor.

Alden, C., Ghosh, S., Coburn, S., et al., (2018). Bootstrap inversion technique for atmospheric trace gas source detection and quantification using long open-path laser measurements. Atmospheric Measurement Techniques, 11, 1565-1582. https://doi.org/10.5194/amt-11-1565-2018: This publication demonstrates algorithmic developments with field measurements.

Coburn, S., Alden, C. B., Wright, et al., (2018). Regional trace-gas source attribution using a field-deployed dual frequency comb spectrometer. Optica, 5(4), 320. https://doi.org/10.1364/OPTICA.5.000320: This publication demonstrates the proof-of-concept methane emission rate estimation with the Long Path system.

Alden, C. B., Coburn, S., Wright, R. J., et al. (2019). Single-blind quantification of natural gas leaks from 1 km distance using frequency combs. Environmental Science & Technology, 53(5), 2908-2917. https://doi.org/10.1021/acs.est.8b06259: This publication validates the emission rate quantification and localization procedures in 3rd party blind testing at an oil and gas field site test bed (METEC) with the Long Path system.

Alden, C. B., Wright, R. J., Coburn, S. C., et al. (2020). Temporal variability of emissions revealed by continuous, long-term monitoring of an underground natural gas storage facility. Environmental Science & Technology, 54(22), 14589-14597. https://dx.doi.org/10.1021/acs.est.0c03175: This publication demonstrates autonomous field collection of long-term continuous emission data from a complex methane-emitting natural gas storage facility with the Long Path prototype system.

Footnotes:

[17] Coburn, S., Alden, C. B., Wright, et al., (2018). Regional trace-gas source attribution using a field-deployed dual frequency comb spectrometer. Optica, 5(4), 320. https://doi.org/10.1364/OPTICA.5.000320

[18] Coburn, S., Alden, C. B., Wright, et al., (2018). Regional trace-gas source attribution using a field-deployed dual frequency comb spectrometer. Optica, 5(4), 320. https:/fdoi.orq/10.1364/OPTICA.5.000320

[19] Alden, C. B., Ghosh, s., Coburn, s., et al. (2018). Bootstrap inversion technique for atmospheric trace gas source detection and quantification using long open-path laser measurements. Atmospheric Measurement Techniques, 11(3), 1565-1582. https:/fdoi.org/10.5194/amt-11-1565-2018

[20] Alden, C. B., Coburn, S., Wright, R. J., et al. (2019). Single-blind quantification of natural gas leaks from 1 km distance using frequency combs. Environmental Science & Technology, 53(5), 2908-2917. https:/ / doi.org /10.1021 /acs.est.8b06259

[21] Coburn, S., Alden, C. B., Wright, et al., (2018}. Regional trace-gas source attribution using a field-deployed dual frequency comb spectrometer. Optica, 5(4), 320. https://doi.org/10.1364/OPTICA.5.000320

[22] https://arpa-e.energy.gov/technologies/programs/monitor; the awarded institution was Univ. Colorado, Boulder.

[23] Rieker, G. B., Giorgetta, F. R., Swann, W. C., et al., (2014). Frequency-comb-based remote sensing of greenhouse gases over kilometer air paths. Optica, 1, 290-298. https://doi.orq/10.1364/OPTICA.1.000290

[24] Coburn, S., Alden, C. B., Wright, et al., (2018}. Regional trace-gas source attribution using a field-deployed dual frequency comb spectrometer. Optica, 5(4), 320. https:/fdoi.orq/10.1364/OPTICA.5.000320

[25] Alden, c., Ghosh, s., Coburn, s., et al., (2018). Bootstrap inversion technique for atmospheric trace gas source detection and quantification using long open-path laser measurements. Atmospheric Measurement Techniques, 11, 1565-1582. https://doi.org/10.5194/amt-11-1565-2018

[26] Alden, C. B., Coburn, S., Wright, R. J., et al. (2019}. Single-blind quantification of natural gas leaks from 1 km distance using frequency combs. Environmental Science & Technology, 53(5}, 2908-2917. https://doi.org/10.1021/acs.est.8b06259

[27] Omara, M., Zimmerman, N., Sullivan, M. R., et al., (2018). Methane emissions from natural gas production sites in the United States: Data synthesis and national estimate. Environmental Science & Technology, 52 (21), 12915-12925. https://doi.org/10.1021/acs.est.8b03535

[28] Rutherford, J., Sherwin, E. Ravikumar, A., et al., (2021). Closing the methane gap in US oil and natural gas production emissions inventories. Nature Communications, 12, 4715. https://doi.orq/10.1038/s41467-021-25017-4

[29] Brandt, A., Heath, G., Cooley, D., et al., (2016). Methane leaks from natural gas systems follow extreme distributions. Environmental Science and Technology, 50 (22), 12512-12520. https://doi.org/10.1021/acs.est.6b04303

[30] Coburn, S., Alden, C. B., Wright, R., et al. (2020). Long distance continuous methane emissions monitoring with dual frequency comb spectroscopy: deployment and blind testing in complex emissions scenarios. https://arxiv.org/abs/2009.10853

[31] Alden, C. B., Wright, R. J., Coburn, S. C., et al. (2020). Temporal variability of emissions revealed by continuous, long-term monitoring of an underground natural gas storage facility.

Environmental Science & Technology, 54(22). 14589-14597.
https://dx.doi.org/10.1021/acs.est.0c03175

Response 2: We thank the commenters for the additional information on continuous monitoring technologies. As discussed in Section II.B of the preamble to the final rule, this final rule integrates advanced measurement approaches for specific sources in certain appropriate circumstances, including for other large release events. The EPA agrees that rapid detection of these large release events resulting in facilities taking immediate action to mitigate the event will substantially decrease the duration of these events and significantly lower methane emissions. However, the Agency recognizes that these technologies, and approaches for using these technologies for long-term quantification of emissions from oil and natural gas operations, have a wide level of uncertainty and are not ready for widespread use for quantification purposes.[10, 11] The EPA acknowledges the rapid evolution of these technologies, and their potential utilization for long term emission quantification. Historically, the Greenhouse Gas Reporting Rule has been revised to incorporate the latest data, updated scientific knowledge or additional measurement methods and EPA intends to continue to evaluate the appropriateness of additional updates. In preparation for future rulemaking, the EPA is actively reviewing peer reviewed literature and pilot programs to explore the potential incorporation of diverse continuous monitoring solutions and methodologies in subpart W.

Commenter: BP America Inc.
Comment Number: EPA-HQ-OAR-2023-0234-0345
Page(s): 3-4

Commenter: Project Canary, PBC
Comment Number: EPA-HQ-OAR-2023-0234-0348
Page(s): 10

Commenter: Honeywell International Inc.
Comment Number: EPA-HQ-OAR-2023-0234-0375
Page(s): 3-6, 6-7

Comment 3: Commenter 0345: **Continuous monitoring systems are capable of emissions source-level leak detection with a high degree of accuracy.**

In discussing the role of advanced emissions monitoring technologies, EPA refers to them broadly as "top-down approaches," and appears to include continuous monitoring in this category.[8] For reporting emissions from any source other than "large emissions events," EPA

[10] Bell, Clay & Vaughn, Timothy & Zimmerle, Daniel. (2020). Evaluation of next generation emission measurement technologies under repeatable test protocols. Elem Sci Anth. 8. 32. 10.1525/elementa.426.
[11] Bell, Clay & IIonze, Chiemezie & Duggan, Aidan & Zimmerle, Daniel. (2023). Performance of Continuous Emission Monitoring Solutions under a Single-Blind Controlled Testing Protocol. Environmental Science &Technology. *57* (14). 5794-5805. 10.1021/acs.est.2c09235

excludes the use of all top-down approaches, asserting that these methods are “not presently able to provide annual emissions data to the degree of accuracy and certainty required by other provisions of this rule.”

This generalized description of “top-down approaches” (e.g., “taken over limited durations,” “when specific meteorological conditions exist,” and “at large spatial scales”) suggests that EPA may be thinking primarily of periodic screening methods. EPA states that “[m]ost top-down, facility measurements are taken over limited durations (a few minutes to a few hours) typically during the daylight hours and limited to times when specific meteorological conditions exist (e.g., no cloud cover for satellites; specific atmospheric stability and wind speed ranges for aerial measurements).” EPA further states that “[t]he data provided by some of these technologies are at large spatial scales, with limited ability to disaggregate to the facility- or emission source-level and have high minimum detection limits.”[9]

This is not an accurate description of most continuous monitoring systems, which can be installed at or near individual pieces of equipment and – when operating normally – are functioning at all times and under most ambient conditions.

In contrast to periodic screening methods, such as satellite or aerial surveys, continuous monitoring systems can entail a network of sensors that are deployed in close proximity to fugitive emissions components throughout a facility, enabling real-time leak detection with a high degree of accuracy. These sensors survey for leaks at very short intervals, often within a matter of seconds or minutes. Continuous monitoring systems are capable of both achieving low minimum detection sensitivities and disaggregating data to the emissions source-level (rather than simply indicating the presence of a leak over a large area). We therefore suggest EPA consider continuous monitoring as a separate category instead of as a “top-down” technology.

Footnotes:

[8] See, e.g., 88 FR at 50289 (“we reviewed measurement approaches that utilize information from satellite, aerial, and continuous monitoring (‘top-down approaches’)”).

[9] 88 FR at 50,290-50,291.

<u>Commenter 0348</u>: **The Proposed Rule’s treatment of continuous monitoring systems is arbitrary and capricious**

The Proposed Rule fails to analyze the distinct capabilities of continuous monitoring systems.

The comments made in the preceding sections assume, for the sake of argument, that the Proposed Rule has accurately described the limitations of “top-down” methods. However, as explained in this section, the Proposed Rule’s analysis of “top-down” methods fails to include any meaningful analysis of the capabilities of continuous monitoring systems.

What scarce discussion there is about continuous monitoring systems in the Proposed Rule mistakenly conflates continuous monitoring systems with satellite and aerial surveying technologies under the broad rubric of "top-down" methods. The first mention of "top-down" methods in the preamble to the Proposed Rule includes continuous monitoring systems, but the discussion of their capabilities is confined to satellite technologies, aerial technologies, and drones. The TSD for the Proposed Rule is even more insufficient. It expressly limits its analysis of "top-down" methods to these remote, periodic surveying technologies—and omits any analysis of continuous monitoring systems. Section 2.2 of the TSD describes its scope of the review as covering "the current and potential future capability of top-down methods for quantifying methane emissions using remote-sensing approaches from aerial and satellite platforms that observe at various spatial scales depending on the altitude of observation."[24]

Continuous monitoring systems are neither remote nor periodic in their operations. They are installed at the site or facility, and they operate on a continuous basis, as described above in Section III. The scholarly literature on methane monitoring recognizes the difference between remote, periodic surveying technologies and continuous monitoring systems. [25] And EPA itself recognized this difference in its NSPS OOOOb and EG OOOOc Proposal. The Agency established an approval matrix for continuous monitoring systems that is entirely separate and distinct from the matrix for periodic surveying by satellite and aerial technologies. The omission of any significant analysis of continuous monitoring systems is a significant gap in the technical record for the Proposed Rule.

Furthermore, the rationales offered by the Agency in the Proposed Rule and the TSD for its dismissal of satellite and aerial surveying technologies do not apply to continuous monitoring systems. As noted above, the EPA ruled out use of "top-down" methods for all but "Other Large Release Events" because measurements from such methods are "taken over limited durations" at "large spatial scales" and at high detection limits. By contrast, again, continuous monitoring systems operate continuously on a facility-specific basis. Many continuous monitoring systems are capable of detecting and measuring emissions at low kg levels; in its NSPS OOOOb and EG OOOOc proposal, EPA has proposed to approve continuous monitoring systems capable of detection at a 0.12 kg/hr or 0.16 kg/hr level.

For these reasons, the technical record in the Proposed Rule is insufficient. EPA should undertake a review of continuous monitoring systems and establish an approval matrix for such systems similar to that which the Agency has proposed to establish in the NSPS OOOOb and EG OOOOc Proposal.

Footnote:

[24] U.S. ENVIRONMENTAL PROTECTION AGENCY, 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, EPA–HQ–OAR–2023–0234; FRL–10246–01– OAR (June 2023) (hereinafter "TSD"), at 6 (emphasis added).

[25] Daniels, W., et al., Toward multi-scale measurement-informed methane inventories: reconciling bottom-up site-level inventories with top-down measurements using continuous monitoring systems, Environ. Sci. Technol. 2023, 57, 32, 11823- 111833 (July 28, 2023), htps://doi.org/10.1021/acs.est.3c01121}

Commenter 0375: *EPA's Proposal to Allow the Use of Top-Down Approaches for Reporting On "Other Large Release Events" But Not for Any Other Source Types, Is Premised on the Assumption That All "Top-Down" Approaches to Emission Monitoring Suffer the Same Limitations as Satellite and Aerial-Based Remote Sensing Systems.*

In its proposed Subpart W revisions, EPA proposes to add as a new emission source "other large release events", which multiple studies have identified as contributors to total emissions that are not accurately captured by current bottom-up emissions estimates. For these emission sources, EPA proposes to permit the use of top-down monitoring approaches that have demonstrated their accuracy and ability to identify "other large release events" to calculate total emissions from these events and/or to estimate the duration of such events. 88 Fed. Reg. 50282, 50290. Honeywell supports efforts to better capture and quantify "super-emitters", now categorized as the "other large release events" emission source, so that the accuracy of the emissions inventory improves.

It is important to note, however, that the opportunity exists to prevent emissions from becoming a "super-emitter" altogether or to greatly reduce emissions through early detection that can alert a more immediate response, if EPA were to incorporate continuous monitoring more broadly as a permitted, and therefore encouraged, leak detection and quantification method for purposes of emissions reporting. However, EPA's proposed revisions do not identify advanced continuous monitoring technologies or top-down approaches as permitted methods for estimating the duration of emission events or calculating total facility emissions for other emissions sources, including for fugitive emissions. 88 Fed. Reg. at 50343, et seq. Notably, with respect to equipment leak survey methods, the proposed Subpart W revisions do not include among the permitted leak survey methodologies continuous monitoring technologies to detect equipment leaks. Nor does EPA include continuous monitoring technologies as a permitted leak detection method even for the purpose of estimating the duration or volume of equipment leaks, as illustrated in the Equipment Leak Survey Methods Table, below.

Equipment Leak Survey Methods

Citation	Equipment source	Segment	Leak Survey Methodology permitted
40 CFR § 98.233(q)(1)(i)	Equipment leaks from valves, connectors, open ended lines, pressure relief valves, and meters 40 CFR § 98.232(e)(7)	Onshore natural gas transmission compression	**For components <u>not</u> subject to OOOOa, OOOOb, or applicable state/Federal plan under OOOOc, any method specified in 40 CFR § 98.234(a), including:** • OGI as specified in (i) § 60.18 of this chapter; (ii) OOOOa (40 CFR § 60.5397a); or (iii) Appendix K to part 60; • Method 21 with a leak definition of 10,000 ppm or 500 ppm; • Infrared laser beam illuminated instrument • Acoustic leak detection device
	Equipment leaks from valves, connectors, open ended lines, pressure relief valves, and meters associated with storage stations 40 CFR § 98.232(f)(5)	Underground natural gas storage	
	Equipment leaks from valves, pump seals, connectors, and other equipment leak sources in LNG service 40 CFR § 98.232(g)(4)	LNG storage	
	Equipment leaks from valves, pump seals, connectors, and other equipment leak sources in LNG service 40 CFR § 98.232(h)(5)	LNG import and export equipment	
40 CFR § 98.233(q)(1)(ii)	Equipment leaks from connectors, block valves, control valves, pressure relief valves, orifice meters, regulators, and open-ended lines at above grade transmission-distribution transfer stations 40 CFR § 98.232(i)(1)	Natural gas distribution	**Any method in 40 CFR § 98.234(a) except (a)(2)(ii):** • OGI as specified in (i) § 60.18 of this chapter; (ii) OOOOa (40 CFR § 60.5397a); or (iii) Appendix K to part 60; • Method 21 with a leak definition of 10,000 ppm; • Infrared laser beam illuminated instrument • Acoustic leak detection device
40 CFR § 98.233(q)(1)(iii)	Equipment leaks for components that **<u>are subject</u>** to the well site or compressor station fugitive emissions standards in OOOOa (40 CFR § 60.5397a) or the fugitive emissions standards for well sites, centralized production facilities, and compressor stations in OOOOb and emissions guidelines in OOOOc	• onshore petroleum and natural gas production facility, • onshore natural gas transmission compression, • underground natural gas storage, • LNG storage, • LNG import and export equipment, • onshore petroleum and natural gas gathering and boosting facilities	• OGI instrument as specified in OOOOa (40 CFR § 60.5397a); • OGI instrument as specified in appendix K to part 60; • Method 21 with a leak definition of 500 ppm
40 CFR § 98.233(q)(1)(iv)	Equipment leaks for components that **<u>are not</u>** subject to the fugitive emissions standards in OOOOa (40 CFR § 60.5397a) or the fugitive emissions standards for well sites, centralized production facilities, and compressor stations in OOOOb and emissions guidelines in OOOOc **<u>may</u>** choose to do leak surveys		**Any method specified in 40 CFR § 98.234(a), including:** • OGI as specified in (i) § 60.18 of this chapter; (ii) OOOOa (40 CFR § 60.5397a); or (iii) Appendix K to part 60; • Method 21 with a leak definition of 10,000 ppm or 500 ppm; • Infrared laser beam illuminated instrument • Acoustic leak detection device
40 CFR § 98.233(q)(1)(v)	Equipment leaks from valves, connectors, open ended lines, pressure relief valves, and meters, and equipment leaks from all other components in gas service (not including thief hatches or other openings on storage vessels) that either are subject to equipment leak standards for onshore natural gas processing plants in § 60.5400b or applicable state/Federal plan	Onshore natural gas processing	If subject to equipment leak standards under § 60.5400b • OGI instrument as specified in appendix K to part 60; • Method 21 with a leak definition of 500 ppm If not subject to standards under § 60.5400b, any method in 40 CFR § 98.234(a)

EPA stated that it reviewed “top-down approaches” (defined as including measurement approaches that utilize information from satellite, aerial and continuous monitoring) to detect and/or quantify emissions from petroleum and natural gas systems for the purposes of Subpart W reporting. 88 Fed. Reg. at 50289. In the preamble, EPA explained its conclusion that top-down approaches are not presently able to provide annual emissions data to the degree of accuracy and certainty required for extrapolating annual emissions data based on several identified limitations of top-down approaches, including that most top-down facility measurements are taken over limited duration, during daylight hours, during specified meteorological conditions, and that direct measurement data taken at a single moment in time may not be representative of facility emissions. EPA also noted that top-down measurement methods like satellite and aerial methods may have detection limits that are too high to detect emissions from sources with relatively low emission rates and may not provide a basis for disaggregating emissions data at the facility or emission source-level. Id. at 50290-50291.

Apart from EPA’s brief mention of continuous monitoring as part of the “top-down approaches” category, the preamble discussion of “top-down” approaches does not identify or address any continuous monitoring technology systems. Rather, the Greenhouse Gas Reporting Rule: Technical Support for Revisions and Confidentiality Determinations for Data Elements Under Greenhouse Gas reporting Rule; Proposed Rule – Petroleum and Natural Gas Systems, June 2023 (“Subpart W TSD”) suggests that EPA is basing its understanding and assumptions about the capabilities of “top-down” technologies on studies that were only conducted of satellite, high-altitude aerial and low-altitude aerial monitoring systems. The Subpart W TSD discusses monitoring systems and research involving systems with the potential to make observations with space-, high-altitude aerial and low-altitude aerial based remote sensing technology. Subpart W TSD, at 6-7.

From Honeywell's perspective, we understand "top-down approaches" to generally be consistent with the GTI Veritas protocols, which envision a broader definition of "Top-Down" to include "Methane measurements taken at spatial scales greater than the component scale", as would be the case for satellite or aerial-based flyover technology, and may include "continuous monitoring systems (CMS) that provide continuous or semi-continuous quantitative measurements of mass emissions of methane and linear assets such as pipelines, when a pipeline route is examined." [3] Generally, such top-down approaches are distinct from a "bottom up" approach in which handheld detection equipment is used to characterize component-specific leaks that can then be used to build up an inventory of site emissions by aggregating the leaks detected from the various components. From our perspective, ground-based continuous monitoring systems such as Honeywell Versatilis™ Signal Scout™ and Rebellion™ GCI cameras can monitor for either groups of components or at the component level based on the deployment configuration for the site. In that context, Honeywell's advanced continuous monitoring technology is best understood as residing somewhere in between the top-down approaches discussed in the Subpart W TSD and bottom-up approaches.

Honeywell shares concerns about sampling error rates in certain top-down measurement approaches, particularly with respect to intermittent emissions, as a study has found that monthly measurements of sites with emissions events of one hour duration result in an average absolute percent error of 23% of annualized emission estimates, with shorter emission events and less frequent measurements resulting in even larger rates of error.[4] That study concluded that measurement technologies with a higher sampling frequency are an important aspect of a measurement portfolio aimed at characterizing site-level emissions that vary temporally.[5]

Continuous monitoring technologies like Honeywell's Rebellion™ GCI cameras and Honeywell's Versatilis™ Signal Scout™ technologies are not like the satellite, high-altitude or low-altitude monitoring systems that were reviewed in the Subpart W TSD. Rather, they are a hybrid technology or somewhat like "bottom-up" technologies, or somewhere between bottom-up and top-down technologies where they can provide methane measurements at component or spatial scales beyond the component level that provide continuous or semi-continuous quantitative measurements of mass emissions of methane and linear assets such as pipelines, when a pipeline route is examined. They are closer to ground-mounted, land-based systems that are capable of detecting leaks at equipment-group and even component-specific locations, on a continuous basis, depending on the deployment configuration of the system components, As such, they should not be lumped in with EPA's narrower analysis of top-down technologies.

Commenter Notes:

[3] GTI Veritas protocols found at link: https://veritas.gti.energy/protocols, p. 8

[4] Schissel, C.; Allen, D. T. Impact of the High-Emission Event Duration and Sampling Frequency on the Uncertainty in Emission Estimates. Environ. Sci. Technol. Lett. 2022, 9, 1063–1067.

[5] See also, Daniels, W., Wang, J., et al., Toward Multiscale Measurement-Informed Methane Inventories: Reconciling Bottom-Up Site-Level Inventories with Top-Down Measurements Using Continuous Monitoring Systems., Environ. Sci. Technol. 2023, 57, 32, 11823–11833.

…

Continuous Monitoring Technologies Are an Effective Way to Ensure the Reporting Under Subpart W Is Based on Empirical Data and Accurately Reflects the Total Methane Emissions and Waste Emissions.

Continuous monitoring systems should not be grouped with top-down systems like satellite, drone and aerial-based approaches when evaluating the extent to which such systems can provide empirical data for purposes of improving the accuracy of the total methane and waste emissions inventory. While satellite, drone and aerial-based systems are periodic monitoring approaches that can be helpful for detecting super-emitters, id. at 50290, continuous monitoring technologies measure continuously, allowing for detection of intermittent emissions and at much lower emission rates down to 0.5 kg/h and therefore can provide better emissions data across a broader set of emissions sources.

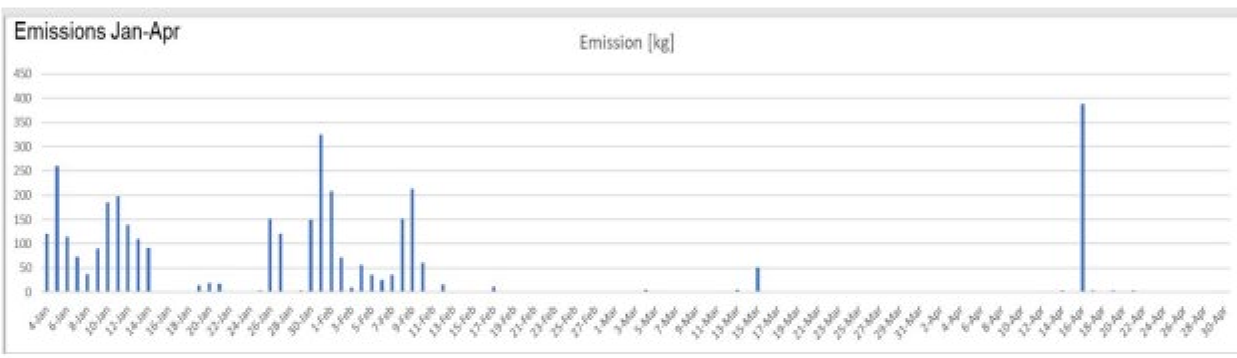
1. Continuous monitoring systems improve the ability to detect and respond to intermittent emissions.

Continuous monitoring generates consistent, automated emission detection and creates a record of emission events or absence of emissions. By operating continuously, the systems detect emission events and intermittent emissions immediately. Continuous monitoring is capable of providing empirical data with better accuracy (closer to the true value), than currently used emission factors and periodic monitoring technologies. The rationale for using such technology is not only to improve the accuracy of GHG emissions reporting, however. Such technology also enables rapid detection and repair. The latter is particularly relevant given that a facility's investment in such technology to satisfy the measurement requirements and emissions fee provisions has important and sustained long-term benefits in helping actually to reduce emissions.

Continuous monitoring has the potential to vastly improve, if not replace, the existing time component (T) of the GHG calculations formula. Currently, the time component is estimated (assumed) based on (1) how many surveys were conducted in a calendar year and (2) when the last survey was conducted in a calendar year. 40 C.F.R. § 98.233(q)(2). T is defined as (1) the total time the surveyed component was assumed to be leaking; (2) a full calendar year, if only one survey was conducted; (3) from the beginning of the year until the first survey (where multiple leak detection surveys were conducted); (4) from the preceding survey through the end of the year (where a leak is detected). These times are then summed for all leaking periods. Id. Whereas before (in 2011) operators may have only been able to conduct annual surveys, survey technology has improved dramatically, with continuous monitoring technologies providing operators the ability to detect and measure leaks in real time, all the time. EPA should thus allow advanced technologies, such as continuous monitoring that can demonstrate equivalency to existing permitted leak detection survey method under 40 C.F.R. § 98.234(a), to be included as a permitted source of empirical emissions data for inventory purposes. Such a change would potentially improve the accuracy of reporting by removing the need for an estimated time component, and replacing it with continuous, hourly leak-detection data.

To provide further context, consider that most emissions at a petroleum or natural gas facility are not continuous in nature; they are intermittent, and their occurrence depends on process events at the plant (for instance, a failed start-up of a burner or a vent through a pressure relief valve or a not well-closing thief hatch). Intermittent emissions cannot be reliably measured with periodic inspections. Only continuous monitoring systems can detect and measure intermittent releases.

To illustrate, this graph shows measurements taken using continuous monitoring technology at one location within the Permian basin over a four-month period. It shows measured emissions in kg CH4 of an upstream plant in Q1 of 2023. As the graph shows, the emissions are highly intermittent



A quarterly inspection on March 1 at this facility would wrongly conclude that there were no emissions. A periodic inspection at this facility on April 16 would wrongly conclude that 400 kg CH4/day was emitted for the last quarter. Neither of those conclusions would be correct. This demonstrates that intermittent, non-continuous emissions can only be detected with a continuous monitoring system, and not with periodic inspections (like drone, satellite, or LDAR). Therefore, measurement systems that operate at a higher sampling frequency, including continuous monitoring systems, are an important aspect of measurement portfolios aimed at characterizing site-level emissions that vary temporally.[6]

Footnotes:

[6] Toward Multiscale Measurement-Informed Methane Inventories: Reconciling Bottom-Up Site-Level Inventories with Top-Down Measurements Using Continuous Monitoring Systems, Daniels, et al., Environ. Sci. Technol. 2023, 57, 32, 11823–11833.

Response 3: The EPA acknowledges the support from commenters regarding the utilization of continuous monitoring for subpart W reporting. We recognize that continuous monitoring approaches are distinct from periodic measurements with satellite, drone, and aerial-based sensors. Peer-reviewed studies assessing the accuracy of Continuous Monitoring Systems (CMS) in detecting and quantifying site-level emissions have been considered. To date, CMS deployments typically fall into two categories: 1) point sensor monitoring, where one or more sensors are deployed to measure methane concentrations at one location (or point), and 2) scanning/imaging monitoring, where one or more sensors are deployed to provide 2-dimensional images (e.g., video image) of a gas plume at a location. In both approaches, additional analytics are required to combine measured concentration data (category 1) or plume images (category 2) with local meteorological conditions in order to quantitatively estimate methane emissions. Therefore, both approaches are sensitive to multiple factors, including specific sensor placement relative to the source, meteorological conditions, emission rates and event duration, and analytical quantification approach. While testing of CMS has been conducted for specific deployments, CMS has not been comprehensively evaluated in typical field conditions, across all site configurations or meteorological scenarios encountered in various operating basins. Of the CMS deployments tested, recent studies have revealed large differences in key performance metrics, including the limit of detection, probability of detection (i.e., false positive/negative detections), as well as large uncertainties in quantified emission rates and total emissions .[12, 13]

As discussed in Section II.B. of the preamble to the final rule, while recent studies have demonstrated that CMS can provide valuable data for detecting anomalous emissions (generally faster than survey methods), determining the temporal nature of an event duration, or complementing/validating alternative satellite, drone, or aerial-based measurements, there remain large uncertainties in using CMS to detect and quantify emissions. For example, emissions quantification from point sensor systems may face challenges at sites with complex infrastructure (which could complicate the data interpretation and quantification analytics) and systems that rely on scanning or imaging sensors may face challenges in visually detecting plumes and quantifying emission rates under specific meteorological or operational conditions. A more extensive range of operating and testing conditions must be evaluated to gain a deeper understanding of the factors influencing CMS and the accuracy of their emission quantification approaches.[14]

The EPA acknowledges the rapid evolution of these technologies and their potential utilization for long-term emission quantification in oil and natural gas operations. In preparation for future rulemaking, the EPA is actively reviewing relevant peer-reviewed literature and pilot programs to explore the potential incorporation of diverse continuous monitoring solutions and methodologies into subpart W.

Commenter: Project Canary, PBC
Comment Number: EPA-HQ-OAR-2023-0234-0348
Page(s): 13

[12] Bell, Clay & Vaughn, Timothy & Zimmerle, Daniel. (2020). Evaluation of next generation emission measurement technologies under repeatable test protocols. Elem Sci Anth. 8. 32. 10.1525/elementa.426.
[13] Bell, Clay & IIonze, Chiemezie & Duggan, Aidan & Zimmerle, Daniel. (2023). Performance of Continuous Emission Monitoring Solutions under a Single-Blind Controlled Testing Protocol. Environmental Science &Technology. *57* (14). 5794-5805. 10.1021/acs.est.2c09235
[14] Day, R.E.; Emerson, E.; Bell, C.; Zimmerle, D. Point Sensor Networks Struggle to Detect and Quantify Short Controlled Releases at Oil and Gas Sites. *Sensors* **2024**, *24*, 2419. https://doi.org/10.3390/s24082419

Comment 4: The Proposed Rule's treatment of continuous monitoring systems is arbitrary and capricious.

The Proposed Rule's approach regarding continuous monitoring systems is inconsistent with leading state methane quantification policies.

The approach in the Proposed Rule would put EPA off pace with leading state policies, which are moving toward intensity-based methane requirements and the use of advanced measurement technologies. The State of Colorado finalized a rule in July 2023 that will require owners and operators of certain types of oil and gas facilities to directly measure their methane emissions on a facility-specific basis. [33] The state will use these calculations to derive state-wide emission inventories to assure compliance with the state's GHG intensity (emissions per unit output) thresholds. It is expected that facility owners will use advanced measurement technologies to comply with their direct measurement obligations.

The Colorado rule came about as the result of a comprehensive stakeholder dialogue involving industry, technology providers, and environmental groups. The Environmental Defense Fund issued a statement praising the rule as a "commonsense proposal to directly measure methane emissions in the field."[34]

Through the implementation of this rule, Colorado is fostering technology advancement and adoption as well as ensuring the operators in the state are utilizing empirical data to reduce their emissions and report the most accurate emissions data available. EPA should partner with Colorado, and other states considering similar approaches, to advance this mutual goal.

Footnotes:

[33] Colorado Dep't of Public Health, "Colorado Adopts First-of-its-Kind to Verify Greenhouse Gas Emissions From Certain Oil and Gas Sites" (July 2023), htps://cdphe.colorado.gov/press-release/colorado-adopts-first-of-its-kind-measures-to-verify-greenhouse-gas-emissions-from.

[34] Environmental Defense Fund, "Colorado Adopts Ground-breaking Methane Measurement Rule" (July 2023), htps://www.edf.org/media/colorado-adopts-groundbreaking-methane-measurement-rule.}

Response 4: We appreciate the information on the Colorado Rule. See also our response to Comment 3 in this section of this document.

Commenter: Sensirion Connected Solutions
Comment Number: EPA-HQ-OAR-2023-0234-0293
Page(s): 8**,** 20-21

Commenter: Project Canary, PBC
Comment Number: EPA-HQ-OAR-2023-0234-0348
Page(s): 16**,** 18

Commenter: Qube Technologies, Inc.
Comment Number: EPA-HQ-OAR-2023-0234-0386
Page(s): 8**,** 8

Commenter: American Petroleum Institute et al. (Part 1 of 2)
Comment Number: EPA-HQ-OAR-2023-0234-0402
Page(s): 57

Commenter: LongPath Technologies, Inc.
Comment Number: EPA-HQ-OAR-2023-0234-0410
Page(s): 3-4

Commenter: Differentiated Gas Coordinating Council (DGCC)
Comment Number: EPA-HQ-OAR-2023-0234-0415
Page(s): 9

Comment 5: Commenter 0293: **The framework for approving advanced measurement technologies should have appropriate criteria.**

SCS proposes additional options within that can streamline these key framework pieces for emissions quantification, not only leak detection and repair at both the sensor and system performance levels. In order to create a robust and reliable advanced technology, the sensor and system must both be operating in unison; but tested separately to validate field performance, applicable environmental conditions, and geographic regions where the solution can best be utilized on facilities subject to the Proposed Rule.

A. Validating Sensor Performance in Continuous Monitoring Systems

SCS proposes validation of the underlying sensor technologies within continuous monitoring systems of all types (fixed point, IR, line path) in controlled lab settings. These should be mutually agreed and scientifically backed criteria handled by a third-party accredited lab (such as UL). SCS proposes the three following key parameters at the sensor level: Accuracy, Cross-Sensitivity (Temperature, Humidity, and Select Gases), and Limit of Detection. These three main parameters will ensure the system performance can be of the highest fidelity data.

b. Validating System Level Performance in Continuous Monitoring Systems

The second layer contributing to a robust and reliable alternative technology is the system level performance, or modelling capabilities. For this, SCS proposes controlled release testing at the facility level with the number of optimal nodes determined by the technology vendor. The primary six test criteria: False positive percentage, False negative percentage, leak rate quantification accuracy, time-to-detection, leak rate localization accuracy, and system level detection limits (in accordance withto Section 111 Supplemental Proposal). These criteria will provide a framework that streamlines testing on an equivalent level to provide assurance that technologies will meet the needs of applicable facilities subject to the Proposed Rule.

The second layer contributing to a robust and reliable alternative technology is the system level performance, or modelling capabilities. For this, SCS proposes controlled release testing at the facility level with the number of optimal nodes determined by the technology vendor. The primary six test criteria: False positive percentage, False negative percentage, leak rate quantification accuracy, time-to-detection, leak rate localization accuracy, and system level detection limits (in accordance with Section 111 Supplemental Proposal). These criteria will provide a framework that streamlines testing on an equivalent level to provide assurance that technologies will meet the needs of applicable facilities subject to the Proposed Rule.

…

The framework for approving advanced measurement technologies should have appropriate criteria.

In adapting the Section 111 Supplemental Proposal's framework for the purpose of emissions quantification, rather than detection, the Agency should use appropriate performance criteria. For continuous monitoring system, these performance criteria should address, at a minimum, the following factors:

- frequency of measurement
- uncertainty
- emissions source attribution capabilities
- probability of detection under various conditions
- operational limitations
- minimum detection thresholds

In addition, the agency should define "continuous" as well as how the Agency wants each performance criterion tested, measured, and demonstrated.

Commenter 0348: Advanced measurement technologies, including continuous monitoring systems, should be allowed to estimate annual emissions for source categories and/or facility-level emissions under Subpart W. EPA should create a framework for approval of such technologies leveraging the NSPS OOOOb and EG OOOOc proposal. In adapting this framework for the purpose of emissions quantification, rather than just detection, the Agency should use appropriate performance criteria. As noted in Section IV.5.f., these performance criteria should include frequency of measurement, uncertainty, emissions source attribution capabilities, probability of detection under various conditions, operational limitations, and minimum detection thresholds. The Agency should define "continuous" and should specify how it wants each performance criterion tested, measured, and demonstrated.

…

EPA should "prescribe a manner" in which owners or operators of applicable facilities may use advanced measurement technologies, including continuous monitoring systems, to calculate their emissions and the extent to which a Methane Waste Emissions Charge is owed.

Section 136(h) requires EPA to "allow owners and operators of applicable facilities to submit empirical emissions data, in a manner to be prescribed by the Administrator, to demonstrate the extent to which a charge under subsection (c) is owed."

Consistent with this Congressional mandate—and in the interest of promoting innovation—EPA should establish a framework in the Final Rule for approval of qualifying advanced measurement technologies for methane emissions measurement, including continuous monitoring systems, that owners and operators of applicable facilities may use to submit facility-specific emissions data.

Project Canary strongly urges EPA not to rely on the site-by-site Alternative Means of Emission Limitation mechanism or future notice-and-comment rulemakings to approve the use of advanced measurement technologies. It is important to recognize the lessons learned from the experience with the OOOOa regulations. As EPA knows, almost immediately after the 2016 promulgation of those regulations, owners and operators of regulated facilities asked to use advanced measurement technologies in lieu of the prescribed technologies, yet revised regulations are not expected until 2024. This time lapse of eight years has been a missed opportunity for the Agency to enable the use of advanced technologies and more accurate measurement, reporting, and reductions. In those revised regulations, the Agency has now wisely proposed to establish a framework for ongoing review and approval of alternative methods. It should do the same here. The matrices that EPA has developed for the NSPS OOOOb and EG OOOOc proposal provide a model for such a method-by-method approval framework for Subpart W.

Commenter 0386: **EPA should "prescribe a manner" in which owners or operators of applicable facilities may use advanced measurement technologies, including continuous monitoring systems, to calculate their emissions and the extent to which a Methane Waste Emissions Charge is owed.**

EPA should develop a framework in the final rule for approval of qualifying advanced measurement technologies for methane emissions measurement that operators of applicable facilities may use to submit facility-specific emissions data.

Although Section 136(i) requires EPA to allow operators of applicable facilities to submit empirical emissions data to demonstrate the extent to which a charge is owed, no direction for doing so is provided, which relegates this important issue to future notice-and-comment rulemakings. Without a prescribed framework, EPA is deferring action. Qube urges EPA to take the initiative now and develop a framework that will enable operators to use qualified advanced measurement technologies such as continuous monitoring for methane emissions measurements.

…

The framework for approving advanced measurement technologies should have appropriate criteria.

In adapting Section 111 Supplemental Proposal's framework for the purpose of emissions quantification, rather than detection, EPA should use appropriate performance criteria.

For continuous monitoring system, these performance criteria should address the following factors:

- frequency of measurement
- uncertainty
- emissions source attribution capabilities
- operational limitations
- minimum detection thresholds

In addition, the agency should define "continuous" as well as how EPA wants each performance criteria tested, measured, and demonstrated. For consistency across related regulatory programs, the performance criteria for continuous monitoring systems in Subpart W should align with performance criteria established in OOOOb/c.

Commenter 0402: The list of approved monitoring technologies should be expanded to include alternative periodic screening and continuous monitoring technologies.

Under proposed NSPS OOOOb and EG OOOOc[46], operators have the ability to use EPA approved alternative periodic screening or continuous monitoring technologies to satisfy the equipment leaks for well sites, centralized production facilities, and compressor stations. The Industry Trades have provided previous comments[47] on how to improve these proposed alternative technology provisions. Furthermore, results from alternative technology surveys could not be used for Subpart W emission calculations as proposed. Therefore:

- Operators would need to conduct an annual OGI or M21 survey for Subpart W for components subject to NSPS OOOOa/b/c or for other components if they elected to not use the population emission factors. This annual survey could be beyond what is required under NSPS.
- Results from use of alternate technology under NSPS OOOOb or EG OOOOc would be reported under large emissions release if thresholds were exceeded under Subpart W.

These two consequences would disincentive the use and development of alternate leak detection technologies. Therefore, 98.234(a) should be updated to include: "Periodic screening or continuous monitoring as specified in § 60.5398b of this chapter or an applicable approved state plan or applicable Federal plan in part 62 of this chapter…"

Footnotes:
[46] Proposed § 60.5398b and § 60.5398c.

[47] The Industry Trades have provided previous comments on how to improve these proposed alternative technology provisions. See Comment 3.0.
https://www.regulations.gov/comment/EPA-HQ-OAR-2021-0317-2428
https://www.regulations.gov/comment/EPA-HQ-OAR-2021-0317-3819

Commenter 0410: On page 50291, EPA correctly points out that top-down measurements are too episodic to be used for annual emissions estimates. EPA invites comment on whether any top-down approaches can be used to estimate annual facility-level emissions.

Continuous monitoring systems with proven quantification capabilities (low or no bias in repeat measurements of emission sources through time) for specific sectors should be used to estimate annual facility-level emissions. For example, Long Path has shown in METEC blind testing the ability to accurately quantify total site-wide emission rates for upstream production facilities.[4/5] Open-path or continuous line sensor systems can be easily networked in design to provide low-cost monitoring for all sites in a basin (or EPA "facility"), thus enabling full basin-wide coverage at an attainable cost point, even for marginal wells. This method is therefore validated and feasible for the upstream production segment.

For any measurement system, accuracy on an individual measurement is typically higher (e.g., 30%) than the accuracy of aggregated, repeat measurements. This is sometimes called the "law of large numbers"; provided there is no measurement bias, a system such as a continuous line sensor monitor, which takes multiple valid emission rate readings per day, can correctly report on the true total emissions over time. Therefore, acceptable accuracy on individual readings may be higher (e.g., 30-40%), and acceptable accuracy on aggregated emissions through time should show no overall high- or low-bias (e.g., 0-20%).

The development of standards for calculating and reporting measurement system accuracy should be maintained and continuously updated by the EPA or a third party.

The frequency of measurements should be daily on average over the year, with maximum 2-week downtime, for example due to inclement weather or instrument repair.

We suggest that EPA allow for accurate (proven in blind tests), continuous top-down methods to be used as a facility-wide emissions estimation method. We also recommend allowing for integration of accurate, continuous top-down measurements with bottom-up numbers, for example, as an upper bound on total bottom-up emissions for a total facility, thereby combining summed bottom-up information with integrated top-down data to eliminate possible double-counting.

With respect to uncertainty calculations, some EPA methods for quantification may not be capable of consistent, accurate quantification of emissions or have no peer-reviewed publications to verify the accuracy. We urge EPA to recognize that emerging technologies, while new, provide an important added layer of quantification accuracy and emissions verification, for use as stand-alone methods or for confirmation of bottom-up methods.

FOOTNOTES

[4] Alden, C. B., Coburn, s., Wright, R. J., et al. (2019). Single-blind quantification of natural gas leaks from 1 km distance using frequency combs. Environmental Science & Technology, 53(5), 2908-2917. https://doi.orq/10.10 21 /acs.est .8b06259

[5] Coburn, Alden, Wright, et al., (2022). Long-distance continuous methane emissions monitoring with dual frequency comb spectroscopy: deployment and blind testing in complex emissions scenarios, https://arxiv.orq/abs/2009.10853

Commenter 0415: **EPA Should Leverage Multiple Applications of Continuous Monitoring and Other Advanced Technologies to Achieve Emissions Goals**

The DGCC recommends the EPA re-evaluate its treatment of continuous monitoring technologies in the proposed rule. These systems play a compelling role in monitoring, detecting, and quantifying methane emissions in the oil and natural gas industry. There are various types of continuous monitoring systems capable of detecting methane leaks and quantifying a facility's methane emissions. While each system has unique characteristics, some general principles apply to the majority of, if not all, such systems.

Continuous monitoring systems provide real-time, on-site monitoring, which makes them highly effective for pinpointing emission sources quickly. In contrast, remote sensing technologies such as satellite-based sensors or aerial surveys can cover large areas but lack precision in identifying specific sources and small sources due to higher detection thresholds, and intermittent sources of emissions due to their periodic nature. The detection thresholds for remote sensing technologies also vary greatly from continuous monitoring systems. Both remote sensing and continuous monitoring technologies have their benefits, and both will play a critical role in determining what the true emissions are at a given site.

One additional use case is the deployment of continuous pilot monitoring systems to facilitate the combustion efficiency of the flaring of natural gas, a well-known source of methane emissions. Typically, energy producers will combust unmarketable natural gas, which is mostly composed of methane, instead of venting it directly into the atmosphere. This combustion process converts the methane into carbon dioxide, which has a much lower warming effect. Unfortunately, flares are often inefficient or unlit for one reason or another, releasing significant amounts of methane into the atmosphere.

Commercially available technologies are already helping monitor, control, and reduce emissions associated with flaring. These devices can reduce methane slip, minimize costs, and improve transparency, and can cover everything from assisted flares associated with downstream petrochemical and refinery flare operations to unassisted flares associated with upstream operations. Unfortunately, the EPA's proposed rule also discourages the use of this type of continuous monitoring of combustion efficiency.

To continue to facilitate pathways for the adoption of multiple types of continuous monitoring technologies, DGCC urges EPA to create a framework that leverages the technology-approval framework it has proposed for NSPS OOOOb and EG OOOOc wherever appropriate and possible. The matrices that EPA has developed for the NSPS OOOOb and EG OOOOc Proposal provide a model for such a method-by-method approval framework.

In developing a framework for approval of advanced technologies, including continuous monitoring, for the purpose of emissions quantification, the Agency could use appropriate quantification-related performance criteria. In addition, the Agency should define how each performance criterion is tested, measured, and demonstrated. In general, EPA should clarify in the rule how continuous measurement of methane emissions data should be reported (e.g., on a five-day moving average) and used.

Response 5: We acknowledge the commenters' support for continuous monitors and the valuable insights they provided on these technologies. See the response to Comment 3 of this section for the EPA's response to the potential use of continuous monitoring systems for emissions quantification.

The EPA has opted not to include at this time a framework for the adoption of advanced measurement technologies analogous to the performance-based technology approval process included in the NSPS OOOOb at 40 CFR 60.5398b(d) for the reasons stated in Section II.B of the preamble to the final rule. Key considerations include the increased complexity associated with quantifying emissions (as opposed to simply detecting emissions), as well as the lack of specific information at this time to establish an alternative quantification technology framework for Subpart W. We agree with the commenter that noted that in order to adopt a similar framework for the purposes of emissions quantification, rather than detection, we would need to consider appropriate performance criteria, which may include measurement frequency, uncertainty, minimum detection thresholds and emissions source attribution capabilities.

Various factors such as field conditions (e.g., operating equipment heat, vibrations, elevated background concentrations), meteorological conditions (wind, low ambient temperatures), a limited number of release events, and background interference (e.g., vegetation, reflections, clouds, sensor distance) require further evaluation to understand and assess their impact on emission quantification accuracy.

Given these considerations and the extended discussion provided in Section II.B of the preamble to the final rule, the EPA believes that a future rulemaking would be necessary to thoroughly and adequately explore the adoption of an alternative technology framework similar to that in 40 CFR part 60, subpart OOOOb, that would be applicable and appropriate for subpart W purposes. We note that we have finalized revisions to Subpart W that provide additional measurement-based methodologies for quantifying emissions where such methodologies were not available in the existing rule.

For our response to the commenter's request to expand the list of approved monitoring technologies to include alternative periodic screening and continuous monitoring technologies, see Section III.P of the preamble to the final rule.

Finally, with regard to flares, we note that the final rule includes provisions allowing for the use of EPA OTM-52 or NSPS-approved alternative testing technologies for measuring destruction efficiency.

Commenter: Sensirion Connected Solutions
Comment Number: EPA-HQ-OAR-2023-0234-0293
Page(s): 18-19

Commenter: Ascent Resources, LLC
Comment Number: EPA-HQ-OAR-2023-0234-0339
Page(s): 3

Commenter: BP America Inc.
Comment Number: EPA-HQ-OAR-2023-0234-0345
Page(s): 2-3**,** 4-5, 5-6

Commenter: Project Canary, PBC
Comment Number: EPA-HQ-OAR-2023-0234-0348
Page(s): 13

Commenter: Honeywell International Inc.
Comment Number: EPA-HQ-OAR-2023-0234-0375
Page(s): 8-10, 10-11, 17, 17-18, 18-20

Commenter: Qube Technologies, Inc.
Comment Number: EPA-HQ-OAR-2023-0234-0386
Page(s): 7

Comment 6: : Commenter 0293: **EPA should allow the use of Agency-approved continuous monitoring systems to address the known limitations of emission factors.**

Project Canary acknowledges that the Subpart W program will continue to make use of emission factors for the foreseeable future. We also recognize that the accuracy of many emission factors has improved considerably. However, emission factors continue to have significant limitations, as the Agency has acknowledged with the imposition of the k factor. It is well known that actual emissions vary substantially among basins, between facilities, and at other levels of calculation.

Over the past decade, numerous peer-reviewed studies featuring field measurements of emissions from oil and natural gas facilities have cast doubt on the accuracy of emissions inventories calculated using emission factors. Finding excerpts from several prominent studies include the following (in addition and including those studies referenced above in Section IV., a., on page 6):

- Recent studies have emphasized a ~1.5-2x divergence between the EPA GHGI estimates of CH4 emissions from O&NG and those estimated from field measurements […] our estimate is ~1.8 times that of the [EPA] GHGI."[34]
- Our facility-based estimate of 2015 supply chain emissions is 13 +/- 2 Tg a-1, equivalent to 2.3% of gross US gas production […] ~60% higher than the US EPA inventory estimate."[35]

- We estimate a mean US oil/gas methane emission of 14.8 (12.4 to 16.5) Tg a^{-1} for 2010 to 2019, 70% higher than reported by the United States Environmental Protection Agency."[36]

To put these shortcomings into perspective, consider the Benchmarking Methane and Other GHG Emissions of Oil & Natural Gas Production in the United States Report by MJBradley[37] which provides operator-specific methane intensities reported to the EPA under Subpart W. Assuming a 0.2% methane intensity threshold for differentiated, often called certified, natural gas, the MJBradley report suggests that over 70% of natural gas production would qualify as certified natural gas with no action taken. An abundance of scientific evidence suggests that emissions exceed GHGRP inventories, yet the status quo reporting methodologies would recognize nearly three quarters of US oil/natural gas production as below 0.2% methane intensity.

Given this pattern of inaccuracy, the burden of proof for the Agency to disallow facility-specific measurements methods in favor of emission factors should be high.

In addition, both emission factors and their embedded k factors are backward-looking. They do not take into account, for example, mitigation that will occur in the years ahead through implementation of the NSPS OOOOb, the EG OOOOc regulations, and the Methane Waste Emissions Charge. As a result, emission factors will only become increasingly inaccurate over time.

For calculations that require use of emission factors, an owner or operator of an applicable facility would have no means of demonstrating that its actual facility emissions are lower than the applicable factor. As a result, it could be liable for a Methane Waste Emissions Charge that does not reflect its actual emissions. Under the Proposed Rule, the owner or operator may not submit data from any kind of continuous monitoring system to rebut such a calculation—even from a continuous monitoring system approved by EPA as a "best system of emission reduction" under the NSPS OOOOb and EG OOOOc regulations. This approach frustrates the Congressional intent to ensure accuracy and fairness in imposition of the charge. It also is inconsistent with Congressional intent to ensure that the Methane Waste Emissions Charge creates an incentive to reduce methane emissions because investment in mitigation could be obscured by the blunt, broad-based application of emission factors.

Footnotes:

[34] Rutherford, J. S.; Sherwin, E. et al. Closing the methane gap in US oil and natural gas production emissions inventories. Nature Comm. 2021 12:4715. DOI: 10.1038 s41467-021-25017-4.

[35] Alvarez, R; Zavala-Araiza, D et al. Assessment of methane emissions from the U.S. oil and gas supply chain. Science. 2018 361 186-188. DOI: 10.1126/science.aar7204

[36] Lu, X; Jacob D et al. Observation-derived 2010-2019 trends in methane emissions and intensities from US oil and gas fields tied to activity metrics. PNAS. 2023 (120)17 10.1073/pnas.2217900120.

[37] Benchmarking Methane and Other GHG Emissions of Oil & Natural Gas Production in the United States, Robert LaCount, Tom Curry, Luke Hellgren, Pye Russell. htps://www.catf.us/wp-content/uploads/2021/06/OilandGas_BenchmarkingReport_FINAL.pdf

Commenter 0339: In several places in the proposed regulation, the EPA requires reporters to assume a leak or upset condition was present all the way back to the previous survey or visual inspection (intermittent bleed controllers, equipment leaks, thief hatch seating, stuck dump valves). The EPA should allow for the use of monitored process parameters or continuous emissions monitoring to make an engineering estimate of when an upset condition began.

Commenter 0345: **EPA Should Expand the Use of Continuous Monitoring under Subpart W**

bp is developing and deploying advanced methane emissions monitoring technologies, including continuous monitoring sensor networks, across its facilities. Such technologies allow bp to more quickly and efficiently detect and repair leaks, thereby reducing overall emissions. bp therefore supports EPA's proposal to allow for the use of advanced monitoring technologies to report on "other large release events."[4] This aspect of EPA's proposal has the potential to incentivize greater deployment of such technologies that more accurately capture the duration and size of large release events, and bp encourages EPA to retain this approach in the final rule.

With respect to sources of emissions other than "large release events," bp is concerned that EPA's proposal may disincentivize the use of advanced monitoring technologies. Specifically, EPA has proposed to exclude advanced monitoring technologies, including continuous monitoring systems, from the requirement to conduct leak surveys to detect equipment leaks other than "large release events."[5] Instead, EPA's proposal allows for the use of only a small set of methodologies for conducting leak surveys — specifically, those that are already employed under the current Subpart W rule, such as handheld optical gas imaging ("OGI") equipment and Method 21.[6]

EPA's exclusion of continuous monitoring systems from the list of authorized equipment leak survey methodologies appears to be (i) based on potentially inaccurate assumptions regarding the capabilities of continuous monitoring systems, (ii) potentially contrary to Congress' intent to incorporate empirical data into the GHGRP, and (iii) contrary to EPA's stated intent to provide consistency with the NSPS and EG OOOO rules.[7] Given that continuous monitoring systems are capable of detecting leaks at the component level, bp urges EPA in the final rule to provide an option for reporters to use continuous monitoring systems to conduct leak detection surveys. EPA can implement this fix by establishing a review and approval process, which would allow operators and technology providers to demonstrate the capabilities of their continuous monitoring systems and identify any necessary adjustments to the factors used when calculating emissions from those leaks.

Footnotes:

[4] See 88 FR at 50,289-290.

[5] See 88 FR at 50,290-291; see also proposed §§ 98.233(q) and 98.234(a).

[6] See proposed §§ 98.233(q) and 98.234(a).

…

EPA should establish a process for approving the use of continuous monitoring systems for equipment leak surveys under Subpart W.

To ensure that continuous monitoring systems may be used to conduct equipment leak surveys under Subpart W, EPA should consider including a process by which operators or technology providers can seek EPA approval of these systems. To do so, EPA can specify in the relevant sections (e.g., proposed §§ 98.233(q)(1) and 98.234(a)) that operators may conduct equipment leak surveys using continuous monitoring systems that have been approved by the EPA. EPA can further detail the approval process by which operators and technology providers would demonstrate the specific capabilities and sensitivities of their continuous monitoring systems in detecting equipment source-level leaks, and identify any necessary adjustments in the emissions factors and assumptions used to calculate total emissions from those leaks.

Creating such an approval mechanism is not without precedent in the GHGRP. Under Subpart E, for example, with respect to calculating emissions from Adipic Acid Production, reporters may "[r]equest Administrator approval for an alternative method of determining N2O emissions."[14] EPA included this provision in the final rule for Subpart E in response to comments requesting that EPA allow for the use of continuous emissions monitoring systems ("CEMS") to directly measure N2O flow.[15] EPA should do the same here. Similarly, in the proposed NSPS and EG OOOO rules, EPA included an "alternative test method approval" process by which technology providers and operators can seek EPA approval of new leak detection methods, including continuous monitoring systems. This process allows parties to demonstrate the capabilities of such systems under certain operating conditions and to establish parameters for their use.[16]

While allowing use of continuous monitoring systems to conduct equipment leak surveys is something that EPA should consider implementing now, EPA can also structure the review and approval process so as to provide future pathways for other uses of continuous monitoring (e.g., for monitoring other sources, or for direct measurement of emissions) and different advanced monitoring technologies to serve various functions under Subpart W, as they develop over time.

Because there is such a wide variety of emissions monitoring technologies under development, creating a mechanism to approve new methodologies into the future would allow the GHGRP to keep pace with technological advancement without requiring notice and comment rulemaking for each new system. Doing so would facilitate greater consistency across regulatory programs and further incentivize the development and deployment of technologies that will enhance the accuracy of GHG reporting.

Footnotes:

[14] See 40 C.F.R. § 98.53(a)(2)

[15] See Mandatory Reporting of Greenhouse Gases, 74 FR 56260, at 56295 (Oct. 30, 2009).

[16] See 87 FR at 74,745-746.

…

Allowing the use of continuous monitoring systems to conduct equipment surveys under Subpart W would enhance consistency among regulatory programs and further incorporate empirical data in GHG reporting.

By excluding the use of continuous monitoring systems from equipment leak surveys under Subpart W, EPA is creating inconsistencies with its proposed NSPS and EG OOOO rules for leak detection and repair ("LDAR"). The OOOO rules, as proposed in December 2022, allow for "alternative" methods for conducting leak surveys in lieu of OGI or Method 21, including the use of continuous monitoring systems.[10] If such systems are excluded from the equipment leak survey methods under Subpart W, operators that have deployed continuous monitoring systems for their LDAR programs (for purposes of CAA Section 111) may be precluded from using those same systems to conduct emissions reporting for the purposes of the GHGRP.

EPA observes that, under the proposed NSPS and EG OOOO rules, "if emissions are detected using one of these advanced technologies [i.e. "top-down" technologies], facilities would be required to conduct monitoring using OGI or Method 21 to identify and repair specific leaking equipment."[11] In fact, the proposed OOOO rules specify that operators using continuous monitoring systems would conduct a "root cause analysis" when a leak is detected, which may or may not entail a follow-up OGI or Method 21 survey, depending on whether one is needed to pinpoint the leak.[12] Providing a pathway for the use of continuous monitoring systems to conduct equipment leak surveys would ensure that operators can use the same continuous monitoring systems under both the NSPS and EG OOOO rules and Subpart W without adding a requirement to conduct a follow-up OGI survey in order to report on those leaks.

Moreover, allowing continuous monitoring systems for leak surveys would enhance the use of empirical data under Subpart W, consistent with EPA's mandate under the IRA. For example, when calculating emissions from equipment leaks, it appears that reporters must assume that the component (during the time that it was operational) has been leaking since the last Subpart W-compliant leak survey, or since the beginning of the reporting year.[13] This approach makes sense when an operator is conducting periodic surveys, as there would be no leak data for the intervening time between surveys. However, when using continuous monitoring systems, an operator may have data that can specify the start and end of an emissions event. Operators using such systems for their LDAR programs should not, therefore, be required to assume that the component has been leaking since the last Subpart W-compliant OGI or Method 21 survey was conducted. Doing so would result in over-estimating the total emissions from those leaks, which would not only be inaccurate but also carry serious monetary implications under the Methane Waste Emissions Charge. Allowing the use of continuous monitoring systems would enable reporters to provide more accurate, empirical data with respect to the duration and total amount of leak emissions.

Footnotes:

[10] See, e.g., 87 FR at 74,744-746

[11] 88 FR at 50,348.

[12] See proposed § 60.5398b(c)(6).

[13] See 88 FR at 50,405 (proposed § 98.233(q)(2)).

Commenter 0348: **EPA should allow the use of Agency-approved continuous monitoring systems to address the known limitations of emission factors.**

Project Canary acknowledges that the Subpart W program will continue to make use of emission factors for the foreseeable future. We also recognize that the accuracy of many emission factors has improved considerably. However, emission factors continue to have significant limitations, as the Agency has acknowledged with the imposition of the k factor. It is well known that actual emissions vary substantially among basins, between facilities, and at other levels of calculation.

Over the past decade, numerous peer-reviewed studies featuring field measurements of emissions from oil and natural gas facilities have cast doubt on the accuracy of emissions inventories calculated using emission factors.

Excerpts from several of these prominent studies include the following (in addition and including those studies referenced above in Section IV.a.):

- • "Recent studies have emphasized a ~1.5-2x divergence between the EPA GHGI estimates of CH4 emissions from O&NG and those estimated from field measurements […] our estimate is ~1.8 times that of the [EPA] GHGI."[35]
- • "Our facility-based estimate of 2015 supply chain emissions is 13 +/- 2 Tg a-1, equivalent to 2.3% of gross US gas production […] ~60% higher than the US EPA inventory estimate."[36]
- • "We estimate a mean US oil/gas methane emission of 14.8 (12.4 to 16.5) Tg a-1 for 2010 to 2019, 70% higher than reported by the United States Environmental Protection Agency."[37]

To put these shortcomings into perspective, consider the Benchmarking Methane and Other GHG Emissions of Oil & Natural Gas Production in the United States Report by MJBradley, which provides operator-specific methane intensities reported to the EPA under Subpart W.[38] Assuming a 0.2% methane intensity threshold for certified natural gas (often called differentiated or low methane intensity), the MJBradley report suggests that over 70% of natural gas production would qualify as certified natural gas with no additional action taken. An abundance of scientific evidence suggests that emissions exceed GHGRP inventories, yet the status quo reporting methodologies would recognize nearly three quarters of U.S. oil/natural gas production as below 0.2% methane intensity.

Given this pattern of inaccuracy, the burden of proof for the Agency to disallow facility-specific measurements methods in favor of emission factors should be high.

In addition, both emission factors and their embedded k factors are backward-looking. They do not take into account, for example, mitigation that will occur in the years ahead through implementation of the NSPS OOOOb, the EG OOOOc regulations and the Methane Waste Emissions Charge. As a result, emission factors will only become increasingly inaccurate over time.

For calculations that require use of emission factors, an owner or operator of an applicable facility would have no means of demonstrating that its actual facility emissions are lower than the applicable factor. As a result, it could be liable for a Methane Waste Emissions Charge that does not reflect its actual emissions. Under the Proposed Rule, the owner or operator may not submit data from any kind of continuous monitoring system to rebut such a calculation—even from a continuous monitoring system approved by EPA as a “best system of emission reduction” under the NSPS OOOOb and EG OOOOc regulations. This approach frustrates the Congressional intent to ensure accuracy and fairness in imposition of the charge. It also is inconsistent with Congressional intent to ensure that the Methane Waste Emissions Charge creates an incentive to reduce methane emissions because investment in mitigation could be obscured by the blunt, broad-based application of emission factors.

Footnotes:

[35] Rutherford, J. S.; Sherwin, E. et al. Closing the methane gap in US oil and natural gas production emissions inventories. Nature Comm. 2021 12:4715. DOI: 10.1038 s41467-021-25017-4.

[36] Alvarez, R; Zavala-Araiza, D et al. Assessment of methane emissions from the U.S. oil and gas supply chain. Science. 2018 361 186-188. DOI: 10.1126/science.aar7204

[37] Lu, X; Jacob D et al. Observation-derived 2010-2019 trends in methane emissions and intensities from US oil and gas fields tied to activity metrics. PNAS. 2023 (120)17 10.1073/pnas.2217900120.

[38] Benchmarking Methane and Other GHG Emissions of Oil & Natural Gas Production in the United States, Robert LaCount, Tom Curry, Luke Hellgren, Pye Russell. https://www.catf.us/wp-content/uploads/2021/06/OilandGas_BenchmarkingReport_FINAL.pdf

Commenter 0375: EPA should include Continuous Monitoring Systems in its permitted leak detection and quantification methods.

Permitting the use of continuous monitoring technologies for leak detection and measurement purposes, and avoiding an overly prescriptive approach, is not only consistent with Congress' requirement that EPA "ensure" GHG reporting and calculations are empirically-based and "accurately reflect" methane and waste emissions, but is also consistent with the U.S. Government Accountability Office's recommendation that EPA give operators greater flexibility in using alternative technologies in order to better detect and reduce methane emissions.[8]

While continued refinement of emission factors, as EPA proposes here, is an appropriate approach, EPA should not implement overly prescriptive regulatory measures that would preclude the use of continuous monitoring technologies to improve the accuracy of GHG calculations. Rather than use static emission factors—or even emission factors supplemented with in-field measurements— continuous monitoring technologies could be used to detect leaks and to better define the magnitude of emissions otherwise calculated with periodic observations using emission factors. Specifically, with the use of continuous monitoring capable of leak detection (even without regard to leak measurement), a source should be able to rely on such detection to determine the duration of the leak from detection to repair, instead of assuming that the leak was ongoing since the last periodic survey.

Footnotes:

[8] U.S. Gov't Accountability Office, Federal Actions Needed to Address Methane Emissions from Oil and Gas Development at 25 ("Without greater flexibility in the process for approving alternative technologies, EPA may hinder the adoption of innovative approaches for detecting and reducing methane emissions.").

…

The Revisions to Subpart W Should Allow for the Use of Empirical Data from Continuous Monitoring Systems for Purposes of Quantifying Emissions for Equipment Leaks and Other Sources

The fundamental calculation for the emissions inventory is based on the emissions rate multiplied by the time period in which the emissions occur. The inputs for that calculation – the rate and the time -- can be directly measured or assumed based on emissions factors or other assumptions. EPA should enable the regulated community to rely on sufficiently qualified technology that provides direct measurement to be used where it is available in lieu of assumptions. While not all continuous monitoring systems will perform with the same degree of accuracy in detecting and quantifying facility emissions, EPA should not preclude the use of advanced continuous monitoring systems that can demonstrate sufficient detection and quantification equivalency with the leak detection methods and quantification methods currently permitted for equipment leak detection surveys.

Commenter 0375: *Continuous Monitoring Technologies Can Account for Potential Flaws in Periodic Surveys and Measurement by the Frequency of Monitoring and Continuous Direct Quantification Capability That It Provides.*

Continuous monitors, by “always looking,” can account for variability in environmental conditions due to their continuous nature and are less prone to operator error and deficiencies in survey protocols (e.g., operating conditions, the speed of the surveyor, etc.). Because continuous monitoring monitors continuously, it provides operators with greater visibility into how to develop inventories based on multiple samples, yielding more representative sampling than periodic approaches, as they accumulate the sheer number of data points available. In that manner, continuous monitoring systems can provide a more robust dataset for understanding the when, where and how much of emissions activity. Although all facility operators may not be capable of submitting measurement data based on continuous monitoring (either because of the current solutions deployed or due to the limitations of some continuous monitoring technologies), allowing operators to invest in advanced continuous monitoring systems so that the empirical data can used to increase the accuracy of their emissions reporting will further Congress’, EPA’s, and industry’s goal of providing more accurate leak measurements.

It is important, therefore, that the approach to leak detection and quantification for purposes of improving the accuracy of the emissions inventory focus on the accuracy of detection, the accuracy as to the time in which emissions take place, and the quantification of the mass rate in order to reliably achieve the goal of increased accuracy. Honeywell recommends that EPA allow for the use of continuous monitoring systems of varying sensitivities and frequencies that can demonstrate equivalent outcomes as the less frequent leak detection survey methods that are presently allowed. In this regard, EPA could support the continued technological advancements in the continuous monitoring field by allowing for the use of empirical data from continuous monitoring systems that can provide verification of the empirical data generated by using testing audits or confirmatory sampling with more established OGI or Method 21 methods. Much like EPA requirements for using Relative Accuracy Test Audits on occasion to ensure accurate calibration of CEMS on stationary source emitters, manufacturers of continuous monitoring technology could provide data generated in controlled release conditions, whether through third party validators or through standards to be set by EPA. Similarly, operators using continuous monitoring technologies could conduct periodic screenings as a backstop to confirm that instrumentation remains appropriately calibrated.

Continuous monitoring technologies like Rebellion™ cameras and the Signal Scout™ system provide more direct measurements. While they also have detection thresholds, and emissions below those thresholds must be characterized using emissions factors or possibly OGI/Method 21 surveys where available, these technologies provide superior direct information to quantify emissions above detection thresholds. They provide reliable continuous information that avoids operator error and can account for wind impacts to avoid meteorological interference. They are able to provide reliable continuous rate calculations, accounting for changes in rate over time. And they provide direct information about the time period of the emissions. As long as the instruments are demonstrated to be reliable, EPA should allow operators to elect to use such technologies to provide superior direct measurements in lieu of assumptions regarding rate and time.

In sum, continuous monitoring systems can provide significant advantages for more accurate measurement of the number of leaks at a facility and for more accurate quantification of total fugitive emissions inventory for reporting purposes. In addition, continuous monitoring systems like the Honeywell Emissions Monitoring Solution can provide earlier detection of leaks, pinpointing of leak locations for follow-up investigations, and correlation of leak and process data to help improve process efficiencies. In its revisions to Subpart W, Honeywell encourages EPA to provide for the use of empirical data from such continuous monitoring systems to improve reporting accuracy and allow operators greater use of empirical data when determining whether methane charges may be due.

…

Allowed Leak Detection and Measurement Methodologies Under Subpart W Are Prone to Error and Inaccurate Assumptions.

Leak detection and measurement methodologies that are currently permitted under Subpart W are prone to error and inaccurate assumptions, yet those methods remain a central tool in calculating emissions. Handheld OGI surveys are prone to significant error depending on operator experience and environmental conditions. OGI cameras are prone to operator error and meteorological interference that can affect measurements and the probability of detection at a specified rate in practice (apart from detection threshold under idealized conditions).[10] Periodic measurement with calibrated bagging or high-volume samplers may fail to reflect accurately overall emissions based on flawed assumptions regarding consistency of the size of a leak over time.

In addition, existing emissions factors suffer from inaccuracies and uncertainties based on a number of factors relating to how they are calculated, Emissions estimates for LNG facilities using generalized emissions factors may apply a single emissions factor to all types of LNG facilities[11], even though facilities built in recent years may have little in common with earlier constructed facilities from which the emissions factors were developed. Developing accurate emissions estimates is also hampered by selection bias. EPA currently uses data reported in accordance with Subpart W to develop GHGI emissions factors for LNG facilities (with certain exceptions), but only facilities that exceed the reporting threshold of 25,000 metric tons of CO2 equivalent per year provide reported data. Many LNG storage facilities fall under that threshold, which introduces uncertainty into aggregate emissions calculated using only a subset of LNG storage facilities.[12] Proposed PMHSA Rule Pipeline Safety: Gas Pipeline Leak Detection and Repair, Preamble, 88 Fed. Reg. 31,890, at 31,906. And EPA's proposed revisions to Subpart W, here, reflect its determinations that various of the emissions factors required for emissions calculations are inaccurate and require further revisions as proposed. E.g., 88 Fed. Reg. at 50,288-50,289.

Commenter Notes:

[10] Daniel Zimmerle, Timothy Vaughn, Clay Bell, Kristine Bennett, Parik Deshmukh, and Eben Thoma, Detection Limits of Optical Gas Imaging for Natural Gas Leak Detection in Realistic Controlled Conditions, Environmental Science & Technology 2020 54(18) 11506-11514, available at: https://pubs.acs.org/doi/10.1021/acs.est.0c01285.

[11] See Roman-White et al., "LNG Supply Chains: A Supplier-Specific Life-Cycle Assessment for Improved Emission Accounting," ACS Sustainable Chemistry & Engineering at 10857, 10861 (2021).

[12] EPA, Memorandum, "Inventory of U.S. Greenhouse Gas Emissions and Sinks 1990–2017: Updates to Liquefied Natural Gas Segment" at 2–3 (Apr. 2019). While EPA identified between 94–98 LNG storage facilities as active each year from 2011–2017, only 8 such facilities reported emissions under Subpart W during that timeframe.

…

Continuous monitoring systems can improve upon the use of emissions factors for emission quantification.

Historically, determining the relative concentration and total mass of methane released from different sources has been difficult, as leaks can be temporary or prolonged, with emission rates changing over time, and can arise from various pieces of processing equipment that may be near each other. As a result, data on the size, location, and duration of leaks have been limited, depending in many cases on statistical probabilities to assign gas characteristics. As discussed above, GHG calculations currently require the use of emission factors (EF) for specific component types. These emission factors have been the subject of much scholarly discussion, with several reports indicating that emission factors do not represent—and significantly underestimate—actual emissions.7

Gas Cloud Imaging ("GCI") technology, when used in continuous monitoring technologies, accurately detects and measures a methane leak instantaneously, including location, size, concentration, and direction. That means companies can use GCI monitoring software to definitively identify the source and composition of a leak so they can diagnose the problem, quantify it, and repair it. This is a very different exercise—one that is more sophisticated, less labor intensive, and ultimately more cost-effective—than periodic monitoring efforts by canvassing a site on foot to look for undifferentiated leaks based on probabilities with no insight into the duration or extent of the problem.

Depending on the configuration of a continuous monitoring system, such technologies present the opportunity for more immediate and precise leak detection and quantification. In general, various continuous monitoring systems are maturing in their ability to measure leak volumes, as the Colorado State University's METEC facility performance benchmarking is showing. See Performance of continuous emission monitoring solutions under single-blind controlled testing protocol, Bell, C. et al., Environ. Sci. Technol. 2023, 57, 14, 5794–5805. This study assessed several types of continuous monitoring systems, including those using the following technologies:

• s/i - Scanning/imaging (laser, camera)

• pt fenceline - Point sensors at Fence-line monitoring

• pt hazloc - Point sensors in hazardous areas (these stand out in detection speed and localization precision)

In fact, earlier this year, Honeywell evaluated our continuous monitoring point sensor network solution, Versatilis™ Signal Scout™, at the METEC facility. The system configuration consisted of 18 Signal Scout™ Detectors, 1 anemometer, and 1 gateway installed across 5 equipment groups. It was tested over a 3-month duration during which over 500 controlled releases of Methane were performed.

The quantification analytics provided in Honeywell system were able to quantify the various release rates as well as determine the location of the release and the start and end times of each release. Processing the results with our latest version of our analytics found that the system can quantify the leak rate to an uncertainty of only 20% (median) over the full range of leak rates from 0.01 – 10 kg/hr. Accuracy at estimating the leak rates from 1 kg/hr to 10 kg/hr was much better than the lower leak rates of 0.01 to 0.1 kg/hr as expected due to the difficulty in detection at those low emissions levels.

Quantification accuracy		
Emission rate	Reported (Default/Conc)	
	median deviation [kg/h]	median deviation%
0.01-0.1 kg/h	0.34	435%
0.1 - 1 kg/h	0.05	18%
1 - 10 kg/h	-0.69	-38%
All	-0.19	-20%

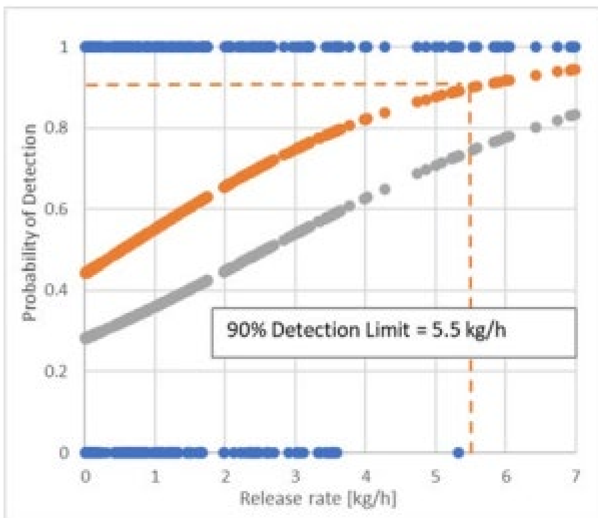
With respect to overall site quantification, the lower leak rates have less of an effect. Overall, this data shows that the Signal Scout™ can provide very accurate estimation of the measured emissions from a site.

The next table, below, provides the detection times from the test, and demonstrates that the time to detect these leaks was on average 30.7 minutes (0.5 hrs).

Detection time [min]				
time to:	min	max	median	average
first event	0.1	388.4	7.6	30.7
first report	1.4	450.6	19.5	50.0

This decrease in detection time is a significant improvement in estimating overall emissions inventory compared to periodic surveys, where the uncertainty for a leak duration could be hours or months depending on the last inspection. For example, the uncertainty in duration for a leak that was 1 hr long but assumed to be 30 days long based on the last inspection would be an over estimation of 30 days x 24 hrs = 720 hours or a 72,000% error in total emissions that would feed into the GHG inventory report. One of the strongest arguments for continuous monitoring is the ability to more precisely determine the duration of an emission. With the leak rate uncertainty of Signal Scout™, the overall error for this example above would be 20% versus the survey approach with 72,000% error.

Lastly, the Signal Scout™ was evaluated for its sensitivity and found to detect leaks with a high probability, even at the lower levels from 0.01 – 0.1 kg/hr. For leaks in those ranges, Signal Scout™ had a probability of detection of 0.3% for relatively short duration releases (< 0.5 day) and would improve in an operational setting where these small leaks would be continuously leaking. As the leak rate increases, the system's ability to detect within the short duration increases up to a 90% probability of detection of 5.5 kg/hr, as shown in the figure below.



For higher probability of detection of larger releases, operators have the ability to install Honeywell GCI cameras which have a probability of detection of 3.7 kg/hr. For a higher probability of detecting smaller leaks, operators may use the Signal Scout™. Should EPA wish, Honeywell is willing to meet to discuss its technology and the available qualification testing data.

Because, various continuous monitoring technologies are maturing and improving. EPA should take care to not foreclose the use of more mature continuous monitoring systems, nor to discourage the advancement and development of such systems, by precluding the use of data gathered by such systems for improving the accuracy of emissions reporting.

Commenter 0386: **EPA should allow the use of Agency-approved continuous monitoring systems to address the known limitations of emission factors.**

Qube recognizes that the accuracy of many emission factors has improved considerably. However, emission factors have significant limitations, which EPA acknowledges with the development of the k factor. It is well known that actual emissions vary substantially among basins and between facilities, and among other factors.

Over the past decade, numerous studies on field measurements of emissions from oil and natural gas facilities have called into question the accuracy of inventories calculated using emission factors.

For calculations that require use of emission factors, an operator of an applicable facility would have no way to demonstrate that its actual emissions are lower than the applicable factor. This incongruity could lead to the operator incurring a Methane Waste Emissions Charge that does not reflect the facility's actual emissions.

Problematically, under the Proposed Rule, the operator may not submit data from a continuous monitoring system to challenge the emissions factor calculation—even if that continuous monitoring system has been approved by EPA as a "best system of emission reduction" (BSER) under NSPS OOOOb and EG OOOOc regulations. This approach countervails Congressional intent to promote accuracy and fairness in issuing a Methane Waste Emissions Charge. It may also undermine Congressional intent for the Methane Waste Emissions Charge to be an incentive to reduce methane emissions because the imprecise application of emission factors can serve as a disincentive for investment in further emissions mitigation efforts.

Response 6: We acknowledge the commenters' support for the use of continuous monitoring technologies for equipment leaks. See responses to Comments 3 and 5 of this section for a discussion on the use of continuous monitoring technologies. Furthermore, in order to quantify emissions from leaks identified using continuous monitoring (or other advanced) technologies, EPA would need to have data collected using these methods compared to data collected with OGI or method 21 (or other appropriate data to quantitatively assess how the detected and quantified emissions compare to total actual leak emissions) in order to develop appropriate leaker factors for technologies that detect but do not directly quantify emissions. In addition, and as discussed in section III.P.1 of the preamble to the final rule, different leak detection methods result in the identification of different subsets of total leaks at a facility due to the limitations of each approach. In order to develop accurate leaker factors or allow direct quantification of leak emission rates, the EPA would need data to understand the population of both detected and undetected leaks specific to the approach and the associated detection limit.

With regards to emission factors and as discussed in sections III.P and III.Q of the preamble to the final rule, the final rule incorporates updates to several equipment leak emission factors based on our review of recent studies, which we expect will improve the accuracy of leak emission estimates. With limited exceptions, the final rule provides measurement-based methods for estimating emissions rather than relying solely on default population emission factors. This includes Calculation Method 1 of 40 CFR 98.233(q) for equipment leaks, which despite relying on leaker emission factors, the factors are applied only when leaks are detected. Furthermore, reporters have the option of developing facility-specific leaker factors. Therefore, mitigation activities taken by reporters that reduce the number of leaking components or leaking emissions can be reflected in estimates of emissions developed using this method in the final Subpart W rule.

Commenter: Clean Connect AI Inc.
Comment Number: EPA-HQ-OAR-2023-0234-0266
Page(s): 7-8

Commenter: LongPath Technologies, Inc.
Comment Number: EPA-HQ-OAR-2023-0234-0410
Page(s): 7-8

Comment 7: Commenter 0266: Methane Waste Emissions Charge

With the enactment of the Methane Waste Emissions Charge, it will be critically important to allow each owner or operator of an applicable facility the opportunity to avail itself of technologies that can generate an accurate measurement of the facility's annual emissions—especially because such facilities will be subject to a charge that is measured on a per-ton basis. Congress clearly did not want EPA to levy Methane Waste Emission Charges exclusively on the basis of generalized emission factors. Congress directed EPA to allow owners or operators to rebut the presumptions inherent in emission factors using measured, facility-specific data.

Using measurement method 1, where you can determine the source, quantity, and duration of a fugitive emission, will result in reportable emission that is substantially less than the default emission factors and default duration of 182 days.

For example, a typical fugitive emission might be cold venting (unlit flare). With OGI+AI, these types of events are detected and repaired rapidly. All of the data is written into a log with video proof of leak source detection, quantification, verified repair, and verified duration. Everything you need for direct measurement.

If you default to emission factors (method 5), you would use the default emission rate x 182-days (4,368 hours), which would be a reportable large emission event over 1,000 times larger than the result of direct measurement under the proposed section (y).

So, if the EPA wants to reward actual emission reductions, speed, and accuracy, it needs to recognize OGI+AI as a direct measurement method.

Commenter 0410: **Continuous Monitoring is a critical for achieving the Inflation Reduction Act's mandate to allow for empirical data to verify that fees are correctly assessed**

The Inflation Reduction Act of 2022 requires the EPA to revise the requirements of subpart W to "ensure the reporting under each subpart … accurately reflect the total methane emissions and waste emissions … and allow owners and operators … to submit empirical emissions data … to demonstrate the extent to which a charge … is owed."

The primary reason for incorporating empirical data is because bottom-up methods historically have not accurately represented total emissions when compared with top-down methods. We suggest that EPA allow for the use of top-down methods, such as quantitative site-wide continuous monitoring, for verifying and justifying total methane (and waste) emissions for demonstrating the extent to which a charge is owed.

It is our interpretation of congress's intent that top-down methods are intended to be allowable for use by operators to validate and verify that fees are not over- or under-paid, given the historical difficulty in accurately summing up sources from the bottom-up.

Two options exist: 1) either EPA can substantially expand the options for reporting emission rates under subpart W to include valid methods for accurate, top-down, site-wide quantification of emissions on a high-frequency basis, or 2) EPA can ensure that under the methane waste fee rule promulgation and implementation, accurate top-down quantification of emissions is allowed to be used to adjust fees for accuracy before they are paid.

We strongly recommend that the former option is included in the final subpart W revisions, given the speed with which advanced technologies are improving upon bottom-up methods and the difficulty that maintaining "two sets of books" would impose on operators.

If the second option is taken, then we would recommend that, when operators are preparing methane fee calculations, they are allowed to use valid top-down information (such as provided by accurate site-wide continuous monitoring methods) to amend their fees downward (or upward if desired) to match site-wide measurements.

Operators can demonstrate credible reconciliation by using Observing System Completeness to show the nature and extent of the emissions measured. Such metrics would allow operators to demonstrate that the empirical data used offers sufficiently comprehensive coverage (temporal coverage, spatial coverage, detection limit, and ability to directly observe intermittency). Thus verified, this reconciliation can provide verification of the extent to which a methane waste fee charge is owed.

In the following Appendix A, we provide a full framework for calculating Observing System Completeness, C, with extension to calculating adjustment factors and leaker emission factors.

Response 7: See responses to previous comments in this section of this document for the EPA's response on the use of continuous monitoring and other advanced technologies. We note that despite not including a general provision to incorporate the use of advanced measurement approaches for sources at this time, and instead specifically allowing its use in certain appropriate cases, the EPA did finalize revisions to Subpart W that provide additional appropriate empirical and measurement-based methodologies for quantifying emissions where such methodologies were not available in the existing rule. We also note that implementation of the Waste Emission Charge is out of scope for this rulemaking.

Commenter: Sensirion Connected Solutions
Comment Number: EPA-HQ-OAR-2023-0234-0293
Page(s): 12-13

Commenter: Sensirion Connected Solutions
Comment Number: EPA-HQ-OAR-2023-0234-0293
Page(s): 14-15

Commenter: Project Canary, PBC
Comment Number: EPA-HQ-OAR-2023-0234-0348
Page(s): 8

Commenter: Qube Technologies, Inc.
Comment Number: EPA-HQ-OAR-2023-0234-0386
Page(s): 5

Commenter: Qube Technologies, Inc.
Comment Number: EPA-HQ-OAR-2023-0234-0386
Page(s): 6

Comment 8: Commenter 0293: **The Proposed Rule broadly precludes use of continuous monitoring systems or any other advanced measurement technologies.**

The Proposed Rule broadly prohibits an owner or operator of an applicable facility from submitting facility-specific quantification data from continuous monitoring systems or from any other advanced monitoring method to calculate the facility's methane emissions.

The possible exception is the "Other Large Release Events" source. Even for this limited source category, the Proposed Rule's embrace of advanced measurement technologies is tentative. The preamble to the Proposed Rule only says that the Agency "expect[s]" that under the proposed methodology for Other Large Release Events, data from some advanced measurement technologies could be used to calculate total emissions and/or estimate duration for such events.[13]

Under certain limited circumstances, EPA has proposed to allow use of continuous monitoring technology to calculate carbon dioxide (CO_2) emissions. Such continuous monitoring technology is a particular type of system, which is placed directly on a stack for purposes of CO_2 emissions monitoring. First, EPA has proposed to allow use of such technologies as part of two of the four permissible CO_2 emissions calculation methods for acid gas removal vents.[14] Second, where a production facility is using a continuous monitor for CO_2 emissions at the outlet of a flare—which EPA describes as a "rare case"[15]—the facility is excused from reporting the CO_2 emissions using equation W-2.[16] Finally, the Proposed Rule specifies certain calculation methods for owners or operators using continuous monitoring systems to calculate combustion CO_2 emissions from regenerator firebox/fire tubes.[17] Again, in each of these three cases, EPA allows only the use of a particular type of continuous monitoring technology and only for calculating CO_2 emissions, not for calculating methane emissions.

Otherwise, the Proposed Rule would forbid owners or operators from using any advanced measurement technologies to calculate their annual methane emissions.

Footnotes:

[13] Proposed Rule, 88 Fed. Reg. at 50,290.

[14] Proposed Rule, 88 Fed. Reg. at 50,316.

[15] Id. at 50,333.

[16] Id. at 50,336.

[17] Id. at 50,390.

Commenter 0293: **The Proposed Rule fails to analyze the distinct capabilities of continuous monitoring systems.**

The comments made in the preceding sections assume, for the sake of argument, that the Proposed Rule has accurately described the limitations of "top-down" methods. However, as explained in this section, the Proposed Rule's analysis of "top-down" methods fails to include any meaningful analysis of the capabilities of continuous monitoring systems.

What scarce discussion there is on continuous monitoring systems in the Proposed Rule mistakenly conflates these systems with satellite and aerial surveying technologies under the broad rubric of "top-down" methods. The first mention of "top-down" methods in the preamble to the Proposed Rule includes continuous monitoring systems, but the discussion of their capabilities is confined to satellite technologies, aerial technologies, and drones. The TSD for the Proposed Rule is even more insufficient. It expressly limits its analysis of "top-down" methods to these remote, periodic surveying technologies—and omits any analysis of continuous monitoring systems. Section 2.2 of the TSD describes its scope of the review as covering "the current and potential future capability of top-down methods for quantifying methane emissions using remote-sensing approaches from aerial and satellite platforms that observe at various spatial scales depending on the altitude of observation."[23]

Continuous monitoring systems are neither remote nor periodic in their operations. They are installed at the site or facility, and they operate on a continuous basis, as described above in Section III. The scholarly literature on methane monitoring recognizes the difference between remote, periodic surveying technologies and continuous monitoring systems.[24] And EPA itself recognized this difference in its Section 111 Supplemental Proposal. The Agency established an approval matrix for continuous monitoring systems that is entirely separate and distinct from the matrix for periodic surveying by satellite and aerial technologies. The omission of any significant analysis of continuous monitoring systems is a significant gap in the technical record for the Proposed Rule.

Furthermore, the rationales offered by the Agency in the Proposed Rule and the TSD for its blunt dismissal of satellite and aerial surveying technologies do not apply with to continuous monitoring systems. As noted above, the EPA ruled out use of "top-down" methods for all but "Other Large Release Events" because measurements from such methods are "taken over limited durations" at "large spatial scales" and at high detection limits. By contrast, again, continuous monitoring systems operate continuously on a facility-specific basis. Many continuous monitoring systems are capable of detecting and measuring emissions at low kg levels; in its Section 111 Supplemental Proposal, EPA has proposed to approve continuous monitoring systems capable of detection at a 0.12 kg/hr or 0.16 kg/hr level. For these reasons, the technical record in the Proposed Rule is insufficient. EPA should undertake a complete review of continuous monitoring systems and establish an approval matrix for such systems similar to that which the Agency has proposed to establish in the Section 111 Supplemental Proposal.

Footnotes:

[23] U.S. ENVIRONMENTAL PROTECTION AGENCY, 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, EPA–HQ–OAR–2023–0234; FRL–10246–01– OAR (June 2023) (hereinafter "TSD"), at 6.

[24] Daniels, W., et al., Toward multi-scale measurement-informed methane inventories: reconciling bottom-up site-level inventories with top-down measurements using continuous monitoring systems, Environ. Sci. Technol. 2023, 57, 32, 11823-111833 (July 28, 2023), htps://doi.org/10.1021/acs.est.3c01121.

Commenter 0348: The Proposed Rule broadly prohibits an owner or operator of an applicable facility from submitting facility-specific quantification data from continuous monitoring systems or from any other advanced monitoring method to calculate the facility's methane emissions.

The possible exception is the "Other Large Release Events" source category. Even for this limited source category, the Proposed Rule's embrace of advanced measurement technologies is tentative. The preamble to the Proposed Rule only says that the Agency "expect[s]" that under the proposed methodology for Other Large Release Events, data from some advanced measurement technologies could be used to calculate total emissions and/or estimate duration for such events.[14]

Under certain limited circumstances, EPA has proposed to allow use of continuous monitoring technology to calculate carbon dioxide (CO2) emissions. Such continuous monitoring technology is a particular type of system, which is placed directly on a stack for purposes of CO2 emissions monitoring. First, EPA has proposed to allow use of such technologies as part of two of the four permissible CO2 emissions calculation methods for acid gas removal vents.[15] Second, where a production facility is using a continuous monitor for CO2 emissions at the outlet of a flare—which EPA describes as a "rare case"[16]—the facility is excused from reporting the CO2 emissions using equation W-2.[17] Finally, the Proposed Rule specifies certain calculation methods for owners or operators using continuous monitoring systems to calculate combustion CO2 emissions from regenerator firebox/fire tubes.[18] Again, in each of these three cases, EPA allows only the use of a particular type of continuous monitoring technology and only for calculating CO2 emissions, not for calculating methane emissions.

Otherwise, the Proposed Rule would forbid owners or operators from using any advanced measurement technologies to calculate their annual methane emissions.

Footnotes:

14 Proposed Rule, 88 Fed. Reg. at 50,290.

15 Id. at 50,316.

16 Id. at 50,333.

17 Id. at 50,336.

18 Id. at 50,390

Commenter 0386: **The Proposed Rule's treatment of continuous monitoring systems is arbitrary and capricious.**

The Proposed Rule broadly precludes use of continuous monitoring systems or any other advanced measurement technologies.

1. **The Proposed Rule fails to sufficiently analyze whether advanced measurement technologies can provide more accurate methane emissions measurement than the measurement methods EPA proposes to approve.**

In the Proposed Rule, EPA refers to advanced measurement technologies under the label of "top-down" methods.[6] Specific technologies under this label include satellite monitoring, aerial monitoring, and continuous monitoring systems. Although EPA acknowledges that "top-down" methods are useful in identifying possible large emissions events that are not captured by other reporting obligations, EPA

insists that they are "not presently able to provide annual emissions data to the degree of accuracy and certainty required by other provisions."[7]

Thus, we find EPA's analysis of "top down" technologies to be overly broad. EPA does not consider whether a specific top-down method could ultimately meet its criteria for quantification accuracy if, for example, a particular method or technology has a sufficient detection limit. Nor does EPA consider whether "top-down" methods would suffice if, for example, they were combined with Optical Gas Imaging (OGI) surveys that occur with greater frequency.

EPA's summary dismissal of "top down" technologies seemingly conflicts with its own analysis put forth in Section 111 of the Supplemental Proposal. The supplement includes a matrix for EPA's approval of the use of certain "top-down" methods and other "advanced measurement technologies" in lieu of OGI surveys and Audio Visual Olfactory (AVO) inspections. (Of note, the evaluation criteria in this matrix emphasizes surveying frequency and detection limits.)[8] Given the EPA's thorough analysis of "top-down" methods at specific detection limits and specific surveying frequencies in the Section 111 Supplemental Proposal, EPA's near-summary dismissal of all "top-down" methods in the Proposed Rule seems to contradict its own findings. Such a contradiction speaks to the vulnerability of this rule.

Footnotes:

[6] See id. at 50, 289 ("[W]e reviewed measurement approaches that utilize information from satellite, aerial, and continuous monitoring ('top-down approaches') to detect and/or quantify emissions from petroleum and natural gas system for the purposes of subpart W reporting.").

[7] Id. at 50,290.

[8] Section 111 Supplemental Proposal, 87 Fed. Reg. at 74,740-746.

<u>Commenter 0386</u>: **The Proposed Rule's treatment of continuous monitoring systems is arbitrary and capricious.**

3. The Proposed Rule fails to analyze the distinct capabilities of continuous monitoring systems.

Our reading of the proposed rule finds that EPA's analysis of "top-down" methods does not include any meaningful analysis of the capabilities of continuous monitoring systems, nor is any attempt made to discuss important distinctions between this technology and other "top down" technologies such as satellite and aerial measurement technologies. And arguably of greatest disservice to the distinctions and benefits of continuous monitoring, they are casually conflated with these other technologies.

The TSD for the Proposed Rule provides an equally insufficient consideration of continuous monitoring's distinctions and benefits. The analysis of "top-down" methods focuses on remote, periodic surveying technologies and avoids any analysis whatsoever of continuous monitoring systems. Section 2.2 of the TSD describes its scope of the review as covering "the current and potential future capability of top-down methods for quantifying methane emissions using remote-sensing approaches from aerial and satellite platforms that observe at various spatial scales depending on the altitude of observation."[9] Continuous monitoring systems are neither remote nor periodic, and therefore should not be evaluated alongside these technologies.

Although EPA recognizes the differences between satellite and aerial systems and continuous monitoring in the Section 111 Supplemental Proposal and establishes an approval matrix for continuous monitoring systems that is distinct from the matrix for periodic surveying by satellite and aerial technologies, no specific review of continuous monitoring is presented. The omission of a robust analysis of continuous monitoring systems compromises the technical integrity of the Proposed Rule. At the same time, the logic used by EPA to preclude satellite and aerial technologies for Subpart W compliance does not apply to continuous monitoring.

The EPA rules out "top-down" methods for all but "Other Large Release Events" because measurements from such methods are "taken over limited durations" at "large spatial scales" and at high detection limits. While these claims can be true for satellite and aerial methods, they are inapplicable to continuous monitoring systems which operate continuously on a facility-specific basis, and many of which can detect and measure emissions at low kg levels. It is again notable that in the Section 111 Supplemental Proposal, EPA has proposed to approve continuous monitoring systems capable of detection at a 0.12 kg/hr or 0.16 kg/hr level.)

For these reasons, the technical record in the Proposed Rule is insufficient. We urge EPA to conduct a complete technical review of continuous monitoring systems and establish both a technology-specific evaluation criteria and approval matrix for these systems that is like what EPA has proposed to establish in the Section 111 Supplemental Proposal.

Footnote:

[9] U.S. Environmental Protection Agency, 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, EPA–HQ–OAR–2023–0234; FRL–10246–01– OAR (June 2023) (hereinafter "TSD"), at 6.

Response 8: See responses to previous comments in this section of this document regarding continuous monitoring and other advanced technologies.

23.4 Other Measurement Approaches

Commenter: Planetary Emissions Management Inc.
Comment Number: EPA-HQ-OAR-2023-0234-0194
Page(s): 1

Commenter: Public Hearing Transcript
Comment Number: EPA-HQ-OAR-2023-0234-0224
Page(s): 50 (Christina Digiulio)

Commenter: Konica Minolta Sensing Americas, Inc.
Comment Number: EPA-HQ-OAR-2023-0234-0340
Page(s): 1

Commenter: Planetary Emissions Management Inc. (PEM)
Comment Number: EPA-HQ-OAR-2023-0234-0419
Page(s): 1-4

Comment 1: Commenter 0194: PEM Inc. … emphasizes the availability and cost-effectiveness of advanced emissions measurement technology.

Importantly, the differentiation of fossil versus modern CH_4 flux for a commercial operation is not clear, and should be addressed in the revisions.
The distinction is crucial to reduce uncertainties in verifying actual net fossil fuel CH4 emission reductions and as a foundation for tradable emission offsets.
Indeed, without empirical data, claimed CH_4 reductions and offsets, as well as charges for waste emissions, may be perceived as inaccurate and unreliable by stakeholders.

An attractive solution to this problem is analysis of radiomethane, or ^{14}C CH_4, which is the anthropogenic fossil fuel perturbation itself to the climate system. Radiomethane flux accounting, however, is not achievable with current bottom-up and top-down ^{12}C CH_4 detection methods.
As a fossil-fuel, radiomethane is devoid of ^{14}C and when emitted to the atmosphere during oil and gas operations, is readily measurable as a decrease in the ratio of atmospheric ^{14}C to ^{12}C, and defines a mixing line to calculate abundance of fossil methane leakage, integrating of all CH_4 sources, across small to large project scales.
As a further safeguard, a central reference laboratory for radiomethane could be established by a third party to electronically verify and certify field measurements, via the cloud, with traceability to the System of International Units ("SI" metric system) ensuring universality and equivalence of results across all measurements and all locations.

PEM's radiomethane measurement technology and sensor system architecture, under development, will provide an even higher level of accuracy than other technologies by distinguishing exact methane sources. EPA's final rule should encourage and allow use of radiomethane measurement technology to achieve its goals.

Commenter 0224: However, there's other things that I would like to bring up and it would be to require optical gas imaging for all affected facilities. Stationary and continuous OGI is an available technology for leak monitoring. OGI is a simple noninvasive qualitative process that consists of surveying a facility with specialized infrared cameras that make gas leaks readily apparent on the screen. This technology will result in more frequent and accurate data that would help catch emissions data from potential super emitter incidents.

Commenter 0340: **Trends in Direct Measurement**

In recent years, measurement-based methane emissions reporting has become active in order to have a more accurate accounting of emissions. The Oil & Gas Methane Partnership 2.0 (OGMP 2.0) provides the comprehensive, measurement-based international reporting framework. The Partnership does not endorse any particular technology. But QOGI cameras are selected and used by multiple companies that are part of this Partnership as the technology to measure source-level emissions.

Commenter 0419: We recommend EPA Subpart W require a more accurate monitoring approach. We propose the adoption of a system of systems ("SoS") sensor architecture and an integrated sensor platform for the detection and quantification of directly measured CH_4 emissions. The SoS is designed to monitor net carbon flux at local-to-regional scales, produce automated reports, respond to remote commands and produce verified data. This approach, if adopted by EPA regulated oil and gas operations, could be employed at both onshore and offshore oil and gas production facilities. The goal of the empirical data and the SoS architecture is to ensure and demonstrate that CH_4 emissions are accurately measured and verifiable across reporting entities.

A key component of the SoS approach is identification and standardization of sensors and gases within the oil and gas operations area that may also be influenced by surrounding lands with variable magnitudes of flux and source apportionment. While the ratio of methane to ethane ratio (CH_4/C_2H_6), and the carbon 13 value ($d^{13}C$, ‰) for gas samples are currently utilized to differentiate fossil from contemporary CH_4, they may not be reliable across all sites and sampling conditions. In contrast, the radiomethane signature ($?^{14}C$) can only be attributed to fossil CH_4, excepting for minor releases of radiomethane from pressurized water nuclear reactors. A plot of $d^{13}C$ vs $?^{14}C$, clearly demonstrates the efficacy of this approach (see endnote 1), depicting a case study of CH_4 emissions measurement from a Canadian oil sands project.

The singular significance of radiomethane in standardizing CH4 derived oil and gas empirical data for operational and regulatory purposes requires that high-precision portable analyzers for radiomethane be installed at each site or group of sites of production and related operations, and anchored by a central reference laboratory such as maintained by the National Institute of Standards and Technology (NIST). An independent third-party for verification of empirical data is necessary to accurately document and verify methane emissions. The NIST for example, operating a central reference facility, would issue certification of radiomethane results via the cloud instantaneously and be reported by the SoS according to a Data Management System that releases information automatically as authorized, including traceability to the System of International Units (SI). Traceability to the SI ensures that all radiocarbon measurements from all locations are directly comparable. Because the Inflation Reduction Act's methane fee requires fees on excess methane emissions, regulated entities will want the most accurate documentation of emissions. Accuracy in documentation will ensure regulated entities avoid unnecessary fees.

An integrated sensor portfolio managed by the SoS could also be installed according to a phased approach. The SoS and sensor platform could be purchased or leased to accommodate the need for each operation (see endnote 2 for examples of configurations). For example, the rule's framework to account for gaps in CH4 emissions reporting, could be immediately strengthened by engaging a third-party central reference facility, such as the NIST, in anticipation of radiomethane and radiocarbon in situ analyses. In the interim, adsorption of CH_4 on zeolite cartridges placed within a facility could be implemented immediately at sites followed by conversion CH_4 to $^{14}CO2$ (e.g., Endnote 2). Concomitantly, reporting oil and gas production facilities could determine the optimal locations for sampling for radiomethane, updating and augmenting existing national databases followed by optional service agreements. Empirical data for diagnostic gases such as (CH_4/C_2H_6) would continue to be gathered by stationary and dynamic methods (e.g., grab samples, eddy covariance, spectroscopic methods) as measures to immediately address gaps in the GHGRP. As a cost-control measure, subscription monitoring, reporting and verification services for facilities could be offered at flat rates according to facility size. Turn-key sensor portfolios could also be leased or purchased with the SoS software. The key point is that radiomethane empirical data organizes facility emissions according to emission levels and provides a central framework for all related sensor methods.

While the SoS reporting architecture software is being tested in the field, the radiomethane analyzer and extraction protocols require further development. PEM is currently in a partnership with the NIST to develop a portable high precision radiocarbon analyzer. Additional funding will be needed to complete and test the benchtop system followed by initial production of analyzers for beta site testing. Thus, a phased approach could be developed that first deploys the SoS reporting on existing sensor results, followed by installation of the radiomethane analyzer. The

SoS will also include collection of air in flasks or as trapped on solid adsorbents for radiomethane analysis by accelerator mass spectrometry.

The confluence of the EPAs agency infrastructure and rulemaking across the US and the infusion of funding specifically for increased empirical data for CH_4, offers an opportunity for game-changing sensor and model development that satisfies the contemplated revisions to the GHGRP, Part W, and results in much more accurate emissions measurement.

endnote 1. Source: acp-22-2121-2022.pdf (copernicus.org)

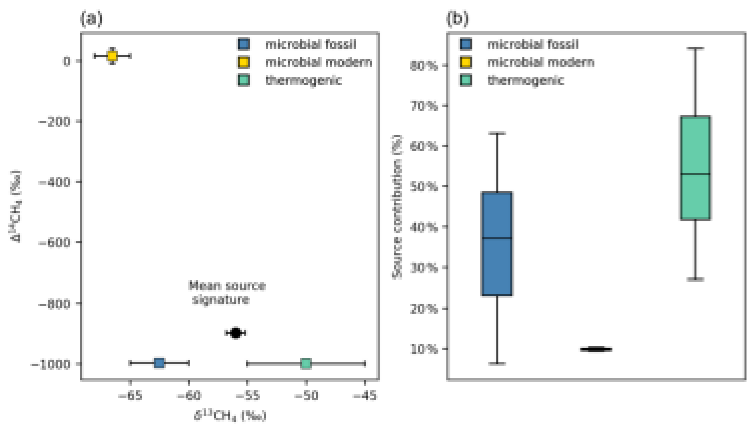
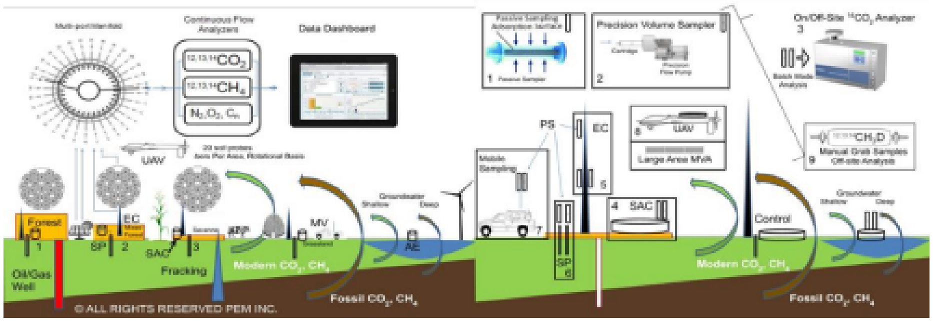


Figure 4. **(a)** $\delta^{13}C$ and $\Delta^{14}C$ signatures of potential CH_4 sources used to estimate source contribution using MixSIAR and mean $\delta^{13}CH_4$ and $\Delta^{14}CH_4$ source signatures of the samples associated with south trajectories derived from Keeling plots. **(b)** Boxplot of the estimated source contributions from microbial fossil CH_4 (tailings ponds), thermogenic CH_4 (surface mines and processing facilities), and microbial modern CH_4 (wetlands) for these samples. The line inside the boxes represents the median, boxes indicate the 25th and 75th percentiles, and whiskers show the 5th and 95th percentiles.

endnote 2: Source: Planetary Emissions Management Inc.

An SoS Node with the Global Monitoring Platform Sensor Package



Left Panel: GMP overview of options for in-situ continuous flow monitoring for three well pads within the QUEST project environment designed to quantify fossil sources of CO2 and CH4 relative to modern sources. Detection of fossil fuel derived CO2 and fossil CH4 will indicate leakage of the injected CO2 gas and associated (e.g., fugitive) emissions of fossil CH4. A multi-port manifold will be used to switch between gas sources. Gas streams flowing from soil chambers (SC), and eddy covariance towers (EC) can be continuously measured for 12,13,14CO2 as well as N2, O2 and hydrocarbons (Cn). Measurements of 14CH4 requires separate collection of CH4 with intermittent analysis utilizing the bench top SCAR batch mode 14C analyzer. Placement of soil chambers have not been determined but can be modified to accommodate PEM measurement equipment and established well pad monitoring sites. Establishment of a control site or sites is required for comparative analysis of data sets representing QUEST and a non-injection environment. Data resulting from continuous flow analyses will be accessible in real time via a secure encrypted portal provided by PEM. The exact configuration of instrumentation and operation will be determined in the final deployment environment. Copyright PEM Inc. © 2023. All Rights Reserved.

Right Panel: Overview of options for discrete passive (1) and controlled-flow (e.g., specified flow rate and time of exposure) (2) sample collection using adsorbent cartridges for a generic well pad within the QUEST project environment. The cartridges, once exposed for specified periods of time, passively or actively, will be analyzed using AMS and the SCAR bench top ^{14}C analyzer (3). The cartridge exposures and subsequent analysis schedules are designed to quantify fossil sources of CO_2 and CH_4 relative to modern sources over large areas or in discrete locations where very small diffusive leakage is suspected. Detection of fossil fuel derived CO_2 and fossil CH_4 may indicate leakage of the injected CO_2 gas and associated (e.g., fugitive) emissions of fossil CH_4. Cartridges can be exposed passively or actively in the environment or inserted in-line within gas streams flowing from soil chambers (SC) (4) or eddy covariance towers (EC) (5). Grab samples in flasks (6) will also be obtained to explore complex isotopologues (e.g., $^{13,14}CH_3D$) and to establish performance of PEM and SCAR measurements relative to NOAA AMS characterized standards and to AMS analysis. Establishment of a control site or several selected sites is required for comparative analysis of data sets representing QUEST and a non-injection environment. Data resulting from cartridge analyses will be accessible as they are available via a secure encrypted portal provided by PEM. The exact configuration of cartridge sampling will be determined in the final deployment environment. Copyright PEM Inc. © 2023. All Rights Reserved.

Response 1: We acknowledge the commenters support for the integration of advanced measurement technologies and thank them for the additional information on new technologies including sensor networks and quantitative OGI. See Section II.B of the preamble to the final rule and our responses to previous comments in this section of this document for additional discussion on the use of advanced technologies for Subpart W reporting purposes.

Commenter: Kirk Frost
Comment Number: EPA-HQ-OAR-2023-0234-0389
Page(s): 2, 2, 2-3

Comment 2: Commenter 0389: All facilities must provide accurate emissions using the methodologies and approaches that EPA has provided. Additionally, all facilities have mechanisms in place that can gauge volume of natural gas input into the facility and output out of the facility. I would require all facilities to provide the input in terms of weight and volume and the net output in terms of weight and volume. This because a fail-safe check point to see if there is emissions not being accounted for.

…

All methane emissions should be reported in measurements of weight and volume of methane. Never should it be calculated as an equivalent with carbon dioxide so that it can be discretely added with carbon dioxide as an equivalent emissions total. Please do not use CO2e as a means for reporting methane emissions.

…

CO2e was developed to assess the equivalency of warming potential based on either after 20 years from the methane emission or 100 years after the methane emission. The docket, as far as I got within the document, does not detail which is being used. Previously, EPA was using the methane warming potential 100 years after the emission took place, which is a multiple of 25 using the IPCC AR version 4 data set. As we are discovering, climate change events and future models have arrived much sooner than anticipated. Part of this is because we are not fully measuring the greenhouse gas emissions (while oil and gas production is steadily increasing) and another part can be attributed to this incorrect equivalency using methane climate warming potential 100 years after the methane was emitted. IPCC AR version 6 has a new warming potential dataset that I have submitted numerous times to EPA. We must report methane emissions as weight and volume emissions of methane, no equivalencies. Then the EPA can perform modeling of using shorter intervals based on the methane warming potential at shorter more specific intervals applying the past 20 years of methane emissions (which continues to rapidly increase) and future 10 years of methane emissions. Climate change modeling is separate than emissions monitoring.

Response 2: With respect to the commenter's request to not use CO_2e as a means for reporting methane emissions, all emissions of methane reported under 40 CFR 98.236 are reported in units of metrics tons of methane. We did not propose nor are we finalizing any changes to the units for reporting methane emissions under 40 CFR 98.236. We disagree with the commenter's request that all facilities provide input and output of natural gas to and from the facility in both weight and volume. EPA is finalizing as proposed requiring throughputs of natural gas in terms of volume. EPA has assessed and is finalizing the reporting requirements needed to verify the reported the emissions, which includes a wide variety of activity data and other reporting information in addition to volumetric throughput. Without knowing which segments the commenter is referring to, we cannot provide a more specific response.

Commenter: Public Hearing Transcript
Comment Number: EPA-HQ-OAR-2023-0234-0224
Page(s): 45 (Scott Yager)

Commenter: Chevron
Comment Number: EPA-HQ-OAR-2023-0234-0232
Page(s): 2-3

Commenter: Independent Petroleum Association of America (IPAA)
Comment Number: EPA-HQ-OAR-2023-0234-0265
Page(s): 15-16

Commenter: Diversified Energy Company
Comment Number: EPA-HQ-OAR-2023-0234-0267
Page(s): 2, 3-4

Commenter: Sensirion Connected Solutions
Comment Number: EPA-HQ-OAR-2023-0234-0293
Page(s): 3, 20, 21-22, 23-24

Commenter: American Exploration and Production Council
Comment Number: EPA-HQ-OAR-2023-0234-0295
Page(s): 27

Commenter: Project Canary, PBC
Comment Number: EPA-HQ-OAR-2023-0234-0348
Page(s): 1, 16, 19

Commenter: Pioneer Natural Resources USA, Inc.
Comment Number: EPA-HQ-OAR-2023-0234-0385
Page(s): 2, 6-7

Commenter: Qube Technologies, Inc.
Comment Number: EPA-HQ-OAR-2023-0234-0386
Page(s): 1

Commenter: American Petroleum Institute et al. (Part 1 of 2)
Comment Number: EPA-HQ-OAR-2023-0234-0402
Page(s): 71-72

Commenter: Bridger Photonics, Inc.
Comment Number: EPA-HQ-OAR-2023-0234-0407
Page(s): 6

Commenter: Differentiated Gas Coordinating Council (DGCC)
Comment Number: EPA-HQ-OAR-2023-0234-0415
Page(s): 2, 6, 8

Commenter: American Gas Association (AGA) and American Public Gas Association (APGA)
Comment Number: EPA-HQ-OAR-2023-0234-0418
Page(s): 6-7**Comment 3:** Commenter 0224: … the first is that -- is regarding methane measurement and monitoring technology, we all know that it's improving, it's changing on an almost monthly basis, and there's better technology out there. It seems like, you know, every month. So we want to make sure that there are streamlined pathways to implement new technology. In essence, to quantify leak rates. The proposal does not address this topic, and limits technology options to those that have been listed already in Subpart W since initial promulgation over a decade ago.

Commenter 0232: Use of Advanced Technology for Emission Quantification

We are concerned that the current proposal disincentivizes the use of advanced technologies that are becoming more prevalent and are being used by industry through voluntary programs to effectively detect and mitigate emissions from sources such as flares, tanks, and compressors. In recent years, advanced methane detection technologies, like flyovers, have improved and become more accessible, which has resulted in more effective detection, localization, and quantification of emissions. In 2022, Chevron conducted methane detection flyovers for approximately 950 facilities in the U.S. Through collaborations like The Environmental Partnership[2], many operators of different sizes and site types have found that, when properly applied, aerial technologies are an effective tool to monitor emissions from operations.

EPA also included a framework for the use of advanced technologies in its proposed OOOOb/c rule[3]. As part of our analysis of the advanced technology provisions of the proposed OOOOb/c rule, Chevron's comment letter[4] provided the results of a modeling study where we recommended that EPA revise its equivalency table for compressor stations and central tank batteries, to include a single category for all low detection limit technologies (=4 kg/hr) with a minimum screening frequency of quarterly (4x/year) for advanced technologies, combined with an annual (1x/year) OGI survey. We believe the use of advanced technologies can bridge EPA's proposed OOOOb/c rule monitoring requirements with GHGRP's measurement-informed methane reporting needs for the Methane Emissions Reduction Program (MERP), provided that EPA aligns the requirements allowing the use of advanced methane detection technologies across related rules. A combined approach that uses multiple types of empirical data, advanced detection technologies, emission factors from field studies for smaller sources (e.g., pneumatics), engineering estimates for sources like blowdowns, and the use of site-specific parametric data (discussed in more detail below) will result in a more robust and comprehensive inventory of methane emissions while advancing detection and monitoring capabilities further to facilitate emission mitigation efforts.

We anticipate that several types of technologies can be used to collect data for measurement-informed emission inventories. Our direct experience with onshore aircraft-based survey technologies has pointed to multiple benefits that would support EPA's methane reporting and reduction goals:

- Mapping to source types – Certain aerial surveys have sufficient resolution to map detected plumes to individual pieces of equipment on a site. We believe this type of granular information would be helpful in updating emissions by source category in the GHGRP.
- Existing voluntary use by operators – Many leading operators, including Chevron, have increasingly incorporated aerial surveys into their voluntary methane reduction programs.
- Detection limits – For the onshore production sector, an aerial service provider (Bridger Photonics) advertises a detection limit of 3 kg/hr with a 90% probability of detection. When combined with emission-factor based estimates for smaller individual emission sources (e.g., pneumatics), we believe that this approach would cover most emissions from oil and gas production operations, based on Bridger Photonics' claims.

- Compatibility with annual reporting cycles – With appropriate timing for aerial survey vendors to scale-up their services, we believe that the survey speed and timelines for information receipt for operators would be compatible with annual GHGRP reporting cycles at reasonable cost to reporting entities.

Subpart W updates should incorporate advanced technologies such as aerial and drone monitoring that can detect and measure methane emissions most efficiently, within a framework based on realistic current capabilities of measurement technologies. We are happy to meet with EPA during the rulemaking process for further discussion of this important topic.

Footnote:

[2] https://theenvironmentalpartnership.org/

[3] https://www.epa.gov/system/files/documents/2022-11/8510_OilandGasClimate_OOOObRegText_Supplemental_20221005.pdf

[4] https://www.chevron.com/-/media/shared-media/documents/chevron-2023-EPA.pdf

Commenter 0265: Use of Advanced Monitoring and Measurement Technologies

For many source categories under Subpart W, EPA has included several options for operators to be able to provide empirical data, such as measurement with metering or using updated emissions factors based on recent field measurement studies. However, under this proposed rule, EPA has not included a pathway for using the results of advanced methane detection and measurement surveys as a source of empirical data for key source categories, like tanks, flares, and compressors.

Methane detection and measurement technologies have advanced in the last few years due to early-phase research efforts, including from the Department of Energy, to develop technologies that have now become commercially available. Some operators have included these technologies in their voluntary methane management programs. Including a pathway for utilization of these technologies for emissions reporting would improve the quality of data submitted under Subpart W while supporting a growing methane detection and measurement industry. A final rule for changes to Subpart W should include a pathway for utilizing survey results from technologies, particularly those approved for use under NSPS OOOOb and OOOOc, for emissions reporting.

Commenter 0267: Methods for New and Alternative Technology

The Proposed Rule fails to include any framework for review and approval of advanced methane measurement technologies and the Proposed Rule's analysis of advanced measurement technologies is insufficient. Congress recognized the critical importance of promoting further innovation in and deployment of such technologies when it enacted section 136 in the IRA. Precluding the use of advanced measurement technologies is inconsistent with this Congressional directive to allow operators the option of using "empirical" methods to calculate their emissions, potentially making the final rule legally vulnerable.

Section 136(i) requires EPA to “allow owners and operators of applicable facilities to submit empirical emissions data, in a manner to be prescribed by the Administrator, to demonstrate the extent to which a charge under subsection (c) is owed.” Consistent with this Congressional mandate—and in the interest of promoting innovation—EPA should establish a framework in the final rule for approval of qualifying advanced measurement technologies for methane emissions measurement, including continuous monitoring systems, that owners and operators of applicable facilities may use to submit facility-specific emissions data.

We believe that EPA can satisfy the provisions of the IRA by simply setting a performance-based criteria for technology similar to thresholds established by proposed NSPS OOOOb.

Requested Action: Establish performance-based criteria for existing and new leak detection technologies, including laser-based technologies.

Commenter 0293: The matrices that EPA has developed for the Section 111 Supplemental Proposal provide a model for a technology approval framework within Subpart W. In adapting this framework for the purpose of emissions quantification, rather than just detection, the Agency should use appropriate performance criteria. These performance criteria should include frequency of measurement, uncertainty, emissions source attribution capabilities, probability of detection under various conditions, operational limitations, and minimum detection thresholds. The agency should define “continuous” and should specify how it wants each performance criterion tested, measured, and demonstrated.

We would be remiss if we did not add the broader point that Project Canary encourages the EPA to advocate within the federal family for other agencies and departments to also rely on this NSPS OOOb/c model, incentivizing the use of alternative technologies while implementing an efficient technology approval program. Other rulemakings that would benefit from such an approach would be:

- the PHMSA Pipeline Safety: Gas Pipeline Leak Detection and Repair Proposed Rule[39] which contemplates a similar measurement methodology approval approach,
- the BLM proposed rule on xxxx,
- the DOE Best Practices Framework initiative which could also rely on EPA-approved measurement methodologies as a reliable source to ensure monitoring is best practice for purposes of verification, auditing, or buyer certainty for purchases of differentiated natural gas.
- Although the final SEC rulemaking is undergoing changes, as we understand it, it would also be advisable for the Administration to rely on Section 111 approved measurement methodologies as best practice for corporate reporting as it can, again, provide a reliable source of assurance that measurement is best practice.

Footnote:

39 Docket No. PHMSA-2021-0039, RIN 2137-AF51

…

EPA should "prescribe a manner" in which owners or operators of applicable facilities may use advanced measurement technologies, including continuous monitoring systems, to calculate their emissions and the extent to which a Methane Waste Emissions Charge is owed.

Section 136(i) requires EPA to "allow owners and operators of applicable facilities to submit empirical emissions data, in a manner to be prescribed by the Administrator, to demonstrate the extent to which a charge under subsection (c) is owed."

Consistent with this Congressional mandate—and in the interest of promoting innovation—EPA should establish a framework in the final rule for approval of qualifying advanced measurement technologies for methane emissions measurement, including continuous monitoring systems, that owners and operators of applicable facilities may use to submit facility-specific emissions data.

Project Canary strongly urges EPA not to rely on future notice-and-comment rulemakings to approve the use of advanced measurement technologies. It is important to recognize the lessons learned from the experience with the OOOOa regulations. Almost immediately after the 2016 promulgation of those regulations, owners and operators of regulated facilities asked to use advanced measurement technologies in lieu of the prescribed technologies, yet revised regulations are not expected until 2024. This time lapse of eight years has been a missed opportunity for the Agency to enable the use of advanced technologies and more accurate measurement, reporting, and reductions. In those revised regulations, the Agency has now wisely proposed to establish a framework for ongoing review and approval of alternative methods. It should do the same here.

Notably, Congress granted the Agency considerable procedural leeway to develop and implement this kind of framework. Section 136(h) expressly authorizes EPA to issue not only regulations but also guidance "as necessary" to carry out its Methane Emission Reduction Program mandates. The matrices that EPA has developed for the Section 111 Supplemental Proposal provide a model for such a method-by-method approval framework.

…

As it has proposed in the NSPS OOOOb and EG OOOOc rulemaking[1], EPA should establish a framework in the Final Subpart W Rule for approval of qualifying advanced methane measurement technologies, including continuous monitoring systems, that owners and operators of applicable facilities may use for compliance with their reporting obligations and for determining their liability for a Methane Waste Emissions Charge. The framework should have performance criteria tailored to advanced methane measurement quantification technology. Project Canary and Sensirion Connected Solutions encourage the EPA to coordinate both internally and with other agencies on a coherent and consistent approach to integrating advanced technologies across all methane-related rulemakings.

SCS proposes specifics regarding appropriate criteria for approval framework to be concluded in a two-step work practice application process validating both sensor and system performance:

-> sensor performance certification based on lab tests: accuracy, cross-sensitivity, limit of detection

-> system performance based on blind controlled release testing: false positives/false negatives, detection limit, leak rate quantification, time-to detection, localization

Footnote:

[1] U.S. EPA, Standards of Performance for New, Reconstructed, and Modified Sources and Emissions Guidelines for Existing Sources for Existing Sources; Oil and Natural Gas Sector Climate Review, 87 Fed. Reg. 74,702 (Dec. 6, 2023) (hereunder "NSPS OOOOb and EG OOOOc Proposal").

…

From the Preamble in Section B. Revisions to Add New Emissions Calculation Methodologies or Improve Existing Emissions Calculation Methodology, EPA asks, "We invite comment on whether there are top-down approaches that could be used to estimate annual emission for any source categories under Subpart W or for facility-level emissions, what level of accuracy should be required for such use and whether the development of standards (either by EPA or third-party organizations) could help inform this determination. We also invite comment on how frequently measurements would need to be conducted to be considered reliable or representative of annual emissions for reporting purposes."

Advanced measurement technologies, including continuous monitoring systems, should be allowed to estimate annual emissions for source categories and/or facility-level emissions under Subpart W. EPA should create a framework for approval of such technologies similar to what was proposed in the Section 111 Supplemental Proposal. In adapting this framework for the purpose of emissions quantification, rather than just detection, the Agency should use appropriate performance criteria. As noted in Section IV., 5. f., these performance criteria should include frequency of measurement, uncertainty, emissions source attribution capabilities, probability of detection under various conditions, operational limitations, and minimum detection thresholds. The Agency should define "continuous" and should specify how it wants each performance criterion tested, measured, and demonstrated.

Commenter 0295: **Alternative Technologies Discussion**

The Proposal fails to include any framework for review and approval of advanced methane measurement technologies and the Proposal's analysis of advanced measurement technologies is insufficient. Congress recognized the critical importance of promoting further innovation in and deployment of such technologies when it enacted section 136 in the IRA. Precluding the use of advanced measurement technologies is inconsistent with this Congressional directive to allow operators the option of using "empirical" methods to calculate their emissions, potentially making the final rule legally vulnerable. However, AXPC would like to stress that the development of "empirical" methods may utilize more standard technologies which EPA should actively employ for all source categories in order to meet congressional intent. For example, all "credible information" such as flyover, OGI source verification, SCADA data, and so on should be permitted to empirically demonstrate magnitude and duration of emissions events where possible.

Section 136(i) requires EPA to "allow owners and operators of applicable facilities to submit empirical emissions data, in a manner to be prescribed by the Administrator, to demonstrate the extent to which a charge under subsection (c) is owed." Consistent with this Congressional mandate—and in the interest of promoting innovation—EPA should establish a framework in the final rule for approval of qualifying for methane emissions measurement, including continuous monitoring systems, that owners and operators of applicable facilities may use to submit facility-specific emissions data.

AXPC strongly urges EPA not to limit its program by providing that notice-and-comment rulemakings are the only means by which EPA can approve the use of advanced measurement technologies for Subpart W reporting. It is important to recognize the lessons learned from the experience with the OOOOa regulations. Almost immediately after the 2016 promulgation of those regulations, owners and operators of regulated facilities asked to use advanced measurement technologies in lieu of the prescribed technologies, but without a workable process for approving their use. Now revised regulations to finally allow their use are not expected until 2024. This time lapse of eight years has been a missed opportunity for the Agency to enable the use of advanced technologies for leak detection and more accurate measurement, reporting, and reductions. In those revised regulations, the Agency has now wisely proposed to establish a framework for ongoing review and approval of alternative methods. It should do the same here.

For these reasons, AXPC respectfully urges the EPA to consider its statutory mandate and the extent to which advanced measurement technologies can materially advance the Agency's goal of methane reduction. Postponing individualized review and approval of such technologies to future notice-and comment rulemakings—which could take years—will chill innovation and deployment. To that end, AXPC recommends that EPA adopt an approval process pathway for new technologies to be usable for compliance with Subpart W, similar to what EPA has proposed in OOOOb.

Commenter 0348: Project Canary has significant concerns about the Proposed Rule. The Proposed Rule fails to include a framework for review and approval of advanced methane measurement technologies, and the analysis of advanced measurement technologies—particularly, continuous monitoring systems—is insufficient. Congress recognized the critical importance of promoting further innovation and deployment of such technologies when it enacted Section 136 in the Inflation Reduction Act (IRA). Precluding the use of advanced measurement technologies is inconsistent with the Congressional directive to allow operators the option of using "empirical" methods to calculate their emissions, potentially making the final rule legally vulnerable. For these reasons, Project Canary respectfully urges the EPA to consider its statutory mandate and the extent to which advanced measurement technologies can materially advance the Agency's goal of methane reduction.

EPA should develop a framework for approval of advanced methane measurement technologies, leveraging the Alternative Test Methods process that it has proposed for the New Source Performance Standards (NSPS) OOOOb and EG OOOOc regulations[2] , with criteria tailored to the objectives of Subpart W and implementation of the Waste Methane Emissions Charge. To that end, our comments recommend performance criteria that EPA should consider. Postponing individualized review and approval of such technologies to future notice-and-comment rulemakings—which could take years—will chill innovation and deployment. We would be pleased to work with the Agency and other stakeholders to develop a robust review framework.

Footnote:

[2] U.S. EPA, Standards of Performance for New, Reconstructed, and Modified Sources and Emissions Guidelines for Existing Sources for Existing Sources; Oil and Natural Gas Sector Climate Review, 87 Fed. Reg. 74,702 (Dec. 6, 2023) (hereinafter "NSPS OOOOb and EG OOOOc proposal").

…

The framework for approving advanced measurement technologies should have appropriate criteria and leverage the proposed NSPS OOOOb and EG OOOOc technology-approval framework.

In developing a framework for approval of advanced technologies, including continuous monitoring, for the purpose of emissions quantification, the Agency should use appropriate quantification-related performance criteria.

These performance criteria could address such factors as:

- frequency of measurement
- uncertainty
- emissions source attribution capabilities
- probability of detection under various condiontis
- operational limitations
- minimum detection thresholds

In addition, for these systems, the Agency should define how each performance criterion is tested, measured, and demonstrated. Finally, in the interest of maximizing administrative efficiency, Project Canary urges EPA to leverage the technology-approval framework it has proposed for NSPS OOOOb and EG OOOOc wherever appropriate and possible. We do not support the use of the site-by-site Alternative Means of Emission Limitation (AMEL) mechanism, which has proven to be administratively cumbersome and insufficiently responsive to the rate of technology advancement in this area.

…

From the Preamble in Section 6. Amendments Related to Oil and Natural Gas Standards and Emissions Guidelines in 40 CFR Part 60, EPA asks, “We request comment on these proposed amendments and whether there are other provisions or reporting requirements relative to NSPS OOOOb or EG OOOOc that we should consider for revisions to the requirements under Subpart W.”

In the Proposed Rule Preamble, EPA states: "This proposal would limit the burden for subpart W facilities with affected sources that would also be required to comply with the proposed NSPS OOOOb or a State or Federal Plan in part 62 implementing EG OOOOc by allowing them to use data derived from the implementation of the NSPS OOOOb to calculate emissions for the GHGRP rather than requiring the use of different monitoring methods." Within the proposed NSPS OOOOb and EG OOOOc, EPA has created a framework for the use of approved advanced measurement technologies, including continuous monitoring systems, to satisfy the LDAR requirements within fugitive affected facility provisions. Many of these technologies are capable of accurately quantifying emissions in addition to detecting them. EPA should establish a framework to approve qualifying advanced technologies for quantification of emissions within this Proposed Rule and is arguably obligated to do so by the statutory requirements of the IRA.

The matrices that EPA has developed for the NSPS OOOOb and EG OOOOc proposal provide a model for a technology approval framework within Subpart W. In adapting this framework for the purpose of emissions quantification, rather than just detection, the Agency should use appropriate performance criteria. These performance criteria should include frequency of measurement, uncertainty, emissions source attribution capabilities, probability of detection under various conditions, operational limitations, and minimum detection thresholds. In addition, for these systems, the Agency should define how each performance criterion is tested, measured, and demonstrated.

Commenter 0385: **The Subpart W Revision Rule Has No Framework for Alternative Measurement Technologies to be Utilized For Compliance With Subpart W**

The Subpart W Revision Rule fails to include any framework for review and approval of advanced methane measurement technologies and the Proposed Rule's analysis of advanced measurement technologies--particularly, continuous monitoring systems--is insufficient. Congress recognized the critical importance of promoting further innovation in and deployment of such technologies when it enacted section 136 in the IRA. Precluding the use of advanced measurement technologies is inconsistent with this Congressional directive to allow operators the option of using "empirical" methods to calculate their emissions, potentially making the final rule legally vulnerable. Section 136(i) requires EPA to "allow owners and operators of applicable facilities to submit empirical emissions data, in a manner to be prescribed by the Administrator, to demonstrate the extent to which a charge under subsection (c) is owed." Consistent with this Congressional mandate-and in the interest of promoting innovation-EPA should establish a framework in the final rule for approval of qualifying advanced measurement technologies for methane emissions measurement that owners and operators of applicable facilities may use to submit facility-specific emissions data.

Pioneer strongly urges EPA not to rely on future notice-and-comment rulemakings to approve the use of advanced measurement technologies. It is important to recognize the lessons learned from the experience with the Quad Oa regulations. Almost immediately after the 2016 promulgation of those regulations, owners and operators of regulated facilities asked to use advanced measurement technologies in lieu of the prescribed technologies, yet revised regulations are not expected until late 2023. This time lapse of seven years has been a missed opportunity for the Agency to enable the use of advanced technologies and more accurate measurement, reporting, and reductions. In those revised regulations, the Agency has now wisely proposed to establish a framework for ongoing review and approval of alternative methods. It should do the same here.

Notably, Congress granted the Agency considerable procedural leeway to develop and implement this kind of framework. Section I36(h) expressly authorizes EPA to issue not only regulations but also guidance "as necessary" to carry out its Methane Emission Reduction Program mandates. The matrices that EPA has developed for the Section 111 Supplemental Proposal provide a model for such a method-by-method approval framework.

Further, to support consistent treatment of technologies and incentives among the rulemakings by EPA, BLM, and PHMSA, EPA has an opportunity to ensure the Subpart W rulemaking reflects the technology opportunities other rulemakings are advancing. Pioneer respectfully urges the EPA to consider its statutory mandate and the extent to which advanced measurement technologies can materially advance the Agency's goal of methane reduction. Postponing individualized review and approval of such technologies to future notice-and comment rulemakings--which could take years--will chill innovation and deployment.

Pioneer recommends that EPA adopt an approval process pathway for new technologies as they have proposed in Quad Ob. Further, to the extent EPA approves an advanced technology to detect fugitive emissions under OOOOb/c regulations, EPA's Subpart W rule should explicitly enable operators to utilize such technologies that can more accurately reflect the duration of any emissions event for a facility (e.g., aerial surveys, drones, continuous monitors, satellites etc.) as well as to gather data for compliance with this rule.

…

Also, Pioneer strongly recommends that EPA allow for the use of emerging, alternative technologies to monitor and measure emissions. As currently proposed, the rule specifies only currently available technology to obtain data for various sources and does not provide a pathway to demonstrate the performance of a new technology for use under the rule that may have more accurate and efficient emission measurement capabilities.

<u>Commenter 0386</u>: Qube Technologies, Inc. (Qube) appreciates the proposed revisions by the Environmental Protection Agency (EPA) to the requirements of the Greenhouse Gas Reporting Program (GHGRP) for the petroleum and natural gas systems source category (hereafter referred to as “Subpart W”) to ensure that Subpart W reporting is based on empirical data and accurately reflects the total methane and waste emissions from applicable facilities, and to allow owners

and operators of applicable facilities to submit empirical emissions data to demonstrate the extent to which a Methane Waste Emissions Charge is owed under CAA section 136.[1]

Qube has several concerns about the Proposed Rule, chiefly that the Proposed Rule fails to include any framework for review and approval of advanced methane measurement technologies. Furthermore, the Proposed Rule's analysis of advanced measurement technologies, which includes continuous monitoring systems, is insufficient. Congress recognized the importance of promoting innovation and deployment of such technologies when it enacted section 136 in the Inflation Reduction Act (IRA); precluding the use of advanced measurement technologies is inconsistent with this directive which was specifically enacted to allow operators the option of using "empirical" methods to calculate their emissions.

For these reasons, Qube urges the EPA to consider the extent to which advanced measurement technologies can advance EPA's goal of methane reduction. Postponing ad hoc review and approval of such technologies to future rulemakings will slow, if not disincentivize, innovation and deployment. Pursuant to the ultimate purpose of this rulemaking, Qube herein recommends performance criteria that EPA should adopt for ongoing review and approval of advanced methane measurement technologies. We would be pleased to work with EPA and other stakeholders to develop a practicable review framework.

Footnote:

[1] Greenhouse Gas Reporting Rule: Revisions and Confidentiality Determinations for Petroleum and Natural Gas Systems, 88 Fed. Reg. 50,282 (Aug 1, 2023) (hereinafter the "Proposed Rule").

Commenter 0402: For many source categories under Subpart W, the Trade Industries appreciate that EPA has included several options for operators to be able to provide empirical data, such as measurement with metering or using updated emissions factors based on recent field measurement studies. However, under this proposed rule, EPA has not included a pathway for using the results of advanced methane detection and measurement surveys as a source of empirical data for key source categories, like tanks, flares, and compressors.

Methane detection and measurement technologies have advanced in the last few years due to early-phase research efforts, including from the Department of Energy, to develop technologies that have now become commercially available. As API shared with EPA during the NSPS OOOOb and OOOOc rulemaking, many operators have included these technologies in their voluntary methane management programs, including the use of quantitative aerial technologies at more than 8,000 sites. Many of these systems provide quantitative information that, when paired with other operational sources of data, provide empirical information about methane emissions from assets. Including a pathway for utilization of these technologies for emissions reporting would improve the quality of data submitted under Subpart W while supporting a growing methane detection and measurement industry. **A final rule for changes to Subpart W should include a pathway for utilizing survey results from technologies, particularly those approved for use under NSPS OOOOb and OOOOc, for emissions reporting.**

Commenter 0407: Create a pathway to approve and update methods for developing measurement-based methane emissions inventories.

Methods for developing measurement-based methane emissions inventories involve both (a) frameworks for using measurement data and (b) technologies and technology deployment used to generate the measurement data. Robust frameworks to determine methane emissions inventories using direct measurement data already exist.[9] These frameworks rely on widespread aerial measurement by technologies with well-characterized performance such as Bridger's GML technology. [9,14] Subpart W should provide a pathway to approve frameworks for determining emissions inventories and it should also provide a pathway to approve suitable technologies to be used within approved frameworks. Precedent for these approval pathways comes from the alternative test method provisions in OOOOb/c proposed rules.

This approval formalism would allow advances in technology and framework methodology to be taken advantage of for improved emissions reporting by allowing new methods to be submitted and approved.

Approved emissions inventory development frameworks should leverage both new data and prior knowledge of emission using standard Bayesian estimation. With current levels of measurement technology deployment, we recommend that the EPA allow data from five years before a given inventory assessment to be used so that enough information is available when the rule goes into effect. As greater volumes of fresh data become available, the EPA should iteratively limit the age of data to be used.

Any data brought into an approved inventory framework should correspond to a representative sample of infrastructure as demonstrated by quantitative evaluation. Sampling should correctly represent different equipment classes, production types and volumes, site types, site ages, and operating companies (in the case of regional inventories). Furthermore, approved frameworks should:

- Include protocols to eliminate systematic errors by accounting for intraday variation in emissions and seasonal changes.
- Include protocols to scale measurements from limited sample sets to the complete population of infrastructure in the region and to annualize emissions.
- Include protocols to integrate data appropriately considering measurement technology sensitivity and quantification uncertainty.
- Include protocols to characterize uncertainty due spatial variation of emissions and variation in emissions over time.

For a technology (and its deployment approach) to be approved for emissions inventory measurements, it should meet the following performance criteria:

- It must have sensitive emissions detection to ensure significant emissions sources are not unaccounted for. (The less sensitive the technology, the more exterior data elements must be incorporated in the inventory, which opens the door to additional sources of error). A sensitivity requirement of ~2 kg/h with > 90% probability of detection is recommended based on existing work.[9]

- The technology must have refined detection sensitivity models to determine missed emission events.
- The technology must provide accurate quantification of aggregate emissions.
- The technology must have refined error models to reduce measurement bias and correctly report instrument quantification uncertainty.
- The technology must be resilient towards systematic sources of error such as incomplete spatial coverage and diminished sensitivity under conditions of low ambient light.
- The application of a technology and its deployment within a framework must be validated for repeatability and consistency through replicate inventory assessments.

Footnotes:

[9] "Measurement-Based Methane Inventory for Upstream Oil and Gas Production in Alberta, Canada Reveals Higher Emissions and Starkly Different Sources than Official Estimates". https://doi.org/10.21203/rs.3.rs-2743912/v1, "Creating measurement-based oil and gas sector methane inventories using source-resolved aerial surveys". https://doi.org/10.1038/s43247-023-00769-7

[14] "Robust probabilities of detection and quantification uncertainty for aerial methane detection: Examples for three airborne technologies". https://doi.org/10.1016/j.rse.2023.113499

Commenter 0415: **EPA Should Provide a Future-Ready Framework for Emissions Reporting Technologies**

In the rapidly evolving landscape of methane emissions measurement and quantification technology, static regulations risk becoming outdated and even counterproductive.[15] This proposal's component-by-component approach does not cover many of the emerging technologies and importantly omits direct measurements for crucial categories such as certain types of tanks and flares. Furthermore, a prescriptive rule simply lacks the flexibility needed to adapt to future technological advancements and process improvements.

Section 136(h) requires EPA to "allow owners and operators of applicable facilities to submit empirical emissions data, in a manner to be prescribed by the Administrator, to demonstrate the extent to which a charge under subsection (c) is owed." Consistent with this Congressional mandate—and in the interest of promoting innovation—EPA should establish a framework in the final rule for approval of qualifying advanced measurement technologies for methane emissions measurement, including continuous monitoring systems, that owners and operators of applicable facilities may use to submit facility-specific emissions data.

It is important to recognize the lessons learned from the experience with the OOOOa regulations. As EPA well knows, almost immediately after the 2016 promulgation of those regulations, owners, and operators of regulated facilities asked to use advanced measurement technologies in lieu of the prescribed technologies, yet revised regulations are not expected until 2024. This time-lapse of eight years has been a missed opportunity for the Agency to enable the use of advanced technologies and more accurate measurement, reporting, and reductions. In those revised regulations, the Agency has now wisely proposed to establish a framework for ongoing review and approval of alternative methods. It should do the same here.

In the interest of maximizing administrative efficiency, DGCC urges EPA to leverage the technology-approval framework it has proposed for New Source Performance Standards (NSPS) OOOOb and Emissions Guidelines (EG) OOOOc wherever appropriate and possible. The matrices that EPA has developed for the NSPS OOOOb and EG OOOOc Proposal provide a model for such a method-by-method approval framework.

In developing a framework for approval of advanced technologies, including continuous monitoring, for the purpose of emissions quantification, the Agency could use appropriate quantification-related performance criteria. In addition, the Agency should define how each performance criterion is tested, measured, and demonstrated.

We do not support the use of the site-by-site Alternative Means of Emission Limitations mechanism, which has proven to be administratively cumbersome and insufficiently responsive to the rate of technology advancement in this area.

The DGCC strongly urges the EPA not to rely on future notice-and-comment rulemaking to approve the use of advanced measurement technologies.

Footnote:

[15] See DGCC's "Measuring Our Way to Differentiation."

…

EPA Must Not Preclude the Use of Advanced Measurement Technologies

In the proposed rule, EPA refers to advanced measurement technologies—satellite monitoring, aerial monitoring, and continuous monitoring systems—under the label of "top-down" methods.[11] Though the Agency acknowledges that "top-down" methods are "very useful in identifying possible large emissions events (i.e., "super-emitter" events) that are not captured by other reporting obligations," EPA categorically concludes that they are "not presently able to provide annual emissions data to the degree of accuracy and certainty required by other provisions."

The Agency insists that most measurements using "top-down" methods are "taken over limited durations" at a facility and at a "single moment in time" that may not be representative of the facility's annual methane emissions. EPA also asserts that the data provided by some top-down methods are at large spatial scales, with limited ability to disaggregate to the facility- or emission source-level. EPA further finds that some of these methods have detection limits that are too high to detect emissions from sources with relatively low emission rates. Citing these generalized conclusions, the EPA proposes to preclude the use of all "top-down" methods for methane quantification—except for the purposes of "Other Large Release Events" source methodology.

This analysis is incomplete. Even accepting for the sake of argument that some of the “top-down” methods have the limitations EPA identified, the Agency failed to analyze whether there are other top-down methods that nevertheless could meet its criteria for quantification accuracy such as methods with more refined detection limits. Further, EPA failed to analyze whether “top-down” methods would suffice if, for example, they were combined with Optical Gas Imaging (OGI) surveys or if they were applied with greater frequency, whether it be quarterly, bimonthly, or continuously.

These omissions are noteworthy because the Agency’s own Section 111 Supplemental Proposal included a matrix for EPA’s approval of the use of certain “top-down” methods and other “advanced measurement technologies” in lieu of OGI surveys and Audio Visual Olfactory inspections.[12] The matrix criteria are framed in terms of surveying frequency and detection limits.[13] Given the Agency’s granular analysis of the sufficiency of “top-down” methods at particular detection limits and particular surveying frequencies in the Section 111 Supplemental Proposal, EPA’s nearly categorical dismissal of all “top-down” methods in the Proposed Rule is arbitrary and capricious.

To address the number of leaks undetected by OGI and Method 21 applications, EPA has proposed to provide a method-specific adjustment factor—referred to as the “k factor”—for calculation methods used to quantify emissions from equipment leaks using the leaker method in 40 CFR 98.233(q). EPA fails to explain why Subpart W reporters may not use data from “topdown” methods at a minimum to rebut emissions attributable to this proposed k factor. As with other emission factor data, the k factor is a generalized estimate that would apply to all relevant sources without regard to the actual volume of leaked emissions from those sources. If a Subpart W reporter is monitoring actual facility-specific emissions using an EPA-approved advanced method and detects lower emissions than the otherwise applicable k factor estimates, it should be able to use data from the former calculation to rebut the latter. We appreciate the Agency’s attempt to adjust emission factors to make up for emission underestimation, but we fail to see that this could not be better and more equitably addressed by readily available, rapidly improving actual facility-specific emissions data derived from advanced technologies.

While the DGCC recognizes the EPA's concerns regarding the limitations of certain 'top-down' methods, we firmly believe that these challenges can be addressed through refined practices and continuously improving technologies. [14] A framework approach, similar to the Section 111 Supplemental Proposal will promote innovation and uphold the integrity of our shared goal: to ensure accurate and effective methane emissions monitoring for a sustainable future.

[11] See Proposed Rule: (“[W]e reviewed measurement approaches that utilize information from satellite, aerial, and continuous monitoring (‘top-down approaches’) to detect and/or quantify emissions from petroleum and natural gas system for the purposes of subpart W reporting.”

[12] See Standards of Performance for New, Reconstructed, and Modified Sources and Emissions Guidelines for Existing Sources: Oil and Natural Gas Sector Climate Review, (Section 111 Supplemental Proposal).

[13] See Section 111 Supplemental Proposal, 87 Fed. Reg. at 74,740-746.

[14] See the Energy Emissions Modeling and Data Lab's (EEMDL) recently released Differentiated Gas Technical Road Mapping Initiative, which will "help inform public and private sector officials across major natural gas exporting and importing countries that have shown interest in expanding the global market for low methane emissions natural gas.").}

…

Advanced measurement technologies present unprecedented opportunities for monitoring and reporting methane emissions in the oil and gas sector. The DGCC emphasizes that the EPA must not exclude advanced measurement technologies, but instead, should take a more supportive approach. While accuracy and yearly data consistency might be of concern in certain circumstances, integrating these with existing methods can result in a significantly improved comprehensive emissions monitoring strategy.

The EPA proposes to preclude the use of all "top-down" methods for methane quantification—except for the limited purposes of calculating "Other Large Release Events." The analysis the EPA relies on for its general exclusion of top-down methods is incomplete because, among other things, it characterizes all top-down methods as providing only periodic surveying. The Agency failed to fully analyze whether there are advanced methane measurement technologies that could meet its criteria for quantification accuracy, such as continuous emissions monitoring.

For calculations that require the use of emission factors, an owner or operator of an applicable facility would have no means of demonstrating that its actual facility emissions are lower than the generalized estimates reflected in the calculation using emission factors. As a result, it could be liable for a Methane Waste Emissions Charge that does not reflect its actual emissions.

With the pace of technological evolution in methane detection and measurement, a static final rule could quickly become obsolete or hinder unexpected advances in emissions monitoring and mitigation. To ensure the rule's continued relevance, the DGCC suggests a dynamic, adaptive approval framework for emissions reporting technologies for the purpose of emissions quantification. The Agency could use appropriate quantification-related performance criteria in the technology approval process. Such measures would nurture and invite continuous innovation.

In conclusion, while the DGCC commends the objectives behind the proposed rule, we advocate for its refinement to address current challenges and future advancements and align more closely with the Congressional vision.

Commenter 0418: **The Associations support EPA's proposal to allow utilities to report emissions based on certain direct measurements; however, EPA should expand these options to include more measurement technologies and apply to additional source types, as this would increase reporting accuracy, provide greater flexibility to reporting facilities, and incentivize methane emission reductions.**

1. The revisions to Subpart W should facilitate the development of new methane detection and measurement technologies and allow their use in GHGRP reporting.

There are many tools now available in the methane detection and quantification toolbox, with more options being developed and refined, and it is important for companies/utilities to be able to pick the appropriate tool or mix of tools for the job at hand. Top-down measures like advanced mobile detection platform ("AMLD") methodology show promise for quantifying the overall methane emissions from all leaks in a gas utility's entire system when deployed with multiple passes of the mobile platform (i.e., by car, drone, airplane, or satellite) in conjunction with a robust, statistically valid sample of direct measurement data. AMLD opens up a new possibility of quantifying the collective methane emissions of a utility's system-wide operations across all assets with a high level of certainty—in particular, it can be quite useful for detecting leaks over large swaths of natural gas assets so those leaks can be prioritized for repairs. Some current top-down methods have limitations, including that certain AMLD technologies may not provide the best quantification of emissions from individual leaks or specific types of sources, while other AMLD options are currently too costly for quick adoption by all companies/utilities. However, top-down technologies are rapidly improving and costs are expected to decrease as more deployment occurs, data is gathered and studied, and algorithms are adjusted. Technologies like top-down AMLD are beneficial but may need to be used in conjunction with traditional bottom-up technologies to provide the most accurate leak detection and quantification reporting. The benefits and drawbacks of current AMLD technology represent just one example of the need for flexible treatment of emerging technologies under Subpart W.

EPA should establish pathways for integrating new methane detection and measurement technologies into Subpart W in order to facilitate ongoing innovation and improvement in this rapidly evolving field while also increasing the accuracy of emissions reporting. Currently, the options for allowing new technologies in Subpart W reporting both involve long lead times and extensive process: EPA can conduct a rulemaking to revise Subpart W or reporters can engage in a laborious, multi-year petition process to obtain permission to use an alternative technology. Neither of these options can occur swiftly, making it nearly impossible for Subpart W to keep up with rapid and meaningful developments in leak detection and direct measurement technology. To remedy this, EPA should define a protocol for accepting new technologies that meet certain performance criteria. For example, a new technology could be deemed presumptively approvable if it shows results within specified ranges of accuracy and confidence levels in a requisite number of side-by-side tests conducted with an already-approved technology. EPA could establish an expert panel that reviews the results and confirms that the criteria is met for using a particular technology for a particular purpose, as specified in an applicant's request for approval. The panel could be given a reasonable deadline within which to decide whether to accept a new technology for use in Subpart W reporting; if a decision is not timely made by the panel, the technology would automatically be approved.

Alternatively, EPA could allow companies/utilities to pilot emerging technologies through best available monitoring method ("BAMM") provisions akin to what EPA provided when Subpart W was first implemented. Technologies like AMLD may still be costly and sophisticated compared with traditional methods, so they may be best introduced by well-resourced utilities in targeted pilot programs. A BAMM or similar pilot option would further build the record for more mainstream acceptance of new technologies in Subpart W reporting. And, as the natural gas industry gains experience with new technologies and more utilities participate, economies of scale should help make this method more accessible to smaller gas utilities—particularly municipal or publicly owned utilities with more limited budgets. A similar pilot-type mechanism could be established by reference to the technological approvals of an outside standard-setting entity, such as American Society for Testing and Materials ("ASTM") International. EPA also should coordinate with the Department of Energy ("DOE") to incorporate the results of DOE-funded research projects aiming to advance the development of new and innovative measurement, monitoring, and mitigation technologies for methane emissions. [22]

As established by the IRA, Section 136(a) of the Clean Air Act authorizes $850 million in federal funding for, among other things, financial and technical assistance to help owners and operators of applicable facilities prepare and submit their Subpart W reports; EPA-led research, testing, and development of methods for sampling, measuring, and monitoring air pollutants pursuant to Section 103; and EPA's direct and indirect costs of administering Section 136, gathering empirical data, and tracking emissions.[23] If EPA develops a streamlined pathway for obtaining Subpart W approval of new emissions monitoring technology, the Agency could use this IRA funding to not only facilitate owner/operators putting new technologies into practice such that they can gain traction in the sector, but also can use this funding for EPA's own administration of the new-technology approval program. The Section 136(a) funding is only available through September 30, 2028; the limited window to leverage this funding in connection with Subpart W monitoring is yet another reason EPA should enable a faster approval process for using new technology to gather empirical data for Subpart W reporting.

Footnotes:

[22] DOE Press Release: DOE Invests $47 Million to Reduce Methane Emissions From Oil and Gas Sector (Mar. 13, 2023), https://www.energy.gov/articles/doe-invests-47-million-reduce-methane-emissions-oil-and-gas-sector.

[23] 42 U.S.C. § 7436(a).

Response 3: We appreciate the additional information on AMLD. As discussed in Section II.B of the preamble to the final rule, this final rule does not include a general provision to incorporate the use of advanced measurement approaches for sources at this time and instead specifically allows its use in certain appropriate cases, including for large release events. However, the Agency recognizes that these technologies, and approaches for using these technologies for long-term quantification of emissions from oil and natural gas operations, are evolving rapidly. Historically, the Greenhouse Gas Reporting Rule has been revised to incorporate the latest data, updated scientific knowledge, or additional measurement methods, and EPA intends to continue to evaluate the appropriateness of additional updates. The EPA is actively reviewing relevant peer-reviewed literature and pilot programs and, in advance of future rulemaking, the EPA intends to initiate a request for information, workshop, or white paper to further solicit feedback on the use of advanced measurement data and methods in subpart W. Additionally, as noted in Section III.P.6 of the preamble to the final rule, the focus of NSPS OOOOb and EG OOOOc is to find and repair leaks as quickly as possible to minimize emissions, and there is no requirement to quantify emissions. The EPA lacks specific information currently to establish an alternative technology framework for subpart W emissions quantification analogous to that finalized for the NSPS OOOOb for fugitive emissions detection. For our discussion and further response to comments requesting the use of survey results from advanced technologies or developing a pathway and framework for advanced technology, particularly those approved for use under NSPS OOOOb and EG OOOOc, for emissions reporting, please see Section III.P of the preamble to the final rule. With respect to the portion of this comment on "k factor," see Section III.P.2 of the preamble to the final rule for our response to this comment. With respect to the commenter's request to use IRA funding to facilitate use of new technologies or the administration of a new technology approval program, use of IRA funding is outside the scope of this rulemaking.

Commenter: Sensirion Connected Solutions
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Commenter: Permian Basin Petroleum Association (PBPA)
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Commenter: Devon Energy
Comment Number: EPA-HQ-OAR-2023-0234-0360
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Commenter: Qube Technologies, Inc.
Comment Number: EPA-HQ-OAR-2023-0234-0386
Page(s): 9

Commenter: Western Energy Alliance
Comment Number: EPA-HQ-OAR-2023-0234-0399
Page(s): 2

Commenter: American Petroleum Institute et al. (Part 1 of 2)
Comment Number: EPA-HQ-OAR-2023-0234-0402
Page(s): 6

Commenter: Differentiated Gas Coordinating Council (DGCC)
Comment Number: EPA-HQ-OAR-2023-0234-0415
Page(s): 2, 4

Comment 4: <u>Commenter 0293</u>: SCS entered this market in order to invest in the ability to improve methane abatement in the energy sector in line with our company values to create a more sustainable future. This investment was also taken by many technology providers and operators in a voluntary basis that has already laid the foundation for the opportunity ahead. As the EPA has stressed the outcome needs to be methane emissions reduction; empirically generated data through direct measurements obtained by an advanced methane emission technology will rapidly help realize this vision setting the gold standard globally.

If the EPA determines to implement improvements offered here by SCS and other industry expert contributors, this will be a pivotal point in the combating of climate change effects and creation of a new methane monitoring infrastructure driving reductions across the ecosystem. The Final Rule has the ability to incentivize the industry for the better, provide new perspectives on the severity of the topic, and maintain the highest levels of accountability between the private and government sectors.

Commenter 0346: Proposed Rule Fails to Incentivize Technology That Would Actually Provide Empirical Data

Unlike the proposed OOOOb and OOOOc rules, this Proposed Rule does not incentivize the use of new and advanced technologies and would, in fact, deter oil and gas companies from investing in the types of technologies that could provide more empirical data. At a minimum, oil and gas operators should at least be able to rely on using the same technologies for collection of empirical data that state air regulators have approved for use in their air programs (e.g., New Mexico).

For example, in the Proposed Rule, EPA makes the case that remote sensing data cannot be used to extrapolate annual emissions data, arguing that these measurements are taken over limited durations or when certain meteorological conditions exist, and that the detection limits are too high to detect emissions from sources with relatively low emission rates. [8] To the contrary, PBPA believes this type of data collection is designed to ensure that there is no double counting and, based on the experience of our members, does not result in undercounting.

Commenter 0360: **EPA should broadly recognize and allow for the use of advanced methane and GHG detection technology.**

Methane emission detection technologies are evolving rapidly and are a key component of Devon's strategy for emission reductions. Devon believes these technologies have the potential to be more effective at finding leaks on a larger scale, allowing for faster detection and mitigation, leading to a greater reduction in methane emissions. More broadly, these detection technologies are quickly becoming the preferred tool to mitigate methane emissions across the oil and gas industry in the United States.

To put it simply, disincentivizing the use of these technologies will impede the progress Devon and the broader oil and gas industry are making in understanding and reducing methane and GHG emissions. EPA should therefore recognize technologies that have been certified for use in other regulations (namely NSPS OOOOb & OOOOc) and include an additional approval process for non-certified technologies that would demonstrate to EPA that an advanced technology can achieve lower emissions through quantification and/or estimation that are as accurate, or better, than EPA's assumptions. If a technology met such criteria, an operator could then elect to submit that information to demonstrate a lower emissions inventory than Subpart W may estimate using default emission factors.

EPA should also clarify that these technologies can be used (voluntarily or as part of a regulatory compliance program) as credible information to constrain assumptions used to calculate “other large release events.” For example, information from continuous or near-continuous monitoring systems, aerial flyovers, drones, satellites, and camera-based systems should be accepted in order to determine the duration of these events. The ability of the technology to produce an estimated quantification or emission rate is not necessary for assumptions such as duration since a simple confirmation of whether the event is occurring or not is sufficient. However, as the capability to quantify continues to develop, operators should be allowed to utilize that data in the calculation of the release.

To further incentivize the use of these technologies, EPA should consider enabling operators to demonstrate lower emissions through a reconciliation process with EPA-approved advanced emissions detection technology that can conduct top-down measurements. The objective would be that over time, operators would be able to demonstrate consistently that their emissions were lower than the default emission factors, or calculation methodologies prescribed by Subpart W.

Footnote:

[8] Proposed Rule at 50291.

Commenter 0386: An objective review of available technologies should determine which technologies may be utilized to satisfy emissions measurement laws. In turn, clear performance criteria that are consistent with other major emissions management programs should be developed to encourage adoption of more advanced technologies as they become available.

If finalized with the considerations outlined here, the Final Rule will foster innovation in advanced emissions management technology while incentivizing operators to implement technologies that provide the best emissions reduction outcomes and the most accurate Methane Waste Emissions Charge.

We sincerely appreciate your consideration of our comments on the proposed rule. We look forward to working with EPA and all stakeholders on this important rulemaking.

Commenter 0399: Instead, the current revisions to the rule disincentivize the use of advanced, field-level technologies and would force the use of direct measurement techniques that have not been proven to provide a more accurate picture of emissions for field-based inventories. As proposed, the rule would result in reported emissions, especially of methane, that are drastically higher than actual emission rates in the field. By placing a heavy burden on operators who wish to use direct data measurement that would confirm lower emissions, EPA is instead forcing the use of conservative factors that would result in over-reporting of emissions and mask the real progress industry is making in reducing emissions. Considering the amount of policy making that flows from data provided by the GHGRP, from local, state, and federal air quality regulations to funding and research to even international obligations, EPA should place paramount importance on accuracy of the overall data. Given that the GHGRP will be the primary assessment mechanism for the methane fee mandated by the Inflation Reduction Act (IRA) , accuracy is even more vital. The Alliance believes the revisions, as proposed, miss the mark with respect to data accuracy, and provides ways to improve that accuracy below.

Commenter 0402: In addition to our technical comments, the Industry Trades have identified four overarching priority items within the proposed rules that if satisfactorily amended, will allow industry to attain the maximum potential methane mitigation and reduce public confusion. These high priority items are as follows:

2. Incentivize Cost-Effective Advanced Methane Detection through Technology Agnostic Rules:

Advanced methane detection technologies and flexibility to implement them are critical to the industry's ability to fully realize methane emissions reductions. Many operators have invested in technological advancements and have deployed and tested the technologies over many years, demonstrating the success of advanced programs and reaching a firm understanding of their operation and deployment. If this component of the suite of methane rule makings, including in Subpart W, is not expanded, the remaining rules will fail to realize the emission reduction goals.

Commenter 0415: The DGCC is concerned that the EPA's proposed rule will impede the adoption of advanced methane detection technologies, despite Congress's specific directive to transition the GHGRP toward empirical measurements. Precluding the use of advanced technologies will reduce the quantity and quality of reliable, granular-level emissions data that can be used to expand the differentiated gas market and accelerate emissions reductions beyond mere regulatory minimums. This document, provided by the DGCC, evaluates the Proposed Rule and offers recommendations that not only align with the Congressional intent of the Methane Emissions Reduction Program in the Inflation Reduction Act (IRA) but also consider the swift advancements in methane detection technologies and the fundamental need for superior emissions data.

…

As stated above, the DGCC seeks to expand the use of differentiated gas to rapidly reduce methane emissions beyond regulatory standards by creating a market for low-methane-loss natural gas. By adopting advanced emissions detection technologies and aligning with robust measurement, monitoring, reporting, and verification (MMRV) best practices, the U.S. energy sector has an opportunity to lead the world in emissions reductions in the short, medium, and long-term.

The DGCC is deeply concerned that EPA's proposed rule could slow the deployment of advanced measurement technologies and hinder the adoption of MMRV best practices, thereby impeding the growing differentiated gas market while it's still in its infancy. Differentiated gas is an affordable, verifiable avenue to achieve deep cuts in emissions using existing and continuously improving technologies. However, this market is inherently driven by the need for more robust, granular emissions data gathered by such technologies. Any misalignment between the 2022 Section 111 Supplemental Methane Rule and Subpart W Reporting Rule may disincentivize the use and unintentionally limit the emissions reduction potential of the advanced technologies needed to establish robust MMRV practices to enable this market, further challenging the Biden Administration's goal of reducing U.S. methane emissions by 30% by 2030, as outlined by the Global Methane Pledge. [6]

Footnote:

[6] See Global Methane Pledge

Response 4: We acknowledge the commenter's support for a pathway for incorporation of advanced technologies. As discussed in Section II.B of the preamble to the final rule, this final rule does not include a general provision to incorporate the use of advanced measurement approaches for sources at this time and instead specifically allows its use in certain appropriate cases, including for large release events. However, the Agency recognizes that these technologies, and approaches for using these technologies for long-term quantification of emissions from oil and natural gas operations, are evolving rapidly. Historically, the Greenhouse Gas Reporting Rule has been revised to incorporate the latest data, updated scientific knowledge, or additional measurement methods, and EPA intends to continue to evaluate the appropriateness of additional updates. The EPA is actively reviewing relevant peer-reviewed literature and pilot programs and, in advance of future rulemaking, the EPA intends to initiate a request for information, workshop, or white paper to further solicit feedback on the use of advanced measurement data and methods in subpart W.

Commenter: Sensirion Connected Solutions
Comment Number: EPA-HQ-OAR-2023-0234-0293
Page(s): 15-17

Commenter: Project Canary, PBC
Comment Number: EPA-HQ-OAR-2023-0234-0348
Page(s): 11

Comment 5: Commenter 0293: **The Proposed Rule mischaracterizes input received by the Agency from the Methane Emissions Reduction Program Request For Information.**

In November 2022, EPA published a Request for Information (RFI) with eight questions about implementation of the Methane Emission Reduction Program (MERP).[25] In question number 8 of the RFI, EPA specifically requested input about how the Agency should revise the Subpart W requirements: “The IRA requires EPA to revise the requirements of GHGRP Subpart W to ensure that reporting is based on empirical data and accurately reflects total methane emissions. What revisions should EPA consider related to GHGRP Subpart W?” [26]

Yet, in the Proposed Rule preamble, EPA does not refer to or cite this input in any way. EPA refers to the RFI only for the limited purpose of demonstrating that it complied with laws and policies requiring the Agency to solicit input from small governments and tribes.[27] The Proposed Rule does not discuss the content of input received from any commenters.

The TSD includes a short discussion of responses to the RFI, but it mischaracterizes the input. The TSD correctly notes that three environmental nongovernmental organization (NGO) comments—one of which is a coalition of 16 NGOs—specifically recommended that EPA integrate both top-down and bottom-up methods into the Subpart W revisions.[28] However, the TSD contrasts this recommendation with the recommendations of "one industry organization" that asserts that advanced measurement technologies are "relatively immature."[29] This is an excerpt from comments from the Interstate Natural Gas Association of America (INGAA). A fuller review of INGAA's comments show that INGAA actually recommended that EPA revise the Subpart W rules to allow greater use of direct measurement methods as those methods improve.[30] The INGAA comments include the following statements:

- *INGAA recommends that EPA provide flexibility in its upcoming revisions to Subpart W to ensure that operators can use site-specific and/or company-specific measurement data to improve methane emissions estimates-e.g., using such data rather than more generic emission factors for estimating source-specific emissions.*
- *It is important to note that INGAA members are continuously looking for new and innovative ways to reduce GHG emissions from transmission & storage ("T&S") sources. In many cases technological advances that reduce GHG emissions or improve GHG emissions measurement outpace the regulatory process. Accordingly, INGAA strongly encourages EPA to include operators with flexibility [sic] to report emissions associated with affected facilities that accurately reflect implementation of new GHG reduction and measurement technologies when those technologies are supported with defensible data. The ability to rapidly deploy new technology to reduce and measure GHG emissions will become even more important with the anticipated revisions to the GHRP mandated by the IRA.*
- *Additionally, EPA should consider the need to develop measurement/monitoring infrastructure to support advanced monitoring, including remote monitoring. This issue is critical in light of the changes mandated by the IRA as well as the Methane Rule Supplemental.*

Another industry organization commenter—the American Petroleum Institute (API)—made similar recommendations:

- *We recommend that EPA propose and seek comment on a definition of "empirical data" that recognizes that emissions factors are based on empirical data, and accounts for the current and growing array of technologies and methods that can be used to collect emissions data from the upcoming MERP rulemaking.*
- *The statutory text is unambiguous with regards to the requirement to revise Subpart W to allow operators to use empirical data in their reporting. Thus, using empirical data in Subpart W reporting is an option, not a requirement. As such, we believe that EPA should give operators the option to use empirical data in place of, or alongside, emission factors. Specific facility or equipment testing data may be more accurate than the average emission factors provided by studies, but due to the complex and geographically*

distributed nature of oil and natural gas operations, we emphasize that emissions factors will continue to be a necessary component of Subpart W reporting.

- *With respect to the transition to empirical data, based on previous work with advanced technologies and protocols, the GHGRP will continue to need both emission factors for smaller dispersed sources and data from advanced technologies to reach a goal of empirical methane reporting on a national scale.*
- *EPA should recognize potential for some OOOO-approved technologies with quantification capabilities to provide useful insight into a facility's actual GHG emissions.*[31]

EPA should revisit the recommendations submitted in response to the MERP RFI and correct its mischaracterization.

Footnotes:

[25] U.S. ENVIRONMENTAL PROTECTION AGENCY, DOCKET 3: METHANE EMISSIONS REDUCTION PROGRAM [60113] (Nov. 2022).

[26] Id. At 2.

[27] Proposed Rule, 88 Fed. Reg. at 50373 (discussing EPA's compliance with the Unfunded Mandates Reform Act and Executive Order 13175: Consultation and Coordination With Indian Tribal Governments).

[28] TSD, at 18.

[29] Id.

[30] Comment Submitted by the Interstate Natural Association of America, https://www.regulations.gov/comment/EPA-HQ-OAR-2022-0875-0051.

[31] Comment submitted by the American Petroleum Institute, https://www.regulations.gov/comment/EPA-HQ-OAR-2022-0875-0020.

Commenter 0348: **The Proposed Rule mischaracterizes input received by the Agency from the Methane Emissions Reduction Program Request for Information.**

In November 2022, EPA published a Request for Information (RFI) with eight questions about implementation of the Methane Emission Reduction Program (MERP). [26] In question number 8 of the RFI, EPA specifically requested input about how the Agency should revise the Subpart W requirements: "The IRA requires EPA to revise the requirements of GHGRP Subpart W to ensure that reporting is based on empirical data and accurately reflects total methane emissions. What revisions should EPA consider related to GHGRP Subpart W?"[27]

Yet, in the Proposed Rule preamble, EPA does not refer to or cite this input. EPA refers to the RFI only for the limited purpose of demonstrating that it complied with laws and policies requiring the Agency to solicit input from small governments and tribes.[28] The Proposed Rule does not discuss the content of input received from any commenters.

The TSD includes a short discussion of responses to the RFI, but it mischaracterizes the input. The TSD correctly notes that three environmental nongovernmental organization (NGO) comments—one of which is from a coalition of 16 NGOs—specifically recommended that EPA integrate both top-down and bottom-up methods into the Subpart W revisions.29 However, the TSD contrasts this recommendation with the recommendations of "one industry organization" that asserts that advanced measurement technologies are "relatively immature."[30] This is an excerpt from comments from the Interstate Natural Gas Association of America (INGAA). A fuller review of INGAA's comments show that INGAA actually recommended that EPA revise the Subpart W rules to allow greater use of direct measurement methods as those methods improve.31 The INGAA comments include the following statements:

- INGAA recommends that EPA provide flexibility in its upcoming revisions to Subpart W to ensure that operators can use site-specific and/or company-specific measurement data to improve methane emissions estimates-e.g., using such data rather than more generic emission factors for estimating source-specific emissions.
- It is important to note that INGAA members are continuously looking for new and innovative ways to reduce GHG emissions from transmission & storage ("T&S") sources. In many cases technological advances that reduce GHG emissions or improve GHG emissions measurement outpace the regulatory process. Accordingly, INGAA strongly encourages EPA to include operators with flexibility [sic] to report emissions associated with affected facilities that accurately reflect implementation of new GHG reduction and measurement technologies when those technologies are supported with defensible data. The1033bilityy to rapidly deploy new technology to reduce and measure GHG emissions will become even more important with the anticipated revisions to the GHGRP mandated by the IRA.
- Additionally, EPA should consider the need to develop measurement/monitoring infrastructure to support advanced monitoring, including remote monitoring. This issue is critical in light of the changes mandated by the IRA as well as the Methane Rule Supplemental

Another industry organization commenter—the American Petroleum Institute (API)—made similar recommendations:

- We recommend that EPA propose and seek comment on a definition of "empirical data" that recognizes that emissions factors are based on empirical data, and accounts for the current and growing array of technologies and methods that can be used to collect emissions data from the upcoming MERP rulemaking.
- The statutory text is unambiguous with regards to the requirement to revise Subpart W to allow operators to use empirical data in their reporting. Thus, using empirical data in Subpart W reporting is an option, not a requirement. As such, we believe that EPA should give operators the option to use empirical data in place of, or alongside, emission factors. Specific facility or equipment testing data may be more accurate than the average emission factors provided by studies, but due to the complex and geographically

distributed nature of oil and natural gas operations, we emphasize that emissions factors will continue to be a necessary component of Subpart W reporting.

- With respect to the transition to empirical data, based on previous work with advanced technologies and protocols, the GHGRP will continue to need both emission factors for smaller dispersed sources and data from advanced technologies to reach a goal of empirical methane reporting on a national scale
- EPA should recognize potential for some OOOO-approved technologies with quantification capabilities to provide useful insight into a facility's actual GHG emissions.[32]

EPA should revisit the recommendations submitted in response to the MERP RFI and correct its mischaracterization.

Footnotes:

[26] U.S. ENVIRONMENTAL PROTECTION AGENCY, DOCKET 3: METHANE EMISSIONS REDUCTION PROGRAM [60113] (Nov. 2022).

[27] Id. At 2.

[28] Proposed Rule, 88 Fed. Reg. at 50373 (discussing EPA's compliance with the Unfunded Mandates Reform Act and Executive Order 13175: Consultation and Coordination With Indian Tribal Governments).

[29] TSD, at 18.

[30] Id.

[31] Comment Submitted by the Interstate Natural Association of America, htps://www.regulations.gov/comment/EPA-HQ-OAR-2022-0875-0051.

[32] Comment submitted by the American Petroleum Institute, https://www.regula?ons.gov/comment/EPA-HQ-OAR-2022- 0875-0020.

Response 5: We disagree with the commenter's assertion that information received through the RFI was not carefully considered or mischaracterized. All information received was carefully considered in this rulemaking, including the final rule. For further discussion of the use of empirical data in Subpart W, see our response to Comment 1 in Section 1 of this document. With respect to the commenter's request that the EPA provide flexibility in its upcoming revisions to Subpart W to ensure that operators can use site-specific and/or company-specific measurement data to improve methane emissions estimates, see our response to Comment 1 in Section 24.1 of this document. See the Introduction to this section for more information on comments received through the RFI.

Commenter: Sensirion Connected Solutions
Comment Number: EPA-HQ-OAR-2023-0234-0293
Page(s): 13-14

Commenter: Project Canary, PBC
Comment Number: EPA-HQ-OAR-2023-0234-0348
Page(s): 9

Comment 6: Commenter 0293: **The Proposed Rule fails to sufficiently analyze whether advanced measurement technologies can provide more accurate methane emissions measurement than the measurement methods EPA proposes to approve.**

In the Proposed Rule, EPA refers to advanced measurement technologies—satellite monitoring, aerial monitoring, and continuous monitoring systems—under the label of "top-down" methods.[18] Though the Agency acknowledges in both the preamble to the Proposed Rule and in the Technical Support Document (TSD) that "top-down" methods are "very useful in identifying possible large emissions events that are not captured by other reporting obligations," EPA categorically concludes that they are "not presently able to provide annual emissions data to the degree of accuracy and certainty required by other provisions."[19]

The Agency Insists that "most" measurements using "top-down" methods are "taken over limited durations" at a facility and at a "single moment in time" that may not be representative of the facility's annual methane emissions.[20] EPA also asserts that the data provided by "some" top-down methods is at large spatial scales, with limited ability to disaggregate to the facility- or emission source-level. EPA further finds that "some" of these methods have detection limits that are too high to detect emissions from sources with relatively low emission rates. [21] Citing these generalized conclusions, the EPA proposes to preclude use of all "top-down" methods for methane quantification—except for the purposes of "Other Large Release Events" source methodology.

This analysis is incomplete. Even accepting for the sake of argument that "some" of the "top-down" methods have the limitations EPA identified, the Agency failed to analyze whether there are other top-down methods that nevertheless could meet its criteria for quantification accuracy such as methods with more refined detection limits. Further, EPA failed to analyze whether "top-down" methods would suffice if, for example, they were combined with Optical Gas Imaging (OGI) surveys or if they were applied with greater frequency, whether it be quarterly, bimonthly or continuously.

These analytical omissions are noteworthy because the Agency's own Section 111 Supplemental Proposal included a matrix for EPA's approval of the use of certain "top-down" methods and other "advanced measurement technologies" in lieu of OGI surveys and Audio Visual Olfactory (AVO) inspections. The matrix criteria are framed in terms of surveying frequency and detection limits.[22] Given the Agency's granular analysis of the sufficiency of "top-down" methods at particular detection limits and particular surveying frequencies in the Section 111 Supplemental Proposal, EPA's nearly categorical dismissal of all "top-down" methods in the Proposed Rule is arbitrary and capricious.

Furthermore, to address the quantity of leaks undetected by OGI and Method 21 applications, EPA has proposed to provide a method-specific adjustment factor—referred to as the "k factor"—for calculation methods used to quantify emissions from equipment leaks using the leaker method in 40 CFR 98.233(q). EPA fails to explain why Subpart W reporters may not use data from "top-down" methods at a minimum to rebut emissions attributable to this proposed k factor. As with other emission factor data, the k factor is a generalized estimate that would apply to all relevant sources without regard to the actual volume of leaked emissions from those sources. If a Subpart W reporter is monitoring actual facility-specific emissions using an EPA-approved advanced method and detects fewer leaks than the otherwise applicable k factor estimate, it should be able to use data from the former calculation to rebut the later. We appreciate the Agency's attempt to adjust emission factors to make up for emission underestimation but we fail to see that this could not be better and more equitably addressed by readily available, rapidly improving actual facility-specific emissions data.

Footnotes:

[18] See id. At 50, 289 ("[W]e reviewed measurement approaches that utilize information from satellite, aerial, and continuous monitoring ('top-down approaches') to detect and/or quantify emissions from petroleum and natural gas system for the purposes of subpart W reporting.").

[19] Id. At 50,290.

[20] Id. At 52,291.

[21] Id. (citation omitted).

[22] Section 111 Supplemental Proposal, 87 Fed. Reg. at 74,740-746.

Commenter 0348: **The Proposed Rule fails to sufficiently analyze whether advanced measurement technologies can provide more accurate methane emissions measurement than the measurement methods EPA proposes to approve.**

In the Proposed Rule, EPA refers to advanced measurement technologies—satellite monitoring, aerial monitoring, and continuous monitoring systems—under the label of "top-down" methods.[19] Though the Agency acknowledges in both the preamble to the Proposed Rule and in the Technical Support Document (TSD) that "top-down" methods are "very useful in identifying possible large emissions events that are not captured by other reporting obligations," EPA categorically concludes that they are "not presently able to provide annual emissions data to the degree of accuracy and certainty required by other provisions."[20]

The Agency insists that "most" measurements using "top-down" methods are "taken over limited durations" at a facility and at a "single moment in time" that may not be representative of the facility's annual methane emissions.[21] EPA also asserts that the data provided by "some" top-down methods is at large spatial scales, with limited ability to disaggregate to the facility- or emission source-level. EPA further finds that "some" of these methods have detection limits that are too high to detect emissions from sources with relatively low emission rates.[22] Citing these generalized conclusions, the EPA proposes to preclude use of all “top-down” methods for methane quantification—except for the limited purposes of “Other Large Release Events” source methodology.

This analysis is incomplete. Even accepting for the sake of argument that “some” of the “top-down” methods have the limitations EPA identified, the Agency failed to analyze whether there are other “top-down” methods that nevertheless could meet its criteria for quantification accuracy, such as methods with more refined detection limits. Further, EPA failed to analyze whether “top-down” methods would suffice if, for example, they were combined with Optical Gas Imaging (OGI) surveys or if they were applied with greater frequency, whether it be quarterly, bimonthly or continuously.

These analytical omissions are noteworthy because the Agency’s own NSPS OOOOb and EG OOOOc proposal included a matrix for EPA approval of the use of certain “top-down” methods and other “advanced measurement technologies” in lieu of OGI surveys and Audio Visual Olfactory (AVO) inspections. The matrix criteria are framed in terms of surveying frequency and detection limits.[23] Given the Agency’s granular analysis of the sufficiency of “top-down” methods at particular detection limits and particular surveying frequencies in the NSPS OOOOb and EG OOOOc proposal, EPA’s nearly categorical dismissal of all “top-down” methods in the Proposed Rule is arbitrary and capricious.

Furthermore, to address the quantity of leaks undetected by OGI and Method 21 applications, EPA has proposed to provide a method-specific adjustment factor—referred to as the “k factor”—for calculation methods used to quantify emissions from equipment leaks using the leaker method in 40 CFR 98.233(q). EPA fails to explain why Subpart W reporters may not use data from “top-down” methods at a minimum to rebut emissions attributable to this proposed k factor. As with other emission factor data, the k factor is a generalized estimate that would apply to all relevant sources without regard to the actual volume of leaked emissions from those sources. If a Subpart W reporter is monitoring actual facility-specific emissions using an EPA-approved advanced method and detects fewer leaks than the otherwise applicable k factor estimate, it should be able to use data from the former calculation to rebut the later. We understand the Agency’s attempt to adjust emission factors to make up for emission underestimation, but we fail to see that this could not be better and more equitably addressed by readily available, rapidly improving actual facility-specific emissions data.

Footnote:

[19] Id. At 50, 289 (“[W]e reviewed measurement approaches that utilize information from satellite, aerial, and continuous monitoring (‘top-down approaches’) to detect and/or quantify emissions from petroleum and natural gas system for the purposes of subpart W reporting.”).

[20] Id. At 50,290.

[21] Id. At 52,291.

[22] Id. (citation omitted).

[23] NSPS OOOOb and EG OOOOc Proposal, 87 Fed. Reg. at 74,740-746

Response 6: For our discussion and response to comments on the appropriateness of the NSPS matrix approach for the purpose of emissions quantification under subpart W, see Section III.P.6 of the preamble to the final rule. With respect to the portion of this comment on the "k factor", see Section III.P.2 of the preamble to the final rule for our response to this comment.

Commenter: Endeavor Energy Resources, L.P.
Comment Number: EPA-HQ-OAR-2023-0234-0381
Page(s): 3

Commenter: Western Energy Alliance
Comment Number: EPA-HQ-OAR-2023-0234-0399
Page(s): 2

Comment 7: Commenter 0381: Further still, as monitoring technologies continue to evolve, EPA must recognize that direct measurement for many sources remains impossible, impractical, or infeasible for a number of reasons, including the limited availability of technicians trained to use certain monitoring devices and the remote locations of many facilities subject to Subpart W. This is why any final rulemaking must ensure flexibility in the availability of monitoring, measurement, and calculation methods and technologies for reporters—not simply be a reflexive directive for direct measurement. EPA should also leave sufficient flexibility in the available types of technologies that can be used for direct measurement to allow for innovation and to recognize that different monitoring schemes will work best for different operations.

Commenter 0399: The Alliance believes the Upstream & Production Segment of the oil and natural gas industry should not be treated like Midstream or Downstream. While part of the same value chain, production facilities are not manned 24 hours a day, are not typically outfitted with the same level of security and automation as a gas plant or refinery, and are far more prevalent in the field. Due to this, when considering the measurement and monitoring required for a single downstream facility in relation to the likely hundreds of production facilities which produce oil and natural gas that flow to a single midstream or downstream facility, there are vastly different technology implementation challenges and vastly different needs. Many of the options proposed for sources in the production sector by this rulemaking are impractical as well as costly. EPA hints at this in the preamble, "direct measurement is the most accurate method for determining…emissions, it may also be time consuming and costly." Yet even this admission is understated and the full effects are not fully taken into consideration.

For widely dispersed production facilities, certain technologies are better suited to estimate emissions. These technologies use empirical data to allow for measurement-informed reporting. The best approach that the GHGRP can take would allow for significant flexibility in the technologies used to collect and report data, while simultaneously allowing for updated default emission factors for equipment to illuminate new information about typical sources in the production segment. Specifically, EPA and the GHGRP should design a program that incentivizes the use of aircraft, drones, satellites, and other full-field measurement technologies, as their success in both identifying leaks and confirming leak rates in the industry is well documented.

Response 7: The EPA acknowledges the commenter's support for incorporating more measurement data. We have finalized revisions to Subpart W that provide additional measurement-based methodologies where such methodologies were not available in the existing or proposed subpart W rules. These include provisions for flowback metering during the initial stage of completions and workovers with hydraulic fracturing, EPA OTM-52 or NSPS-approved alternative testing technologies for flare destruction efficiency, equipment leak survey and measurement of transmission company interconnect metering-regulating stations and farm tap and/or direct sale stations, and performance testing for methane combustion slip.

After consideration of comments, we have also finalized provisions for increased flexibility in methods available to reporters, which include alternatives to the proposed flare flow and composition monitoring requirements and the addition of default population factors for intermittent bleed devices.

The Agency also recognizes that advanced measurement technologies, and approaches for using these technologies for long-term quantification of emissions from oil and natural gas operations, are evolving rapidly. Historically, the Greenhouse Gas Reporting Rule has been revised to incorporate the latest data, updated scientific knowledge, or additional measurement methods, and EPA intends to continue to evaluate the appropriateness of additional updates. The EPA is actively reviewing relevant peer-reviewed literature and pilot programs and, in advance of future rulemaking, the EPA intends to initiate a request for information, workshop, or white paper to further solicit feedback on the use of advanced measurement data and methods in subpart W. See Section II.B of the preamble to the final rule for EPA's discussion of the use of aerial observations and other advanced measurement approaches.

Commenter: Oceana
Comment Number: EPA-HQ-OAR-2023-0234-0391
Page(s): 4-5

Comment 8: EPA's reliance on BOEM's OCS Emissions Inventory fails to meet the Inflation Reduction Act's requirement that the reporting of emissions and calculation of the waste emissions charge accurately reflect the total methane emissions and waste emissions from applicable facilities. Several studies have shown that emissions from offshore facilities are higher than what is reported to BOEM. And the EPA is unlikely to fix these shortcomings with the proposed rule.

Ayasse et al. 2022[16] used an airplane to measure methane emissions in the Gulf of Mexico. They surveyed over 150 offshore platforms and surrounding infrastructure in shallow water. Tanks, pipelines, wells, and vents all released methane. Some vents were persistently releasing methane for days or months. The loss rates compared to production offshore varied from 10% to 66%, vastly higher than onshore estimates for the Permian Basin around 3.3%– 3.7%.

Gorchov Negron et al. 2020[17] used methane measurements from aircrafts to show the Environmental Protection Agency Greenhouse Gas Inventory (GHGI) and the US Bureau of Ocean Energy Management Gulfwide Offshore Activities Data System (GOAD) underestimate emissions. Methane emissions from the largest shallow water facilities were underestimated by at least an order of magnitude compared to GOAD. The true emission factor for shallow oil platforms could be 80% higher than what is used by the GHGI. Under-sampling of facilities with disproportionately high emissions can lead to underestimates of basinwide emissions. Empirical measurements are needed to fulfill the mandate of the IRA and accurately assess the emissions.

Gorchov Negron et al. 2023[18] collected airborne observations and combined them with previous surveys to evaluate the climate impact of offshore drilling in the Gulf of Mexico. The study included methane from losses and venting as well as CO2 from combustion. Based on their research, the climate impacts of drilling in the Gulf of Mexico are over twice what is reported in government inventories, and on average, shallow water platforms in the Gulf of Mexico are worse for the climate than typical oil production around the world.

Footnotes:

[16] Alana K. Ayasse et al., Methane remote sensing and emission quantification of offshore shallow water oil and gas platforms in the Gulf of Mexico, ENVTL. RES. LETTERS 17(8) (Aug. 11, 2022), https://doi.org/10.1088/1748- 9326/ac8566.

[17] Alan M. Gorchov Negron et al., Airborne Assessment of Methane Emissions from Offshore Platforms in the U.S. Gulf of Mexico, ENVTL. SCI. & TECH. 54(8) 5112–5120 (April 13, 2020), https://doi.org/10.1021/acs.est.0c00179.

[18] Alan M. Gorchov Negron AM et al., Excess methane emissions from shallow water platforms elevate the carbon intensity of US Gulf of Mexico oil and gas production, PROCEEDINGS OF THE NAT'L ACADEMY OF SCI.120, 10.1073/pnas.2215275120

Response 8: We disagree with commenter's assertion that reliance on BOEM's OCS Emissions Inventory fails to meet the Inflation Reduction Act's requirement that the reporting of emissions and calculation of the waste emissions charge accurately reflect the total methane emissions and waste emissions from applicable facilities. As discussed in Section III.R of the preamble to the final rule, this final rule directs reporters to use BOEM methods to calculate emissions every year that the system is available and they have the necessary data available to do so, which we expect to increase the accuracy of reported emissions. We note that the new source category 'other large release events' is being finalized for all 10 industry segments in subpart W, including offshore, which may result in the incorporation of remote sensing data for offshore facilities and thus account for any large emission events not accounted for in BOEM's methods.

Commenter: Western Energy Alliance
Comment Number: EPA-HQ-OAR-2023-0234-0399
Page(s): 9

Comment 9: EPA should consider how the Colorado Department of Public Health & Environment (CDPHE) has improved accuracy. The CDPHE Air Pollution Control Division, in its 2022 Production (Upstream) Emissions Inventory Instructions for Regulation No. 7, allows the use of site-specific emission factors that are included in the source permit. If the site-specific emission factor has not been incorporated into a permit it can be used in the emission inventory by providing the base sampling data and supporting emission factor development. This has resulted in a much more reliable and accurate emissions inventory for Colorado than currently exists in the GHGRP or if finalized as proposed.

Response 9: We appreciate the information on CDPHE's 2022 Production (Upstream) Emissions Inventory Instructions for Regulation No. 7. However, we note that the commenter did not provide a detailed recommendation concerning how similar site-specific emission factors could be incorporated.

Commenter: Oceana
Comment Number: EPA-HQ-OAR-2023-0234-0391
Page(s): 6

Commenter: Offshore Operators Committee (OOC)
Comment Number: EPA-HQ-OAR-2023-0234-0409
Page(s): 1

Comment 10: Commenter 0391: **THE EPA'S MUST INCLUDE RELIANCE ON TOP-DOWN MEASUREMENTS FOR VALIDATION OF REPORTED DATA AND EXPAND DIRECT MEASUREMENT REQUIREMENTS TO INCREASE THE ACCURACY OF REPORTED DATA**

While the EPA is updating some emissions categories onshore to supplement and verify reported data with direct measurement data, it has not done so for offshore facilities. The EPA can and must require that offshore facilities use top-down measurements, such as remote sensing and aerial surveys, to supplement and validate data reported and require reporters to update the reported data in accordance with the results of the top-down measurements. This can be particularly helpful for offshore facilities because of the high persistence rate pointed out in Ayasse et al. study. The authors even say that "2-3 samples a year may be sufficient to characterize and monitor emissions in this region."[20]

Additionally, the EPA has the authority to require that offshore facilities conduct direct measurements of different emissions categories. Currently, BSEE requires that any facility that processes more than 2,000 barrels of oil per day during any calendar month install flare/vent meters that measure flare and vented gas within five percent accuracy.[21] The EPA could expand on this requirement or work with BSEE to ensure that the requirements are expanded to more facilities.

Footnotes:

[20] Ayasse et al., at 5.

[21] 30 C.F.R. § 250.1163(a).

Commenter 0409: EPA requested feedback on advanced methane monitoring technologies. The maturity levels of advanced methane monitoring technologies are variable across technology platforms and oil and natural gas sectors. While advanced methane monitoring technologies have been deployed and tested extensively onshore, offshore deployment of advanced methane monitoring technology is still challenging because equipment is typically more densely placed on a platform, weather may impact results more often and safety and environmental considerations can restrict deployment opportunities.

Response 10: For our discussion and comment responses related to final calculation methodologies and final reporting elements added to support verification for offshore, see Section III.R.2 of the preamble. With respect to the commenter's assertion that we must require top-down measurements for offshore facilities, we did not propose and are not finalizing provisions requiring the use of top-down measurements, including for the reasons discussed in Section II.B of the preamble to the final rule; however, we note that the new source category 'other large release events' is being finalized for all 10 industry segments in subpart W, including offshore, which may result in the incorporation of remote sensing data for offshore facilities. With respect to the commenter's suggestion that we expand on BSEE's requirement or work with BSEE to expand GHGRP requirements to apply BSEE's flare and vented gas measurement requirements to GHGRP facilities, we did not propose and are not finalizing provisions requiring the use of BSEE measurements.

24 General Calculation/Measurement Methods

24.1 Requiring Measurement vs. Providing Measurement Options

Commenter: Marcellus Shale Coalition (MSC)
Comment Number: EPA-HQ-OAR-2023-0234-0275
Page(s): 3

Commenter: The Petroleum Alliance of Oklahoma
Comment Number: EPA-HQ-OAR-2023-0234-0398
Page(s): 2-3

Commenter: American Petroleum Institute et al. (Part 1 of 2)
Comment Number: EPA-HQ-OAR-2023-0234-0402
Page(s): 7, 15-16

Comment 1: <u>Commenter 0275</u>: <u>Other Emission Inventory Programs</u>

Similarly, annual emission inventories, as part of the operating permit programs, and Toxic Release Inventory (TRI) also collected data that was used by industry and others to identify issues and develop responses.

The U.S. EPA's TRI website (https://www.epa.gov/toxics-release-inventory-tri-program) notes a similar purpose to the GHGRP. As noted on the site:

The Toxics Release Inventory (TRI) is a resource for learning about toxic chemical releases and pollution prevention activities reported by industrial and federal facilities. TRI data supports informed decision-making by communities, government agencies, companies, and others. Section 313 of the Emergency Planning and Community Right-to-Know Act (EPCRA) created the TRI.

A key difference between these programs and GHGRP is that the GHGRP is overly prescriptive as to how emissions are to be calculated. Under annual emission inventories and TRI, industry determines how best to calculate emissions. This can range from using data from emission monitors, stack testing, engineering calculations, manufacturers' data, or recognized emission factors. The submissions also require a certification by a responsible official.

The MSC recommends that the GHGRP should follow a similar approach to allow for variations in sources and minimize the reporting burden on the regulated community, while promoting consistency in data that is reported publicly.

<u>Commenter 0398</u>: In some provisions of the Proposed Rule, EPA limits the use of reporting methodologies e.g., EPA proposes direct measurement only and removes the use of existing EFs. Depending on a reporter's situation (e.g., facility location, size or type of equipment, staffing, or funding), one reporting methodology may not be appropriate or reasonable.

We support the collection of accurate data; however, EPA should allow operators to choose multiple reporting methodologies that best fit their needs.

Action Requested: We request EPA allow reporters the widest array of options (e.g., direct measurement, EFs, representative samples, engineering estimates) to report emissions.

Commenter 0402: **Generally, the Industry Trades support the optional use of measured data in addition to EPA or company developed emission factors, when the measured data are appropriate.** Allowing reporters the option to use measured data or emission factors (EPA or company-developed) would increase data accuracy and avoid disincentivizing emission reduction measures. While EPA is increasing the sources for which direct measurement is allowed, there are still some methodologies which only allow the use of prescriptive emission factors and parameters with no alternative options (e.g., flare methane destruction efficiency, fraction of un-combusted gas from engines, crankcase venting). While we support the option to use default emission factors and parameters, requiring reporters to use prescriptive emission factors and parameters in lieu of an option to use directly or representatively measured data disincentivizes deployment of emission reduction measures. Additionally, there are some sources where measured data is required to be used, even if the measured data is infeasible, incomplete or potentially unreliable (e.g., flare flow and composition monitoring, mud degassing methane content). EPA should allow operators to utilize the growing number of technologies with quantification capabilities to report empirical data for source categories covered under Subpart W.

…

Subpart W and the Waste Emissions Charge Program

Reporting requirements under Subpart W must be reconsidered in light of the role that Subpart W will play in implementing the Waste Emissions Charge Program.

…

The rule must also allow an option to use directly or representatively measured data under all sources to demonstrate reductions in emissions. As proposed, not all source categories allow the use of directly measured data to demonstrate true reductions and improvements (i.e., flare combustion efficiency, crankcase venting, and any other area in the rule where reporters are required to use emission factors instead of having the option to directly measure).

Response 1: The EPA acknowledges the commenter's support for the use of measured data and we have finalized revisions to Subpart W that provide additional measurement-based methodologies where such methodologies were not available in the existing or proposed subpart W rules. These include provisions for flowback metering during the initial stage of completions and workovers with hydraulic fracturing, EPA OTM-52 or NSPS-approved alternative testing technologies for flare destruction efficiency, equipment leak survey and measurement of transmission company interconnect metering-regulating stations and farm tap and/or direct sale stations, and performance testing for methane combustion slip.

After consideration of comments, we have also finalized provisions for increased flexibility in methods available to reporters, which include alternatives to the proposed flare flow and composition monitoring requirements and the addition of default population factors for intermittent bleed devices. With regards to mud degassing, we note that both the proposed and final Subpart W does not require measurement of CH_4 emissions. When measurement data are not available, reporters will have the option of using the engineering equations in Calculation Method 2 with default emission factors.

Commenter: Public Hearing Transcript
Comment Number: EPA-HQ-OAR-2023-0234-0224
Page(s): 12 (Morgan King), 17 (Laurie Anderson), 20 (Antoinette Reyes), 22-23 (Cyrus Reed), 24 (Camilla Fiebelman) 30-31 (Ann McCartney) 32 (Tracy Sabetta) 53 (Pattrice Tomcik)

Comment 2: West Virginia Rivers would like to suggest a few recommendations including more comprehensively incorporating measurement data…

…

The EPA can and should further strengthen reporting requirements in the final rule by more comprehensively incorporating measurement data …

…

Please consider incorporating measurement data from aerial observations that provide a full picture of total emissions in a region.

…

Still as others have already mentioned, there are some ways to strengthen this rule, both more comprehensively or incorporating measurement data including from larger aerial observations…

…

EPA should strengthen reporting requirements in the final rule by comprehensively incorporating measurement data including from aerial observations…

…

I strongly encourage you to strengthen the reporting requirements by more comprehensively incorporating measurement data, including data from aerial observations …

…

While we are generally supportive of the proposed changes, we do believe that EPA should strengthen reporting requirements in the final rule by more comprehensibly incorporating measurement data …

…

We already have the technology and knowledge to get more accurate data and I would like to recommend the EPA further strengthen reporting requirements in the final rule by more comprehensively incorporating measurement data, including from aerial observations …

Response 2: The EPA acknowledges the commenter's support for incorporating more measurement data. See Section II.B of the preamble to the final rule for EPA's discussion of the use of aerial observations and other advanced measurement approaches.

Commenter: Chesapeake Energy Corporation
Comment Number: EPA-HQ-OAR-2023-0234-0400
Page(s): 3-4

Comment 3: EPA should consistently define a range of acceptable emissions measurement options to strike an appropriate balance between accuracy and compliance cost.

EPA's broad authority to require reporting must be appropriately informed by considerations of cost-effectiveness, so that any final rule strikes the appropriate balance between increasing the amount and accuracy of reported emissions while ensuring that compliance costs are not unduly burdensome for operators. Chesapeake strongly encourages EPA to consider cost-effectiveness and finalize a rule that provides appropriate flexibility for operators in measuring emissions across a broad range of emissions sources.

Section 114 of the Clean Air Act provides EPA with broad general authority to require GHG emissions reporting for stationary sources,[1] but EPA has recognized that this authority is tempered by the need for economy-wide emissions reporting to balance "impacts on small entities, consistency with other programs, costs incurred by the reporting entities, and emissions coverage."[2] This balancing act likewise is reflected in recently promulgated provisions of the Inflation Reduction Act providing incentives to encourage industry to invest in innovating emissions monitoring and reduction measures, as well as directing EPA to provide options for operators to base emissions reporting on empirical data.[3]

For this reason, EPA's original Subpart W rulemaking "carefully weighed the burden of incrementally more comprehensive methods of measuring and calculating emissions against the increase in coverage and accuracy."[4] EPA also specifically analyzed the cost-effectiveness of these reporting requirements, and in some cases revised measurement and calculation requirements based on unreasonable cost-effectiveness metrics.[5] For example, EPA determined that for compressors in onshore petroleum and natural gas production, "use of emission factors for calculating GHG emissions from centrifugal and reciprocating compressors… rather than conducting an annual measurement of each compressor in the mode in which it is found" would avoid unreasonable compliance burdens.[6]

EPA should make changes to the Proposed Rule to strike this same balance. Congress' directive in Section 136(h) to allow facilities to use empirical data does not alter the purpose and intent of

EPA's Section 114 authorities. Instead, this provision recognizes that empirical data, where available, may streamline reporting while improving accuracy, without significant increases in compliance costs. EPA recognizes as much in certain aspects of its Proposed Rule, allowing facilities to incorporate empirical data, rather than mandating that they do so.[7] However, the Proposed Rule does not consistently permit this flexibility, instead mandating onerous, measurement-based reporting obligations that will require operators to incur outsized compliance costs with few corresponding reporting benefits.[8] Such a rigid approach is neither required by nor consistent with Section 136(h).

In addition, the Proposed Rule does not account for cost-effectiveness more generally. EPA's Regulatory Impact Analysis considers industry-level compliance costs but fails to similarly consider or compare associated increases in coverage and accuracy based on specific regulatory updates. These cost-effectiveness metrics vary substantially not only by industry, but by the specific source being estimated, because costs are highly influenced by the level of flexibility permitted. For this reason, the generic industry-level analysis currently provided does not adequately capture and convey the impacts of the rulemaking.

By defining a range of acceptable emissions reporting options, EPA can still increase the accuracy of reported emissions while striking a better balance with compliance costs. EPA's broad authority under Clean Air Act Section 114 provides EPA with the flexibility to permit several methods to record emissions, all within an acceptable range of accuracy, in recognition of the unique challenges and circumstances that operators may face.

Footnotes:

[1] 42 U.S.C. § 7414.

[2] See, e.g., Mandatory Reporting of Greenhouse Gases, 74 Fed. Reg. 56,260, 56,364 (Oct. 30, 2009).

[3] Inflation Reduction Act of 2022 § 60113, P.L. 117-169 (codified at 42 U.S.C. § 7436(h)).

[4] Mandatory Reporting of Greenhouse Gases: Petroleum and Natural Gas Systems, 75 Fed. Reg. 74,458, 74,477 (Nov. 30, 2010).

[5] See id.

[6] Id. at 74,468.

[7] See, e.g., 88 Fed. Reg. 50,282, 50,310 (Aug. 1, 2023) (expanding available options for emissions reporting for pneumatic devices and pumps).

[8] See infa Comment E.

Response 3: As discussed in the response to Comment 1 of this section and in the preamble to the final rule, EPA is providing additional measurement-based methodologies and increased flexibility in methodologies available to reporters in the final subpart W rule. Furthermore, as discussed in Section I.F of the preamble to the final rule, the EPA has also identified areas where additional revisions to part 98 will better align subpart W requirements with recently promulgated requirements in 40 CFR part 60 and part 62, allow facilities to use a consistent method to demonstrate compliance with multiple EPA programs (and thereby limit burden), and improve the emission calculations reported under subpart W. The EPA disagrees that our impacts analysis is deficient, and as explained in the preamble, is also undertaking this rulemaking consistent with the directives in CAA section 136(h), which additionally include that the emissions reported must be based on empirical data and reflect accurate total emissions from each facility. We also disagree that the EPA is required to undertake a specific cost-effectiveness approach. As discussed in Section VI.A of the preamble to the final rule, the anticipated costs are reasonable and support the final rule. Additionally, the EPA has updated the impacts analysis for the final rule, as discussed in Section 25 of this document and Section VI.A of the preamble to the final rule.

Commenter: Colorado Department of Public Health and Environment (CDPHE)
Comment Number: EPA-HQ-OAR-2023-0234-0373
Page(s): 2

Comment 4: CDPHE considers inclusion of source or facility level emission monitoring critical to long-term emission accuracy, but basin-wide monitoring is a necessary and near-term achievable effort.

Under Colorado's program, production segment operators are required to create a measurement-informed inventory of their methane emissions, whether by an operator-specific program or by using a state-developed (via state-directed measurement campaigns) default intensity verification factor. Of these two methods, the first is much more difficult given the current state of technical knowledge.

For EPA's purposes, it may be useful to focus on the second option - basin-wide development of factors which represent the amount of un- or under-reported emissions, applied to the total company reported methane emissions. Nationwide development of basin correction factors would improve operator understanding of their emissions contributions as well as what is possible based on varying basin conditions. CDPHE is developing a methodology with academic partners using private, nonprofit, and public sources of methane emission data that will allow us to develop basin-wide default factors.

Response 4: We acknowledge the commenter's suggestion of development of basin-wide factors. The EPA did not propose and is not finalizing the development of basin-wide factors, and at this time we believe further research and analysis are necessary to better understand and assess the validity of such an approach for subpart W purposes.

24.2 Incorporation of Top-Down Data for Specific Emission Sources or Events Such As Other Large Release Events

Commenter: Carbon Mapper and RMI
Comment Number: EPA-HQ-OAR-2023-0234-0301
Page(s): 5-7

Comment 1: Implementation considerations for effective operator and third-party reporting and validation

To support the integration of top-down observational data in the "other large release events" category and for validation more broadly, we make several recommendations below related to necessary funding, staffing, and technical support to ensure this program realizes its full potential.

…

EPA should develop a robust and consistent framework to support decision-making regarding responses to "other large release event" observations. As the "other large release event" category is a new emissions reporting category, EPA should develop clear and thorough guidelines to support implementation. Additionally, EPA should coordinate these efforts with other agencies, such as the Pipeline and Hazardous Materials Safety Administration, PHMSA) in the Department of Transportation. EPA can also rely on progress made by major existing initiatives such as OGMP 2.0, Veritas, MiQ, and the Department of Energy's (DOE) Emissions Measurement, Monitoring, Reporting and Verification (MMRV) framework under development.

…

EPA should build out technical staff capacity to support self-reported and third-party-submitted observational data. We anticipate that the "other large release events" reporting category will significantly increase reporter activity year-round. The e-GGRT "help desk" model is structured to provide basic technical assistance to operators but is ill-equipped to respond to the volume and complexity of "other large release events" that are likely to be observed by planned satellite constellations. A business-as-usual solution is unlikely capable of providing data validation and rapid notification to enable timely detection and mitigation of large emitters. EPA should build out technical staff capacity, including at state air programs and regional offices, to ingest, review, and notify operators of large-emission events.

Response 1: Since the comments do not specifically address the rulemaking itself and instead relate to post-rulemaking implementation, the comments are beyond the scope of this rulemaking. However, the EPA may consider the commenter's suggestions as part of the implementation of these final amendments.

Commenter: David Allen
Comment Number: EPA-HQ-OAR-2023-0234-0243
Page(s): 5

Commenter: Sensirion Connected Solutions
Comment Number: EPA-HQ-OAR-2023-0234-0293
Page(s): 19

Commenter: Project Canary, PBC
Comment Number: EPA-HQ-OAR-2023-0234-0348
Page(s): 15, 17

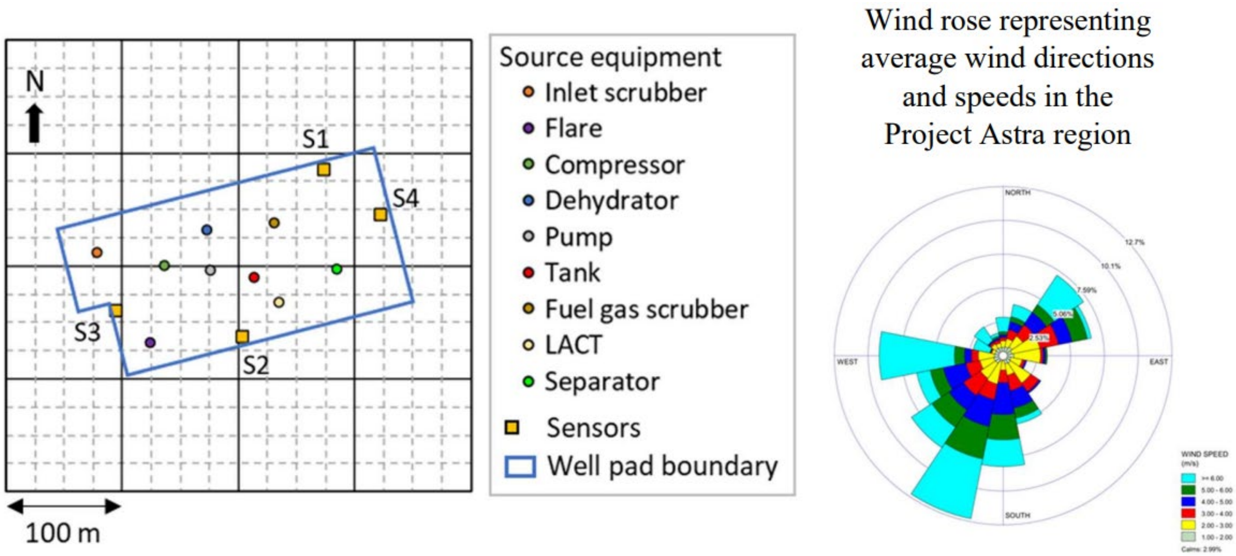
Commenter: Qube Technologies, Inc.
Comment Number: EPA-HQ-OAR-2023-0234-0386
Page(s): 8

Commenter: LongPath Technologies, Inc.
Comment Number: EPA-HQ-OAR-2023-0234-0410
Page(s): 4-5

Commenter: Environmental Defense Fund, et al.
Comment Number: EPA-HQ-OAR-2023-0234-0413
Page(s): 15

Comment 2: Commenter 0243: **Detecting and Estimating the Duration of Large Release Events**

While monitoring systems such as Project Astra operate continuously, their efficiency in detecting emissions will depend on meteorological conditions, sensor detection limits, the number of sensors deployed, and sensor placement strategies. The Project Astra team demonstrated and published an approach for assessing the effectiveness of continuous sensor networks in detecting long and short duration emission events (Chen, et al., 2023a,b). The published case studies examine both a pad with a single idealized source, and a pad with characteristics similar to Project Astra pad sites, with 9 different emission sources at varying heights and locations on the pad. Using meteorological data and dispersion modeling developed from Project Astra data, the emission detection performance of various sensor deployments was characterized. For these case studies, long duration emission events were detected within 1 hour to multiple days, depending on the numbers of sensors deployed and how an event detection was defined. In all cases, even in cases with just one continuous sensor deployed per site, the average time required to detect a large emission event (100 kg/hr) averaged less than a day (Chen, et al., 2023a,b). Dispersion modeling can be used for specific detections of releases to estimate upper bounds on the time to detect those events.



A typical tank battery site configuration with multiple emission source locations and four sensor locations arrayed around the perimeter of the pad was simulated as a case study. On average, a methane release of 100 kg/hr from any of the source locations would be detected in less than a day using a single sensor at the site for the wind conditions represented by the wind rose on the right hand side of the Figure.

Continuous monitoring systems can be used to detect large methane release events, typically with a temporal resolution of a day or less.

Commenter 0293: **EPA should allow submission of data from Agency-approved advanced measurement technologies, including continuous monitoring systems, to establish the duration of Other Large Release Events.**

The Proposed Rule states that EPA expects that “under the proposed methodology for other large release events in this proposal, data from some top-down approaches, including data derived from equipment leak and fugitive emissions monitoring using advanced screening methods which is conducted under NSPS OOOOb or the applicable Federal plan in 40 CFR part 62, in combination with other empirical data, could be used for reporters to calculate the total emissions from these events and/or estimate duration of such an event.”[38]

If EPA finalizes the Other Large Release Event source methodology, such events could account for a large volume of emissions for an applicable facility and therefore have a significant impact on a facility’s exposure to the Methane Waste Emissions Charge. Therefore, it will be especially important for the Agency to fully comply with its section 136 mandate to ensure that the data used to calculate emissions attributable to such an event are both empirical and accurate—rather than based solely on broad estimates.

For these reasons, Project Canary urges the Agency to clarify that owners and operators of applicable facilities are permitted to use EPA-approved advanced measurement technologies—

including continuous monitoring systems—to submit data on both the quantity of emissions and the duration of such events.

Footnote:

[38] Proposed Rule, 88 Fed. Reg. at 50,290.

Commenter 0348: **EPA should allow submission of data from Agency-approved advanced measurement technologies, including continuous monitoring systems, to calculate emissions attributable to and/or establish the duration of Other Large Release Events.**

The Proposed Rule states that EPA expects that "under the proposed methodology for other large release events in this proposal, data from some top-down approaches, including data derived from equipment leak and fugitive emissions monitoring using advanced screening methods which is conducted under NSPS OOOOb or the applicable Federal plan in 40 CFR part 62, in combination with other empirical data, could be used for reporters to calculate the total emissions from these events and/or estimate duration of such an event."[39]

Sources of emissions at oil and gas facilities are often intermittent and of short duration. Multiple studies indicate that actively capturing temporal variability of emissions events is critical to accurately characterizing annual emissions. [40] [41] [42] Periodic measurement campaigns to detect "other large release events" have the potential to result in large errors if shorter duration or intermittent events must be assumed to have been emitting for a duration of 182 days. Error increases as the duration of events become shorter, making temporal frequency of these emissions events very important when calculating annual emissions inventories. [43]

If EPA finalizes the Other Large Release Event source methodology as proposed, such events could account for a large volume of emissions for an applicable facility and therefore have a significant impact on a facility's exposure to the Methane Waste Emissions Charge. Therefore, it will be especially important for the Agency to fully comply with its Section 136 mandate to ensure that the data used to calculate emissions attributable to such an event are both empirical and accurate—rather than based solely on broad estimates.

Finally, the Agency is proposing to require that Subpart W reporters account for large events detected by advanced measurement technologies deployed by third parties participating in the Super Emitter Response Program under the NSPS OOOOb and EG OOOOc proposed rule.[44] It would be arbitrary and capricious for the Agency to allow third parties to use an advanced methane measurement technology to calculate the duration and quantity of an operator's emissions while prohibiting the operator itself from using an advanced methane measurement technology to rebut that determination.

For these reasons, Project Canary urges the Agency to clarify that owners and operators of applicable facilities are permitted to use EPA-approved advanced measurement technologies—including continuous monitoring systems—to submit data on both the duration and quantity of emissions attributable to such events.

…

From the Preamble in Section B. Revisions to Add New Emissions Calculation Methodologies or Improve Existing Emissions Calculation Methodology, EPA asks “In addition to the proposed use of top-down data to help identify and quantify super-emitter and other large emissions events, we invite comment on whether there are other appropriate uses of top-down data for the purposes of reporting under Subpart W of the GHGRP, including what types of emissions sources and emission events, what specific top-down methods may be appropriate, especially in terms of spatial scale and minimum detection limits.”

As stated in Section IV above, EPA should not limit the use of advanced measurement technologies to just the “Other Large Release Events” emission source. Advanced measurement technology quantification has been thoroughly tested and is currently deployed throughout the country in both LDAR programs as well as emissions quantification applications. Continuous monitors, for example, can be used to better define start and end times for events under the Other Large Release Event category. All top-down methods are unique and may be more appropriate for certain types of events and emissions quantification.

Footnotes:

[39] Proposed Rule, 88 Fed. Reg. at 50,290.

[40] Daniels, W., et al., Toward multi-scale measurement-informed methane inventories: reconciling bottom-up site-level inventories with top-down measurements using continuous monitoring systems, Environ. Sci. Technol. 2023, 57, 32, 11823- 111833 (July 28, 2023), htps://doi.org/10.1021/acs.est.3c01121.

[41] Schissel, C.; Allen, D. T. Impact of the High-Emission Event Duration and Sampling Frequency on the Uncertainty in Emission Estimates. Environ. Sci. Technol. Lett. 2022, 9, 1063–1067, DOI: 10.1021/acs.estlet.2c00731

[42] Cusworth, D et al. Intermittency of Large Methane Emitters in the Permian Basin. Env. Sci. Tech. Lett. 2021, 8, 567-573. DOI: 10.1021/acs.estlet.1c00173

[43] Schissel, C.; Allen, D. T. Impact of the High-Emission Event Duration and Sampling Frequency on the Uncertainty in Emission Estimates. Environ. Sci. Technol. Lett. 2022, 9, 1063–1067, DOI: 10.1021/acs.estlet.2c00731

[44] Proposed Rule, 88 Fed. Reg. at 50,290 (“In this proposal, we are proposing to require facilities to consider notifications of potential super-emitter emissions event under the super-emitter provisions of NSPS OOOOb at 40 CFR 60.5371b and calculate associated events when they exceed our proposed thresholds if they are not already accounted for under another source category in subpart W.”)

Commenter 0386: **EPA should allow submission of data from Agency-approved advanced measurement technologies, including continuous monitoring systems, to establish the duration of Other Large Release Events.**

Qube expects that "Other Large Release Event" sources will account for a large volume of emissions for regulated facilities, and therefore such events will have a significant impact on a facility's exposure to the Methane Waste Emissions Charge. It is thus critical for EPA to comply with its section 136 mandate to ensure that data used to calculate emissions attributable to such an event are empirical and accurate, rather than based solely on emission factors or duration estimates.

Qube urges EPA to clarify that operators of applicable facilities are permitted to use EPA-approved advanced measurement technologies, including continuous monitoring systems, to submit data on both the quantity of emissions and the duration of such events.

Commenter 0410: **Continuous Monitoring is a necessary tool for determining emission duration and intermittency**

EPA notes that "studies on large releases from oil and gas facilities commonly report that these emissions are intermittent". The EPA "specifically [proposes] to allow monitoring or measurement surveys to include methods specified in 40 CFR 98.234(a) through (d) as well as advanced screening methods such as monitoring systems mounted on vehicles, drones, helicopters, airplanes or satellites". Continuous monitoring has been shown in the peer reviewed literature as not only capable of measuring total emissions,[8] but also necessary for accurate reconciliation of emission inventories, particularly for start and end times.[9] For that reason, we strongly recommend that continuous monitoring be specifically included as a method for determining start, end, duration, intermittency, and rate of emissions.

EPA suggests on page 50291 that top-down measurements are too episodic to be reliable for accurate emissions estimates at longer time frames. We note that continuous monitoring systems capable of high spatial coverage are not episodic and are, therefore, reliable for accurate emissions estimates at longer time frames.

On Page 50299, EPA states that other large release event "emissions are generally intermittent, with widely varying durations. Releases from maintenance activities, for example, may occur for a few hours, but these large, short events can significantly contribute to a facility's emissions." EPA uses an example of a short-duration (but not necessarily intermittent) event. In fact, the intermittency, or "on-off-on-off" nature of emissions, has been widely observed. In one study of 1100 individual leaks, 89% of emissions were only "on" for less than 50% of the total duration of the malfunction. It is therefore not reasonable to expect short-duration surveys to be capable of accurately identifying the presence or nature of intermittent emissions for the purposes of determining start, end, or duration of other large release events.

Daniels et al.'s study of advanced technologies for accurate inventorying of large release events demonstrates that aerial survey programs, such as EPA proposes for use in establishing duration, are not capable of providing accurate intermittency or duration information about other large release events.[10] We recommend that EPA specifically identify continuous monitoring systems with accurate quantification, and in particular those with high spatial coverage (see Appendix A), as the gold-standard for identifying start time, intermittency, overall duration and rate of other large release events.

Footnotes:

[6] Howard. University of Texas study underestimates national methane emissions at natural gas production sites due to instrument sensor failure, Energy Science & Engineering, 3, 443-455. https://doi.orq/10.1002/ese3.81

[7] Howard, Ferrara and Townsend-Small, Sensor transition failure in the high flow sampler: implications for m ethane emission inventories of natural gas infrastructure, JAWMA, 65, 2015. https://doi.org/10.1080/10962247.2015.1025925

[8] Alden, Wright, Coburn, et al., Temporal variability of emissions revealed by continuous, long-term monitoring of an underground natural gas storage facility, Environ. Sci. Technol., 54, 14589-14597, 2020. https:/ / dx.doi.orq /10.1 0 21 / acs.est.0c03175

[9] Daniels, Wang, Ravikumar, et al., Toward multiscale measurement-informed methane inventories: reconciling bottom-up site-level inventories with top-down measurements using continuous monitoring systems, Environ. Sci. Technol., 57, 11823-11833, 2023. https://doi.org/10.1021/acs.est.3c01121

[10] Daniels, Wang, Ravikumar, et al., Toward multiscale measurement-informed methane inventories: reconciling bottom-up site-level inventories with top-down measurements using continuous monitoring systems, Environ. Sc i. Technol., 57, 11823-11833, 2023. https://doi.orq/10.1021/acs.est.3c01121

Commenter 0413: What are the best methods to estimate duration of events measured using top-down measurements and extrapolation to annual emissions?

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.

Footnote:

[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.

Response 2: Under the final rule, reporters have the flexibility to use various advanced technologies, including continuous monitoring systems, aerial surveys, etc., for potentially aiding in the detection of large release events provided these technologies are able to identify emission rates of 100 kg/hr with a 90 percent probability of detection as demonstrated by a controlled release test. Additionally, reporters are permitted, and may opt for more frequent surveys as this approach could be used to assign a start date more easily and potentially shorten the duration of these events. See Section III.B of the preamble to the final rule for further discussion and response to comments on establishing the duration of Other Large Release Events and the EPA's responses in Section 23.3 of this document regarding the use of continuous monitoring.

24.3 Incorporation of Top-Down Data vs. Bottom-Up Reports

Commenter: Physicians for Social Responsibility Pennsylvania (PSR)
Comment Number: EPA-HQ-OAR-2023-0234-0192
Page(s): 2

Commenter: Public Hearing Transcript
Comment Number: EPA-HQ-OAR-2023-0234-0224
Page(s): 9-10 (Edwin LeMair), 15-16 (Jessica Moerman), 28 (Rebecca Edwards), 31 (Ann McCartney), 33 (Margeret Bell), 34 (Dr. Dakota Raynes), 37 (Sarah Bradley), 38 (Liz Scott)**,** 42 (Glenn Wikle), 44 (Shanna Edberg), 48 (Lisa Finley-DeVille)

Commenter: Physicians for Social Responsibility Pennsylvania (PSR)
Comment Number: EPA-HQ-OAR-2023-0234-0226
Page(s): 2

Commenter: Ceres, Inc.
Comment Number: EPA-HQ-OAR-2023-0234-0236
Page(s): 2

Commenter: National Tribal Air Association (NTAA)
Comment Number: EPA-HQ-OAR-2023-0234-0239
Page(s): 3, 4

Commenter: Interfaith Center on Corporate Responsibility (ICCR)
Comment Number: EPA-HQ-OAR-2023-0234-0242
Page(s): 3

Commenter: Sensirion Connected Solutions
Comment Number: EPA-HQ-OAR-2023-0234-0293
Page(s): 21-22

Commenter: California State Teachers' Retirement System CalSTRS
Comment Number: EPA-HQ-OAR-2023-0234-0347
Page(s): 2

Commenter: Evangelical Environmental Network (EEN)
Comment Number: EPA-HQ-OAR-2023-0234-0371
Page(s): 2

Commenter: Miller/Howard Investments, Inc.
Comment Number: EPA-HQ-OAR-2023-0234-0380
Page(s): 2

Commenter: Kirk Frost
Comment Number: EPA-HQ-OAR-2023-0234-0389
Page(s): 3

Commenter: Environmental Defense Fund, et al.
Comment Number: EPA-HQ-OAR-2023-0234-0413
Page(s): 14

Comment 1: Commenter 0192: Still, there is more work to be done to ensure that the strongest possible emission safeguards are finalized by EPA to protect public health, including:

1. EPA should integrate top-down data to give a clear picture of the overall accuracy of reported emissions.

Commenter 0224: However, there are many ways that the rule can and must be strengthened to eliminate these deadly dangerous and wasteful "known unknowns." Specifically, EPA should integrate top-down basin-level measurement data which provides a full picture of total emissions in a region or basin, strengthening the overall accuracy of reported emissions. Studies based on observed measured emissions at the regional level show that current emission inventories are underestimating methane pollution.

…

The technology and innovations required for robust and full methane monitoring is available and at hand. I urge the EPA to help the industry be better stewards of our precious natural resources and the good neighbors to nearby communities and the world by incorporating these improvements in monitoring.

…

To improve the accuracy of methane reporting under Subpart W, we support the following proposed changes: EPA should integrate top-down basin-level measurement data which provides a full picture of total emissions in a region or basin, strengthening the overall accuracy of reported emissions.

…

I particularly want to emphasize the importance of using the top-down measurement data, as current emission inventories are underestimating methane pollution to our detriment. EPA should integrate top-down basin-level measurement data which will provide a full picture of emissions in a region or basin, which will strengthen the overall accuracy of reported emissions. This is critical for our state, and the Permian basin region, as well as our Four Corners area, to get our arms around the health risk posed by the current and possibly increasing levels of oil and gas production here in New Mexico.

…

I would also recommend the EPA use top-down measurement approaches and data; studies based on observed, measured emissions at the regional level show that current emissions inventories are underestimating methane pollution. EPA should integrate top-down basin level measurement data which provide a full picture of total emissions in a region or basin, strengthening the overall accuracy of reported emissions.

…

Research has demonstrated, as many have already noted, that current emissions inventories vastly underestimate methane pollution. Therefore, the EPA should integrate both top-down and bottom-up basin-level direct measurement data to provide a complete picture of the total emissions in a region or a basin.

…

The EPA must strengthen its rules, reporting requirements in order to improve accuracy and hold polluters accountable for harming people and the planet. More specifically, reporting needs to be more comprehensive by incorporating top-down and bottom-up direct measurement data and aerial observations.

…

Current methods are underestimating the levels of methane pollution. We encourage EPA to integrate top-down basin-level measurement data to get a better picture of total regional level emissions. This will help ensure that communities located closest to facilities are not suffering from escaped emissions, since we know that methane is not the only thing that leaks from oil and gas facilities.

…

… integrate top-down basin level data to provide the full picture of total emissions in a region or basin.

…

With that said, there are more improvements to be made to cover gaps in our measurements of oil and gas emissions. Studies show the current emissions inventories are really underestimating methane pollution, which must be corrected now for us to have any hope of reducing those emissions. So for example, EPA should integrate top-down basin-level measurement data to provide a full picture of emissions in a region, and strengthen the accuracy of reported emissions.

…

EPA should strengthen reporting and requirements in the final rule and should integrate top-down basin-level measurement data, which provides a full picture of reported emissions.

…

[W]e urge EPA to further strengthen reporting requirements in the final rule by more comprehensively incorporating measurement data, including from aerial observations …

…

Specifically, we hope to see EPA integrate top-down basin-level data into the reporting program. This data can provide a full picture of total emissions in a region or basin, allowing for comparison of reported emissions to ensure accuracy with basin-level totals.

Commenter 0226: Still, there is more work to be done to ensure that the strongest possible emission safeguards are finalized by EPA to protect public health, including:

1. EPA should integrate top-down data to give a clear picture of the overall accuracy of reported emissions.

Commenter 0236: To address the problem of underreported emissions and ensure that MERP's waste charge is assessed on the true volume of pollution created by the oil and gas industry, we urge the agency to improve the proposal by:

- Integrating top-down, basin-level data alongside site- and equipment-level measurement data. Top-down, basin-level data provide a full picture of total emissions in a region, while site-level, population-based measurement data can provide insights of emissions at a finer resolution, all of which strengthen the accuracy of reported emissions.

Commenter 0239: The EPA should build on its already strong proposal by:

…

3. Comparing, as part of the EPA's emissions verification procedure, inventories of site-level emissions data to scientifically robust top-down approaches, like satellite, aerial, and continuous monitoring for gathering emissions data at the regional or sub-basin scale. This comparison will allow the EPA to verify the completeness of the aggregated site-level data. Currently, the EPA proposes to use top-down approaches for large emissions events, but not for other purposes. As the accuracy and completeness of top-down approaches improves, the EPA should continue to explore ways to verify site-specific data to ensure important air emissions data from the petroleum and natural gas systems are completely and accurately recorded.

Commenter 0242: To address the well-known problem of underreported emissions and ensure that MERP's waste charge is assessed on the true volume of pollution created by the oil and gas industry, we urge the agency to improve the proposal by:

- Integrating top-down, basin-level data alongside site- and equipment-level measurement data. Top-down, basin-level data provides a full picture of total emissions in a region, while site-level, population-based measurement data can provide insights of emissions at a finer resolution, all of which strengthen the accuracy of reported emissions.

Commenter 293: As stated in Section II above, EPA should not limit the use of advanced measurement technologies to just the "Other Large Release Events" emission source. Advanced measurement technology quantification has been thoroughly tested and is currently deployed throughout the country in both leak detection and repair programs as well as emissions quantification applications. Continuous monitors, for example, can be used to better define start and end times for events under the Other Large Release Event category. All top-down methods are unique and may be more appropriate for certain types of events and emissions quantification.

Commenter 0347: To further address the well-known problem of underreported emissions and ensure that MERP's waste charge is assessed on the true volume of methane emissions, we urge the EPA to improve the proposal by:

- Integrating top-down, basin-level data alongside site and equipment-level measurement data. Top-down basin-level data provides a picture of total emissions in a region, while site-level measurement data can provide insights about emissions at a finer resolution, all of which strengthen the accuracy of reported emissions.

Commenter 0371: However, there are many ways that rule can and must be strengthened to eliminate these deadly, dangerous, and wasteful "known unknowns". Specifically,

- EPA should integrate top-down, basin-level measurement data which provides a full picture of total emissions in a region or basin, strengthening the overall accuracy of reported emissions. Studies based on observed, measured emissions at the regional level show that current emissions inventories are underestimating methane pollution.

Commenter 0380: To address the well-known problem of underreported emissions and ensure that MERP's waste charge is assessed on the true volume of pollution created by the oil and gas industry, we urge the agency to improve the proposal by:

--Integrating top-down, basin-level data alongside site- and equipment-level measurement data. Top-down, basin-level data provides a full picture of total emissions in a region, while site-level, population-based measurement data can provide insights of emissions at a finer resolution, all of which strengthen the accuracy of reported emissions.

Commenter 0389: EPA asks for comments and input regarding top down, bottom up approaches for emissions quantification. It is all of the above, and using the built in technologies and monitors that each facility and central monitoring headquarter locations have for each of the owners/operators.

Commenter 0413: 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.

Response 1: We acknowledge the commenters' suggestion for integrating top-down measurements with site- and equipment-level data. Comparisons of top-down and bottom-up estimates have shown persistent differences between results from aerial/satellite and official bottom-up inventories.[15, 16, 17] The various sensors within each technology and their individual algorithms used to interpret raw concentration data play an important part in the quantification of emissions. The performance of these technologies is not only affected by the various sensor capabilities but also factors such as environmental conditions.[18] These differences can lead to different quantification of emissions between different technologies. A better understanding of these discrepancies is needed to improve confidence and the adoption of top-down methodologies. The EPA is actively reviewing relevant peer-reviewed literature and pilot programs regarding advanced measurement technologies. In advance of future rulemakings, the EPA intends to initiate a request for information, workshop, or white paper to further solicit feedback on the use of advanced measurement data and methods in subpart W. See Section II.B of the preamble to the final rule for further discussion of combining top-down and bottom-up

[15] Shen, L. et al. Satellite quantification of oil and natural gas methane emissions in the US and Canada including contributions from individual basins. Atmos. Chem. Phys. 22, 11203–11215 (2022).
[16] Alvarez, R. A. et al. Assessment of methane emissions from the U.S. oil and gas supply chain. Science (80-.). 361, 186–188 (2018).
[17] Schneising, O. et al. Remote sensing of methane leakage from natural gas and petroleum systems revisited. Atmos. Chem. Phys. 20, 9169–9182 (2020).
[18] Ravikumar, AP, et al. 2019. Single-blind inter-comparison of methane detection technologies – results from the Stanford/EDF Mobile Monitoring Challenge. Elem Sci Anth, 7: 37. DOI: https://doi.org/10.1525/elementa.373

methods and the EPA's responses in Section 23.3 of this document regarding the use of continuous monitoring.

Commenter: Sensirion Connected Solutions
Comment Number: EPA-HQ-OAR-2023-0234-0293
Page(s): 2-3, 21-22

Commenter: Project Canary, PBC
Comment Number: EPA-HQ-OAR-2023-0234-0348
Page(s): 17

Commenter: Endeavor Energy Resources, L.P.
Comment Number: EPA-HQ-OAR-2023-0234-0381
Page(s): 13

Comment 2: Commenter 0293: The EPA proposes to preclude the use of all "top-down" methods for methane quantification—except for the purposes of "Other Large Release Events". The analysis EPA relies on for this conclusion is incomplete because, among other things, it characterizes all top-down methods as providing only periodic surveying. The Agency failed to fully analyze whether there are advanced methane measurement technologies that could meet its criteria for quantification accuracy such as continuous emissions monitoring. For calculations that require use of emission factors, an owner or operator of an applicable facility would have no means of demonstrating that its actual facility emissions are lower than a calculation using emission factors. As a result, it could be liable for a Methane Waste Emissions Charge that does not reflect its actual emissions.

This approach frustrates the Congressional intent to ensure accuracy and fairness in imposition of the charge. It also is inconsistent with Congressional intent to ensure that the Methane Waste Emissions Charge creates an incentive to reduce methane emissions because investment in mitigation could be obscured by the blunt, broad-based application of emission factors.

…

From the Preamble in Section B. Revisions to Add New Emissions Calculation Methodologies or Improve Existing Emissions Calculation Methodology, EPA asks "In addition to the proposed use of top-down data to help identify and quantify super-emitter and other large emissions events, we invite comment on whether there are other appropriate uses of top-down data for the purposes of reporting under Subpart W of the GHGRP, including what types of emissions sources and emission events, what specific top-down methods may be appropriate, especially in terms of spatial scale and minimum detection limits."

…

By allowing all sources of emissions to be informed by measurement-based and quantified emissions values, EPA will incentivize the investment in and adoption of advanced emissions detection technologies. In addition to these technologies providing the basis for a more accurate and robust GHG emissions inventory, they will also help to drive down emissions. An accurate GHG emissions inventory will result in more precise payments to the Treasury with respect to the methane fee.

Commenter 0348: **From the Preamble in Section B. Revisions to Add New Emissions Calculation Methodologies or Improve Existing Emissions Calculation Methodology, EPA asks "In addition to the proposed use of top-down data to help identify and quantify super-emitter and other large emissions events, we invite comment on whether there are other appropriate uses of top-down data for the purposes of reporting under Subpart W of the GHGRP, including what types of emissions sources and emission events, what specific top-down methods may be appropriate, especially in terms of spatial scale and minimum detection limits."**

…

By allowing all sources of emissions to be informed by measurement-based and quantified emissions values, EPA will incentivize the investment in and adoption of advanced emissions detection technologies. In addition to these technologies providing the basis for a more accurate and robust GHG emissions inventory, they will also help to drive down emissions and will result in more precise payments to the Treasury with respect to the Methane Waste Emissions Charge.

Commenter 0381: **EPA Should Reconsider the Proposed Revisions to Calculation Methods for Several Emission Sources.**

As noted elsewhere, Endeavor opposes EPA's efforts to add increased granularity and site-specific requirements to emissions data collection; at best, it will result in unnecessary additional burdens to report the same data that EPA is already receiving, and at worse it will introduce more inaccuracies into the reporting of emissions, undermining Congress's directive in the IRA that EPA ensure more accurate data collection under Subpart W. We nevertheless appreciate EPA's recognition that for such site-specific requirements—to the extent they are retained in any final rule—direct measurement may not be feasible or cost-effective in all circumstances or for all emission sources. Endeavor thus supports EPA's integration of parametric monitoring, site-specific emissions factors, and advanced "top-down" monitoring systems (e.g., satellites, aerial flyovers).

Response 2: We acknowledge these comments but note that the WEC is being addressed through a separate rulemaking process. The implementation of WEC is discussed in the Notice of Proposed Rulemaking for the Waste Emissions Charge for Petroleum and Natural Gas Systems published on January 26, 2024 (89 FR 5318), and comments related to how payments to the Treasury will be evaluated are outside the scope of this subpart W rulemaking. For details on the utilization of advanced measurement technologies (including remote sensing and continuous monitoring), please refer to Section II.B of the preamble to the final rule. EPA's responses to the use of continuous monitoring systems are available in Section 23.3 of this document. Discussion of expanded calculation methodologies in the final Subpart W rule can be found in the response to comment 1 in Section 24.1 of this document.

Commenter: Carbon Mapper and RMI
Comment Number: EPA-HQ-OAR-2023-0234-0301
Page(s): 4-5

Commenter: Project Canary, PBC
Comment Number: EPA-HQ-OAR-2023-0234-0348
Page(s): 18

Commenter: Endeavor Energy Resources, L.P.
Comment Number: EPA-HQ-OAR-2023-0234-0381
Page(s): 13

Commenter: MiQ
Comment Number: EPA-HQ-OAR-2023-0234-0392
Page(s): 9

Commenter: Bridger Photonics, Inc.
Comment Number: EPA-HQ-OAR-2023-0234-0407
Page(s): 4

Commenter: Environmental Defense Fund, et al.
Comment Number: EPA-HQ-OAR-2023-0234-0413
Page(s): 6-7

Commenter: Environmental Defense Fund, et al.
Comment Number: EPA-HQ-OAR-2023-0234-0413
Page(s): 9-10

Commenter: Environmental Defense Fund, et al.
Comment Number: EPA-HQ-OAR-2023-0234-0413
Page(s): 15-16

Comment 3: <u>Commenter 0301</u>: EPA should further integrate top-down measurements at the basin-, site and equipment-level to validate and improve the accuracy of reported emissions

Several research studies have shown that bottom-up inventories consistently report lower emissions compared with top-down assessments (Alvarez et al. 2016[2]; Shen et al. 2022[3]). While EPA is taking steps to improve the accuracy of bottom-up reporting, with updated emission factors, expanded use of empirical data, and the new "other large release event" category, we strongly recommend EPA further integrate top-down (aerial and satellite) observations to more accurately reflect total methane emissions from applicable facilities.

An integrated approach to reconciling operator-reported emissions with top-down observations is much more likely to meet IRA goals of accuracy and completeness, by providing the information needed to effectively track emissions reductions and administer fair Waste Emission Charge fees, based on actual emissions. Discrepancies in annual emissions reported to EPA and those quantified using observational data can help inform EPA of critical inventory gap-filling needs or misreporting.

Methane measurement by advanced technologies can help improve and validate GHGRP reporting at the basin- and site-level.

- Basin-level observations, such as those made by area flux mappers (e.g., TROPOMI, MethaneSAT), provide a full picture of methane emissions in a region. EPA should use basin-level data to check if the parts (i.e., bottom-up, operator-reported emissions) sum up to the whole. We recommend EPA create a framework to ingest credible, basin-level observations to evaluate the extent of unreported or underreported emissions and inform potential revisions to Subpart W. Basin-level data will help EPA ensure it is meeting the MERP requirements to accurately reflect total methane emissions from applicable facilities.
- Site-level and equipment-level measurement data, such as the high-resolution observations that Carbon Mapper and other emerging advanced technologies provide, can be used to supplement operator-reported emissions. Frequent, high spatial resolution observations will provide valuable empirical data for the "other large release event" category and inform site-specific leaker factors, as EPA has proposed. In addition, we recommend that EPA support the collection of sufficient top-down data at the site- and equipment-level to help reconcile the basin-level estimates, described above, with those of individual sites or companies through the use of probabilistic emission models. Site-specific data can help appropriately attribute the unreported or underreported inventory emissions identified in basin-scale observations to Subpart W reporters. Operators demonstrating lower emissions through sufficient site-specific measured data would be rewarded with fewer attributed emissions and associated fees during basin-level reconciliation. Such a process will allow EPA to take appropriate follow-up action, such as seeking additional information from an operator about specific events that may be driving discrepancies (e.g., operations, noncompliance, gathering lines, excluded source categories), revising annual operator-reported emissions, and improving the accuracy of inventories over time.

Colorado’s Methane Intensity Verification Rule provides an example for how basin-level and site-level top-down data can be integrated to improve inventory accuracy. Under the rule, the Colorado Department of Public Health and Environment’s Air Pollution Control Division establishes a state-derived default intensity verification factor to better account for underreported or unreported emissions. Alternatively, the Colorado rule allows operators to use an operator-specific measurement program to demonstrate better than default performance through monitoring efforts, with specified reporting and auditing requirements. Colorado’s framework rewards operators who take action to more accurately quantify their methane emissions and reduce those emissions over time. We recommend that EPA study Colorado's precedent as it provides a mechanism to improve accounting accuracy over time in a way that static emissions factor calculations do not.

Footnotes:

[2] Alvarez, R. A., et al. (2016). Assessment of methane emissions from the US oil and gas supply chain. Science, 361(6398), 186–188. https://doi.org/10.1126/science.aar7204

[3] Shen, L., et al. (2022) Satellite quantification of oil and natural gas methane emissions in the US and Canada including contributions from individual basins. Atmos. Chem. Phys., 22, 11203–11215, https://doi.org/10.5194/acp-22-11203-2022.

Commenter 0348: **Responses to EPA's Specific Solicitation of Comments**

From the Preamble in Section B. Revisions to Add New Emissions Calculation Methodologies or Improve Existing Emissions Calculation Methodology, EPA asks, "We invite comment on how to best combine top-down data with bottom-up methods in a way that avoids double counting of emissions. For example, top-down data may be used to refine emission estimates for particular sources or for the facility. We also seek comment on the best methods to estimate duration of events measured using top-down measurements and extrapolation to annual emissions. We also invite comment on the associated modeling necessary to incorporate top-down data and the associated uncertainties for calculating facility-level emissions. We also request comment on how to account for the types of limitations described in this section

Multi-scale measurements, including the use of continuous monitoring systems, are important for creating accurate measurement-informed emissions inventories. A recent 11-month, peer reviewed, methane measurement study used continuous monitoring systems to validate snapshot measurements from aerial technologies to determine how they relate to the temporal emission profile of given sites and to create a measurement-informed site-level inventory that can be validated with aerial measurements to update calculated conventional inventories. This study demonstrates that multi-scale advanced measurement technologies can be used to accurately reconcile emissions in a way that results in an accurate annual emissions inventory without double counting emissions. Reconciliation protocols, such as OGMP2.0 and GTI Veritas, can serve as models for EPA to develop a specific Subpart W protocol for reconciliation of bottoms-up and top-down inventories. Colorado is also evaluating these models.

Commenter 0381: **EPA Should Reconsider the Proposed Revisions to Calculation Methods for Several Emission Sources.**

Endeavor supports the flexibility for expanded use of direct measurement to calculate emissions, where feasible, in lieu of less accurate general emission factors or similar calculation methods because we believe a shift towards the option for greater direct measurement is in keeping with the IRA's mandate for accurate and empirical calculations and reporting. In many instances, top-down, such as aerial flyovers, and similar systems can produce more consistently accurate results both identifying and quantifying emissions from facilities, as compared to emission factors, especially default factors. For the Onshore Petroleum and Natural Gas Production segment in particular, direct measurement is not always feasible due to the remote location of many facilities and the limited availability of trained technicians who can perform direct measurements with the available technologies. Endeavor thus recommends that any final rulemaking more explicitly reference top-down systems, like aerial flyovers, as permissible means for emissions quantification under Subpart W.

Commenter 0392: **Preamble II.B: We invite comment on how best to combine top-down data with bottom-up methods in a way that avoids double counting of emissions. For example, top-down data may be used to refine emission estimates for particular sources or for the facility. We also seek comment on the best methods to estimate duration of events measured using top-down measurements and extrapolation to annual emissions. We also invite comment on the associated modeling necessary to incorporate top-down data and the associated uncertainties for calculating facility level emissions.**

MiQ Comments: MiQ requires operators to assess the "additionality" of emissions discovered via usage of advanced technology compared to the operator's existing baseline inventory. The attached resource sheet provides current guidance given by MiQ to operators and MiQ auditors to organize data collected and justifications of the data based on further investigation. For example, if an operator discovers through top-down inspections multiple uncontrolled produced water tanks that are venting, the operator may either

1) assess additionality through causal analysis and quantify the emissions impact of each individual event, or

2) analyze the root causes of the detections to determine if a common root cause exists, and use the results of that analysis to either refine an existing emission source calculation methodology or add a new emission source to the operator's inventory.

EPA's current reporting threshold of 100 kg/hr or 250 MT CO2e for "other large release events" is a large enough threshold to remove most scenarios where a determination of double-counting is difficult to make. We recommend EPA review the GTI Veritas protocol for a discussion on how technology specifications, including MDL and PoD, can impact the risk of double-counting emissions detected top-down data. We recommend that EPA further clarify the follow-up requirements of an operator and allow operators to use relevant process parameters, parametric monitoring and equipment monitoring results to present justifications around the usage of top-down data in emissions inventories.

Commenter 0407: Fund the development of regional measurement-based methane emissions inventories and use findings to strategize and track emissions reductions.

The IRA charged the EPA to "revise the requirements of subpart W to ensure that reporting under subpart W (and corresponding waste emissions charges under CAA section 136) is based on empirical data, [and] accurately reflects the total CH4 emissions (and waste emissions) from the applicable facilities…” [7] However, the proposed revisions will not make subpart W reporting an accurate reflection of methane emissions. For example, the approach for detecting other large release events is unmethodical and will cause operators to report this source category with an unreliable level of accuracy and consistency.

The best way to ensure methane emissions reported under subpart W are accurate is to base reporting on methane emissions inventories that are founded on direct measurements (we advocate for the EPA to follow Colorado’s approach, see Recommendation 1). Developing inventories with equipment-level resolution would further allow the EPA to identify and reconcile discrepancies between the subpart W bottom-up model and the measured magnitude of emissions. Not only does this approach critically enable the nation to determine and eliminate true emissions drivers, but it also provides an avenue to accurately benchmark emissions and track reductions as inventories are updated with new data.

During the last several years, methods to use aerial measurements to generate source-resolved methane emissions inventories became mature. The EPA’s assertion that snapshot technologies are not sensitive enough or suitable for annualized emissions is patently false. [8] To Bridger’s knowledge, a satisfactory explanation of this assertion was not provided in either the preamble or the technical support document. While technologies relying on sunlight (e.g. solar infrared hyperspectral imaging) may lack sufficient detection sensitivity, LiDAR technologies are capable of widespread deployment with detection sensitivities near or below 1 kg/hr. In fact, methane emissions inventories based on LiDAR measurements have already been used benchmark oil and gas emissions in Canadian provinces[9] and Canada is using this work to guide national emissions reduction efforts. The US can retain its leadership in methane action by developing rules that embrace a similar scientific approach to emissions measurement and reduction.

Because emissions profiles change between different oil and gas regions (Figure 2), it is essential to develop separate inventories for different subpart W reporting jurisdictions. Meanwhile, the methods for developing methane emissions inventories at the regional scale can, in many cases, also be used to develop inventories for individual oil and gas operators (i.e., inventories can be developed at the subpart W reporting facility-level). In our 3 rd recommendation, we urge the EPA to allow operators to report methane emissions using approved inventory development methods. By doing so, operators can reliably demonstrate that their operations cause less emissions than the regional expectation. This objective is in line with the IRA.

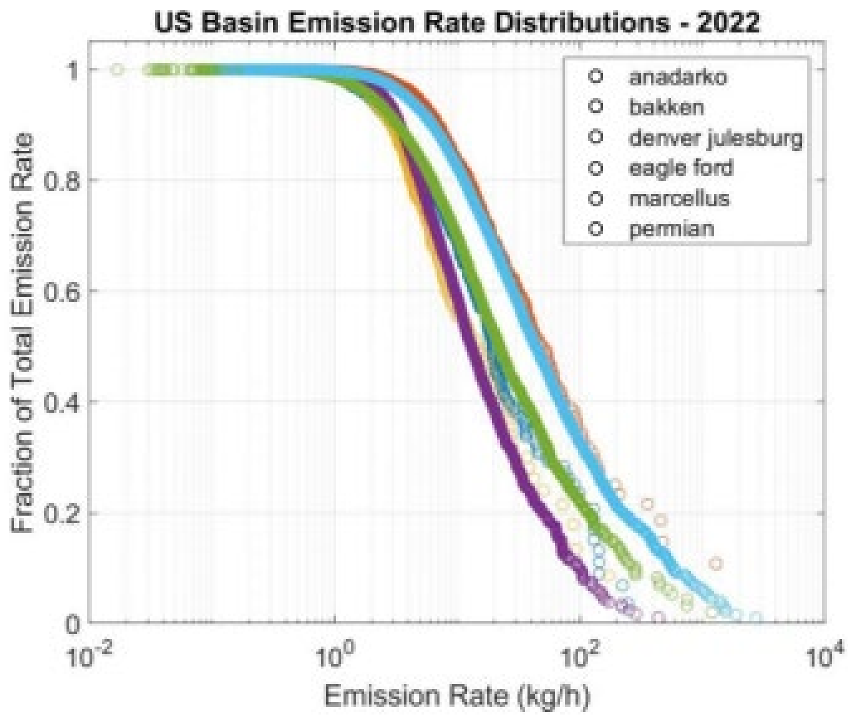


Figure 2. Cumulative emission rate distributions in major US oil and gas production basins measured by Gas Mapping LiDAR™ (colors have been removed from the legend and basins are not listed in any particular order). Note the log scale on the x-axis and that emissions profiles are dramatically different between basins.

The EPA should prioritize ongoing characterization of production basin infrastructure (e.g., production and gathering and boosting infrastructure) considering its sizeable share of total emissions.[10] Sufficient data for developing production basin methane emissions inventories is already available and will become increasingly available. Bridger has collected high-resolution data in every major US production basin. We have already published comprehensive data on Permin Basin emissions rates, [11] and during the next year we will continue to publish research using Gas Mapping LiDAR measurement data. Furthermore, DOE grants to characterize emissions in numerous production basins have begun implementation. [12] More than adequate funding from the IRA Methane Emissions Reduction Program is available for use in developing methane emissions inventories throughout the US and across all segments if this funding is appropriately allocated. Information is becoming increasingly available that demonstrates measured emissions volumes from oil and gas operations differ from bottom-up models and the EPA is responsible for ensuring that subpart W reporting is accurate based on these findings.

We urge the EPA to use regional emissions inventories that are based on widespread aerial measurements to ensure overall methane emissions reporting accuracy (in a similar fashion to Colorado's GHG Emissions Intensity Verification Rule) and as a reconciliation tool for bottom-up calculations. Measurement-based inventories are the best way to ensure accurate emissions reporting and to correctly inform emissions reduction efforts. Yearly inventory updates should be performed to ensure information is up-to-date and relevant.

Footnotes:

[7] 88 FR 50284

[8] 88 FR 50291

[9] "Measurement-Based Methane Inventory for Upstream Oil and Gas Production in Alberta, Canada Reveals Higher Emissions and Starkly Different Sources than Official Estimates". https://doi.org/10.21203/rs.3.rs-2743912/v1, "Creating measurement-based oil and gas sector methane inventories using source-resolved aerial surveys". https://doi.org/10.1038/s43247-023-00769-7

[10] "Assessment of methane emissions from the U.S. oil and gas supply chain". doi: 10.1126/science.aar7204

[11] "Extension of Methane Emission Rate Distribution for Permian Basin Oil and Gas Production Infrastructure by Aerial LiDAR". https://doi.org/10.1021/acs.est.3c00229

[12] Project Selections for FOA 2616: Innovation Methane Measurement, Monitoring and Mitigation Technologies (IM4 Technologies), Area of Interest 3. https://www.energy.gov/fecm/project-selections-foa-2616-innovative-methane-measurement-monitoring-and-mitigation

Commenter 0413: 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/subbasin 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.
- 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.

Footnotes

[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.

Commenter 0413: 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 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.

Footnote:

[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.

Commenter 0413: What associated modeling is necessary to incorporate top-down data and what are the associated uncertainties for calculating facility-level emissions?

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

Footnotes:

[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.

[41] Alvarez et al., supra note 5.

Response 3: Each advanced technology possesses unique limitations and is applicable in specific scenarios. It is imperative to explore how these technologies can complement each other, alongside tailored policies, and operational standards. Variations exist in key performance metrics among different technologies, including the limit of detection and the probability of detection (i.e., false positives/negatives). Additionally, significant differences in deployment methodologies, labor requirements, and levels of leak detection efficacy exist across these technologies.[19] A comprehensive understanding of emission estimates derived from various advanced technologies is crucial for unbiased emission quantification.

Comparisons at basin scale between top-down and bottom-up estimates have consistently revealed differences between the two methods and demonstrated that a direct comparison of emissions estimates between methods covering different timescales can be misleading. A deeper understanding of the discrepancies between top-down and bottom-up approaches is necessary to enhance confidence in comparing emissions inventories using the two methods. We will continue to review available literature, including studies cited by commenters as well as any new research that emerges, and may consider such information for future rulemakings. See Section II.B of the preamble to the final rule for further discussion on the use of top-down methods and other advanced measurement technologies.

[19] Ravikumar, AP, et al. 2019. Single-blind inter-comparison of methane detection technologies – results from the Stanford/EDF Mobile Monitoring Challenge. Elem Sci Anth, 7: 37. DOI: https://doi.org/10.1525/elementa.373

Commenter: Bridger Photonics, Inc.
Comment Number: EPA-HQ-OAR-2023-0234-0407
Page(s): 1, 4

Comment 4: Recommendation 1: Remove incentives to use less-effective emissions monitoring technology.

One way to improve the representativeness of the subpart W bottom-up model would be by developing improved equipment-level emission factors. This avoids the need to rely on a large set of onsite observations to determine if abnormal process conditions exist such as stuck separator dump valves, improperly seated thief hatches, flare pilot flame malfunctions, or additional abnormal process conditions that might otherwise be considered an other large release event.

The Proposed Rule technical support document argues that including large releases within emissions factors would incorrectly skew the emissions factor for normal operations. However, with a sufficient sample size, even the detection of a single, extremely large release does not cause large fluctuation in average emissions values. For example, removing the largest emission rate detected in the set of equipment-level detections in Figure 1 changes the total detected emission rate by only 2% (and this effect could be suppressed by using a functional form of the underlying distribution). In fact, as previously noted, the EPA already proposed to include super emitters in equipment leak population emission factors.

While most abnormal process conditions could be accounted for using appropriate equipment emissions factors, it may be reasonable to require individual reporting of well blowouts and explosions because they are significant events, and they should be easy to identify. Notably, well release incidents are already reportable under certain state rules. A 4,000 metric ton CO_2e reporting threshold for well blowouts and explosions would capture even the smallest well blowout event described in Proposed Rule technical support document.

We urge the EPA to remove the incentive for operators to select less-effective emissions monitoring approaches by making sure source-level emissions accounting methodologies are systematic and without the potential for bias due to the type of monitoring technology that is deployed.

…

The Proposed Rule preamble indicates that significant emissions come from sources not currently accounted for in subpart W and the Proposed Rule works to address this problem by adding the “other large release event” source to reporting. This source is intended to cover a variety of unexpected abnormal process conditions and equipment failures. To determine the presence of other large release events, operators must consider any credible information.[1] Notably, this includes detections from advanced methane sensing technologies whether these technologies are used by operators on a voluntary basis or as part of regulatory compliance under proposed OOOOb/c.

Research has shown that advanced methane sensing technology detects remarkably greater volumes of emissions compared to default emissions screening approaches like OGI or EPA M21.[2] As a result, using high-performance advanced methane sensing technology is likely to increase the identification of other large release events and correspondingly increase the total volume of methane reported by operators. The pending IRA waste methane emissions charge will mean greater fines for greater volumes of emissions reported under subpart W in cases where target methane intensity thresholds are exceeded. [3] Therefore, the proposed other large release event reporting requirement causes the unintended consequence of incentivizing operators to use less-effective emissions monitoring technologies when this reporting requirement is coupled to the waste methane emissions charge.

The fact that operators could find more emissions or fewer emissions depending on their technology deployment while remaining in compliance with subpart W highlights that the Proposed Rule enforces a nonsystematic approach to evaluating other large release event emissions and will result in inaccurate and biased inventory records.

The need to accurately account for emissions that might qualify as other large release events is made clear by looking at their important contribution to total emissions. For example, an extensive equipment-level measured emission rate distribution for Permian Basin production sites (Figure 1) shows that approximately 37% of total emissions above 3 kg/hr measured have a rate over 100 kg/h (2.2% of total detected emissions by number).4,11 Of course, this point of reference only considers the 100 kg/h methane reporting threshold and does not even consider the 250 metric ton CO2e threshold. However, expecting to account for this extensive set of emissions using an ad hoc mixture of technologies and accounting approaches is ill-advised.

Trying to determine if a release is over 250 metric tons CO2e and/or evaluate if it is already accounted for in subpart W is a daunting and impractical task. For example, high emission rate events may already be accounted for in emission factors which are time-averaged values for emission types that might be episodic. Detection of a high emission rate episodic event might lead an operator to believe that this emission is an other large release event, whereas in reality it may be already accounted for by emission factors or engineering calculations. Furthermore, the proposed equipment leak population emission factors from Rutherford et al. include “super emitters”. [5] This raises the question of whether individually reported other large release events do not cause double counting for emissions already accounted for in these population emission factor. This discussion of pitfalls for reporting other large release events is non-exhaustive—we advocate for the EPA to consider an improved approach. The 250 metric tons CO2e threshold is, in general, much more problematic than the 100 kg/h methane threshold on its own because extensive analysis may be required to determine affected emission events.

Footnotes:

[1] 88 FR 50300

[2] “Equipment leak detection and quantification at 67 oil and gas sites in the Western United States”. https://doi.org/10.1525/elementa.368, “Where the Methane Is—Insights from Novel

Airborne LiDAR Measurements Combined with Ground Survey Data". https://doi.org/10.1021/acs.est.1c01572

[3] Inflation Reduction Act Methane Emissions Charge: In Brief. Congressional Research Service. https://crsreports.congress.gov/product/pdf/R/R47206

[4] We note that a large number of these detections may be due emission mechanisms like unlit flares, separator blow through to production tanks, and improperly seated thief hatches. While the proposed rule does have additional provisions to account for these emissions sources, these additional provisions are subject to considerable potential for user error and have not been validated for accuracy. Some detections may also be due to emissions that may be well accounted for such as blowdowns or other maintenance events.

[5] 88 FR 50351

Response 4: See Section III.B.2 for EPA's response to comments regarding potential disincentives for voluntary monitoring and the 250 mt CO_2e threshold. See the EPA's response to Comment 1 in Section 18.1 of this document regarding the commenters' assertion that the default population factors include emissions from super-emitter events.

Commenter: Sensirion Connected Solutions
Comment Number: EPA-HQ-OAR-2023-0234-0293
Page(s): 21-22

Commenter: Environmental Defense Fund, et al.
Comment Number: EPA-HQ-OAR-2023-0234-0413
Page(s): 7-8, 9, 10, 12-13, 14-15

Commenter: Environmental Defense Fund, et al.
Comment Number: EPA-HQ-OAR-2023-0234-0413
Page(s): 8-9, 9, 10, 14-15

Comment 5: Commenter 0293: Multi-scale measurements, including the use of continuous monitoring systems, are important for creating accurate measurement-informed emissions inventories. A recent 11-month methane measurement study used continuous monitoring systems to validate snapshot measurements from aerial technologies to determine how they relate to the temporal emission profile of given sites and create a measurement informed site-level inventory that can be validated with aerial measurements to update calculated conventional inventories. Using multi-scale advanced measurement technologies can be used to accurately reconcile emissions in a way that results in an accurate annual emissions inventory without double counting emissions. Various protocols are available, such as GTI Veritas and OGMP 2.0 that suggest frameworks for emissions reconciliation and building measurement-informed inventories.

Commenter 0413: 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 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.

…

Multi scale 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:

…

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.

…

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

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 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.

> 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?

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]

…

> <u>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 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.

Footnotes:

[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 mega herbivore 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/.

[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.

[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.

[34] Rutherford et al., supra note 20.

[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.

<u>Commenter 0413</u>: 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:

…

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.

…

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 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).

Footnotes

[15] Alvarez et al., supra note 5; Zavala-Araiza et al., supra note 11. <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/industrialmethane-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/methaneemissions-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),>

[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.

[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.

…

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?

…

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.

Response 5: Basin-level emission factors were not proposed, and the EPA is not finalizing any provisions for their development at this time. The temporal behavior of emissions can vary significantly within and among basins due to differences in facility factors (age, gas compositions, operator practices, etc.). aggregate individual emission sources within a facility for reporting to the GHGRP. See the response to Comment 4 in Section 24.1 of this document for additional response regarding basin-wide default factors. For discussion of combing top-down and bottom-up methods see response to Comment #3 of this section and Section II.B of the preamble to the final rule.

Commenter: Kairos Aerospace
Comment Number: EPA-HQ-OAR-2023-0234-0240
Page(s): 14

Commenter: Environmental Defense Fund, et al.
Comment Number: EPA-HQ-OAR-2023-0234-0413
Page(s): 11-12, 13-14

Comment 6: Commenter 0240: EPA should also consider enabling operators to demonstrate lower emissions through a reconciliation process with EPA-approved advanced technology that can conduct top-down measurements. The objective would be that over time, operators would be able to demonstrate consistently that their emissions were lower than the default emission factors. In order to avoid top-down approaches failing to capture intermittent and smaller emissions, EPA should specify the reconciliation requirements, including potentially third-party auditing, and transparent reporting of demonstrations to ensure accurate emissions data is submitted. EPA could also only authorize such top-down measurements for technologies approved by EPA.

Commenter 0413**:** How frequently do measurements need to be conducted to be considered reliable or representative of annual emissions for reporting purposes?

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 topdown 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.

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.

Footnotes:

[38] Zavala-Araiza et al., supra note 11.

…

How can snapshot in time top-down observations be used to estimate annual emissions?

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.

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.

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.

Footnotes:

[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.

[29] Veritas, Measurement Protocol of Production Segment, https://veritas.gti.energy/protocols (last visited Oct. 1, 2023).

Response 6: The EPA acknowledges the current protocols (GTI Veritas, MiQ, etc.) being developed for methane emissions. We are undertaking research on and exploring options for using advanced technologies for the purpose of emissions detection and quantification and may consider adding specific methods, technologies, or protocols in future rulemakings. See Section II.B of the preamble to the final rule for a discussion of top-down measurement methods and other advanced technologies.

Commenter: Independent Petroleum Association of America (IPAA)
Comment Number: EPA-HQ-OAR-2023-0234-0265
Page(s): 16-17

Commenter: GPA Midstream Association
Comment Number: EPA-HQ-OAR-2023-0234-0299
Page(s): 62-63

Commenter: American Gas Association (AGA) and American Public Gas Association (APGA)
Comment Number: EPA-HQ-OAR-2023-0234-0418
Page(s): 11

Comment 7: Commenter 0265: Environmentalists' Recommendations Inappropriate and Unworkable

As a component of its efforts to suppress American oil and natural gas production, professional environmental lobbying organizations have orchestrated initiatives to press for additions to the Subpart W reporting regulations that are either inappropriate or unworkable. This effort was evident during the August 2023 EPA public hearing on its current Subpart W proposal where about 40 testifiers used exactly the same terms to demand changes to the Subpart W proposal. These demands reflect comments made by the Environmental Defense Fund in several forums regarding Subpart W and the methane tax.

Following is a list of the key demands:

- Integrating top-down, basin-level data alongside site- and equipment-level measurement data. Top-down, basin-level data provides a full picture of total emissions in a region, while site-level, population-based measurement data can provide insights of emissions at a finer resolution, all of which strengthen the accuracy of reported emissions.
- Building in appropriate statistical analysis of measurement data to provide a representative assessment of pollution at the facility and basin levels. Measurement data

requires statistical analysis to account for intermittent emission events that may be missed by individual, one-time measurements.

- …

One of the key issues here is the relationship between these recommendations and Subpart W. Everyone would like to have the relationship between top-down basin-level data and site- and equipment-level measurement data better understood to resolve the recurring contentious debates regarding these issues. However, such an analysis is well outside the scope of facility reporting under Subpart W. Subpart W is predicated on individual companies reporting emissions estimates based on artificially contrived facilities, e.g., all their operations in an APGA basin. Even if EPA alters the reporting structure to require reporting by well pad, the reporting remains a company-based report. Conversely, basin level data is just that – basin level. It contains information that reflects emissions from numerous well pads, owned and operated by different companies. Moreover, Subpart W information reports annual emissions; top-down basin-level data is temporal in nature perhaps hours, perhaps days, perhaps minutes. No analysis that compares the top-down data and equipment-level measurement data can realistically use Subpart W reporting. These analyses must have a coordinated effort to assess data from both components simultaneously.

Similarly, while statistical analysis can be valuable, it is not in the purview of Subpart W reporting. If EPA wants to conduct appropriate statistical analysis, it must design a more rigorous direct sampling or estimating strategy. Such an effort could be valuable if developed by and validated by EPA. To date, the analyses that have been generated have been thinly veiled advocacy efforts designed to press for regulations so quickly that EPA has never developed a full and accurate understand of the emissions profiles of oil and natural gas production operations.

Taken as a whole, these environmental lobbying organizations' recommendations are either inappropriate in the context of Subpart W or unworkable or both.

Commenter 0299: **Although GPA supports the use and development of advanced technologies to detect emissions, these technologies are not yet ready to supplant or be incorporated into bottom-up inventories.**

EPA has invited feedback on various aspects of what are commonly referred to as "top-down approaches" for the detection and quantification of emissions from petroleum and natural gas systems, particularly for Subpart W reporting. [139] GPA supports the advancement of cutting-edge technologies, such as satellite, aerial, and continuous monitoring systems. Several GPA member companies actively collaborate with technology vendors and research partners to pilot, evaluate, and refine these innovative methods. We also appreciate EPA's willingness to explore alternative approaches to GHG reporting beyond rigid, prescriptive requirements.

Nevertheless, it is essential to recognize that these technologies are still in the early stages of development, especially with regard to the quantification of emissions and the comprehensive assessment of inventories. Brown et al. (2023) compared two independent top-down full-facility estimates to contemporaneous daily inventories assembled by the facility operators at 15 midstream natural gas facilities in the U.S. and found that:

Significant disagreement was observed at most facilities, both between the two [topdown] methods and between the [top-down] estimates and operator inventory. These findings have two implications. First, improving inventory estimates will require additional on-site or ground-based diagnostic screening and measurement of all sources. Second, the [top-down] full-facility measurement methods need to undergo further testing, characterization, and potential improvement specifically tailored for complex midstream facilities.[140]

While GPA fully embraces the integration of new technology for GHG emission detection, it is crucial to acknowledge that any methods employed in the GHGRP must be well-established. These technologies have not reached that level of maturity yet. At present, the quantification of emissions through remote detection and their integration into inventories remains more of an art than a well-defined process. Our industry is actively exploring how emission detection data can be incorporated into inventories, but substantial progress is needed—particularly before these technologies and methodologies can serve as a foundation for a methane fee.

Furthermore, EPA's assertion that "top-down monitoring methods … measure large emission events" is not correct.[141] These technologies primarily identify specific information, such as the "absorption of reflected sunlight by methane molecules," and subsequently employ data analyses and various algorithms to derive an estimate of emission rates.[142,143] It is critically important for both EPA and the general public to understand this crucial distinction and refrain from assuming that these technologies directly or accurately "measure emissions." In reality, they provide indirect estimations, and many of these technologies can only estimate emissions for specific, brief moments in time.

Footnotes:

[139] 88 Fed. Reg. at 50,291.

[140] J. Brown, et al., "Informing Methane Emissions Inventories Using Facility Aerial Measurements at Midstream Natural Gas Facilities," ENVIRONMENTAL SCIENCE & TECHNOLOGY, (Feb. 13, 2023), https://pubs.acs.org/doi/10.1021/acs.est.3c01321.

[141] 88 Fed. Reg. at 50,291.

[142] Kairos Aerospace, "Methane Detection from a Unique Perspective," https://kairosaerospace.com/methanedetection/.

[143] K. Branson, et al., Kairos Aerospace, Methane Emissions Quantification, https://kairosaerospace.com/wpcontent/uploads/2021/03/Kairos-Emissions-Quantification-v7.4.pdf.

Commenter 0418: **The Associations agree with EPA's assessment of the current state of top-down data and support the Agency's proposal to not require its use in Subpart W reporting.**

As noted in Section II.A.1. of these comments, the Associations recognize both the promise and potential drawbacks of using top-down data to estimate methane emissions. EPA recognizes this as well, and as such is not proposing to require the use of top-down approaches for Subpart W reporting but is instead open to the use of top-down methods "to supplement the other requirements for periodic measurement and calculation of annual emissions."[33] In support of EPA's proposed approach, the Associations offer the following information for the Agency's consideration.

Some stakeholders allege that current bottom-up methods significantly underestimate fugitive methane emissions from natural gas pipeline facilities as compared to top-down methods; however, sound science shows that this is not the case. Both a landmark, peer-reviewed study and a National Academy of Sciences ("NAS") report explain that the perceived gap between top-down studies and inventories that are based on bottom-up measurements and emission factors is largely explained by the temporal and spatial differences in the two types of measurements. The study and the NAS report each concluded that the top-down and bottom-up approaches can be reconciled when both are conducted in the same time and place. The Associations would like to highlight the 2015 Fayetteville Basin Methane Reconciliation Study, [34] which found that the difference between the top-down and bottom-up methane measurements could be largely explained by the different time and spatial scale of the measurements. The Fayetteville Study generated eight peer-reviewed scientific journal articles, culminating in a 2018 capstone paper titled "Temporal Variability Largely Explains Difference in Top-Down and Bottom-Up Estimates of Methane Emissions from a Natural Gas Production Region." [35] The paper demonstrated how the Fayetteville Study successfully provided the first temporally and spatially aligned top-down and bottom-up methane emissions estimates for a shale gas production basin in the United States. The study reconciled top-down aircraft measurements with facility- and equipment-level bottom-up measurements on basin, site, and component scales by aligning them in the same time frame and place. The Fayetteville Study website contains a summary paper that describes, in layman's terms, the study's key findings, insights, and implications for industry practice and future studies.[36]

The Associations also wish to highlight a 2018 NAS consensus report, which recommended that other studies seeking to reconcile top-down and bottom-up methane measurements use the methodology from the Fayetteville Study. [37] The NAS report specifically recommended that researchers work with facility operators to obtain site access for bottom-up facility and equipment measurements, and then align those measurements in time and space with top-down measurements. Notably, one of the reasons that the Associations support EPA's proposal to not rely on the Weller Study—as discussed above in Section II.B.1. of these comments—is that it did not evaluate top-down measurements together with bottom-up facility measurements paired in time and space. For further detail on this issue, the Associations invite EPA to review their recent comments on the Pipeline and Hazardous Materials Safety Administration's ("PHMSA") proposed rule titled "Pipeline Safety: Gas Pipeline Leak Detection and Repair," which were filed together with INGAA and several other oil and natural gas industry associations.[38]

Footnotes:

[33] Proposed Rule, 88 Fed. Reg. at 50,291.

[34] Colorado State University: Energy Institute, Fayetteville Study: Basin Reconciliation, https://energy.colostate.edu/ metec/fayetteville-study-basin-reconciliation/ (last visited Oct. 2, 2023). The website contains a summary paper, a series of methodology papers, and an explanatory video.

[35] Timothy L. Vaughn et al., Temporal Variability Largely Explains Top-Down/Bottom-Up Difference in Methane Emission Estimates from a Natural Gas Production Region, 115 PROC. NATL. ACAD. SCI. 11712–17 (Oct. 29, 2018), https://www.pnas.org/doi/10.1073/pnas.1805687115.

[36] Garvin Heath, National Renewable Energy Laboratory, Basin Methane Reconciliation Study: Overview of Results (Oct. 25, 2018), https://energy.colostate.edu/wp-content/uploads/sites/28/2021/03/BasinMethaneOverview.pdf.

[37] National Academies of Sciences, Engineering, and Medicine, Improving Characterization of Anthropogenic Methane Emissions in the United States (Mar. 27, 2018), https://nap.nationalacademies.org/catalog/24987/improving-characterization-of-anthropogenic-methane-emissions-in-the-united-states.

[38] AGA and APGA et al. Comments on Pipeline Safety: Gas Pipeline Leak Detection and Repair (Aug. 16, 2023), https://www.regulations.gov/comment/PHMSA-2021-0039-26350.

Response 7: Historically, the Greenhouse Gas Reporting Rule has been revised to incorporate the latest data, updated scientific knowledge, or additional measurement methods, and EPA intends to continue to evaluate the appropriateness of additional updates. The EPA is actively reviewing relevant peer-reviewed literature and pilot programs and in advance of future rulemakings, the EPA intends to initiate a request for information, workshop, or white paper to further solicit feedback on the use of advanced measurement data. See Section II.B of the preamble to the final rule for a discussion of advanced technologies.

24.4 Intermittent Emissions

Commenter: Physicians for Social Responsibility Pennsylvania (PSR)
Comment Number: EPA-HQ-OAR-2023-0234-0192
Page(s): 2

Commenter: Public Hearing Transcript
Comment Number: EPA-HQ-OAR-2023-0234-0224
Page(s): 9-10 (Edwin LeMair), 12 (Morgan King), 15 (Jessica Moerman), 17 (Laurie Anderson), 20 (Antoinette Reyes), 23 (Cyrus Reed), 24 (Camilla Fiebelman), 28 (Rebecca Edwards), 30-31 (Ann McCartney), 32 (Tracy Sabetta), 37 (Sarah Bradley), 38-39 (Liz Scott), 44 (Shanna Edberg), 48 (Lisa Finley-DeVille), 53 (Pattrice Tomcik)

Commenter: Physicians for Social Responsibility Pennsylvania (PSR)
Comment Number: EPA-HQ-OAR-2023-0234-0226
Page(s): 2

Commenter: Ceres, Inc.
Comment Number: EPA-HQ-OAR-2023-0234-0236
Page(s): 2

Commenter: Interfaith Center on Corporate Responsibility (ICCR)
Comment Number: EPA-HQ-OAR-2023-0234-0242
Page(s): 3

Commenter: California State Teachers' Retirement System CalSTRS
Comment Number: EPA-HQ-OAR-2023-0234-0347
Page(s): 2

Commenter: Evangelical Environmental Network (EEN)
Comment Number: EPA-HQ-OAR-2023-0234-0371
Page(s): 2

Commenter: Miller/Howard Investments, Inc.
Comment Number: EPA-HQ-OAR-2023-0234-0380
Page(s): 2

Comment 1: Commenter 0192: Still, there is more work to be done to ensure that the strongest possible emission safeguards are finalized by EPA to protect public health, including:

…

2. EPA should ensure precise statistical analysis and methods are finalized to account for intermittent emission events that may be missed by individual observations.

Commenter 0224: [W]e urge EPA to further strengthen reporting requirements in the final rule by … accounting for intermittent emissions through statistical methods …

…

Second, we hope to see EPA ensure robust statistical analysis and methods are finalized that account for intermittent emissions that may be missed during observations or one-time measurements.

…

West Virginia Rivers would like to suggest a few recommendations including … accounting for intermittent emissions with statistical methods …

…

EPA should also ensure robust statistical analyses and methods that are finalized to account for intermittent emission events, which may be missed by individual one-time measurements or not detected during observations.

…

The EPA can and should … account for intermittent emissions with statistical methods …

…

Intermittent events account for a significant share of overall emissions in certain basins, and robust analytical methods are necessary to account for these.

…

Still as others have already mentioned, there are some ways to strengthen this rule … accounting for intermittent emissions …

…

EPA should … account for intermittent emissions with statistical methods …

…

Intermittent events account for a significant share of overall emissions from the oil and gas sector, but may be missed by individual one-time measurements. Emission factors could benefit from recently available statistical techniques that can quantify the contribution of intermittent events. A second benefit of this approach is the simplification of the calculations used by reporters which improves compliance.

…

I strongly encourage you to strengthen the reporting requirements by … accounting for intermittent emissions by statistical methods …

…

While we are generally supportive of the proposed changes, we do believe that EPA should strengthen reporting requirements in the final rule by … accounting for intermittent emissions with statistical methods …

…

Intermittent emissions and leaks must be accounted for …

…

We also support more accurate accounting for intermittent events. These events can account for a significant share of overall emissions but may be missed by one-time measurements. We urge EPA to ensure robust methods and analysis are used to better account for these intermittent emissions events more broadly.

…

EPA should ensure robust statistical analysis and methods finalized to account for intermittent emissions events.

…

Including intermittent emissions which are often not caught because they do not happen all the time.

…

We already have the technology and knowledge to get more accurate data and I would like to recommend the EPA … account for intermittent emissions with statistical methods.

Commenter 0226: Still, there is more work to be done to ensure that the strongest possible emission safeguards are finalized by EPA to protect public health, including:

…

2. EPA should ensure precise statistical analysis and methods are finalized to account for intermittent emission events that may be missed by individual observations.

Commenter 0236: To address the problem of underreported emissions and ensure that MERP's waste charge is assessed on the true volume of pollution created by the oil and gas industry, we urge the agency to improve the proposal by:

- Building in appropriate statistical analysis of measurement data to provide a representative assessment of pollution at the facility and basin levels. Measurement data requires statistical analysis to account for intermittent emission events that may be missed by individual, one-time measurements.

Commenter 0242: To address the well-known problem of underreported emissions and ensure that MERP's waste charge is assessed on the true volume of pollution created by the oil and gas industry, we urge the agency to improve the proposal by:

…

• Building in appropriate statistical analysis of measurement data to provide a representative assessment of pollution at the facility and basin levels. Measurement data requires statistical analysis to account for intermittent emission events that may be missed by individual, one-time measurements.

<u>Commenter 0347</u>: To further address the well known problem of underreported emissions and ensure that MERP's waste charge is assessed on the true volume of methane emissions, we urge the EPA to improve the proposal by:

- Building in appropriate statistical analysis of measurement data to provide a representative assessment of pollution at the facility and basin level. Measurement data requires statistical analysis to account for intermittent emissions events that may be missed by individual, one-time measurements.

<u>Commenter 0371</u>: However, there are many ways that rule can and must be strengthened to eliminate these deadly, dangerous, and wasteful "known unknowns". Specifically,

…

- EPA should ensure robust statistical analysis and methods are finalized to account for intermittent emission events. which may be missed by individual, one-time measurements or not detected during observations.

<u>Commenter 0380</u>: To address the well-known problem of underreported emissions and ensure that MERP's waste charge is assessed on the true volume of pollution created by the oil and gas industry, we urge the agency to improve the proposal by:

…

--**Building in appropriate statistical analysis of measurement data to provide a representative assessment of pollution at the facility and basin levels**. Measurement data requires statistical analysis to account for intermittent emission events that may be missed by individual, one-time measurements.

Response 1: The commenters did not provide details regarding the types of statistical analysis that the EPA should add to measurement methods. While the EPA cannot evaluate this recommendation further without additional support or detail than provided in this comment, our assessment is that the calculation methodologies provided in the final rule will appropriately estimate emissions, including those associated with intermittent events.

24.5 Third-Party Verification and/or Auditing

Commenter: Physicians for Social Responsibility Pennsylvania (PSR)
Comment Number: EPA-HQ-OAR-2023-0234-0192
Page(s): 2

Commenter: Public Hearing Transcript
Comment Number: EPA-HQ-OAR-2023-0234-0224
Page(s): 9-10 (Edwin LeMair), 12 (Morgan King), 15 (Jessica Moerman), 17 (Laurie Anderson), 20 (Antoinette Reyes), 23 (Cyrus Reed), 24 (Camilla Fiebelman), 25 (Joan Brown), 26 (Bill Midcap), 27 (Arthur Gershkoff), 28 (Rebecca Edwards), 30-31 (Ann McCartney), 32 (Tracy Sabetta), 33 (Margeret Bell), 34-35 (Dr. Dakota Raynes), 37 (Sarah Bradley), 39 (Liz Scott), 43 (Etta Albright), 44 (Shanna Edberg), 48-49 (Lisa Finley-DeVille), 52-53 (Pattrice Tomcik)

Commenter: Physicians for Social Responsibility Pennsylvania (PSR)
Comment Number: EPA-HQ-OAR-2023-0234-0226
Page(s): 2

Commenter: Ceres, Inc.
Comment Number: EPA-HQ-OAR-2023-0234-0236
Page(s): 2

Commenter: Interfaith Center on Corporate Responsibility (ICCR)
Comment Number: EPA-HQ-OAR-2023-0234-0242
Page(s): 3

Commenter: Independent Petroleum Association of America (IPAA)
Comment Number: EPA-HQ-OAR-2023-0234-0265
Page(s): 4, 16, 17

Commenter: American Lung Association
Comment Number: EPA-HQ-OAR-2023-0234-0335
Page(s): 1-2

Commenter: California State Teachers' Retirement System CalSTRS
Comment Number: EPA-HQ-OAR-2023-0234-0347
Page(s): 2

Commenter: Evangelical Environmental Network (EEN)
Comment Number: EPA-HQ-OAR-2023-0234-0371
Page(s): 2

Commenter: Miller/Howard Investments, Inc.
Comment Number: EPA-HQ-OAR-2023-0234-0380
Page(s): 2

Commenter: Kirk Frost
Comment Number: EPA-HQ-OAR-2023-0234-0389
Page(s): 3

Commenter: MiQ
Comment Number: EPA-HQ-OAR-2023-0234-0392
Page(s): 11-12

Commenter: Kirk Frost
Comment Number: EPA-HQ-OAR-2023-0234-0414
Page(s): 1

Comment 1: Commenter 0192: Still, there is more work to be done to ensure that the strongest possible emission safeguards are finalized by EPA to protect public health, including:

…

3. EPA should define guardrails and require independent verifications of self reported measurements from O&G companies to ensure that any company reported data accurately reflects ongoing operations.

Commenter 0224: [W]e urge EPA to further strengthen reporting requirements in the final rule by … providing clear guardrails for operator measurement and self-reporting.

…

Third, EPA should clearly define guardrails and require independent verification of any self-reported measurements from companies to ensure that companies are accurately representing their operations and not selectively choosing unrepresentative sites. Auditing and reporting emissions will also be important for ensuring accuracy after emissions have been reported to EPA.

…

West Virginia Rivers would like to suggest a few recommendations including … providing clear guardrails for operator measurements and self-reporting.

…

EPA should define guardrails and require independent verification of self-reported measurements from companies to ensure any company-reported data accurately represents emissions and is not limited to unrepresentative sites or equipment that typically have lower emissions. Now unfortunately, and respectfully, as a mom I've found that the honor system does not always work and industry self-reporting at times may be as accurate as my 8-year-old son self-reporting how many cookies he ate while I wasn't looking.

…

The EPA can and should … provide clear guardrails for operator measurements and self-reporting.

…

Then lastly, please do more to ensure self-reporting is accurate by requiring independent verification of self-reported measurements…

…

Still as others have already mentioned, there are some ways to strengthen this rule … and then providing clear guardrails for operator measurements and self-reporting.

…

EPA should … provide clear guardrails for operator measurements and self-reporting …

…

Often our community members state that we can have all the regulations we want, but if they're not enforced, that does not help, and it doesn't. So EPA must be very vigilant with these companies to have strong and clear guardrails to require independent verification of the self-reported measurements to address these concerns. The front-line communities and some of us do not trust the self-reporting and rightfully so of corporations in the region.

…

Rocky believes that the EPA should define guardrails and require independent verification of self-reported measurements from companies to ensure any company reported data is accurate and represents their emissions and that the data is not limited to unrepresented sites or equipment that typically has lower emissions.

…

In addition to improving the accuracy of measuring and reporting leaks of such equipment, the EPA should also use some of the Methane Emission Reduction Program funds to pay for external professionals knowledgeable in monitoring techniques to work with the EPA to verify reports from facilities of the amounts of emissions leaked. Such professionals may also have access to data from satellites and overflying planes and be able to interpret such data. The EPA should also consider recruiting residents of communities near fossil fuel extraction and processing sites to participate in community-focused air monitoring, perhaps with those professionals.

…

Finally, the EPA should improve accountability for self-reported measurements from companies by defining guardrails and requiring independent verification of self-reported measurements.

…

I strongly encourage you to strengthen the reporting requirements by … providing clear guardrails for operator measurements in self-reporting. … Second, self-reporting by oil and gas companies needs requirements for verification for self-reported measurements so companies are not limiting their reporting to unrepresentative sites or equipment that typically have lower emissions.

…

While we are generally supportive of the proposed changes, we do believe that EPA should strengthen reporting requirements in the final rule by … providing clear guardrails for operator measurements in self-reporting.

…

Lastly, I would ask that the EPA require independent verification of self-reported measurements from companies to ensure any company-reported data accurately represent emissions and is not limited to unrepresentative sites or equipment that typically have lower emissions.

…

Lastly, as many others have noted, the EPA should define clear guardrails and require truly independent verification of companies self-reported measurements to ensure that any company-reported data actually represents true emission levels and isn't based on unrepresentative samples of sites or equipment that typically have lower emissions.

…

[C]lear standards for operating measurements and self-reporting are necessary. The EPA should define guardrails and require independent verification of self-reported measurements from companies.

…

Additionally, one of the provisions of the Methane Emissions Reduction Program was to allow owners and operators to submit emissions data. We strongly urge EPA to define clear guardrails and require independent verification of self-reported measurements.

…

The egregiousness nature of the fossil fuel industry is not to be trusted for self-regulation. Any resistance to partnering with EPA to modify changes needed for accurate reporting emissions of methane would be testimony to that egregiousness.

…

EPA should require independent verification of self-reported measurements from companies to ensure that their data is accurate and not misrepresented.

…

In order to ensure accuracy in reported numbers, EPA must require independent verification of what industry is reporting, and what locations industry is getting their numbers, so not just the least polluting sites and equipment are used.

…

Now while we're all vulnerable to air pollution and climate change, certain populations are impacted more such as children and front-line communities located the closest to oil and gas operations. Over nine years ago, parents in my community protested the proposal to frack unconventional gas wells approximately half a mile from our children's school campus, where there's 3,200 students in attendance. As I was doing research on the subject, I remembered how absolutely shocked and in disbelief I was to find out that emissions from oil and gas operations are based on industry self-reported emissions estimates and not on empirical measurements. I think the general public is amazed at this too. This is what began my advocacy work to protect children from air pollution and climate change. Through my science background, I knew that the accuracy of emissions data is so important and serves as a foundation for critical rules and policies to protect communities from air pollution and climate change. EPA should define guardrails and require independent verification of self-reported measurements to ensure any company reported data accurately represents emissions and is not limited to under, unrepresentative sites or equipment that typically have lower emissions. Today in the U.S., more than 3 million children go to school within a half mile of oil and gas operations that puts their health at risk.

<u>Commenter 0226</u>: Still, there is more work to be done to ensure that the strongest possible emission safeguards are finalized by EPA to protect public health, including:

…

3. EPA should define guardrails and require independent verifications of self reported measurements from O&G companies to ensure that any company reported data accurately reflects ongoing operations.

<u>Commenter 0236</u>: To address the problem of underreported emissions and ensure that MERP's waste charge is assessed on the true volume of pollution created by the oil and gas industry, we urge the agency to improve the proposal by:

- Defining guardrails and requiring independent verification for self-reported measurements from companies to ensure any company reported data accurately represents operations and is not limited to unrepresentative sites or equipment known to have lower emissions.

<u>Commenter 0242</u>: To address the well-known problem of underreported emissions and ensure that MERP's waste charge is assessed on the true volume of pollution created by the oil and gas industry, we urge the agency to improve the proposal by:

…

- Defining guardrails and requiring independent verification for self-reported measurements from companies to ensure any company reported data accurate represents operations and is not limited to unrepresentative sites or equipment known to have lower emissions.

Commenter 0265: *New Implications of Subpart W*

A different, but similar, issue arises for all reporting entities. With Subpart W becoming the basis for the methane tax, any and all information submitted become the subject of audit and enforcement under the CAA. This creates the potential for frivolous and harassing actions by OECA. The history of OECA interaction with American petroleum and natural gas producers has been characterized by OECA actions to target smaller producers with fine threats that would bankrupt them. These actions have included interpretations of regulations by OECA that differed from the interpretation and guidance from the regulatory authors within EPA. Filing under Subpart W creates hundreds of thousands of opportunities to challenge any submitted information. Since EPA has proposed numerous different approaches to submitting information and creates the opportunity for reporters to submit facility specific information, EPA must now assure that good faith actions by reporters are not windows of opportunity for OECA to pursue harassing actions. However, EPA has not provided clear and straightforward guidance in this Subpart W proposal. Nor has it shown that OECA will use such guidance.

…

Environmentalists' Recommendations Inappropriate and Unworkable

As a component of its efforts to suppress American oil and natural gas production, professional environmental lobbying organizations have orchestrated initiatives to press for additions to the Subpart W reporting regulations that are either inappropriate or unworkable. This effort was evident during the August 2023 EPA public hearing on its current Subpart W proposal where about 40 testifiers used exactly the same terms to demand changes to the Subpart W proposal. These demands reflect comments made by the Environmental Defense Fund in several forums regarding Subpart W and the methane tax.

Following is a list of the key demands:

- …
- Defining guardrails and requiring independent verification for self-reported measurements from companies to ensure any company reported data accurately represents operations and is not limited to unrepresentative sites or equipment known to have lower emissions.

…

The final recommendation reflects the environmental lobbying position that only it can be trusted; everyone else must be put to a higher level of scrutiny. The American oil and natural gas production industry is committed to managing its emissions, including methane emissions. It has invested millions of dollars in meeting its requirements and will continue to make necessary investments. While differences may exist regarding the best, most cost-effective actions that should be taken, producers will continue their commitment to protect the environment. Certainly, the idea of having independent verification of self-reported emissions data is appealing. Presently, many of the Subpart W reports are prepared by independent consultants because of the complexity of the current requirements, particularly for smaller producers. The larger issue may well be whether the restructuring of Subpart W reporting in the context of the methane tax will adversely affect access to independent consultants. This issue has arisen in previous EPA NSPS regulations where EPA required professional engineers (PE) to certify information. Two issues arose. First, there were not enough PEs with expertise to undertake the tasks. Second, the license risks for the PE in undertaking the task were too great to bring more into the arena. A similar dynamic may occur in the methane tax context. Because OECA can challenge any reported information and because OECA has a history of using its enforcement power in this industry to target smaller producers, independent contractors may conclude that the risks to their businesses to too high to participate given the magnitude of penalties under the CAA.

Taken as a whole, these environmental lobbying organizations' recommendations are either inappropriate in the context of Subpart W or unworkable or both.

Commenter 0335: Reliably consistent and accurate measurement of greenhouse gas emissions are the only way to fairly implement the provisions of the Inflation Reduction Act's (IRA) methane fee across the oil and gas industry. To this end, there must be strong guardrails in place and mandatory, independent, third-party verification measures actively enforced to ensure a level playing field between all private firms in the oil and gas industry as well as trustworthy information sharing between state and local environmental regulators.

Commenter 0347: To further address the well known problem of underreported emissions and ensure that MERP's waste charge is assessed on the true volume of methane emissions, we urge the EPA to improve the proposal by:

- Defining guardrails and requiring independent verification for self-reported measurements to ensure that company-reported data accurately represents operations and is not limited to unrepresentative sites or equipment known to have lower emissions.

Commenter 0371: However, there are many ways that rule can and must be strengthened to eliminate these deadly, dangerous, and wasteful "known unknowns". Specifically,

…

- EPA should define guardrails and require independent verification of self-reported measurements from companies to ensure any company-reported data accurately represents emissions and is not limited to unrepresentative sites or equipment that typically have lower emissions.

Unfortunately, as a mom, I've found the honor system does not always work and industry self-reporting can be as accurate as my eight-year old son self-reporting how many cookies he ate while I wasn't looking.

Commenter 0380: To address the well-known problem of underreported emissions and ensure that MERP's waste charge is assessed on the true volume of pollution created by the oil and gas industry, we urge the agency to improve the proposal by:

…

--**Defining guardrails and requiring independent verification for self-reported measurements from companies.** This will ensure any company reported data accurately represents operations and is not limited to unrepresentative sites or equipment known to have lower emissions.

Commenter 0389: OGI Audits of facilities. I urge the EPA to build this Audit team tasked to work with state DEPs in auditing and keeping all natural gas facilities accurate in their reporting.

Commenter 0392: MiQ encourages EPA to consider a construct for requiring third-party verification of oil and gas operators subject to Subpart W reporting. This addition will improve confidence in the underlying data reported by operators to calculate their emissions and assist EPA in ensuring that the usage of empirical data by operators is accurate and appropriately demonstrates the extent to which a charge is owed. The substantial revisions by Subpart W may create much more variation in how emissions are reported by operators within the same segment. While this is a welcome consequence, the addition of more methods increases the chance that operators may incompletely report emissions or misinterpret certain aspects of the revised protocols. EPA can drive consistency in reporting by requiring third-party verification of operators' reported emissions, also increasing trust in the implementation and enforcement of the waste emissions charge. We believe that synergies could be realized with the additional proposed requirements of public companies by the Securities and Exchanges Commission to report third-party verified corporate-level greenhouse gases[4], and requirements by various international organizations to require third party-verification of greenhouse gases from member companies[5,6]. In addition to these corporate-wide protocols which require or propose requirements for third-party verifications of emissions information, MiQ has led in developing auditing requirements for more granular Facility-level greenhouse gas audits, which generally covers the same Facility boundaries as operators reporting to Subpart W. We suggest that EPA consider MiQ's public requirements for auditors and requirements set forth by the State of Colorado in their recently adopted GHG Intensity Verification rule for guidance on accreditation processes, necessary details of verification, and frequency and timelines of Facility-level audits[7,8].

Footnotes:

[4] Securities and Exchange Commission, 17 CFR 210, 229, 232, 239, and 249, [Release Nos. 33-11042; 34-94478; File No. S7-10-22], RIN 3235-AM87, The Enhancement and Standardization of Climate-Related Disclosures for Investors, Proposed Rule

[5] IFRS Foundation, International Sustainability Standards Board, IFRS Sustainability Disclosure Standard, Climate-related Disclosures, June 2023

[6] World Business Council for Sustainable Development, World Resources Institute, A Corporate Accounting and Reporting Standard, March 2004

[7] MiQ Standard for Methane Emissions Performance, Introduction for Auditors v2.0, 2023. https://miq.org/document/miq-introduction-for-auditors/\\

[8] Department of Public Health and Environment, Air Quality Control Commission, Regulation Number 7, Control of Emissions from Oil and Gas Emissions Operations, 5 CCR 1001-9. https://drive.google.com/drive/u/0/folders/1sD6Vzvjq2Z4xK1-_AuaUfnzJRBFcGrLD

Commenter 0414: For TGP, all the FERC dockets that exist online provide the specifications for CS-325 going back to 2000. In 2009, TGP submitted resource report 09 to FERC (link: https://elibrary.ferc.gov/eLibrary/filedownload?fileid=01518EF0-66E2-5005-8110-C31FAFC91712) detailing project air emissions. Page 618 details CS-325 emissions. On that page, note that is methane combustion emissions, methane fugitive emissions and methane venting emissions. Blow downs are not detailed because they are typically in response to an emergency condition that require extended duration of venting beyond just the valves of the facility. Then compare the annual reported methane emissions that TGP submitted to NJDEP and EPA for CS-325 after the FERC project was completed:
2010: 0.33 tons; 2011: 0.68 tons; 2012: 0.71 tons; 2013: 1.19 tons; 2014: 1.45 tons; 2015: 1.07 tons;
2016: 1.28 tons; 2017: 1.27 tons; 2018: 1.23 tons; 2019: 1.19 tons; 2020: 1.29 tons; and 2021: 1.3 tons.

I used a TGP facility, but this is also true for all of the other transmission pipeline companies that own/operate pipelines in all of the projects that I have researched across many states. The EPA rules need to correct the methods that enable owners/operators to falsely under report emissions by dividing a factor of 100 or more from the actual emissions.

EPA needs to start an audit division that visits sites unannounced on days when the facility would most likely be at 100 percent load and monitor using a FLIR camera using the EPA OGI standards for a period of 8 hours. It should not be legal for a facility owner/operator not accurately and fully reporting all toxic air emissions (HAPs and VOCs) and methane emissions from a natural gas facility. This is true for the electric compressor stations.

A local Texas Eastern Transmission Corp.'s Freehold Compressor station located at 110 Weston Rd, Somerset, NJ 08873, has been leaking like a sieve during winter months in the mornings from 6am to 10am. Despite being 2,000 feet from a high school and the parking lot smelling like a gas leak every morning, this issue has continued on for years unresolved. Since it is a small electric (5,000hp) compressor station, NJDEP and EPA do not view it as a methane emissions source. Yet, it leaks profusely during winter months.

We need all facilities reporting accurate emissions that include all sources and types of methane emissions.

Response 1: The EPA did not propose and is not finalizing provisions for third-party audits within subpart W. The EPA implements a robust, multi-step data verification process for all information reported under subpart W to ensure reported data are accurate, complete, and consistent. The EPA will be developing additional processes to verify data reported under the new requirements in this final rule. We note that under a separate rulemaking the EPA plans to address additional verification of subpart W reporting, including any potential use of third-party verification, as it relates to and under the waste emissions charge (WEC) rule. Stakeholders should review the proposed WEC rule for additional information.

25 Impacts and Burden Estimate

Commenter: American Petroleum Institute (API)
Comment Number: EPA-HQ-OAR-2023-0234-0199
Page(s): 1 and 2

Commenter: GPA Midstream Association
Comment Number: EPA-HQ-OAR-2023-0234-0299
Page(s): 1-2, 63-65

Commenter: National Federation of Independent Business, Inc. (NFIB)
Comment Number: EPA-HQ-OAR-2023-0234-0336
Page(s): 2

Commenter: Endeavor Energy Resources, L.P.
Comment Number: EPA-HQ-OAR-2023-0234-0381
Page(s): 3

Commenter: Arkansas Independent Producers and Royalty Owners (AIPRO)
Comment Number: EPA-HQ-OAR-2023-0234-0382
Page(s): 9

Commenter: CrownQuest Operating
Comment Number: EPA-HQ-OAR-2023-0234-0393
Page(s): 178, 357

Commenter: American Petroleum Institute et al. (Part 1 of 2)
Comment Number: EPA-HQ-OAR-2023-0234-0402
Page(s): 7, 18, 22

Commenter: North Dakota Petroleum Council (NDPC)
Comment Number: EPA-HQ-OAR-2023-0234-0417
Page(s): 2-3

Comment 1: Commenter 0199: The American Petroleum Institute (API) respectfully submits the attached comments on the Environmental Protection Agency's (EPA) burden assessment found in the Greenhouse Gas Reporting Rule: Revisions and Confidentiality Determinations for Petroleum and Natural Gas Systems ICR (OMB control number 2060-NEW, ICR number 2774.01). The burden assessment is provided by EPA in two separate documents.[1]

As this rulemaking pertains to a reporting-based rule that has specific requirements to complete reporting, the paperwork burden is the same as the compliance burden because it includes operation and maintenance (O&M) and capital costs to gather the necessary data to complete reporting.

EPA's estimated annual costs of $92 million for this proposal underestimate the costs of these rulemaking changes and the impact on the entire oil and natural gas industry. The revisions to the Subpart W are all covered by the term "collection of Information" under the Paperwork

Reduction Act, therefore all costs imposed by the rule should be included in the assessment of paperwork burden.

API reviewed EPA's burden analysis and via a survey of member companies determined there are several areas where EPA underestimates the cost on industry to implement the proposed changes to Subpart W of the Greenhouse Gas Reporting Program (GHGRP). Given the tight deadline of submitting comments to the Office of Management and Budget (OMB) by August 31, 2023, API was only able to analyze specific parts of the rule. However, this initial analysis indicates EPA underestimated the labor cost and the O&M and capital costs of activities needed to comply with the proposed changes.

API appreciates OMB and EPA’s engagement and responsiveness to our questions during the comment period. We remain committed to working constructively with EPA and the Administration to finalize a cost-effective rule that accurately and appropriately estimates the burden of the proposed changes to Subpart W of the GHGRP.

API notes that this submission is specifically made to support the review of the burden assessment by EPA and OMB. API plans to submit additional technical comments on the Rule and may submit additional comments on the burden assessment prior to the October 2, 2023, deadline.

API remains committed to working with EPA and the Administration to identify cost-effective solutions to improve accuracy of reported emission data and to reduce methane emissions from petroleum and natural gas systems.

API performed a high-level survey to gauge estimates of the burden expected to be placed upon industry and a subset of results indicate EPA underestimated the burden. Furthermore, it is expected that additional activities under this rulemaking were also underestimated by EPA given API's initial analysis.

The comments provided herein focus on legal, technical, and feasibility challenges with specific provisions EPA included within the proposed updates to Subpart W. Listed below are API’s primary concerns with the burden analysis that was provided in EPA's ICR.

Footnote:

[1] Supporting Statement - Environmental Protection Agency, Information Collection Request for the Greenhouse Gas Reporting Rule: Revisions and Confidentiality Determinations for Petroleum and Natural Gas Systems; Proposed Rule (May 2023), available at https://www.regulations.gov/document/EPA-HQ-OAR-2023-0234-0164. Memorandum to Docket ID. No EPA-HQ-OAR-2023-0234 from Stephanie Bogle, OAR/OAP, dated June 2023 with the subject Assessment of Burden Impacts for Proposed Greenhouse Gas Reporting Rule: Revisions and Confidentiality Determinations for Petroleum and Natural Gas Systems, available at https://www.regulations.gov/search?filter=EPA-HQ-OAR-2023-0234-0165

Commenter 0299: In the proposed rule, EPA proposes to revise Subpart W and says that it is doing so to account for total methane emissions through the inclusion of new emission sources, to improve the accuracy of calculated methane emissions using empirical data through new and revised emission calculation methodologies, and to enhance the verification and transparency through increased granularity in emissions reporting. While GPA understands that EPA has a congressional mandate to revise Subpart W, EPA must fully acknowledge that these proposed changes will have significant financial implications to GPA members due to new monitoring and reporting requirements, the impact of newly reported methane emissions on the Inflation Reduction Act's waste emissions charge, and the potentially illogical decisions operators would be forced to make to reduce reported emissions (such as spending huge amounts of money to comply with a refinery rule). This goes beyond Congress's direction that EPA revise Subpart W to ensure that any fees imposed under the Inflation Reduction Act be based on empirical data and accurately reflect methane and waste emissions.

…

Flawed assumptions in EPA's "Assessment of Burden Impacts" could significantly downplay the proposed rule's impact.

Significant problems in the burden assessment and associated Information Collection Request ("ICR") include the following:

- EPA did not provide labor estimates for emission sources[144] that are already reported under the rule; however, many (if not all) sources have changed data collection, calculation, or reporting requirements under the proposal that impact labor.
- The EPA's estimation of operations and maintenance ("O&M") costs covers only select monitoring requirements, neglecting, for example, the flare monitoring requirements they propose must be implemented for a reporter to claim 98 percent destruction efficiency, or performance test monitoring for combustion methane slip. EPA must address the fact that reporters will need to incur these costs to be allowed to calculate lower methane emissions and reduce their methane fees.
- It appears EPA only included costs related to revisions to reporting and recordkeeping requirements for just four specific revisions.[145] Perhaps this is due to the unclear presentation of the information, but GPA struggles to believe that EPA estimated zero cost associated with the dozens and dozens of changes to 98.236 reporting requirements. If EPA indeed failed to account for costs associated with the extensive changes to reporting requirements, however, this massive gap in cost impacts must be addressed.

To highlight the assessment's overall deficiencies by way of example, the only cost EPA accounted for with regard to flares was "Purchase and installation of continuous parameter monitoring systems" [Table A-3]. EPA does not estimate costs associated with collecting and otherwise using this data. EPA does not estimate costs for periodic flare pilot monitoring. EPA does not estimate costs for the significant exercises of estimating fraction of total volume flared that was received from another facility solely for flaring [98.236(n)(10)] and estimating disaggregated CH4, CO2, and N2O emissions attributed to each source type [98.236(n)(19)].

EPA must explain why certain labor, O&M, and capital costs associated with non-optional rule provisions were excluded from this assessment.

EPA's cost estimate for Other Large Release Events fails to contemplate the practical realities of this proposal.

The EPA's estimate of $188,688 for the other large release event emission source is far from realistic. The proposal, requiring reporters to assume event durations of 182 days unless proven otherwise, forces significant additional surveillance and technology expenses (see Comment 19). GPA does not argue that additional monitoring can be beneficial for numerous reasons. EPA overlooks these substantial cost implications, however, rendering the burden assessment incomplete.

Footnotes:

[144] The document also incorrectly characterizes "Malfunctioning dump valves on atmospheric storage tanks" and "combustion slip" as new emission sources. These sources are currently reported under the GHGRP with different requirements.

[145] EPA, Memorandum from S. Bogle to Docket ID No EPA-HQ-OAR=2023-0234, Assessment of Burden Impacts for Proposed Greenhouse Gas Reporting Rule: Revisions and Confidentiality Determinations for Petroleum and Natural Gas Systems (June 2023) at Table A-4 (analyzing the burden and costs of only the following four items: (1) Changing reporting basis to the well-pad instead of the basin, (2) Changing reporting basis to the site ID instead of the county or sub-basin, (3) Gathering quantities related to plugged wells (quantities of natural gas, crude oil, and condensate produced that is sent to sale), (4) Monitoring and reporting the quantities of natural gas, crude oil, condensate, residue gas, liquefied natural gas, hydrocarbon liquid, etc. that are sent to sale in the calendar year).

Commenter 0336: EPA should consider carefully the costs of compliance with the proposed regulations. The American Petroleum Institute (API) informed the Director of the Office of Management and Budget (by letter of August 31, 2023, in the rulemaking docket, EPA-HQ-OAR-2023-0234) that EPA had underestimated the costs to implement the proposed rules. API noted in particular that the proposed rules impose the following costly mandates, for which EPA did not take sufficient account of the costs: (a) the disaggregation requirement for the Onshore Production segment and the Onshore Gathering and Boosting segment that forces reporting at the well pad or site level instead of the basin level; (b) provisions for monitoring intermittent bleed natural gas pneumatic devices; and (c) the requirement to purchase and install continuous parameter monitoring systems. EPA should weigh carefully the real costs of implementing the proposed rules against any benefits of the proposed rules. EPA also should note that the result of the implementation costs will be an increased cost to consumers of fossil-fuel energy.

Commenter 0381: Further, we believe the Agency has not taken into full account the increased recordkeeping and reporting burdens associated with EPA's proposed additional emission sources and revisions to existing measurement and calculation methods, such as for "other large release events," flare stack emissions, blowdown events, and produced water tanks (among others), or the full range of technical challenges in integrating direct measurement into the GHGRP. EPA estimates the total annual incremental burden on reporters in the Onshore Production segment would be about $80,000.[6] Endeavor believes the costs associated with the Subpart W Proposal—taking into account the implementation of additional technologies, the hiring of additional technicians, and the additional personnel hours to understand and implement the Subpart W Proposal—would be *significantly* more than EPA projects, likely tens of thousands of dollars more annually. Endeavor requests that EPA revise its cost estimate to more accurately reflect these burdens. We respectfully suggest that saddling our industry with these additional costs, many of which have no corresponding benefit to reporting accuracy, is not appropriate at a time when there are already concerns about domestic energy costs and energy security.

Footnote:

[6] Id. at 50,370 (Table 7).

Commenter 0382: General:

i. The proposed Subpart W revisions, in their current form, would impose overly burdensome and unnecessary implementation complexities for a relatively small overall improvement in the accuracy of reported emissions. This is true for many of the proposed requirements; including, but not limited to, those related to intermittent bleed pneumatic devices, dehydrators, acid gas removal units, equipment leaks, and the proposed disaggregation of sources in the Onshore Production and Gathering & Boosting segments, as well as several others. AIPRO proposes that EPA and the OMB should further scrutinize the estimated burden and forecasted benefits of the proposed revisions. Further, AIPRO encourages EPA to comprehensively review and amend the proposed revisions to significantly reduce the implementation burden to the regulated community. AIPRO welcomes the opportunity to work collaboratively with EPA on this effort.

Commenter 0393: Regarding control devices and closed vent systems for tanks on the proposed rule. API members performed a supply chain study. The EPA's proposed compliance timeline of 60 days in wildly inaccurate. The anticipated supply chain delay for this segment from API members/operators is 18-24 months. We ask that the EPA please Take this timeline into account in the final rule.

…

As stated in our previous comments in this document, we believe that the EPA has drastically understated both the physical paperwork associated with this rule as well as the estimated annual average burden hours and physical dollars cost burden that would be absorbed by operators. We recommend that EPA reviews the cost burden studies provided. With the unspecified change of what a "facility" is, it has complicated Subpart W and emission calculations.

Commenter 0402: **Many proposed Subpart W requirements would impose high implementation burdens for small accuracy improvements for most sources and overall reported emissions.** This overarching theme applies to numerous proposed requirements, especially flare flow monitoring, flare combustion efficiency reporting, gas composition requirements, liquids unloading, and intermittent-bleed pneumatic devices. The Industry Trades have proposed more efficient and feasible alternatives.

…

Pneumatic Devices

Given the proposed zero-emitting standard in NSPS OOOOb and EG OOOOc, EPA should alleviate the burden with measuring and monitoring emissions across the proposed methodologies from natural gas driven pneumatic controllers during their transitional phase out in upcoming years.

…

EPA Has Underestimated the Cost of Direct Measurement for Pneumatic Devices

Oil and gas companies do not currently own or have training to conduct direct measurement of pneumatic devices. EPA included no additional cost for purchasing the high flow sampling equipment, staff or training on the equipment. With the large number of operators having to acquire this data at the same time, new equipment must be first manufactured and then purchased by these operators to do this work concurrently. EPA added no additional labor impact; it will require significantly more staff to conduct the measurements. The company will need to hire staff, as additional staff will be needed to conduct these measurements that require 15 minutes per measurement minimum over a range of device counts per facility depending on whether it is a gas or oil well, number of wells, and the equipment required for production. It will likely not be possible to cover 5-10 sites per day, considering repairs will likely be performed at the same time and many sites and pneumatic devices will be spread out over long distances. Furthermore, operators will need to be trained to use high flow samplers as this equipment is currently not used in the oil and gas industry. None of these additional costs have been addressed in the Regulatory Impact Analysis. EPA claimed all this could be done with only an additional $600,714 in cost which would not be sufficient to cover the cost for a medium sized operator.

Commenter 0417: **General Comments**

The oil and natural gas industry is an integral part of the U.S. and North Dakota economies. In April 2023, oil and natural gas accounted for 69 percent of the energy consumption in the U.S, according to the U.S. Energy Information Administration. Affordable energy prices generally benefit all sectors of the American public, and cost-effective regulation of the energy industry can benefit human health and the environment.

North Dakota is ranked third in the nation in oil production, and NDPC members produce 98 percent of the oil in North Dakota. North Dakota produced approximately 2.94 billion cubic feet of natural gas per day and 390.4 million barrels of oil in 2022, contributing significantly to supplying clean and cost-effective energy for Americans and America’s energy independence.

To demonstrate the significance of the oil and natural gas industry to North Dakota's economy, the taxes from oil and natural gas production accounts for nearly 53 percent of North Dakota's tax revenue. Since 2008, North Dakota's oil extraction and production tax revenues have generated over $26 billion and provided over $1.8 billion for education and $5.9 billion in funding for communities and infrastructure across the state. The taxes have also contributed nearly $9 billion to the North Dakota Legacy Fund, which creates a perpetual source of revenue for the state's general fund and tax relief for its citizens.

Many of North Dakota lessees are small businesses that run wells with little room for changes that would render their wells uneconomical. Even though these wells are considered small producers, they make up a large portion of the wells in North Dakota and across the nation. Under the proposed language of this rule change, these lessees will now be faced with a choice to continue their livelihood at great expense that may never be recovered or to abandon those locations. The loss of this production not only impacts the energy security of the nation, but the economic security of thousands of North Dakotans. These small producers support other small service businesses that will also be forced into uncertain economic situations. According to a 2021 economic impact study, almost 50,000 jobs in North Dakota are a result of the oil and natural gas industry with a payroll totaling $4.5 billion dollars. Operating under the current regulatory oversights and requirements, families are provided with the opportunity to make a living wage and support themselves and their families. Burdensome and duplicative environmental regulations will cause more damage than good to the economics of North Dakota, impacting disadvantaged communities and small businesses and, as stated previously, the economic security of thousands of North Dakotans.

NDPC believes the Regulatory Impact Analysis (RIA) performed for the proposal does not appropriately justify the economic burden of the proposed regulation on domestic oil and natural gas producers. Industry's concern is that this proposed rule will force producers to plug and abandon wells before the end of a well's useful life. This will have a direct economic impact on North Dakotans and particularly on the Mandan, Hidatsa, and Arikara Nation, which is paid royalties for the oil and natural gas production in addition to the over $2.12 billion in oil and gas taxes the Nation has received since 2008. NDPC encourages careful consideration of the potential economic burdens on North Dakota's citizens and oil and natural gas producers when performing the regulatory impact analysis, including the useful life of equipment and wells.

Over-regulation of the oil and natural gas industry increases production costs and discourages investment in the industry with little if any environmental benefit. This can lead to higher costs of electricity, heating fuels, food, and transportation, which disproportionately impact low income Americans. As inflation has increased, we have seen tangible evidence of this over the last few years.

Response 1: The comments listed above did not include specific cost data to support changes to the cost assumptions made at proposal. Please see the EPA's responses to other comments in this section of this document, including from some of the same commenters, and the preamble for the final rule for changes from proposal the EPA made in the final impacts and costs analysis.

- As stated above, many of the comments in this section are addressed more fully in the EPA's responses to other comments in this section, as shown below:

- See Comment 4 of this section for the EPA's response to comments regarding the disaggregation requirement for the Onshore Production segment and the Onshore Gathering and Boosting segment.
- See Comment 6 of this section for the EPA's response to comments regarding the provisions for monitoring intermittent bleed natural gas pneumatic devices.
- See Comment 7 of this section for the EPA's response to comments regarding the requirement to conduct continuous or monthly gas composition monitoring on flare stacks, and the costs for periodic flare pilot monitoring.
- See Comment 10 of this section for the EPA's response to comments regarding dump valve inspection requirements.
- See Comment 13 of this section for the EPA's response to comments regarding the requirement to require flow meter measurements of liquids unloading venting using Method 1 once every three years.

- Multiple comments warranted more specific responses as shown below:

- Concerning the comment that noted, "Many proposed Subpart W requirements would impose high implementation burdens for small accuracy improvements for most sources and overall reported emissions… especially flare flow monitoring, flare combustion efficiency reporting, gas composition requirements, liquids unloading, and intermittent-bleed pneumatic devices," the EPA is only finalizing the flare combustion efficiency reporting from that list. See Section 15 of this document for further information about the final amendments related to flare combustion efficiency.
- Concerning the comment that "EPA did not provide labor estimates for emission sources that are already reported under the rule" and "only included costs related to revisions to reporting and recordkeeping requirement for just four specific revisions," see Comment 18 of this section for the EPA's response to comments regarding changes to the rule that were determined to have no significant impact on burden.
- Concerning the comment that the EPA's estimation of operations and maintenance costs neglected performance test monitoring for combustion methane slip, the performance test is optional and therefore is not required. Therefore, no costs were estimated for the performance testing.
- Concerning the comment, "With the unspecified change of what a *facility* is, it has complicated Subpart W and emission calculations," it is unclear what change the commenter is referencing or how it affects costs.
- With regard to the comment about small businesses, see Section VII.C of the preamble to the final rule for the EPA's small business analysis.

Commenter: CrownQuest Operating
Comment Number: EPA-HQ-OAR-2023-0234-0393
Page(s): 354, 356

Comment 2: This is a logical fallacy for the calculation of emissions and still expecting this to decrease emissions. This rule is supposed to be for measurement, not to decrease emissions.

…

We are all for the reduction of emissions, but no benefit is quantified here.

Response 2: The EPA clearly stated the purpose of this rulemaking in the preambles for both the proposal and final rule. See, for example, the preamble for the final rule Sections I and II. When analyzing the potential impacts of the final rule, the EPA also noted that reporters will have a better understanding of their emission levels and sources which could better allow them to identify opportunities to reduce emissions. No benefits and no emissions reductions were quantified in this rulemaking. As stated in the proposed rule preamble, "Because this is a proposed reporting rule, the EPA did not quantify estimated emission reductions or monetize the benefits from such reductions that could be associated with this proposed action."

Commenter: American Petroleum Institute (API)
Comment Number: EPA-HQ-OAR-2023-0234-0199
Page(s): 2 and 5

Commenter: American Petroleum Institute (API)
Comment Number: EPA-HQ-OAR-2023-0234-0245
Page(s): 1-3, 6, 8

Comment 3: Commenter 0199: **Survey Process Summary**

API performed a survey of member companies to gather preliminary data to create the comments provided below and as summarized in Appendix A – API Membership Survey Responses. Data was collected per respondent, and segment-wide impacts were estimated by applying them to the total number of respondents, consistent with EPA's approach.

Due to the requirement to submit comments to OMB by August 31, 2023, comprehensive impacts for each source across each segment of the industry were not collected. Therefore, API presents the results of the survey collection process to present data on the activity occurrence estimations only. See Appendix A- Information on Activity Occurrence. API's membership indicates there is likely a consistent trend of burden underestimation across all industry segments.

Commenter 0245:

In this letter, the American Petroleum Institute (API) submits supplemental comments on Environmental Protection Agency's (EPA) burden assessment found in the Greenhouse Gas Reporting Rule: Revisions and Confidentiality Determinations for Petroleum and Natural Gas Systems ICR (OMB control number 2060-NEW, ICR number 2774.01). Our submission supplements our previous comments submitted August 31, 2023. After our previous comments, API further engaged membership to provide EPA with additional quantitative data to provide a more accurate assessment of cost estimates. This process allowed API to complete a more thorough analysis and identify additional concerns related to EPA's labor and cost burden estimates, which API first articulated in our August 31, 2023, comment letter. [1]

API appreciates OMB and EPA's engagement and responsiveness during the comment period. We remain committed to working constructively with the Administration to finalize a cost-effective rule that accurately and appropriately estimates the burden of the proposed changes to GHGRP Subpart W

Due to the limited timeframe that EPA provided stakeholders to respond to the burden assessment of Greenhouse Gas Reporting Rule, API provides here a supplemental analysis of the data from a survey of API member companies, focused on sources of material omission or underestimation that API member companies identified—specifically, issues regarding (1) disaggregation; (2) pneumatic devices; (3) flares and costs associated with downtime. From the reviewed sources of data on these issues, ***API finds compliance costs could be at least twice as high as EPA estimates ($92 million) and range from $167 million to $242 million when the analysis accounts for some production losses necessary for equipment installations—see Table 1.*** Of particular concern, on the overall flare costs, we believe EPA has significantly underestimated the cost of installing flow meters on flares across the country. This analysis aligns with API's initial comments [2] where we stated there was a general trend of underestimating labor costs, operation and maintenance (O&M) costs, and capital costs.

In sum, EPA has dramatically underestimated the burden associated with the proposed reporting requirements with no concomitate increase in the utility or value of the information required to be reported. Unless corrected to reduce the burden and increase the utility of the information, OMB should not approve the ICR.

Table 1. Environmental Protection Agency (EPA) Burden Estimate Compared to Adjusted Estimate, *USD*

Source	*Labor*	*O&M*	*Capital*	*Lost production*	*Total*
EPA Estimate					
Table A-1	20.4				20.4
Table A-2		17.6			17.6
Table A-3			12.1		12.1
Table A-4	1.1				1.1
Table A-7	11.2	6.0			17.3
Table A-8	7.6	7.0	6.1		20.7
Table A-9	1.1	1.2	0.9		3.2
Total	**41.4**	**31.8**	**19.1**		**92.3**
API Adjusted Estimate					
Source	*Labor*	*O&M*	*Capital*	*Lost production*	*Total*
Table A-1	20.4				20.4
Table A-2		87.7			87.7
Table A-3			12.1		12.1
Table A-4	6.4				6.4
Table A-7	11.2	6.0			17.3
Table A-8	7.6	7.0	6.1		20.7
Table A-9	1.1	1.2	0.9		3.2
Total	**46.7**	**101.9**	**19.1**	**18.6 - 74.4**	**186.4 - 242.2**
Difference	5.3	70.1	0.0	18.6 - 74.4	94.1 - 149.9

Notes: Based on a select review of EPA estimates which is not inclusive of all costs API believes will likely occur. For example, API used EPAs estimates for most variables—including for flare continuous parameter monitoring systems (CPMS)—given the short time frame to conduct a quantitative assessment. However, EPA does not account for several costs of CPMS for flares which would increase labor costs, O&M, and capital costs. Adjusted estimate uses more realistic pneumatic device cost and disaggregation costs. The production estimates assume that installation requires one day of down time and that either 15 thousand (the low) or 80 percent (the high) of existing wells need CPMS installations.

Methodology of API's Survey and the API Adjusted Estimate

To better understand this rule's costs, we surveyed API membership. The survey was developed by API's Statistics Department with input from policy and Subpart W subject matter experts. After the survey was sent to API members, a conference call was held with members to summarize the ICR burden estimates, solicit additional member input on priority burden assessment areas, and answer questions on the survey. API focused on industry segments and equipment types that the EPA believes generate the largest labor and cost burdens rather than all industry sources, given the initial limited-comment deadline (August 31, 2023). Thus, while EPA's deadline did not allow for the generation of comprehensive estimates, API's survey focused on the largest labor and cost burdens does help gauge the spread between EPA's most substantial cost estimates and our member companies' estimates based on historical cost of the categories in the proposed rule. API then used our findings[3] to identify elements of EPA's analysis that appear to be underestimated and to re-estimate the rule's cost using a methodology that is consistent with EPA's approach. A**PI finds that costs could be twice as high as EPA suggests ($92 million) ranging from $167 million to $242 million when accounting for limited production losses associated with equipment installation.** However, we reiterate that our results are not comprehensive and empathize that API members indicated that there is likely burden underestimation across all industry segments which neither EPA nor our-adjusted estimates include. For example, API members identified both one-time costs—such as establishing or updating data management systems—as well as recurring costs such as annual reporting, periodic testing, and maintenance continuous parameter monitoring systems that appear to be underestimated or not captured at all.

…

Conclusion

After reviewing the cost of providing disaggregated data, the O&M costs for pneumatic devices, and the cost of CPMS installation for flares, API is concerned that EPA has underestimated this rulemaking's burden. We emphasize that these issues and the others we discuss also suggest a general trend of burden underestimation across additional source types and segments. Based on discussions of EPA's estimates with API member companies, API believes that EPA's estimates of administrative burden per the Paperwork Reduction Act of this rulemaking would benefit from a more rigorous review as it appears to contain material omissions and potential errors that significantly underestimate its burden. As discussed above API finds that this rule's compliance costs, based on our limited review given the limited time that EPA allowed for comments, could range from $167 million to $242 million when considering production losses and changes to EPA's calculations reflected in the API Adjusted Estimate in Table 1. Further, the rule's cost could far exceed the limited cost estimate we provide in these comments.

Ultimately, a better understanding of this rulemaking's costs would provide a more robust, accurate, and transparent analysis that would be beneficial for policymakers, the public, and industry. As always, API welcomes the opportunity to collaborate with the Administration as we share the mutual goal of implementing cost-effective rulemaking that minimizes burdens while improving GHG-emissions reporting.

Footnotes:

[1] API Comments to EPA Burden Assessment, August 31, 2023.
https://www.regulations.gov/comment/EPA-HQ-OAR-2023- 0234-0199

[2] Ibid.

[3] Data was collected per respondent, and segment-wide impacts were estimated by applying them to the total number of respondents.

…

Annex A

Table 1. Environmental Protection Agency (EPA) Burden Estimate Compared to Adjusted Estimate, Million *USD*

EPA Burden Estimates

Source	**Labor Costs**	**O&M Costs**	**Capital Costs**	**Production Losses**	**Total Costs**
Table A-1	$ 20,381,440				$ 20,381,440
Table A-2 (O&M Costs Table)		$ 17,600,500			$ 17,600,500
Table A-3 (Flare Costs Table)			$ 12,096,569		$ 12,096,569
Table A-4 (Disaggregation Table)	$ 1,076,249				$ 1,076,249
Table A-7	$ 11,227,480	$ 6,023,839			$ 17,251,318
Table A-8	$ 7,616,790	$ 6,991,102	$ 6,090,670		$ 20,698,562
Table A-9	$ 1,111,078	$ 1,169,136	$ 926,182		$ 3,206,396
Total	$ 41,413,037	$ 31,784,577	$ 19,113,421		$ 92,311,035

API Updated Total Estimates

Source	**Labor Costs**	**O&M Costs**	**Capital Costs**	**Production Losses**	**Total Costs**
Table A-1	$ 20,381,440				$ 20,381,440
Table A-2 (O&M Costs Table)		$ 87,737,934			$ 87,737,934
Table A-3 (Flare Costs Table)			$ 12,096,569		$ 12,096,569
Table A-4 (Disaggregation Table)	$ 6,395,916				$ 6,395,916
Table A-7	$ 11,227,480	$ 6,023,839			$ 17,251,318
Table A-8	$ 7,616,790	$ 6,991,102	$ 6,090,670		$ 20,698,562
Table A-9	$ 1,111,078	$ 1,169,136	$ 926,182		$ 3,206,396
				$ 18,603,108 to 74,412,431	$ 18,603,108 to 74,412,431
Total	$ 46,732,704	$ 101,922,011	$ 19,113,421	$ 18,603,108 to 74,412,431	$ 186,371,244 to 242,180,567

General Note: API has reviewed the three sources below, API does not necessarily agree with any value not commented on

API used EPA estimate for flares given short time frame to provide comments on proposed rule. However, EPA has underestimated the capital and operational expenditure of CMPS for flares.

Adjusted EPA estimate to account for a more realistic pneumatic device cost (Updated $/device)

Adjusted EPA estimate to account for a more realistic disaggregation cost (Updated hr/reporter)

Response 3: The EPA has reassessed the costs estimated at proposal and made adjustments as appropriate, including where the EPA underestimated costs at proposal. The final annual incremental costs are $183.6 million. Specific comments and responses are broken out by emission source throughout the remainder of this section, as follows:

- Disaggregation for Onshore Production and G&B (see Comment 4 of this section)
- Mud degassing Method 2 (see Comment 5 of this section)
- Pneumatic devices (see Comment 6 of this section)
- Flares (see Comment 7 of this section)
- Combustion and combustion slip (see Comment 8 of this section)
- Quantity “sent to sale” (see Comment 9 of this section)
- Dump valves (see Comment 10 of this section)

- Thief hatches (see Comment 11 of this section)
- GOR method for atmospheric storage tanks (see Comment 12 of this section)
- Liquids unloading (see Comment 13 of this section)
- Compressors (see Comment 14 of this section)
- Other miscellaneous emission source changes (see Comment 18 of this section)

Commenter: American Petroleum Institute (API)
Comment Number: EPA-HQ-OAR-2023-0234-0199
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Commenter: American Petroleum Institute (API)
Comment Number: EPA-HQ-OAR-2023-0234-0245
Page(s): 3, 9

Comment 4: Commenter 0199: **The disaggregation requirement for the Onshore Production and Onshore Gathering and Boosting industry segments will impose a significant burden on industry.**

The proposed revisions require Onshore Production and Gathering & Boosting industry segments to change historical reporting requirements from reporting total emissions at the basin level to reporting emissions at the well pad or site ID level.

API's survey indicates EPA underestimated the level of effort required by industry to meet the proposed requirements. For example, EPA assumes reporting is completed only on an annual basis; however, API members indicate reporting activity is commonly conducted numerous times throughout the year (monthly or quarterly) to reduce year end burden. In addition to the underestimate of frequency, EPA vastly underestimates the level of effort to perform this update. EPA assumes on average a respondent will complete this change in 12 hours for Onshore Production operators, while API survey results estimate it will require Onshore Production operators approximately 90 hours to perform these updates. It is expected that EPA underestimated effort for Gathering & Boosting at a similar level.

…

Table 1. Subpart W Labor Costs by Emission Source/Event and Industry Segment

Year 1-3	Hours activity per Occurrence	Activity occurrences per year
B. Required Activities		
Mud degassing 1		
Use emission factor to calculate emissions (M2)		
Onshore Petroleum and Natural Gas Production reporters	22.50	88.0
E. Write Report		
Changing to reporting at the well-pad level or site ID		
Onshore Petroleum and Natural Gas Production reporters	88.50	4.3
Onshore Petroleum and Natural Gas Gathering and Boosting reporters	62.42	4.3

Commenter 0245: **Supplemental Quantification of Underestimate of Administrative Burden of Reporting Well Pad/Site ID Disaggregation**

The proposed revisions require onshore production and gathering and boosting industry segments to switch from reporting total emissions at the basin level to reporting emissions at the well pad or site ID level. This change is significant, and API believes that EPA underestimated the cost burden associated with these changes. Specifically, API is concerned EPA's cost estimates only reflect the increased time associated with submittal of the final inventory data even though the new reporting requirements will require updates to underlying data systems that have been in place since the onset of Subpart W Reporting. These proposed changes require significant efforts involving IT, management, and operations personnel that EPA does not consider in its cost burden estimate. While these costs represent the biggest impact in year 1 it is a significant material cost burden missing from EPA's assessment.

EPA's burden assessment assumed that onshore production reporters would spend 12 hours per year and that gathering and boosting operators would spend 3 hours per year conducting reporting. We find that onshore production reporters could spend 88 hours per year and that gathering and boosting operators could spend 62 hours per year on average to comply with this rule. **Using EPA's assumptions regarding the number of reporters, API calculates total costs per year that are over 8 times EPA's costs for onshore production reporting and over 15 times EPA's costs for gathering and boosting reporting.** Our labor estimates include all reportable segments and account for the need to update underlying data systems as well as additional source-by-source quality assurance procedures.

…

Table 2. EPA Burden Estimate of Disaggregation Compared to Adjusted Estimate

Industry Segment	Proposed Revision	Number of Affected Reporters	EPA Burden Hours	EPA Labor Cost	API Estimated Reporter Burden (hr/reporter)	API Labor Cost Estimate
Onshore Petroleum and Natural Gas Production	Changing reporting basis to the well-pad instead of the basin or sub-basin.	478	7,170	$786,837	87	$4,563,390
Onshore Petroleum and Natural Gas Gathering and Boosting	Changing reporting basis to the site ID instead of the county.	354	1,770	$188,238	30	$1,731,352
		EPA Total Labor Cost	9,841.5	$1,076,249		

EPA Assumptions:
44 Assumed 15 hours per reporter per year to report by well-pad instead of by sub-basin (12 hours of an Engineer's time, 2 hours of a Middle Manager's time and 1 hour of a Technician's time).
45 Assumed an average of 3.44 wells per well-pad from NSPS OOOOb TSD.
46 Assumed 5 hours per reporter per year to report by G&B site instead of by county (3 hours of an Engineer's time, 1 hour of a Middle Manager's time and 1 hour of a Technician's time).

Response 4: See Section VI.A.2 of the preamble to the final rule for the EPA's response to comments regarding costs for reporting well pad and site ID disaggregation for the Onshore Petroleum and Natural Gas Production and Onshore Petroleum and Natural Gas Gathering and Boosting industry segments, respectively.

Commenter: American Petroleum Institute (API)
Comment Number: EPA-HQ-OAR-2023-0234-0199
Page(s): 5

Comment 5:

Table 1. Subpart W Labor Costs by Emission Source/Event and Industry Segment

Year 1-3	Hours activity per Occurrence	Activity occurrences per year
B. Required Activities		
Mud degassing 1		
Use emission factor to calculate emissions (M2)		
Onshore Petroleum and Natural Gas Production reporters	22.50	88.0
E. Write Report		
Changing to reporting at the well-pad level or site ID		
Onshore Petroleum and Natural Gas Production reporters	88.50	4.3
Onshore Petroleum and Natural Gas Gathering and Boosting reporters	62.42	4.3

Response 5: For mud degassing, Method 2 is the use of an emission factor. The impacts are based on multiplying an emission factor by the number of drilling days (which should be tracked as part of day-to-day operations) to determine emissions. As this is only a calculation, ten minutes per calculation is sufficient. The commenter offered no justification for changing to 22.5 hours per calculation. The number of occurrences were adjusted from 65.6 per year to 88 per year in the final rule analysis. Costs changed from approximately $239,200 per year at proposal to approximately $332,000 per year at final.

These costs are detailed in the information collection request (ICR) document OMB Number 2060-0751 (EPA ICR number 2774.02) and the memorandum *Assessment of Burden Impacts for Greenhouse Gas Reporting Rule: Revisions and Confidentiality Determinations for Petroleum and Natural Gas Systems* dated February 2024.

Commenter: American Petroleum Institute (API)
Comment Number: EPA-HQ-OAR-2023-0234-0199
Page(s): 3, 5

Commenter: American Petroleum Institute (API)
Comment Number: EPA-HQ-OAR-2023-0234-0245
Page(s): 3-4, 10

Comment 6: Commenter 0199: **Burden from the intermittent bleed device monitoring provisions.**

The proposed provisions relative to intermittent bleed natural gas driven pneumatic devices require operators to monitor and inspect these devices on a recurring basis, estimating a cost burden of $12.5 million for the Transmission, Onshore Production, and Gathering & Boosting industry segments. This creates significant concern as the proposed rule appears to underestimate other burdens associated with this provision which include administrative recordkeeping, training, and staffing. API supports intermittent bleed surveys as an option for reporters to reduce a potential methane fee burden; however, given the very large burden associated with this proposal, this provision cannot be mandated.

Also, EPA's burden assessment did not recognize that this source will be effectively removed from the US GHG Inventory once NSPS OOOOb and EG OOOOc are implemented. Based on the timelines EPA proposes, natural gas driven pneumatics will be phased out by sometime in 2028, which is sooner than the maximum survey cycle time of 5 years (2029).

Furthermore, monitoring and inspections for intermittent bleed pneumatic devices require niche skills. As such, this proposal will require the US workforce to accommodate an unstainable demand for skills and workers to complete the monitoring function. Given the brief period expected, as soon as the skills become available in the market, they will become immediately obsolete. The burden on the US economy and workforce should be considered in the analysis for this rulemaking.

In light of the foregoing, it is imperative to understand the increased burden on industry to collect data from a source that will be effectively removed through regulation.

…

Appendix A

Table 2. Subpart W Operation and Maintenance Costs and Capital Costs by Emission Source/Event and Industry Segment

Year 1-3	Occurrences per Year
ANNUAL COSTS (O&M)	
Pneumatic Devices-measure volumetric flow rate regularly 2	
Onshore Natural Gas Transmission Compression reporters	1004
Onshore Petroleum and Natural Gas Production reporters	2,328
Onshore Petroleum and Natural Gas Gathering and Boosting reporters	380

Commenter 0245: **Supplemental Quantification of Underestimate of Administrative Burden of Reporting for Intermittent Bleed Pneumatic Devices**

EPA's O&M and capital cost estimates associated with the measurement of volumetric flow from pneumatic devices underestimate or omits material issues that result in additional burdens. Specifically, we find that EPA overestimates the number of devices at a single site, thereby underestimating the assumed travel time associated with conducting measurements that materially impact EPA's assumed cost per device burden assessment.

EPA assumes that volumetric testing costs per pneumatic device are $60. However, EPA does not fully account for these assets' geographic distribution and, instead, assumes that 25 pneumatic devices exist on each site, causing the EPA to conclude that 25-28 pneumatic devices can be tested per day and that each test is completed in 15 minutes. Thus, the EPA's $60 per device cost estimate is derived by averaging mobilization costs and testing hourly rates based on 25 to 28 tests per day. These values are reflected in Table 3, these are assumptions from EPA's ICR calculation. For the production and gathering and boosting industry segment, based on operator responses, API finds that pneumatic devices are not centralized at single sites as EPA assumes. The geographical distribution results in significant unaccounted for travel time as crews move between sites and will significantly reduce the number of tests per day, resulting in an increased burden assessment on a per device basis.[4]

Based on historical costs, API member companies estimate a more appropriate average cost would be $421 per device measurement for onshore production and $380 per device measurement for gathering and boosting. These values are reflected in Table 3, in the column "API Average Device Cost" of the API Adjusted Estimate. The variability in operator cost is based on whether their devices are centralized or decentralized, as some operators have hundreds or thousands of intermittent bleed pneumatic devices spread across their assets. In some locations, like parts of the Permian Basin, assets may be close together; however, in other locations, such as the Marcellus Shale and Utica Shale and across the Denver-Julesburg Basin, Bakken Powder River Basin, Uinta Basin and Green River Basin, traveling between assets can take far greater time than linear distance would indicate.

Footnote:

[4] Memorandum of meeting with EPA filed March 24, 2022. https://www.regulations.gov/document/EPA-HQ-OAR-2021-0317-1480

…

Table 3. EPA Burden Estimate of Pneumatics O&M Compared to Adjusted Estimate

Emission Source	Activity	Industry Segment	Assumptions	EPA Occurrences/ Respondent/Year	EPA Respondents/Year	EPA O&M Cost	API Average Device Cost	API Estimated O&M Cost
Pneumatic Devices	Contractor to measure volumetric flow rate	Onshore Petroleum and Natural Gas Production	31, 55, 56	1765	478	$10,122,492	$421	$71,037,014
		Onshore Petroleum and Natural Gas Gathering and Boosting	31, 55, 56	407	354	$1,727,016	$380	$10,949,928
					EPA Total O&M Cost	$17,600,500		$81,986,942

Assumptions:
31 Number of occurrences per respondent based on average number reported by segment for RY2019
55 Based on average number of pneumatic devices per facility, assumed would test 1/5 of devices every year.
56 Assuming the testing crew would cost $300 to show up (travel, + set up) + $150/hr for measurements. Vent measurements are 15 minute long, so max 4 device measurements/hour, and 25-28 total devices could be measured in an 8 hour day and would cost about $1,500. Second day costs would be similar, since multi-day monitoring would incur hotel and additional per diem costs. Based on 25 devices at the site, an average cost of about $60 per device for the vent measurements

Response 6:

The EPA has decided not to finalize the changes to require flow measurements or surveys for pneumatic devices. The use of population emission factors is being retained in the final rule. Therefore, there are no costs for pneumatic devices related to flow measurements or surveys for the final amendments. See Section 6 of this document for more information related to pneumatic devices.

Commenter: American Petroleum Institute (API)
Comment Number: EPA-HQ-OAR-2023-0234-0199
Page(s): 3

Commenter: American Petroleum Institute (API)
Comment Number: EPA-HQ-OAR-2023-0234-0245
Page(s): 4-6, 11

Commenter: Ascent Resources, LLC
Comment Number: EPA-HQ-OAR-2023-0234-0339
Page(s): 1-2

Commenter: CrownQuest Operating
Comment Number: EPA-HQ-OAR-2023-0234-0393
Page(s): 214

Commenter: American Petroleum Institute et al. (Part 1 of 2)
Comment Number: EPA-HQ-OAR-2023-0234-0402
Page(s): 37, 40-42

Comment 7: Commenter 0199: **Underestimated burden for purchase and installation of continuous parameter monitoring systems**.

The proposed rule requires at least continuous parameter monitoring systems (CPMS) to determine gas flow to flares. EPA's burden assessment underestimates the burden associated with the purchase and installation of CPMS. EPA's estimate also neglects to include an analysis of other burdens associated with this requirement including IT communications systems, connectivity and electricity setup (particularly in remote locations), labor hours associated with updates to include in the new monitoring systems, and staffing resources required to calibrate, maintain, and monitor these CPMS systems. API believes that the burden associated with the installation of these systems is significantly underestimated. API believes these costs to be considerable, and respectfully requests consideration of the matters discussed herein.

Commenter 0245:

Supplemental Quantification of Underestimate of Administrative Burden of Reporting for Continuous Parameter Monitoring Systems (CPMS) for Flares

EPA appears to inaccurately account for the burden associated with installing continuous parameter monitoring systems (CPMS) because EPA underestimated the capital costs for these systems and does not account for other costs associated with operating and maintaining the equipment, production down-time related to equipment installation, and the burden associated with reporting. EPA also overestimated the number of existing systems or meters in operation and thus underestimated the portion of flares that will require new monitoring components. Furthermore, flares without continuous pilot monitoring will require monthly pilot light inspection that EPA did not estimate.

Additionally, EPA did not properly account for costs associated with installing and maintaining flare monitoring. Instead, EPA made numerous assumptions about the effort needed to install continuous parameter monitoring and "that [a] continuous parameter monitoring device would cost $5,000 per flare. Assuming 10-year life and 7% interest, annualized cost is $712 per flare."[5] The EPA does not provide additional context on their estimate. However, it appears that EPA only accounted for the cost of the instrumentation for flow, temperature and pressure differential monitoring and did not account for the other costs associated with parametric monitoring, such as installation of supervisory control and data acquisition (SCADA) systems in unconnected remote locations, as well as their operating and maintenance costs. API members indicated that the capital cost of installing a SCADA system is roughly $100,000 per site and some operators estimated a burden of more than $1 million per site.

EPA did not include citations to support their $5,000 per flare assumption. However, surveyed API member companies pointed out that flow conditions within closed vent systems for the production and gathering and boosting industry segment will require specialized flow meters to accurately measure the flow of the waste gas streams to the flare. And **API members also**

highlighted that the cost of these specialized meters, based upon current market availability and pricing, is closer to $20,000 to $30,000 per flow monitor[6] each to purchase, and additional capital required for installation and labor—which is significantly higher than EPA's estimate. Additionally, the proposed changes to the rule will likely significantly increase demand for these specialized meters placing a strain on the supply chain, in the short run, and potentially increase costs which EPA may want to consider.

EPA also did not accurately account for the number of flares operating without this type of device. Instead, EPA assumed 80 percent of the oil and natural gas industry already monitors flowrate[7] and incorrectly applied this assumption across every industry. However, each oil and natural gas industry segment has different requirements. Unlike a more complex site, such as a refinery or petrochemical plant, the flows to a flare have historically not required metering since conditions at a well site or gathering facility are less variable and more readily estimated based on operating conditions and stream properties which do not vary as much as in a refinery or chemical plant operation. Surveyed API member companies indicated that most existing flares would require upgrades and strongly suggests that EPA should correct this critical assumption. In addition to the underestimated number of flares, EPA also did not include a cost estimate regarding the installation of these devices across various geographic locations.

In addition, API expects that installation and upgrades of CPMS devices will require significant downtime. If one uses the EPA's estimate, which API believes is too low, 15 thousand wells will need to install CPMS devices, and the cost would be roughly $18.6 million per day of downtime for all wells. However, as discussed above, surveyed API member companies expect that the number of existing flares requiring updates could approach 80 percent, suggesting that **CPMS installation costs could reach $74.4 million per day of downtime that causes lost production**, which is reflected in Table 1, in the column "Lost Production" of the API Adjusted Estimate. This calculation suggests that EPA should consider and account for production losses associated with their proposed installation requirements which according to their own estimates will be required on approximately 15 thousand devices.

Additionally, EPA did not account for the costs required to maintain and calibrate these types of devices. When parametric monitoring equipment is installed, these devices cannot function and provide accurate data without maintenance. Yet, EPA assumed zero O&M costs, minimizing the effort needed to provide accurate data for emission calculations. Similarly, EPA did not account for labor burdens associated with collecting and validating these devices' data. However, to utilize any data from this system, operators will require IT support, engineering support and field teams to assist as well as access, verify, and apply the data collected. In total, EPA did not include costs associated with required personnel (office or field based) needed to validate this data, perform additional calculations, and report the emissions to EPA.

EPA did not provide a burden estimate for the gas sampling requirements. Multiple operators have expressed to API through the survey process that they currently do not have sample ports installed on the closed vent systems between the emission sources and the flare. The introduction of direct sampling and measurement requirements through the proposed updates presents a significant burden to procure, install, and maintain sampling points. A characterization of the streams within the closed vent systems has historically been provided using engineering estimates or the use of process simulation software. Along with the cost to install sampling ports that are not included in the burden assessment, EPA has not considered the downtime associated with the installation of these sample points. Operators have expressed that these downtimes could be significant. One example includes the operator of a storage tank battery, which is required to operate a flare to control flashing, working, and breathing emissions from storage tanks. The isolation of vapors from the closed vent system may require operators to shut-in production and empty the contents of the storage tanks to prevent the release of uncontrolled emissions during the installation of sample ports. The extent of downtime here is significant and the emptying and isolation of tanks is not common, generally conducted approximately once every 10 years for internal tank integrity testing.

Further, EPA did not address the direct reoccurring cost to pull samples. The average cost for a gas sample is $500, which can amount to a significant burden given the number of streams that would have to be sampled per flare on a quarterly basis. Further, EPA's burden assessment does not account for the monthly visual inspections required for flares that are not equipped with continuous pilot light monitoring. To complete these inspections, operators need to create a framework for data collection and recordkeeping that the existing rule does not currently require. Monthly inspection will require the mobilization of personnel to each of the sites, including many non-manned facilities in the production and gathering and boosting industry segments. Based upon these devices' geographic distribution API expects significant travel time as crews move from site to site and conduct the required inspections, yet these costs are not included in EPA's current assessment.

Footnotes:

[5] Supporting Statement, Table 4. Assumption No. 65

[6] API comments submitted to EPA on February 13,2023
https://www.regulations.gov/comment/EPA-HQ-OAR-2021-0317-2428

[7] Supporting Statement, Table 4; assumption No. 64.

…

Annex A

EPA's Burden Estimate Compared to Adjusted Estimate

Table 4. EPA Burden Estimate of Flares and Production Loss Estimate

List of Cost Estimates

EPA Accounted Costs		Other Costs Associated with CPMS	Estimated Costs
Device Purchase Cost (Individual Cost)	$5,000 per device	Production Loss	~$18.6 million per day (See calculation below)
Device Purchase Cost (Annualized Cost)	$712 per device	SCADA System (New or Upgrades)	~$100,000 per site
		Installation & Equipment Cost	~$50,000 per CPMS device
		Gas Sampling Collection Costs	Not quantified by API, but expected to be a material cost that EPA needs to consider
		Operating Costs	Not quantified by API, but expected to be a material cost that EPA needs to consider
		Maintenance Costs	Not quantified by API, but expected to be a material cost that EPA needs to consider
		Data Collection Labor Costs	Not quantified by API, but expected to be a material cost that EPA needs to consider
		Reporting Labor Costs	Not quantified by API, but expected to be a material cost that EPA needs to consider

EPA Costs Table

Emission Source	Activity	Industry Segment	Total Capital Cost	Annualized Capital Cost
Flare stacks	Purchase and installation of continuous parameter monitoring systems	Onshore Natural Gas Processing	$901,514	$128,355
		Onshore Natural Gas Transmission Compression	$864,000	$123,014
		Underground Natural Gas Storage	$171,500	$24,418
		LNG Import and Export Equipment	$27,500	$3,915
		Onshore Petroleum and Natural Gas Production	**$75,208,723**	**$10,708,030**
		Onshore Petroleum and Natural Gas Gathering and Boosting	$7,788,000	$1,108,836
TOTAL			**$84,961,238**	**$12,096,569**

API used EPA estimate for flares given short time frame to provide comments on proposed rule. However, EPA has underestimated the capital and operational expenditure of CMPS for flares.

EPA Assumptions:

3 New equipment purchase requirements for the listed industry segment(s).
31 Number of occurrences per respondent based on average number reported by segment for RY2019.
63 Assumed one continuous parameter monitoring device per flare stack.
64 Estimated that 80% of oil and gas industry already monitors flow rate, so the need for continuous parameter monitoring is reduced.
65 Assumed that continuous parameter monitoring device would cost $5,000 per flare. Assuming 10 year life and 7% interest, annualized cost is $712 per flare.

Production Loss from CPMS Onshore Production Downtime

	Value	Unit	Data Source/Assumption Source
Total Cost of Installing CPMS on Estimated Number of Flares	$10,708,030		EPA - GHGRP Subpart W ICR; OMB control number 2060-NEW; ICR number 2774.01, Table 2
EPA's Estimate of Cost of Flares	$712	$/flare	EPA - GHGRP Subpart W ICR; OMB control number 2060-NEW; ICR number 2774.01, Table 2
EPA's Estimated Number of Affected Flares	15,039	flares	
API's Estimated Number of Affected Flares	60,157	flares	API assumes that only 20% of flares have CPMS already installed, and 80% of flares will require CPMS
Average Oil Well Production	26	bbl oil/day per well	EIA - The Distribution of U.S. Oil and Natural Gas Wells by Production Rate - Dec 2022 (Page 9)
Average Natural Gas Well Production	181,647	cf/day per well	EIA - The Distribution of U.S. Oil and Natural Gas Wells by Production Rate - Dec 2022 (Page 9)
Estimated Price of Crude Oil	$70.70	$/bbl	EIA - 2013 - 2022 10 Year Average Price of WTI Crude Oil
Estimated Price of Natural Gas	$3.43	$/MMBTU	EIA - 2013 - 2022 10 Year Average Price of Henry Hub Natural Gas
Assumed HHV	1,020	BTU/SCF	Average Natural Gas HHV value
Average Cost of Oil Well Production	$1,838	$/day per well	
Average Cost of Natural Gas Well Production	$636	$/day per well	
Average Cost of Well Production	$1,237	$/day per well	
EPA Minimal Estimate of Wells	15,039	Wells	At minimum; an equal number of wells will be affected by CPMS installations
API Minimal Estimate of Wells	60,157	Wells	At minimum; an equal number of wells will be affected by CPMS installations
EPA Estimated Production Loss	**$18,603,108**	**$ loss per day of downtime**	
API Estimated Production Loss	**$74,412,431**	**$ loss per day of downtime**	

Commenter 0339: Flares

EPA's proposed changes with respect to flares will impose additional costly monitoring requirements without providing improved accuracy and introduce complexity in calculation methodologies due to discrepancies between Subpart W and various state permitting practices and federal requirements. The monitoring requirements will increase company spending on emissions monitoring without associated improved emissions reduction benefit.

Commenter 0393: It is our opinion that the EPA underestimated the time/cost burden involved with installing continuous monitoring on flares. With an average cost of ~$24,000 to install the correct type of meter that is capable of monitoring various flow of gas to flares and the number of flares in the field, an estimated cost would be $3,750,000. This is in comparison to the EPA total cost per year estimate of $128,355. As you can see the estimate is grossly underestimated. It is our concern that EPAs proposed requirements to install, calibrate and maintain meters on flares to measure flow will be extremely costly and burdensome while also failing to bring in more accurate reporting. In our case this would affect hundreds of flares, requiring either new meter installation or a monitoring configuration.

Commenter 0402: Flares

Flow Measurement

Proposed Flare Flow Measurement and Monitoring Requirements are Overly Burdensome

The cost and burden associated with measuring every stream is significant and understated by EPA.

Continuously measuring flow volumes or utilizing parametric monitoring devices for each source that routes gas to a flare will be extremely burdensome while failing to result in more accurate emissions reporting. Many operators have thousands of flares that would be affected, requiring either new meters or parametric monitoring devices. The majority of flares would require at least two gas streams to be monitored – the main vent line or "waste gas" stream and the purge/sweep/auxiliary gas stream. The cost and burden impact of monitoring – at a minimum – must include:

- Minimum of 2 or more specialized meters, or parametric monitoring systems
- Labor for installation
- Loss of production for shutdowns for installation
- Retrofitting the flare line for the run for the meter
- Expanding or adding the remote facility computer (remote oil field controller)
- Expanding or adding data storage capacity on site
- Wiring to the remote facility computer
- Expending or adding the remote transmitting unit
- Calibration and maintenance
- SCADA and alarm programming
- Data management system
- Data review and analytics
- Data entry for calculations

The capital and operational costs to continuously monitor flare volumes using meters or parametric monitoring devices, as proposed, would result in significant costs to reporters that were not adequately addressed in the proposed rule's burden assessment. EPA did not explain the cost estimates in Table A-3 of "Assessment of Burden Impacts for Proposed Greenhouse Gas Reporting Rule: Revisions and Confidentiality Determinations for Petroleum and Natural Gas Systems," and we note that significant contributions to cost and burden were likely not included in the analysis based upon the magnitude of the estimate. As important, however, is the unjustified acceleration of installation of equipment that is already anticipated over the course of the next few years.

Paradoxically, this increased capital and operational cost can lead to flare volumes becoming less accurate than using the methodology under the current rule, as described below.

The requirement to continuously monitor at least two streams for thousands of flares at remote locations across the upstream oil and gas industry would require significant capital and operational expenditure with little benefit given the legitimate concerns regarding meter accuracy. As noted above, continuous monitoring flare flow volume would require costly specialized meters. As such, the Industry Trades believe EPA has underestimated the capital cost burden for purchase and installation of continuous parameter monitoring systems. The Industry

Trades provided the Office of Management and Budget (OMB) this comment in response to Docket ID EPA-HQ-OAR-2023-0234.

…

Gas Composition Requirements

The proposed requirements to measure or sample the gas composition for each flare are economically and technically infeasible, and engineering estimates and representative analysis should be allowed.

EPA has not justified the costs related to the installation of continuous composition analyzers or quarterly sampling, and go beyond NSPS OOOOb and EGOOOOc compliance assurance requirements. Installation of a continuous monitor for each stream or quarterly sampling will be extremely costly for installation, data gathering and management, calibration and maintenance or sampling and analysis for the thousands of flares impacted. Costs for continuous monitors include:

- Monitor(s) (one for each stream)
- Labor for installation
- Loss of production for shutdowns for installation
- Retrofitting the flare line for the continuous analyzer
- Expanding or adding the remote facility computer (remote oil field controller)
- Expanding or adding data storage capacity on site
- Wiring to the remote facility computer
- Expending or adding the remote transmitting unit
- Calibration and maintenance of the monitor
- SCADA and alarm programming
- Data management system
- Data review and analytics
- Data entry for calculations

For quarterly sampling, the associated costs include:

- Minimum of 2 sample ports (one for each stream)
- Labor for installation
- Loss of production for shutdowns for installation
- Retrofitting of the flare line for the sample ports
- Cost of gathering the samples each quarter
- Cost of analyzing the samples every quarter
- Data management system
- Data review and analytics
- Data entry for calculations

Flare systems in upstream operations are not designed for sampling, meaning that physical modifications to install sampling ports would be required to enable samples to be taken, which is costly and not always technically feasible. Also, installing sampling ports, meters/instrumentation, or continuous gas analyzers would require production to be shut down, which would be logistically challenging and generally result in flaring to accommodate causing more emissions.

As noted in API's comments on NSPS OOOOb:[35] "Calorimeters and other compositional analyzers (e.g., gas chromatographs or mass spectrometers) have an approximate minimum installed cost of $164,000 to $245,000." The estimated cost per gas sample was "$1,500 to $2,000 including shipping and analysis." Therefore, the annual cost for quarterly sampling could easily exceed $10 million for an operator considering 4 samples per year per stream, at least 2 streams per site, and a thousand or more sites to sample annually.

Footnote:

[35] Comment 5.6.4. https://www.regulations.gov/comment/EPA-HQ-OAR-2021-0317-2428.

Response 7: The EPA has decided not to finalize the proposed amendments to require continuous flow monitoring and continuous or monthly gas composition monitoring on flare stacks. Therefore, no costs are estimated for continuous flow monitoring or continuous or monthly gas composition monitoring on flare stacks. See Section 15 of this document for more information related to flares.

See Section VI.A.2 of the preamble to the final rule for the EPA's response to comments regarding costs related to flare pilot light inspections.

All costs are detailed in the information collection request (ICR) document OMB Number 2060-0751 (EPA ICR number 2774.02) and the memorandum *Assessment of Burden Impacts for Greenhouse Gas Reporting Rule: Revisions and Confidentiality Determinations for Petroleum and Natural Gas Systems* dated February 2024.

Commenter: GPA Midstream Association
Comment Number: EPA-HQ-OAR-2023-0234-0299
Page(s): 63-65**,** 102-103

Comment 8: Flawed assumptions in EPA's "Assessment of Burden Impacts" could significantly downplay the proposed rule's impact.

For the costs that are included, specific incorrect assumptions[146] include:

- *ICR, Table 1 (Labor). Combustion Emissions. Determine fuel consumption through company records and calculate emissions (to incorporate combustion slip). Onshore Petroleum and Natural Gas Gathering and boosting reporters.*

  <u>EPA assumption 72</u>: "Assumed an additional 0.5 hours per year to incorporate combustion slip into existing calculations."[153] EPA also assumes 1

occurrence/respondent/year and 354 gathering and boosting respondents/year. EPA did not assume any costs for Natural Gas Processing.

GPA comment: First, EPA failed to estimate burden for the industry segments that report their combustion emissions to Subpart C, even though this proposed rule impacts those segments.[154]

Second, as GPA has previously commented, the requisite fuel allocation that results from these changed requirements is a significant burden. EPA is proposing revisions to 98.36(c)(1) and (c)(3) to clarify that reporters must separately report equipment type (e.g., 4SRB RICE) within the same aggregation of units or common pipe configuration. The calculations necessitate using different CH_4 emission factors per equipment type, and possibly per equipment. This will result in significant burden. At gas plants, it is not common (and is possibly never the case) to have an individual fuel meter on each piece of fuel combustion equipment. Reporters use the Subpart C aggregation/common pipe methods because that aligns with how fuel meters are set up—one meter for multiple pieces of equipment. Disallowing aggregation/common pipe between compressor driver engines and other combustion units will result in much more work, because instead of simply collecting volume and composition for a meter, reporters will have to apportion fuel use for all equipment on the meter. Reporters will have to collect fuel volume, fuel composition, heat rate for each equipment, run hours for each equipment (which is often not automated), and calculate the portion of fuel use per equipment using heat rate and run hours, and multiply that portion by the total fuel volume. While GPA understands that methane emission factors cannot be mixed between equipment types, EPA must at the very least properly account for the increase in burden. We estimate at least 2 hours per year per each aggregation of units/common pipe reported under Subpart C.

For gathering and boosting, EPA assumes that for the dozens (or hundreds) of fuel combustion equipment per reported facility/basin, it will only take 30 minutes to allocate fuel to all equipment (or group of equipment) and incorporate performance test results and/or OEM data. This should be increased to 1 hour per site (as the term is proposed), not per gathering and boosting facility/basin.

Footnotes:

[146] EPA, Supporting Statement: Information Collection Request for the Greenhouse Gas Reporting Rule: Revisions and Confidentiality Determinations for Petroleum and Natural Gas Systems; Proposed rule (June 2023), Docket ID No. EPA-HQ-OAR-2023-0234-0164 ("EPA Supporting Statement").

[153] EPA Supporting Statement at 33.

[154] 88 Fed. Reg. at 50,357 (noting that "[f]or the subpart W industry segments that estimate and report their combustion emissions to subpart C, we are proposing amendments in subpart C analogous to the proposed amendments described in this section for the three industry segments that estimate and report their combustion emissions to subpart W….").

…

EPA is proposing revisions to 40 C.F.R. § 98.36(c)(1) and (c)(3) to clarify that reporters may not report a combination of one design class of compressor driver engines (using one Table W-9 CH_4 emission factor) and other combustion units (e.g., using a Table C-2 CH_4 emission factor or another Table W-9 CH_4 emission factor) in the same aggregation of units or common pipe configuration. EPA claims the proposed change does not impose any new monitoring or reporting requirements and therefore has no impact on burden. This is false. At gas plants, it is not common (and is possibly never the case) to have an individual fuel meter on each piece of fuel combustion equipment. Reporters use the Subpart C aggregation/common pipe methods because that aligns with how fuel meters are set up – one meter for multiple pieces of equipment. Disallowing aggregation/common pipe between compressor driver engines and other combustion units will result in much more work, since instead of simply collecting volume and composition for a meter, reporters will have to apportion fuel use for all equipment on the meter. Reporters will have to collect fuel volume, fuel composition, heat rate for each equipment, run hours for each equipment (which is often not automated), and calculate the portion of fuel use per equipment using heat rate and run hours, and multiply that portion by the total fuel volume. While we understand that methane emission factors can't be mixed between design classes of compressor driver engines and other combustion units, EPA must at the very least properly account for the increase in burden. We estimate at least 2 hours per year per each aggregation of units/common pipe reported under Subpart C.

Response 8: See Section VI.A.2 of the preamble to the final rule for the EPA's response to comments regarding costs related to combustion and combustion slip.

Commenter: GPA Midstream Association
Comment Number: EPA-HQ-OAR-2023-0234-0299
Page(s): 63, 65

Comment 9: Flawed assumptions in EPA's "Assessment of Burden Impacts" could significantly downplay the proposed rule's impact.

…

For the costs that are included, specific incorrect assumptions[146] include:

- EPA does not estimate a burden impact on reporting quantities "sent to sale." EPA proposes, however, that liquid hydrocarbons must quantified with flow meters, which is unworkable (see Comment 84). If EPA does not resolve this issue, the burden assessment must be increased by hundreds of millions of dollars to install liquid flow metering at every site/facility in the industry segment.

Footnote:

[146] EPA, Supporting Statement: Information Collection Request for the Greenhouse Gas Reporting Rule: Revisions and Confidentiality Determinations for Petroleum and Natural Gas Systems; Proposed rule (June 2023), Docket ID No. EPA-HQ-OAR-2023-0234-0164 ("EPA Supporting Statement").

Response 9: Costs were not estimated because it is reasonable to assume that reporters already measure the quantities sent to sale. Accurate measurement using flow meters ensures that the buyer receives the appropriate quantity of the product and that the reporter receives the appropriate payment for that quantity. Therefore, no changes have been made to costs related to the reporting of quantities sent to sale.

Commenter: GPA Midstream Association
Comment Number: EPA-HQ-OAR-2023-0234-0299
Page(s): 63-64

Comment 10: Flawed assumptions in EPA's "Assessment of Burden Impacts" could significantly downplay the proposed rule's impact.

…

For the costs that are included, specific incorrect assumptions[146] include:

…

- *ICR, Table 1 (Labor). Dump valves 1. Onshore Petroleum and Natural Gas Gathering and boosting reporters.*

  EPA assumption: 1.6 occurrences/respondent/year and 22 respondents/year.[150]

  GPA comment: The burden to be assessed should be the requirement to inspect dump valves, not the number of malfunctioning dump valves. Nearly every tank will have at least one dump valve upstream of it. As such, EPA's assumptions must be adjusted to reflect the number of tanks reported under gathering and boosting. In 2021, for gathering and boosting, 31,543 tanks were reported under calculations methods 1 or 2, [151] and 7,544 tanks were reported under calculation method 3.[152]

Footnotes:

[146] EPA, Supporting Statement: Information Collection Request for the Greenhouse Gas Reporting Rule: Revisions and Confidentiality Determinations for Petroleum and Natural Gas Systems; Proposed rule (June 2023), Docket ID No. EPA-HQ-OAR-2023-0234-0164 ("EPA Supporting Statement").

[150] EPA Supporting Statement at 13.

[151] Envirofacts GHG Query Builder at Table ef_w_atm_stg_tanks_calc1or2, Field "Atmospheric Tank Count," *available at* https://enviro.epa.gov/query-builder/ghg.

[152] *Id*. at Table ef_w_atm_stg_tanks_calc3, Field "Atmospheric Tank Count."

Response 10: See Section VI.A.2 of the preamble to the final rule for the EPA's response to comments regarding costs related to dump valve inspections.

Commenter: CrownQuest Operating
Comment Number: EPA-HQ-OAR-2023-0234-0393
Page(s): 178

Comment 11: It is of our opinion that the EPA underestimated the time and cost burden for yearly inspections of thief hatches per tank. With an estimation of ~$185/hr and ~2 hours per occurrence, this is not an insignificant cost with little to no validation of data. This is going to include thousands of tanks.

Response 11:

The comments do not match the assumptions made in the EPA's analysis. First, technicians are assumed to conduct the thief hatch inspections and their labor rate is $77.99 per hour, not $185 per hour as stated by the commenter. Second, these are simple visual inspections of the thief hatches, which should take 10 minutes per tank. No explanation was given by the commenter for the assertion that an inspection would take 2 hours per tank.

Due to the lack of more specific cost data or support for the assertions made by the commenter, the EPA determined no changes should be made after consideration of this comment.

Commenter: CrownQuest Operating
Comment Number: EPA-HQ-OAR-2023-0234-0393
Page(s): 195, 196

Comment 12: Obtaining direct lab measurement on a per facility basis annually would be extremely costly and the emissions reduction benefit would not be justified. As mentioned before, the dozens of representative samples that have been obtained are more than adequate because they are similar in pressure, GOR and formation type.

The estimated cost to obtain site specific samples annually per facility is $6,000. EPA gives no justification as to how by site sampling would improve emission reporting.

Response 12: We are not finalizing the option of using laboratory measurement of the GOR to calculate emissions from atmospheric storage tanks. See Section 14 of this document for more information related to atmospheric tanks.

Commenter: American Petroleum Institute et al. (Part 1 of 2)
Comment Number: EPA-HQ-OAR-2023-0234-0402
Page(s): 26

Comment 13: Well Venting for Liquids Unloading

EPA should not require flow meter measurements of liquids unloading venting under Calculation Method 1 as it is technically and economically infeasible.

…

The volume of gas, and associated GHG emissions, is relatively low and therefore does not warrant the additional expense and effort of measurement. In fact, the total emissions reported in 2021 for all operators was a very small percentage of overall methane emissions from onshore production.

Measuring the small volume will be extremely challenging and likely require a costly ultrasonic meter (please see the flow meter challenges discussed in more detail in Section 3.8.13.8.1 of the comments). The measurements will be challenging to obtain, as they are short duration and turbulent flow; therefore, the low flow is unlikely to be measured by a flow meter.

The rule does not account for all the added costs of a flow meter that will likely not be capable of measuring the small volume of the gas. These costs include:

- The flow meter(s)
- Labor for installation
- Loss of production for shutdowns for installation
- Retrofit the line to add a flow meter
- Expanding or adding the remote facility computer (remote oil field controller)
- Expanding or adding data storage capacity on site
- Wiring to the remote facility computer
- Expanding or adding the remote transmitting unit
- Calibration and maintenance of the flow meter
- SCADA and alarm programming
- Data management system
- Data review and analytics
- Data entry for calculations

Response 13: The EPA has decided not to finalize the changes to require Method 1 once every three years. Costs related to this amendment were inadvertently excluded from the impacts analysis at proposal, so no changes to costs have been made to the final impacts analysis as a result of this comment or the decision not to finalize this change.

Commenter: GPA Midstream Association
Comment Number: EPA-HQ-OAR-2023-0234-0299
Page(s): 63-64

Comment 14: Flawed assumptions in EPA's "Assessment of Burden Impacts" could significantly downplay the proposed rule's impact.

…

For the costs that are included, specific incorrect assumptions[146] include:

- *ICR, Table 2 (O&M). Centrifugal and Reciprocating Compressors—contractor to perform compressor leak measurements. Onshore Petroleum and Natural Gas Gathering and boosting reporters*.

  EPA assumption 51: "Assumed an average of 6 compressors per reporter (based on average number of reciprocating compressors per reporter from RY2019). NOD measurements are only required once every 3 years, so 2 compressors per year over the 3 year period of the ICR."[147]

  GPA comment: The average number of reciprocating compressors per gathering and boosting reporter in 2021 was 50.2.[148] The average number of centrifugal compressors per gathering and boosting reporter in 2021 was 4.4.[149] This should be 18.2 occurrences/respondent/year which increases the burden by nearly $3.5MM.

Footnotes:

[146] EPA, Supporting Statement: Information Collection Request for the Greenhouse Gas Reporting Rule: Revisions and Confidentiality Determinations for Petroleum and Natural Gas Systems; Proposed rule (June 2023), Docket ID No. EPA-HQ-OAR-2023-0234-0164 ("EPA Supporting Statement").

[147] *Id*. at 32.

[148] Envirofacts GHG Query Builder at Table ef_w_recip_comp_onshore, Field "Compressor Count," *available at* https://enviro.epa.gov/query-builder/ghg.

[149] *Id*. at Table ef_w_centrif_comp_onshore, Field "Compressor Count."

Response 14: The EPA has decided not to finalize the changes to require compressor measurements in NOD mode such that at the end of each calendar year, reporters have taken measurements in NOD mode over the last 3 consecutive calendar years for at least one-third of the compressors at the facility. In the final rule, measurements in NOD mode will only be required if the compressor is in NOD mode at the time of compressor measurements. The costs of complying with subpart W already account for these "as found" measurements that are included in the final rule. See Section 16 of this document for further information. Therefore, no costs are estimated for the measurement of compressors in NOD mode such that at the end of each calendar year, reporters have taken measurements in NOD mode over the last 3 consecutive calendar years for at least one-third of the compressors at the facility.

Commenter: Wyoming Department of Environmental Quality (WDEQ)
Comment Number: EPA-HQ-OAR-2023-0234-0388
Page(s): 7

Commenter: Ute Indian Tribe of the Uintah and Ouray Reservation
Comment Number: EPA-HQ-OAR-2023-0234-0421
Page(s): 1-2

Comment 15: Commenter 0388: **WDEQ respectfully requests that EPA allows for flexibility in its emissions calculation methodologies.**

Furthermore, WDEQ respectfully requests that EPA evaluate the cumulative burdens associated with simultaneously implementing the requirements of the proposed rule, as well as the proposed methane rule and supplement, proposed Bureau of Land Management regulations that affect oil and natural gas operators, proposed Pipeline and Hazardous Materials Safety Administration (PHMSA) regulations for methane emissions from pipelines, etc. The extraordinarily heavy implementation load merits flexibilities for reporting requirements in order to ensure that operators can focus attention and resources on interfacing with state regulatory agencies on permitting and compliance activities that may have more significant environmental outcomes.

Commenter 0421: The Tribe is aware that the Inflation Reduction Act of 2022 ("IRA") amended the Clean Air Act ("CAA") by adding Section 136, which, among other things, directed the EPA to revise the reporting requirements of Subpart W to ensure that reporting and calculation of charges are based on empirical data which accurately reflects total emissions from applicable facilities.

While the Proposed Rule is a statutory requirement, its impacts cannot be assessed in a vacuum and must be considered alongside the array of air quality regulations being promulgated contemporaneously with this Proposed Rule by the EPA. These regulations, cumulatively, threaten to have significant impacts on the Tribe's oil and gas-based economy. While these comments will focus on the parameters of the Proposed Rule, our underlying sentiments are a response to what could be fairly characterized as the EPA's efforts to regulate the oil and gas industry out of a profitable existence in the pursuit of its mission under the CAA and subsequent federal legislation.

Response 15: The EPA has appropriately estimated costs for the individual rulemaking at issue here, not a cumulative total of multiple separate rulemakings. Therefore, no changes have been made as a result of consideration of these comments. Where appropriate, the EPA has aligned requirements with other rules, including the final NSPS OOOOb and EG OOOOc, in order to minimize burden.

Commenter: Kirk Frost
Comment Number: EPA-HQ-OAR-2023-0234-0389
Page(s): 2

Comment 16: API submitted a comment (https://downloads.regulations.gov/EPA-HQ-OAR-2023-0234-0199/attachment_1.pdf) claiming that EPA has calculated it would cost $92,000,000 to implement the proposed rules. API also claimed "a reporting-based rule that has specific requirements to complete reporting, the paperwork burden is the same as the compliance burden because it includes operation and maintenance (O&M) and capital costs to gather the necessary data to complete reporting." There are easy engineering and programmatic approaches that would enable each facility to report these proposed changes without a significant O&M net increase in cost or labor. It is ironic, because methane emissions as detailed in the studies of this report really indicate that the emissions are out-of-control, wasteful and excessively beyond what the oil and gas have been reporting to EPA as emissions over the past 20 years. The massive emissions of methane from all source points collectively supersedes the carbon dioxide emissions due to its high atmospheric warming potential in the first ten to twenty years and the methane atmospheric feedback loop that is caused as atmospheric methane concentrations increase. This feedback extends the life of the methane and the warming potential over extended years. The resulting climate change impact costs will extend into the trillions of dollars. When oil and gas are reporting record earnings and currently not deemed liable for the damage that oil and gas greenhouse gas emissions are directly causing, I find it unremarkable that a trillion-dollar industry overall and wholly based and operated within the US is complaining and exaggerating the costs for accurate emissions reporting and control.

Response 16: No changes have been made as a result of this comment.

Commenter: GPA Midstream Association
Comment Number: EPA-HQ-OAR-2023-0234-0299
Page(s): 102, 103

Comment 17: Burden Impacts

Comment: The overall burden of $842/year per Subpart W reporter to comply with the proposed rule changes is grossly underestimated. Per Table 3-2 of the Assessment of Burden document, EPA estimates an annual average cost per reporter for reporting and recordkeeping requirements of $412 for Subpart W. EPA estimates an annual average cost per reporter for monitoring and calculation methodology of $430 for Subpart W. At a cost $91/technical labor for Subpart W, simply reading the rule once would cost $228, which is 27% of EPA's average annual cost. The rule itself contains 101 new G&B data elements. Responding to the proposed changes will require many hours of additional work for which EPA has not appropriately accounted. GPA welcomes the opportunity to further discuss development of more realistic burden estimates with the Agency.

Comment: The method of determining respondent hours is inappropriate for G&B. For G&B, EPA attests there are 101 new data elements. The calculations multiply the respondent hours by the number of reporters, but this grossly underestimates the true level of effort because there is not one data element per reporter; the data element is repeated by the number of applicable pieces of equipment within the basin, which could be hundreds. For any new data element that is reported per equipment (i.e., more than once per report), EPA must assess how many affected pieces of equipment would have a new data element and use that number as the multiplier (not simply the number of reporters). EPA has all the data necessary to perform these calculations. If EPA assumes that a data element which may need to be reported for hundreds of pieces of equipment within a basin takes a grand total of 3 minutes per year per reporter to gather, QA/QC, and report, then EPA is completely detached from the reality of reporting under this rule.

Comment: In the Cost Spreadsheet, EPA nets out removed data elements from the cost estimate. This is inappropriate. For the initial year of reporting, any change results in work, even the exclusion of data elements. This is because reporters need to update their documentation, procedures, databases, and report mapping to remove these elements. Removed elements result in work. As such, the removal of a data element doesn't somehow negate the burden of an additional data element, especially in the first year of reporting when reporters must update procedures, documentation, calculations, databases, reporting mapping, etc.

…

Comment: The time estimated per data element is too low, especially for calculated data elements. Per the Cost Spreadsheet tab "W (Data Elements)", EPA estimates 0.05 hours per data element, or 3 minutes per data element. EPA claims in the Assessment of Burden document that "There are no capital or operation and maintenance costs associated with the proposed revisions to add, revise, or remove data elements, because the proposed data elements may generally be obtained from existing company records or are readily available from existing information gathered under part 98, therefore, no additional monitoring or sampling is required" and "With the exception of new data elements required of reporters using the aggregation of units or common pipe configuration under subpart C, EPA assumed 3 minutes of technical labor to calculate each data element using readily available data and to submit the value via e-GGRT or enter the value into IVT." We do not understand how EPA can, with a straight face, assume such a tiny amount of time to gather the necessary data, calculate, QA/QC and report. GPA members anticipate spending a significant amount of time (e.g., months) gathering information, updating database calculations, updating reporting mapping, and updating QA/QC procedures just to initially set up the structure required to comply with these rules. This is far cry from EPA's estimate of a grand total of 6.84 hours of additional effort per year per G&B reporter and 3.68 hours per year per Processing reporter. At the very least, EPA needs to differentiate between data elements that are simple reporting elements (like count of pumps) versus data elements that have calculations behind them (like parsing out flare volumes and emissions data between different flared sources or calculating a flow-weighted basin average tank flash gas composition). While it *might* be appropriate to estimate *some* of the simple reporting elements at 3 minutes annually, any element involving a volume, emission, or composition calculation should be estimated at no less than 15 minutes.

Response 17: This comment was included as an attachment to the commenter's letter, but it is a comment on the 2022 GHGRP Proposal and is not relevant to the 2023 Subpart W Proposal or this final rule.

Commenter: GPA Midstream Association
Comment Number: EPA-HQ-OAR-2023-0234-0299
Page(s): 103-104

Comment 18: Burden Impacts

Comment: EPA assumes the following changes have no significant impact on burden. These changes include new emission source measurements, calculations, and reporting requirements that must be incorporated into a reporting program. This reporting rule is prescriptive, complex, and expansive; most midstream reporters have implemented one or multiple databases to make the workload manageable. Operators also have documentation, QA/QC procedures, and other tools to ensure the data is complete and potentially auditable by a third party. As such, *any* change in measurements, calculations or how information is to be reported (even changes that are meant to simplify or clarify) will likely result in work. Operators must update documentation, redo training, change QA/QC procedures, update data collection systems, update database calculations, and update report mapping. It is incorrect to assume changes to measurements, calculations, or reporting have no significant impact on burden.

- Adding add standby-pressurized-mode to the defined modes for centrifugal compressors.
- Measurement of rod packing leaks from reciprocating compressors when found in standby-pressurized mode.
- Revise § 98.233(r)(2) to state that the gas service emission factors and default component counts in Table W-1A and Table W-1B should be used for all subject components at Onshore Petroleum and Natural Gas Gathering and Boosting facilities.
- Revise reporting elements related to flare stacks in § 98.236(e), (g), (h), (j), (k), (l), and (m) to include the data elements formerly reported in § 98.236(n).
- Clarifying edits to § 98.236(j) related to open thief hatches for atmospheric storage tanks.
- Revise the reporting elements for atmospheric tanks from "the minimum and maximum concentrations (mole fractions) of CO_2 and CH_4 in the tank flash gas" to "the flow-weighted average concentration (mole fraction) of CO_2 and CH_4 in the flash gas" in § 98.236(j).
- Modify reporting requirements in § 98.236(n) to capture information only from "miscellaneous flared sources" (i.e., emission sources which are not listed separately in the reporting form or in the XML schema).

Response 18: The labor costs to comply with subpart W already include reporting and recordkeeping costs detailed in EPA ICR number 2300.18. Those costs cover the amount of time needed to report through e-GGRT and the amount of time needed to maintain records, including all of the emission sources listed above.

In addition, each of the emission sources above already include labor, operation and maintenance (O&M), and capital costs related to measurements, monitoring, counting, and inspections to gather the information required by the rule. The only change from proposal to final is the inclusion of additional annual O&M costs of $1.1 million for a contractor to measure compressor vents, which includes the addition of standby-pressurized mode to the defined modes for centrifugal compressors and the addition of required measurements of rod packing leaks from reciprocating compressors when found in standby-pressurized mode.

The EPA disagrees that additional costs are needed to account for the remaining reporting elements above. While there are changes to the elements, the new requirements are similar enough to the existing requirements that these changes will result in no significant impact on burden.

All costs are detailed in the information collection request (ICR) document OMB Number 2060-0751 (EPA ICR number 2774.02) and the memorandum *Assessment of Burden Impacts for Greenhouse Gas Reporting Rule: Revisions and Confidentiality Determinations for Petroleum and Natural Gas Systems* dated February 2024.

26 Other Executive Orders

Commenter: CrownQuest Operating
Comment Number: EPA-HQ-OAR-2023-0234-0393
Page(s): 360

Comment 1: EPA is stating that this new rule will no effect small entities, however with the span of entity sizes, no entity effects or clarity are provided. This document is so confusing, how would a small entity of 5-6 employees are subject to the rule.

Response 1: The EPA conducted a small entity analysis that assessed the costs and impacts to small entities in the development of the proposed rule, and has updated this analysis to reflect revised costs in the development of the final rule. Details of this analysis are in the memorandum *Assessment of Burden Impacts for Greenhouse Gas Reporting Rule Revisions for Petroleum and Natural Gas Systems* available at Docket Id. No. EPA-HQ-OAR-2023-0234. To evaluate the impacts to small entities, the EPA conducted an analysis to estimate cost-to-revenue ratios (CRR) based on the total annualized costs of the proposed rule and reported parent company revenues for various business sizes. The CRR provides a measure of the cost of compliance relative to the entities' income or assets and can highlight the type of entities likely to face more substantial costs. The EPA's analysis acknowledges that some small entities in the smallest business sizes (1-19 or 20-99 employees) could have cost-to-revenue ratios exceeding 1% and 3%. However, EPA determined that there are only a limited number of small entities (73-75 entities) for which costs would likely have an impact of greater than 3%; these impacts are likely limited to entities with facilities in the onshore petroleum and natural gas production and onshore natural gas processing industry segments. Based on the small proportion of small entities that may have an impact exceeding 3% (6.3% to 14.0% of all affected small entities), EPA concluded that the final rule costs are not likely to have a significant impact on a substantial number of small entities.

Commenter: National Tribal Air Association (NTAA)
Comment Number: EPA-HQ-OAR-2023-0234-0239
Page(s): 2-3

Commenter: Ute Indian Tribe of the Uintah and Ouray Reservation
Comment Number: EPA-HQ-OAR-2023-0234-0421
Page(s): 3

Comment 2: Comment 0239: Methane is a potent greenhouse gas with at least 25 times the global warming potential of carbon dioxide.[1] Because climate change "impacts subsistence resources, contributes to wildfires, road dust, flooding, and impacts Tribes across the country,"[2] ensuring robust regulation of methane is of paramount importance to many Tribes.

Methane emissions disproportionately burden Indigenous communities. For example, the Navajo Nation has 65% higher methane emissions from oil and gas companies than the national average.[3] An analysis by Environmental Defense Fund and Taxpayers for Common Sense found that oil and gas companies on public and Tribal lands wasted over $500 million worth of gas in 2019, suggesting that these emissions are an issue across Tribal lands.[4]

The emissions from oil and natural gas sources not only contribute to climate impacts, but seriously burden the health of nearby Tribal communities. Ozone-forming VOCs and HAPs like benzene are emitted alongside methane. Inhalation of these dangerous pollutants can lead to irreversible lung damage, asthma attacks, and cancer, and Tribal communities already suffer from these illnesses at disproportionate rates. Properly measuring methane emissions is one step in the EPA's overall efforts to reduce those emissions and related emissions from the oil and natural gas sector.

…

<u>Tribal Implications</u>

In this rulemaking, the EPA must look at the environmental justice implications of the proposed action and seek to advance equity for all. While environmental justice concerns may apply to many American Indian/Alaska Native (AI/AN) communities, the NTAA urges that the EPA properly address environmental justice concerns. That concern for environmental justice, however, cannot replace government-to-government consultation with Tribes. Tribes are sovereign nations with self-determination and cannot be treated the same as environmental justice communities.

Each Tribe's unique circumstances must be evaluated. As the EPA knows, public listening sessions and training webinars are helpful but not sufficient. The EPA must consult directly with Tribes on a government-to-government basis and must evaluate the proposed rule's unique impacts to Tribes.

Footnotes:

[1] EPA, Understanding Global Warming Potentials, *available at* https://www.epa.gov/ghgemissions/understanding-global-warming-potentials, last accessed Feb. 11, 2023 (explaining that methane is estimated to have a global warming potential of 27-30 over 100 years).

[2] National Tribal Air Association, Status of Tribal Air Report 2022, at 28, *available at* https://www.ntaatribalair.org/status-of-tribal-air-report/.

[3] Audrey Carleton & Briana Flin, "Methane Is Leaking Over Native Grounds. Citizen Scientists Are Fighting Back" (July 13, 2022), https://nexusmedianews.com/methane-is-leaking-overnative-grounds/ (citing Environmental Defense Fund, "New Report Reveals Scale of Natural Gas Waste on Navajo Nation Lands," (Mar. 21, 2019), https://www.edf.org/media/new-reportreveals-scale-natural-gas-waste-navajo-nation-lands); American Lung Association, "State of the Air" 2022 Report Cards: New Mexico, San Jan County, https://www.lung.org/research/sota/cityrankings/states/new-mexico/san-juan.

[4] Griot, O, et al., Onshore Oil and Natural Gas Operations on Federal and Tribal Lands in the United States: Analysis of Emissions and Lost Revenue (Jan. 26, 2023), *available at* https://www.edf.org/media/new-study-quantifies-natural-gas-wasted-us-public-and-tribal-lands

Commenter 0421: In conclusion, we ask that EPA defer to the Tribe for implementation of measures on our Tribal lands and carefully consider the implementation timelines of contemporaneous air quality regulations. We encourage the EPA to explore off-ramps or fee implementation extensions for operators producing Tribal assets. Such an option would allow for continued innovation toward sustainable production, cleaner ambient air, and would most importantly reduce obstacles to Tribal energy development and economic self-determination. …

Our Tribe, like others, must carefully balance the health concerns of our members with the economic viability of our sovereign government. Therefore, while there are parts of the Proposed Rule that we may support, we caution the EPA against overregulation in its continued proliferation of air quality standards and ask that you defer to Tribal law where applicable.

Response 2: In response to the comment that the EPA must look at the environmental justice implications of the proposed action, the EPA considered the environmental justice impacts associated with the revisions in the development of the rule; in general, the EPA concluded that the human health or environmental risk addressed by this action would not have direct human health or environmental effects on minority, low-income, or indigenous populations. Although this rule does not directly affect human health or environmental conditions, the EPA identified and addressed environmental justice concerns by developing requirements that improve the quality of data available to communities. The EPA has developed improvements to the GHGRP in the final rule that benefit the public, including environmental justice communities, by increasing the availability, completeness, and accuracy of facility emissions data and relevance of this information to their communities. We have noted that data collected through this action will provide an important data resource for communities and the public to understand GHG emissions, including requiring reporting of GHG data from additional emission sources (i.e., other large release events, nitrogen removal units, produced water tanks, crankcase venting, and mud degassing), and locations of emissions sources. The rule also improves the emissions estimation methodologies of subpart W, ensures reporting is based on empirical data and accurately reflects total methane emissions and waste emissions from affected facilities, and improves the quality of the data collected under the program and available to communities. The EPA believes that the transparency provided by the data reported under these final revisions will ultimately encourage and result in reduction of GHG emissions and other co-pollutants, such as hazardous air pollutants and volatile organic compounds.

The EPA acknowledges the comment that addressing environmental justice concerns does not preclude the EPA from conducting Tribal consultations or consideration of Tribal impacts. In assessing the potential impacts of the proposed revisions to Tribal communities, the EPA considered both petroleum and natural gas facilities directly owned by Tribes and affected by the rule, as well as the impacts to communities where certain facilities (e.g., production wells) not owned by Tribes but subject to the rule are located on Tribal land. The EPA, therefore, took a number of steps to consult with and obtain input from tribal governments and representatives during the development of the rule. As noted in the preamble to the proposed rule, on November

4, 2022, the EPA published an early request for information (RFI) seeking public comment on a range of questions related to the Methane Emissions Reduction Program, including subpart W revisions (see Docket Id. No. EPA– HQ–OAR–2022–0875). The EPA received comments on the RFI from one tribal entity relevant to subpart W and considered these comments during the development of the proposed rule. On July 11, 2023, the EPA subsequently invited all 574 federally-recognized Tribes, Alaska Native Villages, and Alaska Native Corporations to consult on the proposed revisions at a date and time developed in consultation with Tribes requesting consultation, with an anticipated consultation timeline of September 4, 2023; a copy of this letter is available in the docket to this rulemaking. Only one Tribe participated in government-to-government consultation with the EPA. In response, the EPA met with the Ute Indian Tribe's Business Committee via video conference at 3:30 p.m. Eastern Time on September 20, 2023. The EPA provided several other opportunities for tribal input; the EPA opened the rule for public comment from August 1 to October 2, 2023, and hosted a virtual public hearing for the proposed revisions on August 21, 2023. The EPA provided a subsequent informational webinar on the technical aspects of the rule on September 7, 2023. The EPA has considered the tribal input from the coordination and consultation calls, informational webinar, and public comments in the development of the final rule.

The final rule has tribal implications. However, it does not impose any direct implementation responsibilities on Tribal governments, does not preempt Tribal law, and does not require the development of any implementation plans. This regulation will apply directly to petroleum and natural gas facilities that may be owned by tribal governments that emit GHGs. However, it will generally only have tribal implications where the tribal entity owns a facility that directly emits GHGs above threshold levels; therefore, relatively few tribal facilities will be affected. This rule implements revisions to subpart W consistent with the EPA's CAA authority and directives set forth in CAA section 136(h) to ensure that reporting is based on empirical data, accurately reflects total methane emissions and waste emissions from applicable facilities, and allows owners and operators of applicable facilities to submit empirical emissions data to demonstrate the extent to which a waste emission charge is owed. However, this rule does not implement the waste emissions charge and the EPA did not propose requirements related to implementation of the waste emissions charge, off-ramping related to the waste emissions charge, or charge implementation; therefore, such comments are outside the scope of this rulemaking. The EPA issued a proposed rule to implement the waste emissions charge and provided an opportunity for public comment in that separate rulemaking. We add that, in developing the amendments to subpart W, the EPA has in some cases referenced or incorporated the final requirements of NSPS OOOOb and EG OOOOc into Part 98, in order to allow facilities to use consistent methods to demonstrate compliance with multiple EPA programs to streamline implementation and reduce burden. The Part 98 requirements are aligned with the implementation of the NSPS and EG, and will not apply to individual Part 98 reporters unless and until their emission sources are required to comply with either the NSPS OOOOb or an approved state plan or applicable Federal plan in 40 CFR part 62. For the EPA's response to comments regarding final requirements of the NSPS and EG referenced or incorporated into Part 98 specific to flares, compressors, or equipment leak surveys in the final rule, see Sections 15 through 17 of this document, respectively; for the EPA's response to comments related to overlap of the final rule with other proposed regulations, see Sections 28.4 and 28.5 of this document.

Commenter: Arkansas Independent Producers and Royalty Owners (AIPRO)
Comment Number: EPA-HQ-OAR-2023-0234-0382
Page(s): 7-8

Comment 3: <u>“Significant Energy Action” Determination:</u>

AIPRO strongly objects to the determination below found in the preamble to the proposed GHGRP revisions:

“H. <u>Executive Order 13211: Actions That Significantly Affect Energy Supply, Distribution, or Use</u>: “This action is not a ‘‘significant energy action’’ because it is not likely to have a significant adverse effect on the supply, distribution or use of energy. The proposed amendments would expand reporting to include new emission sources; add, remove, or refine emissions estimation methodologies improve the accuracy and transparency of reported emission data; for the Onshore Natural Gas Production and Onshore Natural Gas Gathering and Boosting segments, revise reporting of emissions from a basin level to a site level; implement requirements to collect new or revised data; clarify or update provisions that have been misinterpreted; or streamline or simplify requirements by increasing flexibility for reporters or removing redundant requirements. We are also proposing revisions that streamline or simplify requirements or alleviate burden through revision, simplification, or removal of certain calculation, monitoring, recordkeeping, or reporting requirements. In general, these changes would not have a significant, adverse effect on the supply, distribution, or use of energy. In addition, the EPA is proposing confidentiality determinations for new and revised data elements proposed in this rulemaking and for certain existing data elements for which a confidentiality determination has not previously been proposed. These proposed amendments and confidentiality determinations do not make any changes to the existing monitoring, calculation, and reporting requirements under subpart W and are not likely to have a significant adverse effect on the supply, distribution, or use of energy.” (FR p. 50373)

Further, AIPRO argues that the proposed revisions to the GHGRP, especially when combined with the proposed NSPS OOOOb and EG OOOOc rules and the “waste emissions charge” (or “methane tax”) provisions of the Inflation Reduction Act (“IRA”), absolutely represent a “Significant Energy Action.” The combined effects of the proposed rules and IRA legislation will likely cause the following:

- Many low producing (“marginal”) wells and related oil & gas operations would become uneconomic and therefore be shut-in or idled.
- Inflated operating costs (quite the opposite of inflation reduction), including compliance and tax costs, for wells and associated oil & gas operations that are able to bear the burden of the costs.
- Sources of capital investment for the oil & gas industry, which are already becoming sparse, will continue to be driven away or, at a minimum, the cost of capital will continue to significantly increase, and ultimately:
- Result in higher commodity prices for end users of oil & gas in America.

In aggregate, these inevitable impacts very much represent a "Significant Energy Action" and a threat to the affordable and reliable American oil & gas resources that provide the majority of energy to America.

Response 3: The EPA disagrees with the commenter's assertion that the Agency must account for the cumulative regulatory impacts of separate rules in determining whether this subpart W rulemaking is a significant energy action under Executive Order 13211. Executive Order 13211 requires agencies to consider, for certain regulatory actions that are a "significant energy action", the potential adverse effects of the specific regulatory action on energy supply, distribution, and use. EO 13211 defines a "significant energy action" as a significant regulatory action under EO 12866 that is likely to have a significant adverse effect on the supply, distribution, or use of energy or that is designated by the administrator of the Office of Information and Regulatory Affairs as a "significant energy action." As such, any analysis is designed to evaluate the direct effect of a specific regulatory action, rather than assess the effects of other rulemaking processes. Given that individual rulemakings within and outside the agency may be subject to separate authorities, Congressional directives, or Court-ordered requirements; follow separate review processes and schedules; and are refined through the public comment and response process, the EPA appropriately accounts for the effects associated with the requirements of a specific action.

As noted in the preamble to the proposed rule, this rule implements improvements and revisions to subpart W consistent with our CAA authority and directives set forth in CAA section 136(h) to ensure that reporting is based on empirical data, accurately reflects total methane emissions and waste emissions from applicable facilities, and allows owners and operators of applicable facilities to submit empirical emissions data to demonstrate the extent to which a waste emission charge is owed. However, EPA did not propose requirements to implement the waste emissions charge in this rule and this final rule does not implement the waste emissions charge. The EPA proposed a separate rulemaking related to the implementation of the Methane Emissions Reduction Program on January 26, 2024 (89 FR 5318) and has assessed the potential effects of the proposed amendments to implement the waste emissions charge, including whether the action is a "significant energy action," therein. Details of this analysis may be found in Docket Id. No. EPA–HQ–OAR–2023–0234.

Concerns regarding the effects of other specific rulemakings on energy supply, distribution, or use cited by the commenter are outside of the scope of this rulemaking and should be appropriately submitted to the specific rulemaking of concern. We note that in reviewing the amendments to subpart W, the EPA has taken the requirements of the NSPS OOOOb and EG OOOOc into consideration in developing the rule and referenced or incorporated consistent requirements into Part 98 where possible to streamline monitoring and reporting. We also note that the EPA previously evaluated the effects of the requirements in the NSPS OOOOb and EG OOOOc rule, as reflected in the preamble for that separate final rule.

Commenter: Public Hearing Transcript
Comment Number: EPA-HQ-OAR-2023-0234-0224

Page(s): 18 (Shaina Oliver), 24 (Joan Brown), 43-44 (Shanna Edberg), 48-49 (Lisa Finley-DeVille)

Comment 4: Today we're really pushing for, you know, being from a disproportionately impacted community where a lot of our communities have been pushed near oil and gas lines, and as well as the need for pipeline safety is urgent for those communities that are disproportionately impacted by oil and gas, by the unknown and unseen pipeline service of oil and gas, we really do need to make sure that we have the most advanced and available technology reporting accurate data of leak detection around pipelines and emissions, and reducing those hazards in our community and to protect our environment, as we see that extreme heat is real in our communities and a lot of communities are disproportionately impacted this year due to the extreme heat and weather events that are currently taking place. It is very urgent for this administration to take seriously and act on measures that will cut methane from pipeline services that are transporting natural gas, which is really detrimental to our environment and further contributes to climate change and to the crisis that we're seeing and will further cost our communities a lot of funding to repair our community after devastations like we've had in the past, like in the Firestone neighborhood with the pipeline leak explosion that happened to the community here in Colorado. We really do need to make sure and ensure that we have the most available, advanced technology being utilized and reporting systems that ensure that we are meeting greenhouse gas reductions through these programs that are available right now and to really ensure that our communities are being protected. And being from a tribal community, I am from the Navajo Reservation and Tribal Affiliate, and seeing the devastation of extraction at all levels, we continue to be undermined for our public health and safety, so I really push for this administration to urge you to take the steps in ensuring that our communities are being protected.

…

During our retreats, we also listen to community members and hear concerns, many concerns of health related to air quality and water in the Permian basin region. And while large corporations and a few people in power are making the most money in the region, that region suffers great economic inequity and there are also many Hispanic residents and new immigrants. So, these rules must address environmental justice concerns, which have been lifted up by the Biden administration as a priority.

…

We are a Latino-led, Latino-serving non-profit with a mission to connect Latinos with partners and opportunities to improve lives and create an equitable society. And I'm speaking here today because from start to finish, the oil and gas system has harmed our Latino communities and communities of color, from the on and offshore drilling that overwhelmingly pollutes our communities; to the burning of oil and gas on our highways and power plants and in dangerous pipelines located disproportionately close to neighborhoods of color; to, as has been vividly seen these past weeks, the storms, drought, extreme heat and out of control wildfires caused by the climate crisis. We're harmed at every step. So, I'm here today to begin to remedy this injustice because better data is the foundation for better policy and accountability. And this is also a critical rule for furthering the goals of the Inflation Reduction Act. Recognizing the disproportionate harm that the oil and gas system has historically inflicted on communities of color, it is imperative that this rule be further strengthened to protect current and future generations from the devastating effects of climate change and local air pollution caused by methane and greenhouse gas emissions.

…

Me, my family and community are living in a doubly sacrificed zone. First, we are negatively impacted by the immediate effects from living in proximity to oil and gas activity. Second, in dealing with impacts of climate change that have been felt throughout my community including drought, fire, and extreme weather events. Mitigating these impacts will ensure that our future generations have clean water, clean air, and clean land to grow food and to live. Native American land has been under attack since the arrival of Europeans. Mother Earth is our identity and when we hurt Mother Earth, we hurt ourselves. … Climate change will be the end of us all. My ancestors fought to protect Mother Earth for their future generations just as I fight today for future generations. Those of us who live near oil and gas activity know that we are being affected. Our lived experience does not match what's being reported by industry. … This is a major environmental justice issue from EPA. Mine is not the only marginalized community to pay with our health, our land, and our future, and I appreciate the opportunity to speak and I hope your changes to Subpart W are strong, lasting, and just.

Response 4: The EPA acknowledges the commenter's support for better data and to further strengthen the rule to address environmental justice concerns. The EPA considered the environmental justice impacts associated with the proposed revisions in the development of the rule; in general, the EPA concluded that the human health or environmental risk addressed by this action would not have direct human health or environmental effects on minority, low-income or indigenous populations. Although this rule does not directly affect human health or environmental conditions, we expect it will affect environmental justice concerns by greatly improving the availability, accuracy, and relevance of information about pollution in their communities. The EPA has developed improvements to the GHGRP in the final rule that benefit the public, including environmental justice communities, by increasing the completeness and accuracy of facility emissions data. The data collected through this action will provide an important data resource for communities and the public to understand GHG emissions, including requiring reporting of GHG data from additional emission sources (i.e., other large release events, nitrogen removal units, produced water tanks, crankcase venting, and mud degassing), and locations of emissions sources. The rule also improves the emissions estimation methodologies of subpart W, ensures reporting is based on empirical data and accurately reflects total methane emissions and waste emissions from affected facilities, and improves collection of data to support verification of GHG emissions and transparency. The revision of requirements within certain industry segments to collect data at the well-pad and gathering and boosting site-level, and the required reporting of geographical coordinates for other large release events, will provide communities with additional, more localized information on GHG emissions that is relevant to their concerns. Although the emissions reported to the EPA by reporting facilities are global pollutants, many of these facilities also release pollutants that have a more direct and local impact in the surrounding communities. GHGRP data are easily accessible to the public via the EPA's online data publication tool (FLIGHT), which allows users to view and sort GHG data from over 8,000 entities in a variety of ways including by location, industrial sector, type of

GHG emitted, and provides supplementary demographic data that may be useful to communities with environmental justice concerns. Transparent, standardized public data on emissions allows for accountability of polluters to the public.

Finally, the EPA has promoted meaningful engagement from communities in developing the action, and in developing requirements that improve the quality of data submitted to the EPA, which are also available to communities as consistent with the EPA's confidentiality determinations. The EPA provided several opportunities for public engagement; the EPA opened the rule for public comment from August 1 to October 2, 2023, and hosted a virtual public hearing for the proposed revisions on August 21, 2023. The EPA provided a subsequent informational webinar on the technical aspects of the rule on September 7, 2023.

For EPA's response to comments related to alternative measurement technologies to improve data collection, see Sections 23 and 24 of this document. For EPA's response to comments related to "other large release events", see Section 3 of this document. For EPA's response to comments related to overlap of the final rule with other proposed regulations, including pipeline safety regulations, see Sections 27.6 and 28.4 of this document.

27 Authority and Implementation

27.1 Legal Authority

Commenter: American Exploration and Production Council
Comment Number: EPA-HQ-OAR-2023-0234-0295
Page(s): 29

Commenter: GPA Midstream Association
Comment Number: EPA-HQ-OAR-2023-0234-0299
Page(s): 10-11

Commenter: Western Energy Alliance
Comment Number: EPA-HQ-OAR-2023-0234-0399
Page(s): 14

Commenter: American Petroleum Institute et al. (Part 1 of 2)
Comment Number: EPA-HQ-OAR-2023-0234-0402
Page(s): 14-15

Commenter: Environmental Defense Fund, et al.
Comment Number: EPA-HQ-OAR-2023-0234-0413
Page(s): 5-6

Comment 1: Commenter 0295: **EPA's Proposal exceeds the scope of Congress's delegation of authority in the new CAA § 136.**

Congress's directive to revise Subpart W has two inextricably linked purposes.

Congress intended EPA to make revisions to subpart W for two specific and tightly interwoven purposes: reporting accuracy and accurate charge calculation. But EPA's Proposal contains extraneous material that goes beyond Congress's direction.

Subsection (h) of CAA 136, 42 U.S.C. § 7436(h), reads in full (emphases added):

Reporting
Not later than 2 years after August 16, 2022, the Administrator *shall revise* the requirements of *subpart W* of part 98 of title 40, Code of Federal Regulations, *to ensure the reporting under such subpart, and calculation of charges* under subsections (e) and (f) of this section, *are based on empirical data*, including data collected pursuant to subsection (a)(4), *accurately reflect* the total methane emissions and waste emissions from the applicable facilities, *and allow* owners and operators of applicable facilities to submit empirical emissions data, in a manner to be prescribed by the Administrator, *to demonstrate the extent to which a charge under subsection (c) is owed*.

This provision directs EPA to revise Subpart W for two reasons, and two reasons only:

1. to ensure that reporting under that subpart is based on empirical data, accurately reflects total emissions from applicable facilities, and allows owners and operators of applicable facilities to submit empirical emissions data, and

2. to ensure that the calculation of charges under the MERP program provisions elsewhere in new CAA § 136 is *also* based on empirical data, accurately reflects total emissions from applicable facilities, and allows owners and operators of applicable facilities to submit empirical emissions data.

Notably, the text and structure of subsection (h) reveals that these are *not truly two independent reasons* for the revisions to the GHGRP that the subsection directs. Instead, *both* the "ensure the reporting under such subpart [W]" *and* the "calculation of charges under subsections (e) and (f) are directed towards the same "what" or "goal" (EPA needs to "ensure" that both the reporting under W and the calculation of the charges are to be based on empirical data etc. etc.) and the same "why" or "purpose" to demonstrate the extent to which a charge under subsection (c) is owed."

The two directives of subsection (h) to EPA are therefore so tightly interwoven that it's far from clear whether they can even be said to be *separate* directives at all in any meaningful sense. Regardless, they are certainly not *independent* from each other. Even if this language and syntax are arguably ambiguous and could be read other than as set forth above, EPA's Proposal doesn't offer *any* interpretation of this language, other than two implicit (and unreasoned) assumptions that: (a) these are independent goals and EPA is free to pursue them siloed off from one another, in a sequence and timing of its choosing, and (b) EPA is free in the course of this rulemaking to pursue whatever other policy goals it wants to. The first assumption is incorrect for reasons stated above, and the latter for reasons stated below.

Crucially, even if for the sake of argument EPA *could* have relied on its general CAA 114 reporting authority as a justification for some of these extraneous proposed changes *before* Congress enacted the MERP, it *cannot* do so now. And this is all the more true with respect to CAA 301, EPA's general "necessary and proper" authority, which provides EPA with no additional substantive authority beyond that provided by the rest of the CAA, and which in any case EPA does not meaningfully invoke here beyond one passing reference with no further analysis.

A fundamental axiom of statutory interpretation is that the specific controls the general. Congress has told EPA to revise Subpart W for specific purposes. EPA has not provided any reason here to depart from that specific direction and propose revisions to Subpart W other than those of the sort and aimed at the goal that Congress explicitly directed. Bare references to its *general* authority under CAA 114 are insufficient. Congress in Section 136 simply did not provide any free-floating residuum of direction to EPA to revise Supbpart W for any purposes beyond the two tightly interrelated purposes described above. EPA must not use this rulemaking to adopt any provisions that are not tailored to those purposes.

Commenter 0299: **EPA is subject to section 136 of the CAA in conducting this rulemaking, which constrains its authority.**

In the Inflation Reduction Act, Congress established the "Methane emissions and waste reduction incentive program for petroleum and natural gas systems," which it codified as section 136 of the CAA.[7] EPA claims that section 136 provides it with "newly established authority."[8] As EPA acknowledges, this rulemaking directly responds to the mandate from Congress in CAA section 136(h) that EPA revise Subpart W.[9] Congress was very explicit in section 136(h) regarding the scope of EPA's revision of Subpart W. Specifically, Congress expressly stated that the purpose of this revision is to ensure that charges for methane emissions in excess of a congressionally established waste emissions threshold "are [(1)] based on empirical data, … [(2)] accurately reflect the total methane emissions and waste emissions from the applicable facilities, and [(3)] allow owners and operators of applicable facilities to submit empirical emissions data … to demonstrate the extent to which a charge … is owed."[10] EPA's authority in this rulemaking is thus constrained to fulfilling this purpose and anything outside this limited scope runs afoul of Congress's clear directive and the plain language of section 136(h) of the CAA.

To attempt to broaden its authority in this rulemaking, EPA also says it is relying on section 114(a)(1) of the CAA. EPA says this provision provides it with "broad authority to require the information proposed to be gathered by this rule because such data would inform and are relevant to the EPA's carrying out of a variety of CAA provisions."[11] But EPA's authority to collect information under section 114 is specifically circumscribed. Under that provision, the Administrator may require the submission of information "[f]or the purpose … of developing or assisting in the development of any implementation plan under" sections 110 or 111(d) of the CAA, any standard of performance under section 111, any emission standard under section 112, regulations related to solid waste, or for purposes "of determining whether any person is in violation of any such standard or requirement of such a plan."[12] None of these purposes apply to the GHGRP, and EPA appropriately does not rely on any of these provisions. Rather, EPA relies on the catch-all provision at the end of section 114(a)(1) that further authorizes the collection of information for the purpose of carrying out any provision of the CAA (with the exception of those portions of Title II of the CAA that apply to a manufacturer of new motor vehicles or their engines).[13]

But, prior to the promulgation of the GHGRP, EPA had never used the catch-all provision of section 114(a)(1) to require the indefinite, if not permanent, gathering and reporting of data. As GPA has pointed out previously, GPA "remains concerned that EPA has not explained, consistent with the limits on the agency's section 114 authority, … the information EPA needs to ensure compliance with rules it has already promulgated" and EPA's primary focus in rulemakings involving the GHGRP should be "tailoring reporting requirements to what is needed to determine whether any source is in violation of an applicable standard."[14] The enactment of section 136(h) now provides the answer to that question. Namely, EPA must tailor the reporting requirements of Subpart W to ensure that any charges under the methane emissions and waste reduction incentive program be "based on empirical data, … accurately reflect the total methane emissions and waste emissions from the applicable facilities, and allow owners and operators of applicable facilities to submit empirical emissions data … to demonstrate the extent to which a charge … is owed."[15] Anything beyond this limited purpose established by Congress exceeds EPA's authority under the CAA.

Footnotes:

[7] Pub. L. No. 117-169, Title VI, § 60113, 136 Stat. 2073 (Aug. 16, 2022).

[8] 88 Fed. Reg. at 50,285.

[9] Id. at 50,284 ("EPA is proposing revisions to Subpart W consistent with the authority and directives set forth in CAA section 136(h)….").

[10] CAA § 136(h), 42 U.S.C. § 7436(h).

[11] 88 Fed. Reg. at 50,285.

[12] CAA § 114(a), 42 U.S.C. § 7414(a).

[13] Id.; see also 88 Fed. Reg. at 50,285-86

[14] GPA, Comments on EPA's Proposed Rulemaking "Revisions and Confidentiality Determinations for Data Elements Under the Greenhouse Gas Reporting Rule" at 8 (Oct. 6, 2022), Doc. ID No. EPA-HQ-OAR-2019-0424-0192 ("GPA Comments on 2022 Proposed Rule") (attached hereto as Attachment A and incorporated by reference).

[15] CAA § 136(h), 42 U.S.C. § 7436(h).

Commenter 0399: The proposed rule represents a far more exhaustive overhaul of emissions calculation and factors than previous years' changes. The Alliance believes the scope of the changes as well as the huge increase in reported emissions are strong indicators that EPA has overstepped with this rule. EPA should consider how implementing such an overreaching rule that contrasts with other ongoing rulemakings will lead to confusion, impracticalities, and legal vulnerabilities.

Commenter 0402: Subpart W and the Waste Emissions Charge Program

EPA does not explain how the direction in CAA§136(h) in conjunction with CAA § 114 provides authority for EPA to develop extensive requirements in order to collect empirical data.

The text of CAA §136(h) provides:

(h) REPORTING.—Not later than 2 years after the date of enactment…the Administrator shall revise the requirements of subpart W of part 98 of title 40, Code of Federal Regulations, to ensure the reporting under such subpart, and calculation of charges under subsections (e) and (f) of this section, are based on empirical data, including data collected pursuant to subsection (a)(4), accurately reflect the total methane emissions and waste emissions from the applicable facilities, and allow owners and operators of applicable facilities to submit empirical emissions data, in a manner to be prescribed by the Administrator, to demonstrate the extent to which a charge under subsection (c) is owed.

Thus, EPA is charged with updating Subpart W reporting to allow for the use of empirical data in reporting methane emissions that will ultimately become the emissions input to calculating the WEC. EPA does not explain in the Proposed Rule how this new congressional direction, layered on top of CAA § 114, provides authority for EPA to develop extensive requirements for installation of monitoring equipment or sampling to acquire empirical data. In the preamble to this Proposed Rule, EPA failed to discuss its definition of empirical data or its views on what costs for implementation would be reasonable for collecting information under the program. Furthermore, in the discussion of new requirements for individual sources under Subpart W, EPA fails to discuss why individual changes are needed to provide empirical data for the purposes of calculating the methane fee. Before issuing a final rule, EPA must provide a thorough discussion of how this limited change to its statutory authority in the IRA provides a basis for these extensive revisions.

Commenter 0413: 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.

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]

Footnotes:

[3] [42 U.S.C.] § 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).

[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/industrialmethane-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/methaneemissions-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.

Response 1: The EPA disagrees with the commenters' assertion that CAA section 136 constrains EPA authority or restricts the EPA's ability to finalize the revisions in this rule under our CAA 114 authority. The final rule's revisions are consistent with the directives in CAA section 136 for the relevant industry segments under subpart W, and EPA appropriately also applied its authority under CAA section 114 to gather information for purposes of carrying out any provisions of the CAA (except for title II with respect to manufacturers of new motor vehicles or engines). For example, CAA section 136 is a provision of the CAA. The EPA also disagrees with commenters assertion that EPA exceeded the scope of authority delegated from Congress in CAA section 136.

As noted in the preamble to the proposed rule for this rulemaking and in the preamble to the 2009 Final Rule, EPA already had and has consistently applied its authority under CAA section 114(a)(1) under the GHGRP for over a decade to require the information proposed to be gathered by this rule because such data would inform and are relevant to the EPA's carrying out of a variety of CAA provisions. Thus, when promulgating amendments to the GHGRP, the EPA has assessed the reasonableness of requiring the information to be provided and explained how the data are relevant to the EPA's ability to carry out the provisions of the CAA.

As described in the preamble of the 2009 Proposed Rule, the GHGRP is intended to gather information that is relevant to the EPA's carrying out a wide variety of CAA provisions, with the goal of supplementing and complementing existing U.S. government programs related to climate policy and research. Throughout the development and implementation of the GHG Reporting Rule, the EPA has proposed and finalized calculation methodologies and associate monitoring requirements which incorporate recent studies on GHG emissions or reflect updates to scientific understanding of GHG emissions sources in order to improve the quality and accuracy of the data collected under the GHGRP.

In enacting CAA section 136, Congress implicitly recognized EPA's appropriate use of CAA authority in promulgating the GHGRP. The provisions of CAA section 136 reference and are in part based on the Greenhouse Gas Reporting Rule requirements under subpart W for the petroleum and natural gas systems source category and require further revisions to subpart W for purposes of supporting implementation of section 136. Under CAA section 136(h), Congress directed the Administrator to revise the requirements of subpart W to ensure that reporting of CH_4 emissions under subpart W (and corresponding waste emissions charges under CAA section 136) is based on empirical data, accurately reflects the total CH_4 emissions (and waste emissions) from applicable facilities, and allows owners and operators to submit empirical emissions data, in a manner prescribed by the Administrator, to demonstrate the extent to which a charge is owed under CAA section 136. The revisions being finalized are consistent with these directives, ensuring that (1) reporting of methane emissions under subpart W are based on empirical data, (2) accurately reflect total methane emissions (and waste emissions) and (3) allow owners and operators to submit appropriate empirical data. The revisions are also intended to inform and help the EPA carry out the provisions of the associated Waste Emission Charge (WEC) under CAA section 136. While Congress specified certain revisions EPA must make to subpart W, aimed at ensuring data quality and accuracy of methane and waste emissions from the WEC applicable facilities for purposes of carrying out the WEC under the CAA, Congress did not include limitations under CAA section 136 on other information EPA may collect under subpart W for purposes of carrying out other provisions of the CAA. Congress was aware that the GHGRP collected information under existing CAA section 114 authority for purposes of carrying out existing provisions of the CAA at the time Congress enacted CAA section 136.[20] Rather than specify that subpart W must be revised to be identical in thresholds, scope of industry, or scope of pollutants as CAA section 136, Congress's directives were limited to ensure the portion of the information reported that corresponded to the WEC was appropriate for

[20] For example, CAA section 136(c) references a reporting threshold for WEC "regardless of the reporting threshold under [subpart W]." Additionally, Congress was aware that the reporting threshold under subpart W was and is based on GHG emissions reporting beyond methane emissions (the pollutant at issue for WEC). For another example, CAA section 136(d) identifies applicable facilities for purposes of WEC as those within a subset of the industry segments that comprise subpart W. To the extent commenters imply EPA can only revise subpart W for purposes of the WEC, they fail to explain how such a reading is consistent with Congress' acknowledgement that subpart W and the WEC may and can diverge on reporting threshold and covered industry segments. Nowhere in CAA section 136 does Congress direct EPA to align the reporting threshold in subpart W with CAA section 136 alone, or with the industry segments relevant for CAA section 136.

carrying out that program. The EPA appropriately applied its authority in this rulemaking in a manner consistent with the directives under CAA section 136 and within its 114 authority.

Regarding assertions in the comment about EPA's CAA section 114 authority generally, as previously noted in the 2024 GHGRP Final Revisions Rule, the EPA disagrees that we should or must interpret the language of CAA section 114 as narrowly as some commenters advocate. As we explained in the original preamble to the Mandatory Reporting of Greenhouse Gases final rule (74 FR 56260, October 30, 2009) promulgating the GHGRP and its corresponding Response to Comments document, while Congress highlighted certain potential uses of the information gathered under CAA section 114 in a portion of CAA section 114(a), Congress also explicitly listed in CAA section 114(a) the potential use of "carrying out any provision" of the Act. We also explained that the EPA has a variety of duties in the CAA that extend to both regulatory and non-regulatory programs, and limiting the scope of CAA section 114 as some commenters urge would hinder the EPA's ability to implement those provisions and subvert Congressional intent. We also explained that the point of gathering information under CAA section 114 is to inform decisions regarding the legal, technical, and policy viability of various options for carrying out provisions under the CAA (which is not limited to determining compliance with existing regulations).

As stated in the preamble to the 2009 Mandatory Reporting of Greenhouse Gases final rule, CAA section 114(a)(1) provides the EPA broad authority to require the information to be gathered by this rule because such data would inform and are relevant to the EPA's carrying out of a variety of CAA provisions. As summarized in the 2009 proposed rule, CAA section 114(a)(1) authorizes the EPA to, *inter alia*, require certain persons on a one-time, periodic, or continuous basis to keep records, make reports, undertake monitoring, sample emissions, or provide such other information as the EPA may reasonably require. The EPA may require the submission of this information from any person who (1) owns or operates an emission source, (2) manufactures control or process equipment, (3) the EPA believes may have information necessary for the purposes set forth in this section, or (4) is subject to any requirement of the Act (except for manufacturers subject to certain title II requirements, who are subject to CAA section 208). The EPA may require this information for the purposes of developing or assisting in the development of any implementation plan, an emission standard under sections 111, 112 or 129, determining if any person is in violation of any such standard or any requirement of an implementation plan, or "carrying out any provision" of the Act. As the EPA noted in the 2022 Data Quality Improvements Proposal, in the development of the GHGRP in the 2009 rule, the Agency considered its authorities under CAA sections 114 and 208 and the information that would be relevant to the EPA's "carrying out" a wide variety of CAA provisions when identifying source categories for reporting requirements. We noted both the scope of the persons potentially subject to a CAA section 114(a)(1) information request (*e.g.*, a person "who the Administrator believes may have information necessary for the purposes set forth in" CAA section 114(a)) and the reach of the phrase "carrying out any provision" of the Act and explained how the reporting requirements being promulgated under the GHGRP for facilities and suppliers were within that authority. As the EPA explained in initially promulgating the GHGRP, it is entirely appropriate for the Agency under CAA section 114 to gather such information (including but not limited to better understanding the reporting industries and their potential impacts, and verifying reported emissions information, from upstream production and suppliers to downstream sources), to allow a comprehensive assessment of how to best address GHG emissions and climate change in carrying out provisions of the CAA, including both regulatory and non-regulatory options.

Regarding commenters assertions regarding collection of monitoring data under this rule, in addition to meeting the directives under CAA section 136(h) regarding accuracy of total methane and waste emissions and allowing owners and operators of applicable facilities to submit appropriate empirical emissions data, collection of additional monitoring data under this final rule will allow the Agency to undertake a more thorough and holistic evaluation of how to utilize its authority under the CAA, both regulatory and non-regulatory, to address GHG emissions and climate change, consistent with its authority under CAA section 114 in carrying out a provision of the CAA.[21] See also Response 3 in this section of this document.

Regarding commenter's assertions that "EPA failed to discuss its definition of empirical data or its views on what costs for implementation would be reasonable for collecting information under the program," the EPA disagrees. See, e.g., the 2023 Subpart W Proposal preamble at 88 FR at 50286 ("Empirical data can be defined as data that are collected by observation and experiment. There are many forms of empirical data that can be used to quantify GHG emissions. For purposes of this action, the EPA interprets empirical data to mean data that are collected by conducting observations and experiments that could be used to accurately calculate emissions at a facility, including direct emissions measurements, monitoring of CH_4 emissions (e.g., leak surveys) or measurement of associated parameters (e.g., flow rate, pressure, etc.), and published data."); the EPA's impacts analysis in Section VI of the preamble to the 2023 Subpart W Proposal, including at 88 FR at 50369 ("To the extent consideration of costs is relevant to the EPA's proposal for meeting its obligation under CAA section 136(h), these anticipated costs are reasonable.").

Regarding commenters assertions that "EPA fails to discuss why individual changes are needed to provide empirical data for the purposes of calculating the methane fee," the EPA disagrees. See section II of the 2023 Subpart W Proposal preamble; see, e.g., the 2023 Subpart W Proposal preamble, 88 FR at 50289 ("We are also proposing to revise several existing calculation methodologies to incorporate empirical data obtained at the facility. Emissions can be reliably calculated for sources such as tanks and glycol dehydrators using standard engineering first principle methods such as those available in API 4697 E&P Tanks and GRI-GLYCalc™. Using such software also addresses safety concerns that are associated with direct emissions measurement from these sources. For example, sometimes the temperature of the emissions stream for glycol dehydrator vent stacks is too high for operators to safely measure emissions. However, currently in subpart W, these methods allow for use of best available data for inputs to the model. The EPA has noted that in some cases, such as with reporting of emissions from some dehydrators, the data used to calculate emissions are not based on actual operating conditions but instead based on "worst-case scenarios" or other estimates. In these cases, the accuracy of the reported emissions would be improved by using actual operating conditions as measured at the unit. In this proposal, for large glycol dehydrators and AGRs, we are proposing to require that

[21] See CAA section 114(a)(1)(c) (including "install, use, and maintain such monitoring equipment" in the list of what EPA may require on a one-time, periodic, or continuous basis).

certain input parameters are based on actual measurements at the unit level in order to improve the accuracy of the reported emissions for these sources.”).

Commenter: American Exploration and Production Council
Comment Number: EPA-HQ-OAR-2023-0234-0295
Page(s): 28, 31

Comment 2: EPA’s Proposal exceeds the scope of Congress’s delegation of authority in the new CAA § 136.

EPA must merge this rulemaking into the forthcoming MERP charge program implementation proposal, and allow supplemental comment in that forthcoming MERP charge rulemaking on this Proposal and this Proposal’s interaction with the pending Section 111 rulemaking once the Section 111 rulemaking is finalized.

As a threshold matter, EPA cannot legally or rationally treat this rulemaking as separate and independent from its forthcoming proposed implementation of the MERP’s “waste emissions charge program.” As explained below, Congress did not intend EPA to proceed this way. To the contrary, it directed EPA to make revisions to Subpart W so that both reporting under the Subpart and the calculation of MERP charges meet certain criteria. Regulated companies are currently in the dark as to how EPA will interpret and implement the MERP’s charge program. This deprives them of the substance of their right to provide informed comment on the significance of the current Proposal with regard to how the changes it proposes to Subpart W will interact with EPA’s implementation of the MERP charge program.

EPA provides no rational explanation, nor any interpretation of CAA § 136, to justify its proceeding in the current manner and treating these two rulemakings as entirely separate matters. It only repeatedly states that comments about MERP charge implementation are outside the scope of the current Proposal because EPA is handling them in two separate rulemakings. See 88 Fed. Reg. at 50,286. This is tautological (EPA is saying only, in effect, “these are separate matters because we are treating them as separate matters”), and offers the public no statement of law or policy on which to comment.

Respectfully, EPA must reboot its approach in that forthcoming proposal by merging the two rulemakings, abandoning the untenable position that these are two separate tasks Congress has given it, accept in that forthcoming MERP implementation rulemaking supplemental comment will be necessary on this Proposal in light of its interaction with the content of that forthcoming proposal, and eventually finalize both proposals as a unified final action. In addition, because the MERP charge program contains an exemption for regulatory compliance with the pending Section 111 rulemaking if certain conditions are met, and because this Proposal contains multiple provisions adapted from the pending Section 111 rulemaking, EPA must accept comment in the forthcoming MERP charge rulemaking on the interaction between the provisions of the Section 111 rule once the latter is finalized. All these actions are pieces of a regulatory puzzle, and it is both contrary to Congress’s intent in CAA § 136 and irrational for EPA not to provide the public an opportunity to comment on all of them in a holistic and unified fashion.

EPA sent the draft proposal of the MERP charge rulemaking to the Office of Information and Regulatory Affairs for interagency review on September 29, one business day before the comment period on the Proposal ended. Now that it is publicly visible that EPA has not only begun work on the MERP charge rulemaking but has reached the stage of soliciting comment from its sister agencies on a draft proposal, EPA has no justification, legal, policy, or logistical, for continuing to treat these rulemakings as isolated from one another. Merger and a renewed opportunity for comment on all aspects of this regulatory puzzle is the only viable path forward.

…

New CAA § 136 has changed the nature and function of Subpart W, and has therefore changed that program's implications for regulated parties and for the Agency itself.

EPA must be mindful that the IRA has raised the stakes for any move it makes with respect to the GHGRP. Previously, whatever the source of EPA's authority to implement the GHGRP, it was an information-only program. Consequences for error on regulated parties' part were relatively limited. Now, the information reported under Subpart W for applicable facilities will have a direct relationship to the imposition of financial harm on those facilities' owner/operators. Both the direct harm and the implications for any noncompliance or even unintentional error are higher, and EPA's litigation exposure with regard to any final rule emerging from this rulemaking is correspondingly higher as well. EPA therefore needs to provide a more, not less, detailed articulation of its authority to make these changes and a more persuasive policy rationale for them. It has not done so. EPA also needs to consider the increased cost that this Proposal would impose in a cumulative fashion, in light of the increased costs that the MERP charge program will levy. This is yet another reason why EPA must merge the two rulemakings …

Response 2: The EPA disagrees with the commenter that the revisions to subpart W and the regulations to implement the waste emission charge must be completed in the same rulemaking. CAA section 136 establishes the Methane Emissions and Waste Reduction Incentive Program for Petroleum and Natural Gas Systems in multiple distinct, but interacting, parts, including an incentive program, the waste emission charge and the revisions to subpart W. Congress gave clear and separate direction on the necessary revisions to subpart W and the required timeframe to complete those revisions, which are being finalized in this rulemaking. The EPA reasonably addressed the direction given by Congress in a manner that best ensured the EPA would meet statutory deadlines where applicable. We note that Congress did not direct that the EPA must undertake any of the other actions commenters raise at the same time or in the same action as the revision to subpart W Congress directed under CAA section 136(h). However, we did evaluate whether particular aspects of this proposed rule should not be finalized at this time and instead should be considered on the same timeline as the implementation of the Waste Emission Charge to maintain alignment between the two rules. We are taking that approach where it seemed appropriate. See Section III.A.1 of the preamble to the final rule for our discussion regarding our intent to finalize provisions related to reporting responsibilities for previous years after an ownership transfer. Regarding the EPA's authority and policy rationale for the subpart W revisions, see the EPA's thorough discussion and response on these issues in the preamble for the final rule and corresponding sections of this document. With respect to the costs associated with this proposal, as discussed in Section VI of the preamble to the final rule, the EPA completed an impacts analysis to estimate the burden of this final rule. However, the EPA disagrees with the commenter's assertion that this proposal needs to consider the increased costs due to the Waste Emission Charge, which is being undertaken in separate regulatory action. The revisions finalized in this action were developed in accordance with the statutory requirements in Sections 136(h) and 114 of the CAA. Comments on the impacts of the regulatory actions to implement the Waste Emission Charge are thus out of scope for this response to comments document. However, we note that the separate proposed rule for implementation of the Waste Emission Charge does include a Regulatory Impact Analysis, consistent with Executive Order 12866, that does consider the impact of the costs associated with the charge.

Commenter: American Exploration and Production Council
Comment Number: EPA-HQ-OAR-2023-0234-0295
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Comment 3: <u>EPA's Proposal exceeds the scope of Congress's delegation of authority in the new CAA § 136.</u>

EPA's Proposal contains provisions that are not authorized by Section 136(h), and EPA in this context cannot properly rely on claims of other authority to propose those provisions here.

EPA is using this Proposal to *de facto* supplement its (already once supplemented) pending CAA § 111 methane standards proposal, and even in some respects to functionally bring that proposal into effect prematurely, without acknowledging that this is what it is doing. But Congress provided EPA no authorization in CAA § 136 to revise Subpart W as an accelerated form of implementing any aspect of its proposed CAA § 111 methane standards. Section 136 refers to that ongoing rulemaking in subsection (f)(6)(A)(ii), which provides that applicable facilities subject to and in compliance with Section 111 methane standards that achieve at least equal reductions as would be achieved under the November 2021 proposal of such regulations. The fact that Congress referred to the pending CAA § 111 rulemaking in this other provision of Section 136, but did not make any mention of it in Subsection (h), confirms that Subsection (h) was considered and yet Congress still provided EPA with no authority relevant to that other rulemaking.

EPA is using this Proposal to supplement the flare monitoring standards as proposed in the pending Section 111 rulemaking. While some aspects of the Proposal are framed as EPA offering companies the option of "voluntarily" adopting certain provisions contained in that proposed rule before they come into effect, see 88 Fed. Reg. at 50,288/2, in light of the observations above regarding the absence of any reference to that other, pending rulemaking in CAA § 136(h), even this aspect of the Proposal is on shaky ground. But there is at least one aspect of this Proposal which would require a measure *not* contained in the pending Section 111 proposal: gas composition monitoring. *See, e.g*., 88 Fed. Reg. at § 60.5417b(d)(1)(viii). This is a requirement of a fundamentally different nature than that contained in the pending Section 111 rulemaking. Whatever the propriety of "voluntary" paths to accelerate measures that *are* contained in that other, pending rulemaking, using this Proposal to adopt measures that are *not* contained in that other rulemaking unequivocally crosses the line into unauthorized supplementation of that rulemaking.

EPA's departing outside the boundaries of the direction and authority provided to it by new CAA § 136(h) is compounded by its proposal to import monitoring provisions from standards designed for another sector (refineries) under a distinct authority (CAA § 112, the air toxics program). In other words, not only is EPA exceeding its authority under Section 136(h) by *de facto* supplementing its pending CAA § 111 proposal, but it's doing so in part by adopting provisions tailored to another sector that is not subject to the MERP charge program and not mentioned anywhere in the text of CAA 136. EPA is going too far, with too little authorization from Congress.

By using this Proposal to accelerate the schedule for all flare monitoring standards that are also in the pending Section 111 proposal, EPA is attempting an end-run around Congress's intent as evidenced in the design of Section 111(d). Under that provision, states are the ones that establish standards of performance for their existing sources in the first instance, substance to state-plan submission, review, approval, and implementation under Section 111(d)(1). And proposed Emissions Guideline (EG) OOOOc provides that states will have 18 months after the final EG is published to submit state plans establishing standards of performance for existing sources, *see* 87 Fed. Reg. at 74,721/2, and that state plans can set compliance deadlines up to 36 months after that state plan submittal deadline, *see id*. At 74,836/1. Under the statute and EPA's implementation of it in the pending Section 111 rulemaking, therefore, compliance under the EG may not be required for many or all sources, even if all these deadlines are met (which experience in other CAA state-planning regimes shows is doubtful), until four and a half years after the final EG is published. EPA cannot jumpstart that process by prematurely using its Section 111(d)(2) authority until a state has had a chance to draw up and submit its plan; *a fortiori* the Agency can't jumpstart the process through a reporting program authorized under an entirely separate provision, as it is attempting to do in this Proposal.

Response 3: The EPA disagrees with the commenter that it lacks authority under CAA section 136(h) to finalize these revisions. Section 136(h) of the Clean Air Act required that the EPA revise the requirements of subpart W to ensure the reporting under subpart W (and corresponding waste emissions charges under CAA section 136) is based on empirical data, accurately reflects the total CH_4 emissions (and waste emissions) from the applicable facilities, and allows owners and operators of applicable facilities to submit empirical emissions data, in a manner to be prescribed by the Administrator, to demonstrate the extent to which a charge is owed under CAA section 136. Consistent with the authority and directives set forth in CAA section 136(h), the EPA proposed several revisions to add new or revise existing calculation methodologies to improve the accuracy of reported emissions, and incorporate additional empirical data. The proposed revisions to the calculation methodologies for flares were proposed to ensure that the calculation of emissions from flares was based on empirical data and accurately reflected total CH_4 emissions (and wasted emissions) from flares. Although in this proposal, the EPA proposed revisions in alignment with the provisions of NSPS OOOOb, we note that the NSPS and this program have complimentary but not identical goals. Under the NSPS, gas composition is important for determining the net heating value of the flare gas to ensure adequate combustion, but it is not used to quantify emissions and can thus be sufficiently monitored with a calorimeter.

However, when calculating emissions, gas composition is a variable in the emissions calculation for flares. Thus, inaccuracy in the determined gas composition would likely result in inaccurate emissions estimates from flares. The commenter also stated that the EPA is undertaking an unauthorized supplementation of the recently finalized section 111 rulemaking. We do not address the merits of these comments here because, based on comments received, as discussed in section III of the preamble to the final rule, the EPA is not finalizing the requirement to complete quarterly composition sampling or use a gas composition analyzer for streams routed to flares. See section III of the preamble to the final rule for our response to comments on the requirements to complete quarterly composition sampling or use a gas composition analyzer.

As previously noted (Docket (EPA-HQ-OAR-2015-0764)), CAA section 114 also provides the EPA with the authority to collect the information covered by this rule. Section 114 generally authorizes the EPA to gather information from any person who owns or operates an emissions source, who is subject to a requirement of the CAA, who manufactures control or process equipment, or who the Administrator believes has information necessary for the purposes of CAA section 114(a). The EPA may gather information for purposes of establishing implementation plans or emissions standards, determining compliance, or "carrying out any provision" of the CAA. For these reasons, the Administrator may request that a person, on a one time, periodic or continuous basis, establish and maintain records, make reports, install and operate monitoring equipment and, among other things, provide such information the Administrator may reasonably require.

See also the EPA's response to Comment 1 in this section of this document.

Commenter: GPA Midstream Association
Comment Number: EPA-HQ-OAR-2023-0234-0299
Page(s): 77

Comment 4: *EPA's Legal Authority*. EPA has consistently stated that the basis for its GHGRP is section 114 of the CAA.[17] In the proposed rule, EPA says that section 114(a)(1) "provides the EPA broad authority to require the information proposed to be gathered by this rule because such data would inform and are relevant to the EPA's carrying out of a wide variety of CAA provisions."[18] EPA also continues to point to a 2008 Consolidated Appropriations Act as part of the basis for the GHGRP.[19] That enactment required EPA to publish a proposed and final rule "to require mandatory reporting of greenhouse gas emissions above appropriate thresholds in all sectors of the economy of the United States."[20]

EPA's authority to collect information under section 114 is specifically circumscribed. The Administrator may require the submission of information "[f]or the purpose … of developing or assisting in the development of any implementation plan under" sections 110 or 111 of the CAA, any standard of performance under section 111, and emission standard under section 112, regulations related to solid waste, or for purposes "of determining whether any person is in violation of any such standard or any requirement of such a plan."[21] Section 114 further authorizes the collection of information for the purpose of carrying out any provision of chapter 85 of title 42.[22]

Prior to the promulgation of the GHGRP, EPA had never used section 114 to require the indefinite, if not permanent, gathering and reporting of data. After many years of collecting GHG data pursuant to subpart W, GPA appreciates EPA's efforts to streamline its regulatory requirements and ease reporting burdens. Nevertheless, GPA remains concerned that EPA has not explained, consistent with the limits on the agency's section 114 authority, the reasons for its continuation of the GHGRP, the agency's ultimate regulatory goals, and the information EPA needs to ensure compliance with the rules it has already promulgated. Indeed, for sources that are already subject to emission limits, tailoring reporting requirements to what is needed to determine whether any source is in violation of an applicable standard should be the primary focus of EPA's rulemaking. At the very least, EPA is obligated to fully explain how its proposed rule is consistent with its section 114 authority. GPA encourages EPA to engage this issue in a supplemental proposal or in its final rule.

Footnotes:

[17] *See, e.g.*, 87 Fed. Reg. at 36,925.

[18] *Id*. at 36,925-26.

[19] *See id*. at 36,924 n.1.

[20] Consolidated Appropriations Act, 2008, Public L. No. 110–161, 121 Stat. 1844, 2128.

[21] CAA § 114(a); 42 U.S.C. § 7414(a).

[22] *Id*.

Response 4: For our response regarding the commenter's assertions about EPA's legal authority, see the response to Comment 1 in this section of this document. The EPA did not reopen any other subpart, or revisions within a subpart, of the GHGRP other than those provisions identified in the 2023 Subpart W Proposal; comments on those other portions of the GHGRP are outside the scope of this rulemaking.

27.2 Effective Date

Commenter: GPA Midstream Association
Comment Number: EPA-HQ-OAR-2023-0234-0299
Page(s): 17

Comment 1: The following is a list of substantive proposed changes that GPA expressly supports.

…

- An effective date of January 1, 2025.

Response 1: The EPA acknowledges the commenter's support and notes that the effective date is being finalized as proposed for the majority of the provisions. As described in the response to Comment 2 in this section and Section IV of the preamble to the final rule, some optional provisions will have an earlier effective date.

Commenter: Riverside Energy Group
Comment Number: EPA-HQ-OAR-2023-0234-0230
Page(s): 1-2

Commenter: Terra Energy Partners (TEP)
Comment Number: EPA-HQ-OAR-2023-0234-0234
Page(s): 1, 3-4

Commenter: Michigan Oil and Gas Association (MOGA)
Comment Number: EPA-HQ-OAR-2023-0234-0298
Page(s): 3

Commenter: Western Energy Alliance
Comment Number: EPA-HQ-OAR-2023-0234-0399
Page(s): 3-4

Comment 2: Commenter 0230: Starting in 2024, under the MERP Act, Waste Emission Charges (WEC) will be assessed $900/ton of methane emitted above the threshold for facilities that report more than 25,000 metric tons of CO2 (mtCO2e) equivalent per year through the GHGRP. Increasing to $1,200/ton for 2025 and then to $1,500/ton in 2026 and beyond.

What makes the MERP a bit more challenging is that applicability and compliance are intertwined with other existing and evolving federal rules and programs. This adds complexity and uncertainty to our oil and gas community, who may be trying to evaluate their risks and liabilities under the program.

There are key exemptions from the methane emissions charge, including exemptions for facilities that are subject to and in compliance with NSPS OOOO rules. The MERP directs operators to use the EPA's GHGRP framework to calculate and report methane emissions. However, both regulatory programs are currently in a state of flux. The EPA has proposed wide-sweeping revisions and updates to the 00006 and OOOOc rules, which have not yet been finalized.

The effective date of the proposed Subpart W rule changes will be January 1, 2025 (to be reported by March 31 , 2026); with an exception for data reporting elements for produced quantities of natural gas, crude oil, and condensate to sales for each well permanently taken out of production (ie: plugged or abandoned) in the reporting year. Reporters must include that information for reporting year 2024 (to be submitted by March 31, 2025).

Riverside would like to request that the EPA implement the Waste Emission Charges simultaneously with the reporting dates of the Proposed Subpart W affected dates. The effective reporting year should be the same as the IRA or vice versa. Riverside does not want the EPA to assess 2024 nonempirical data as it most likely will be higher emissions due to unrealistic emission factors and minimal direct measurements and would result in higher WEC fees. Having the same affective dates would also make the data management much clearer and precise for the stakeholder as well as the EPA.

Commenter 0234: Terra Energy Partners ("TEP") appreciates the opportunity to submit comments regarding the U.S. Environmental Protection Agency's ("EPA") proposed amendments to the petroleum and natural gas systems source category of the Greenhouse Gas Reporting Rule (i.e., "Subpart W Amendments"). TEP agrees that Subpart W reporting must be based on empirical data that accurately reflects facility emissions. TEP believes that the Subpart W Amendments, particularly those regarding reporting of pneumatic controller emissions, will allow operators to utilize empirical data, resulting in greater accuracy for reported emissions.

For this reason, Congress, via the Inflation Reduction Act of 2022 ("IRA"), mandated that EPA revise Subpart W to ensure that any waste emissions charge that may be owed under the IRA is based on accurate, empirical data. Indeed, Congress specifically directed EPA to complete these Subpart W Amendments within 2 years "**to ensure the reporting under [Subpart W], and calculation of charges under [the IRA] … are based on empirical data … [to] accurately reflect the total methane emissions and waste emissions from applicable facilities, and allow owners and operators of applicable facilities to submit empirical emissions data . .. to demonstrate the extent to which a charge . .. is owed.**"[1] This amounts to a direct mandate from Congress to EPA to revise Subpart W accordingly and to make the revised methodologies effective and available for use for the first year that waste emission charges are due under the IRA. Accordingly, TEP requests that EPA revise its proposal to make the Subpart W Amendments effective on January 1, 2024, or sufficiently retroactive, so that reporters can utilize the revised emission calculation methodologies for reporting year 2024 and any waste emissions charge that may be owed under the IRA.

…

Congress Mandated that the Subpart W Amendments Be Effective and Available for Reporting Year 2024 and Determinations of Waste Emission Charges

As discussed above, Congress specifically directed EPA to revise Subpart W to ensure that any waste emission charges imposed under the IRA are based on better and more accurate empirical data.[2] Accordingly, TEP believes that the Subpart W Amendments must be made effective and available so that reporters can utilize the revised emission calculation methodologies for reporting year 2024, and any waste emissions charge that may be owed under the IRA.

The current Subpart W program is not sufficiently accurate to serve as the basis for a system that has the potential to impose billions of dollars in charges on the regulated community, many of which are small businesses. EPA's GHG Reporting Program was developed more than a decade ago and was intended to gather emissions data to better understand GHG emissions and to inform potential policy and regulatory decision-making going forward.[3] The program was not intended to support future emissions fees to be imposed on the regulated community. Indeed, from the beginning, EPA recognized the limitations of the emission calculation and reporting methodologies and that additional data and information were necessary so that the methodologies could be further refined and revised going forward to provide more accuracy.[4] And EPA continues to recognize and acknowledge the deficiencies of the current program.[5] For example, the current Subpart W reporting program includes emission factors for pneumatic controllers that rely upon methodologies based on a 1996 pneumatics study that made only 44 in-field measurements. 6 That study, however, has recently been updated, resulting in updated and more accurate methodologies based on 308 in-field measurements, which EPA has incorporated into the Subpart W Amendments.[7]

Again, for these reasons, Congress specifically directed EPA to revise Subpart W before waste emission charges are first due in 2025. EPA's proposal to not make the Subpart W Amendments effective until 2025 is therefore contrary to congressional intent and therefore lacks statutory authority.

Impact on Small Business

Many operators subject to Subpart W reporting and the IRA's waste emission charge are small businesses like TEP. Delaying the effective date of the Subpart W Amendments to reporting year 2025 will force smaller operators to pay a waste emissions charge based on reported emissions that are inaccurate and potentially significantly higher than actual emissions. This places an unreasonable burden on small businesses and is a misdirection of capital that can be better spent on actual emission reductions in the field. Not only is this unfair, but it is arbitrary and capricious and, as discussed above, contrary to congressional intent.

Conclusion

TEP supports EPA's proposed Subpart W Amendments. EPA, per the directives of the IRA, is taking steps to include more empirical data, which will yield a more accurate inventory. But, as stated herein, TEP respectfully requests that EPA allow the use of the revised methodologies for the purposes of reporting year 2024 and calculating any associated waste emissions charges.

Footnotes:

[1] Inflation Reduction Act of 2022, Pub. L. No. 117-169, 136 Stat. 2073, § 60113 (codified as amended at 42 U.S.C. 7436, § 136(h).

[2] Inflation Reduction Act of 2022, Pub. L. No. 117-169, 136 Stat. 2073, § 60113 (codified as amended at 42 U.S.C. 7436, §§ 136(a)(3)(F), (c)).

[3] 74 Fed. Reg. at 56,265.

[4] *Id*. In a response to comment, EPA stated "[i]f new and improved emission factors become available, at an appropriate time, EPA may re propose applicable parts of subpart W." EPA

Response to Comment, EPA-HQ-OAR2009-0923-1202-9 (Nov. 2010); EPA Response to Comment Number EPA-HQ-OAR-2009-0923-1299-5 (Nov. 2010).

[5] EPA explains that the proposed rule revises existing calculation methodologies to "improve the accuracy of reported emissions … " 88 Fed. Reg. at 50,284. In some cases, EPA scraps the current methodology entirely and proposes "new calculation methodologies for equipment leaks and natural gas pneumatic devices." *Id*. at 50284-85. These changes reflect EPA's "improved understanding of emission sources" and that EPA has "become aware of discrepancies between assumptions in the current emissions estimation methods and the processes or activities conducted at specific facilities, where the proposed revisions would reduce reporter errors." *Id*. at 50,289. In other cases, revised methodologies "incorporate recent studies on GHG emissions or formation that reflect updates to scientific understanding of GHG emission sources." *Id*. All of these changes will "improve the quality and accuracy of the data collected under the [rule]." *Id*.

[6] *Compendium of Greenhouse Gas Emissions Methodologies for the Oil and Gas Industry*, American Petroleum Institute, 5-66 (Aug. 2009) ("API 2009 Methodology"); *Methane Emissions from the Natural Gas Industry, Volume 2: Technical Report*, National Risk Management Research Laboratory, 53 (June 1996).

[7] 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, U.S. EPA, 60-61 (June 2023); Paul Tupper, API Field measurement Study: Pneumatic Controllers, EPA Stakeholder Workshop on Oil and Gas, 5 (Nov. 7, 2019).

<u>Commenter 0298</u>: Regulation Dates & Timelines

MOGA constituents are concerned with the variation in proposed regulation timelines. The IRA and subsequent Waste Emission Charges are set to take place in 2024, yet the calculation methodologies proposed in the revisions to Subpart W calculations will not take place to January 1, 2025. MOGA constituents are concerned that emission estimates will likely be overstated and result in taxation beyond actual estimates prior to the allowance of independent analysis of actual emissions. MOGA believes that proposed regulations should align to allow inclusion of actual emissions.

<u>Commenter 0399</u>: First, the timing of requirements are contradictory. The methane fee applies in 2024 for Q1 2025 reporting, whereas these proposed Subpart W revisions will not apply until 2025 for Q1 2026 reporting. By finalizing the proposal by August 2024, it meets the two-year deadline in IRA, but it will not be implemented for the first year of the methane fee.

Response 2: The EPA acknowledges commenters’ concerns that an effective date of January 1, 2025 for the final rule that requires application of the revised subpart W methodologies begin with the 2025 reporting year could limit reporters’ ability to report certain types of empirical data for the 2024 reporting year and thus have implications for the WEC. The EPA disagrees that the approach in this rulemaking is inconsistent with our authority and the statutory provisions in CAA section 136. In the final rule, the EPA is finalizing an effective date of January 1, 2025, for

most of the provisions; however, after consideration of the concerns raised by commenters, the EPA is finalizing an effective date of 60 days after the publication of the final rule for some of the new calculation methodologies and associated reporting requirements on an optional basis. This earlier effective date will allow reporters to voluntarily use revised subpart W methodologies to calculate emissions from certain sources for the 2024 reporting year and thus have any WEC for the 2024 reporting year calculated based on emissions reported using the new methodologies, if elected. In some cases, the voluntary use of these methods may only apply for the 2024 reporting year; any provisions that require use of one of the new or revised calculation methods (e.g., for facilities subject to NSPS OOOOb) will then be effective January 1, 2025. See also Section IV of the preamble to the final rule for additional discussion.

Commenter: Public Hearing Transcript
Comment Number: EPA-HQ-OAR-2023-0234-0224
Page(s): 45 (Scott Yager)

Commenter: American Exploration and Production Council
Comment Number: EPA-HQ-OAR-2023-0234-0295
Page(s): 9

Commenter: GPA Midstream Association
Comment Number: EPA-HQ-OAR-2023-0234-0299
Page(s): 16, 75-76

Commenter: Duke Energy
Comment Number: EPA-HQ-OAR-2023-0234-0376
Page(s): 9-10

Commenter: Arkansas Independent Producers and Royalty Owners (AIPRO)
Comment Number: EPA-HQ-OAR-2023-0234-0382
Page(s): 7

Commenter: Pioneer Natural Resources USA, Inc.
Comment Number: EPA-HQ-OAR-2023-0234-0385
Page(s): 8

Commenter: Interstate Natural Gas Association of America (INGAA)
Comment Number: EPA-HQ-OAR-2023-0234-0387
Page(s): 18-19

Commenter: Wyoming Department of Environmental Quality (WDEQ)
Comment Number: EPA-HQ-OAR-2023-0234-0388
Page(s): 10

Commenter: Downstream Natural Gas Initiative
Comment Number: EPA-HQ-OAR-2023-0234-0396
Page(s): 8

Commenter: The Petroleum Alliance of Oklahoma
Comment Number: EPA-HQ-OAR-2023-0234-0398
Page(s): 3

Commenter: American Petroleum Institute et al. (Part 1 of 2)
Comment Number: EPA-HQ-OAR-2023-0234-0402
Page(s): 72

Commenter: American Petroleum Institute et al. (Part 1 of 2)
Comment Number: EPA-HQ-OAR-2023-0234-0402
Page(s): 73

Commenter: Encino Energy (EAP Ohio, LLC)
Comment Number: EPA-HQ-OAR-2023-0234-0408
Page(s): 7

Commenter: American Gas Association (AGA) and American Public Gas Association (APGA)
Comment Number: EPA-HQ-OAR-2023-0234-0418
Page(s): 21

Comment 3: Commenter 0224: Best available monitoring methods or BAMM were allowed to facilitate implementation when Subpart W is promulgated and when previous Subpart W amendments were adopted, since the final rule will not likely be promulgated until sometime in the year 2024, in essence within the 2024 reporting year, BAMM options should be included through the initial one to two years of reporting years.

Commenter 0295: **Timing/Interrelatedness of Proposed Changes with Other Federal Regulations**

The proposed Subpart W requirements expressly reference and/or are directly related to a number of other pending regulations in development, namely CAA Section 111(b) standards of performance for certain new, reconstructed, and modified oil and natural gas sources (40 CFR Part 60, Subpart OOOOb, a.k.a. "NSPS OOOOb"), emissions guidelines under CAA Section 111(d) for certain existing oil and natural gas sources (40 CFR Part 60, Subpart OOOOc, a.k.a. "EG OOOOc"), the Inflation Reduction Act Section 60113 methane emissions reduction program's waste emission charge for oil gas facilities ("MERP WEC"), the Pipeline Safety: Gas Pipeline Leak Detection and Repair amendments ("PHMSA LDAR") and the Bureau of Land Management's Waste and Prevention Rule.

In principle, AXPC supports EPA's efforts to allow facilities to use a consistent method to demonstrate compliance with multiple applicable regulatory programs. However, significant portions of the proposed Subpart W requirements are inherently intertwined with critical compliance aspects of these other programs, which have not yet been finalized. This creates substantial challenges to the ability to consider impacts of potential changes and or offer meaningful comment when so many variables are indeterminable. It also presents considerable compliance risk to affected facilities by introducing significant levels of regulatory uncertainty. Facilities that are faced with implementing new monitoring requirements and calculation methods under this Proposal will need to evaluate any correlating requirements under NSPS

OOOOb or EG OOOOc in order to proceed with the most cost-effective compliance option that meets the requirements of both rules. For example, as facilities contemplate the investment of equipment and resources to implement direct measurement of vented gas from pneumatic devices for Subpart W reporting, they would want to compare the cost of retrofitting said devices to comply with final standards under NSPS OOOOb. Similarly, when facilities are evaluating the monitoring options and calculation method hierarchy for flares under proposed Subpart W, they will need regulatory certainty for corresponding requirements under NSPS OOOOb and EG OOOOc before making the significant investment in monitoring equipment, personnel training, analytical services, etc. Other EPA and BLM rulemaking efforts propose to diminish or fully phase out certain source categories, so burdensome and costly programs to improve measurement accuracy for those sources may not be prudent depending on the language of the final rules. Facilities cannot make fully informed decisions, which have significant economic impacts, unless all of these interdependent rules have been finalized with adequate consideration to their interaction. For all of the above reasons, AXPC asks that the implementation year of the rule be pushed back from 2025 to 2026 so operators can have time to fully develop implementation plans that are fully informed by all ongoing rulemaking.

The legal section at the end of these comments explains that EPA can only legally and rationally proceed here by merging this Subpart W rulemaking with its forthcoming MERP charge implementation rulemaking. We additionally urge EPA to delay taking final action on the proposed Subpart W changes until EPA finalizes NSPS OOOOb, EG OOOOc, and the yet-to-be-proposed regulatory framework for administering the MERP WEC. Given the inherent interrelatedness of Subpart W with these other CAA programs, it is imperative that any potential inconsistencies and uncertainties across the various programs be avoided. Affected facilities are unable to fully evaluate their technical or financial compliance obligations under the proposed Subpart W requirements until such time as these other regulations are finalized, and therefore cannot provide adequate comment on the Proposal at this time. Therefore, AXPC requests, as set forth in fuller detail in the introduction to the legal comments below, that EPA in its forthcoming proposal to implement the MERP charge program take supplemental comment on this Proposal in light of its interaction with that forthcoming proposal, as well as on the interaction of the forthcoming final provisions of the pending Section 111 rulemaking and the interaction between all three regulations: (a) the Section 111 rule; (b) the Subpart W revisions; and (c) the MERP charge rulemaking.

Commenter 0299: **EPA should grant automatic use of Best Available Monitoring Methods ("BAMM") for reporting year 2025.**

EPA's proposed changes to the GHGRP are extensive and will require substantial modifications to data collection and reporting systems. Additionally, EPA has proposed requirements that may necessitate the installation of flow meters … GPA strongly urges EPA to eliminate any requirements that necessitate installation of equipment, but if EPA finalizes these unnecessary requirements, then BAMM will be required. EPA must grant BAMM automatically for RY2025 and by request for RY2026.

…

Use of Best Available Monitoring Methods ("BAMM"). To allow for a successful transition to the requirements of subpart W, as it would be revised under this proposed rule, EPA proposes to allow reporter to use BAMM "for the 2023 reporting year for only the specific industry segments and emission sources for which new monitoring or data collection requirements are being proposed."[12] The reason for allowing the use of BAMM in the manner EPA proposes is to "allow reporters to use best available methods to estimate inputs to emission equations for the newly proposed emission sources using their best engineering judgment for cases where the monitoring of these inputs would not be possible beginning on January 1, 2023."[13] EPA envisions facilities using the period during which the availability of BAMM is in effect (from January 1, 2023 to December 31, 2023, as proposed) "to install the necessary monitoring equipment during other planned (or unplanned) process unit downtime, thus avoiding process interruptions."[14] EPA says that it is not proposing to allow the use of BAMM beyond RY2023.[15]

As stated above, GPA does not believe that an effective date of January 1, 2023, is realistic or workable. For that reason, GPA encourages EPA to adopt an effective date of January 1, 2024, and to provide for automatic availability of BAMM for RY2024. If EPA adheres to its plans for a January 1, 2023 effective date, GPA requests that EPA make BAMM automatically available for RY2023 and RY2024. As explained above, the changes to the GHGRP that EPA has proposed are extensive and will require substantial modifications to data collection and reporting systems. As described below, those changes cannot be made until EPA finalizes updated reporting forms and schema. Regardless of the effective date, GPA does not believe that its members will be able to complete the necessary changes to their systems prior to the end of 2024.

Further, completion of the necessary changes and ensuring that the systems are operating correctly may take longer than EPA has initially estimated. Accordingly, GPA requests that EPA provide for optional BAMM in 2025. EPA could require that reporters making a request for BAMM for RY2025 certify that additional time is needed to install necessary monitoring equipment or to otherwise upgrade systems to ensure accurate reporting. Such an approach would be consistent with EPA's goals for the GHGRP, the Agency's past and current policies regarding BAMM, and would allow the regulated community to work with EPA to provide the information the agency hopes to receive.

Footnotes:

[12] 87 Fed. Reg. at 36,995.

[13] *Id*. at 36,995.

[14] *Id*.

[15] *Id*.

<u>Commenter 0376</u>: **The Proposed Rule compliance date of January 1, 2025, is not reasonable.** EPA anticipates the changes in the Proposed Rule may take effect on January 1, 2025, and would apply beginning with reports submitted for reporting year 2025, which are required to be submitted to EPA by March 31, 2026.

Comments are due to EPA on or before October 2, 2023. It is reasonable to expect that there will be numerous comments in this docket for EPA to review and consider in determining the final rule, and it is likely a final rule will not be promulgated until sometime in 2024. In some instances, data systems may need to be updated, internal processes and procedures written and implemented, and training of staff (including operator qualifications) executed. Because revisions to the Subpart W methodologies could result in significant reported increases in methane emissions, it is important that natural gas facilities be given appropriate time to assess the alternative procedures prior to their implementation.

The ability for companies to obtain the necessary resources to implement the proposed changes for managing emissions detection, remediation and reporting will likely take greater than 12 months to secure and put into action. Accordingly, Duke Energy recommends that the final rule reflect a compliance date of January 1, 2026.

Commenter 0382: “Advanced Notice of Proposed Rulemaking” NOT a “Proposed Rule”:

EPA’s proposed revisions to its GHGRP do not satisfy the requirements of a “Proposed Rule” as it references requirements from NSPS OOOOb and EG OOOOc, which are not final rules. And, in the case of EG OOOOc, no regulatory text has been provided for and presumably doesn’t yet exist. EG OOOOc specifically will require states to develop and gain approval from EPA for implementation plans and rules, which will likely take years to accomplish.

…

At a minimum, the agency should delay the effective date until NSPS OOOOb and EG OOOOc promulgation efforts are finalized, and states are able to develop and gain EPA approval for EG OOOOc State Implementation Plans.

Commenter 0385: **Lack of Timing/Interrelatedness of Proposed Changes with Other Federal Regulations**

The proposed Subpart W requirements expressly reference and/or are directly related to a number of other pending regulations or legislation, namely CAA Section 11l(b) standards of performance for certain new, reconstructed, and modified oil and natural gas sources (40 CFR Part 60, Subpart OOOOb, a.k.a. "NSPS OOOOb"), emissions guidelines under CAA Section 111(d) for certain existing oil and natural gas sources (40 CFR Part 60, Subpart OOOOc, a.k.a. "EG OOOOc"), and the IRA Section 60113 methane emissions reduction program's waste emission charge for oil gas facilities ("MERP WEC").

In principle, Pioneer supports EPA's efforts to allow facilities to use a consistent method to demonstrate compliance with multiple applicable regulatory programs. However, significant portions of the proposed Subpart W requirements are inherently intertwined with critical compliance aspects of these other programs, which have not yet been finalized. This presents considerable compliance risk to affected facilities by introducing regulatory uncertainty. Facilities that are faced with implementing new monitoring requirements calculation methods under this proposal will want to evaluate any correlating requirements under NSPS OOOOb or

EG OOOOc in order to proceed with the most cost-effective compliance option that meets the requirements of both rules. For example, when facilities are evaluating the monitoring options and calculation method hierarchy for flares under proposed Subpart W, they will need regulatory certainty for corresponding requirements under NSPS OOOOb and EG OOOOc before making the significant investment in monitoring equipment, personnel training, analytical services, etc. Facilities cannot make fully informed decisions, which have significant economic impacts, unless all of these interdependent rules have been finalized with adequate consideration to their interaction.

We urge EPA to delay taking final action on the proposed Subpart W changes until EPA finalizes NSPS OOOOb, EG OOOOc, and the yet to be proposed regulatory framework for administering the MERP WEC. Given the inherent interrelatedness of Subpart W with these other CAA programs, it is imperative that any potential inconsistencies and uncertainties across the various programs be avoided. Affected facilities are unable to fully evaluate their technical or financial compliance obligations under the proposed Subpart W requirements until such time as these other regulations are finalized.

Therefore, Pioneer recommends that EPA delay the effective date of the proposed Subpart W changes to go into effect only after NSPS OOOOb standards, EG OOOOc presumptive requirements, and the MERP WEC regulatory language have been finalized.

Commenter 0387: **Consistent with past practice when Subpart W was promulgated and amended, Best Available Monitoring Methods (BAMM) should be allowed in select cases during the initial (2025) reporting year.**

When Subpart W was promulgated and in subsequent amendments, selective use of BAMM was allowed in the first one or two reporting years. The Proposed Rule eliminates those previously applicable provisions in §98.234(f) and (g) and does not allow BAMM for any of the new requirements proposed. The Proposed Rule implements significant new requirements, and BAMM should be allowed in select cases for the initial reporting year. An appropriate BAMM section should be added to §98.234.

INGAA recommends that BAMM be included in select cases where new data or operational requirements may take some time to implement. Three examples follow for T&S:

- New requirements for natural gas transmission pipelines require data gathering on interconnects, farm taps, and other M&R stations along affected pipelines. These assets can be spread over hundreds of pipeline miles across several states. Operators can initiate programs to collect accurate and complete data, but more than a single year may be needed. BAMM should be allowed in the first applicable year for these transmission pipeline activity data so that operators have adequate time to complete data collection.
- New measurements are required for pneumatic devices and centrifugal compressor dry seals. For the former, the Proposed Rule will require annual measurement in most cases. If an EF option is not included, operators in T&S should be allowed two years to complete pneumatic device vent measurements. For centrifugal compressor dry seals, ports may need to be installed that require planning and a maintenance shutdown to be

completed. Operators should be allowed two years to complete the initial measurements; EFs based on measured data acquired over the first two years can be used to estimate emissions from units not measured in a particular year.
- Throughput reporting adds QA/QC requirements that may not be met by meters currently installed at a subject facility. For example, custody transfer metering along a pipeline may meet the proposed QA/QC, but meters at a compressor station may need to be upgraded or replaced, and/or operating and maintenance practices may need to be upgraded. Systemwide implementation within a year may be challenging and two years should be allowed for implementing throughput metering criteria at all affected facilities.

Commenter 0388: **WDEQ raises concerns that the implementation timeframe for the proposed rule may be too expedited for affected sources to comply with.**

WDEQ has concerns that the January 1, 2025 implementation date is far too expedited, especially given that the proposed OOOOb and OOOOc requirements have not yet been finalized and EPA has not yet proposed its forthcoming Waste Emissions Charge rule. If EPA responds to comments and finalizes this Greenhouse Gas Reporting Rule by the Spring of 2024, it will leave affected sources with a mere matter of months to evaluate and comply with the requirements of the final rule. This is not a sufficient implementation timeframe, especially considering the aforementioned regulatory uncertainty that surrounds so many other proposed EPA regulations affecting the oil and natural gas industry. Furthermore, WDEQ requests that EPA consider the recent presentation given by the American Petroleum Institute regarding supply chain delays for equipment needed for EPA' s proposed OOOOb. Industrial operators are experiencing significant difficulties in obtaining certain necessary equipment to comply with the requirements under that proposed rule. WDEQ raises concerns that similar delays could occur for some of the equipment necessary for undertaking emissions measurements and reporting under this proposed rule. In short, EPA must propose rules on a workable implementation timeframe for the regulated community to comply with and WDEQ respectfully requests that EPA consider comments it receives requesting an extension of that implementation date.

Commenter 0396: Given the addition of new sources, inclusion of direct measurements, and updates to the emission factors and calculation methodologies, the timeline proposed for implementing the rule may not be feasible for reporting entities. DSI suggests extending the timeline for implementation to provide sufficient time to the entities to establish data collection and processing systems and personnel to meet the new reporting requirements. In previous versions of the GHG Reporting Rule, EPA allowed use of Best Available Monitoring Methods (BAMM) for new and modified emission sources. EPA should consider allowing BAMM for an interim period (e.g., one year) to allow reporting entities to fully comply with the revised regulations.

Commenter 0398: EPA proposes numerous requirements throughout its Proposed Rule that requires the installation of additional equipment (e.g., installation of flow meters). We have concerns with supply chain issues that may prevent our members from obtaining and installing equipment and complying with EPA's Proposed Rule. We reference API's September 20, 2023, letter and study submitted to Administrator Regan on this issue.[3]

Action Requested: We request EPA review and consider API's letter and study regarding supply chain issues, consider the comments submitted below, and revise the proposed requirements and compliance periods accordingly.

Footnotes:

[3] API September 20, 2023 letter and study submitted to EPA Administrator Michael Regan regarding supply chain issues.

Commenter 0402: Administrative Recommendations

Streamline Existing Reporting Forms to Reduce Duplicative Reporting and Reduce Unnecessary Submittal Errors

Due to the proposed requirement to report information on a more granular basis, the Industry Trades recommend the following streamlining efforts to reduce duplicative reporting, and to reduce the possibility of administrative error.

…

EPA has not indicated how Best Available Monitoring Methods (BAMM) will be allowed for the newly proposed sources. The Industry Trades reiterates the need for ample implementation time.

…

Rule Implementation

EPAs plans to finalize the rule in August 2024, with an implementation date of January 1st, 2025. The impractical tight timeframe to implement the final rule places an unrealistic expectation on reporters, especially given that (as proposed) they will have to install new equipment and develop inspection programs to comply with the rule. The impracticality of the proposed timeline is further exacerbated by the persistent supply chain shortages operators are experiencing for critical equipment necessary to comply with the proposed NSPS OOOOb, as the Industry Trades have described to EPA.[60] Primarily, the Industry Trades reiterates its position that measurement, sampling and monitoring requirements should not be included in the GHGRP itself. However, should any measurement, sampling and monitoring requirements be codified in Subpart W for sources not required to comply with other regulatory programs, EPA should allow for a phase-in period (as it did during the first two years of Subpart W implementation) to allow for reporters to incorporate those requirements.

Footnote:

[60] https://www.api.org/news-policy-and-issues/letters-or-comments/2023/09/20/API-Letter-to-EPA-Administrator-Regan-on-EPA-Methane-Rule.

Commenter 0408: EAP Ohio, LLC asks the implementation year of the rule be pushed back from 2025 to 2026 so operators can have time to fully develop implementation plans while prioritizing the very important upcoming NSPS OOOOb/c implementation schedule.

Commenter 0418: **The Associations request that EPA provide a reasonable time—at least one year after publication—before facilities must comply with the new Subpart W requirements.**

The IRA requires EPA to finalize the Subpart W revisions by August 16, 2024; however, it does not specify a particular effective date or compliance deadline for these revisions.[71] EPA is proposing to make the Subpart W amendments effective on January 1, 2025, with reporters implementing the resulting changes beginning with reports prepared for Reporting Year 2025 and submitted by March 31, 2026.[72] This is an aggressive timeline given the extent of processes that would have to be changed by LDCs in order to comply with the new direct measurement requirements and calculation methods. The Associations urge EPA to establish either an effective date or a compliance deadline that is no shorter than one year after publication of the final rule.

Emission data collection processes at natural gas distribution systems are embedded in larger operations and maintenance procedures. Those procedures can only be modified within often rigorous Management of Change ("MOC") programs , which are deliberately designed to require significant subject matter input and approval by employees or departments impacted by a given change. A requirement to immediately modify the data collection procedures after the new requirements are finalized (followed by training for employees implementing the new procedures) is far from a reasonable expectation. Additionally, given the technological elements of the Proposed Rule, LDCs will need to work closely with contractors to implement permanent measuring equipment and/or significantly change their monitoring programs and related IT systems. Companies/utilities across the country will all be seeking new or modified measuring equipment at the same time as one another, which could cause both labor shortages and supply-chain issues. It is not reasonable to expect reporting entities to be able to evaluate the new requirements and establish systems to accurately collect the required data elements within such a short period (roughly four-and-a-half months, as currently proposed). Further, in certain jurisdictions, public utility commission approval may be needed to deploy certain leak detection technologies.[73] The Associations ask EPA to provide at least one year for compliance with the new Subpart W requirements. Given that the reporting year aligns with the calendar year, this means that compliance with the Subpart W revisions would not be required until January 1 of the year that is at least 12 months after publication of the final rule (*e.g.*, assuming the final rule is timely published on August 16, 2024, the compliance deadline would be no earlier than January 1, 2026).

EPA has chosen to implement the Section 136(c) methane fee through a separate rulemaking from the Subpart W revisions; EPA is targeting October 2023 for issuing a proposed rule and May 2024 for issuing a final rule.[74] Because the rulemaking process and schedule of these two regulations have been decoupled from one another, EPA clearly recognizes that it is not necessary to tie the effective date of the Subpart W revisions to the statutory start date of the methane fee program.[75] This is particularly true with regard to Subpart W compliance for the distribution segment, which is not subject to the methane fee.[76] Therefore, if EPA determines that it will not extend the proposed effective date for the entire source category, it could still provide a longer compliance date with respect to natural gas distribution facilities.

The compliance deadline for the Subpart W revisions also should align with deadlines for forthcoming regulations—two in particular—that are expected to require similar, yet not identical, methane emission monitoring requirements for the natural gas industry. First, PHMSA recently closed a public comment period on its proposed rule titled "Pipeline Safety: Gas Pipeline Leak Detection and Repair."[77] The PHMSA proposal would regulate methane emissions from new and existing gas transmission pipelines, distribution pipelines, underground natural gas storage facilities, LNG facilities, and certain gas gathering pipelines. PHMSA has proposed new leakage survey and patrolling requirements; performance standards for advanced leak detection; leak grading and repair criteria with mandatory repair timelines; requirements for mitigation of emissions from blowdowns; pressure relief device design, configuration, and maintenance requirements; clarified requirements for investigating failures; and expanded reporting requirements for all gas pipeline facilities within PHMSA's jurisdiction. PHMSA has not yet indicated when it aims to finalize its proposal.

Second, by the end of 2023, EPA is expected to issue a final rule on new source performance standards ("NSPS") and emission guidelines ("EGs") for methane emissions from the oil and natural gas sector under 40 C.F.R. Part 60, Subparts OOOOb and OOOOc. In their capacity as LDCs, Association members do not expect to be covered by this forthcoming final rule.[78] However, many AGA member companies also operate equipment within industry segments other than distribution, including onshore natural gas transmission compression, both intrastate and interstate transmission pipelines, underground natural gas storage, and LNG storage. Thus, many natural gas facilities will be subject to as-yet undetermined requirements for methane monitoring, emissions calculations, and reporting—meaning that they will have to develop and deploy new or modified systems, equipment, and procedures to comply with the new NSPS and EG requirements, the PHMSA rule, and the new Subpart W requirements. It would be much more efficient, cost-effective, reasonable, and technically effective for companies to be able to make the requisite changes all at once instead of doing so in a manner that is both rushed and piecemeal.

Footnotes:

[71] *See* 42 U.S.C. § 7436(h).

[72] Proposed Rule, 88 Fed. Reg. at 50,364–65.

[73] For example, in New York, leak detection instruments must be approved by the Department of Public Service ("DPS"). See 16 NYCRR Part 255.3; see also NY DPS, Gas Leak Detection Instruments and Devices, https://dps.ny. gov/gas-leak-detection-instruments-and-devices (last accessed Sept. 29, 2023).

[74] *See* Spring 2023 Unified Agenda, RIN 2060-AW02: Methane Emissions and Waste Reduction Incentive Program for Petroleum and Natural Gas Systems,

https://www.reginfo.gov/public/do/eAgendaViewRule?pubId=202304&RIN =2060-AW02. The Associations believe that this separate rulemaking process makes sense, as the IRA directive to ensure that methane reporting is accurate and based on empirical data is broader than just the methane fee. *See* 42 U.S.C. § 7436(h) (stating that EPA "shall revise [Subpart W] to ensure the reporting under such subpart, . . . [is] based on empirical data . . . [and] accurately reflect[s] the total methane emissions and waste emissions from the applicable facilities . . . ."). For the distribution segment, which is not statutorily subject to the methane fee, the separate rulemaking reaffirms Congress's intent for all Subpart W facilities to be able to use empirical data in their reporting.

[75] The projected timing of the methane fee regulatory program is not even tied to the start of the statutory program: Section 136(g) of the Clean Air Act states that the methane fee "shall be imposed and collected beginning with respect to emissions reported for calendar year 2024 and for each year thereafter," 42 U.S.C. § 7436(g), yet EPA is targeting mid-2024 for issuing the final methane fee rule.

[76] *Id*. § 7436(f) (distribution not identified as a segment subject to the methane fee).

[77] 88 Fed. Reg. 31,890 (May 18, 2023) (comments accepted through August 18, 2023).

[78] For facilities inside and including the LDC custody transfer station, EPA has proposed to maintain the methane NSPS exemption, which has been in place since the methane NSPS was first established for the oil and natural gas source category. *See* 86 Fed. Reg. 63,110 (Nov. 15, 2021) (proposed rule); 87 Fed. Reg. 74,702 (Dec. 6, 2022) (supplemental proposed rule).

Response 3: The EPA disagrees with commenters' position that the effective date of the subpart W revisions should be delayed beyond January 1, 2025 and that EPA should allow use of BAMM in the 2025 reporting year. Our assessment is that industry will have sufficient time between publication of the final rule and the final effective date of January 1, 2025, to implement any new requirements. Further, most of the new methodologies are optional unless equipment is already in place and in many cases reporters can continue to use existing methodologies that only have updates that do not affect data collection (e.g., updated default emissions factors) for the 2025 reporting year. The EPA also notes that there are missing data procedures in the current rule that are available to assist reporters. In regard to the API letter and study on supply chain issues, the EPA notes that the letter and study address concerns related to EPA's separate rulemaking under CAA section 111(b), and the commenters do not provide information on how the topics in the letter and study specifically apply to this rulemaking.

We agree with commenters that is important to align subpart W requirements with other EPA regulations, where appropriate. On March 8, 2024, the final NSPS OOOOb and EG OOOOc rules were published in the Federal Register (89 FR 16820) and references to that final rule have been updated in this final rule to ensure alignment between the two rules. See Section I.F and Section II.B of the preamble to the final rule for our discussion of the alignment of the final rule with the final NSPS OOOOb and EG OOOOc. As discussed in Section I.F of the preamble to the final rule, the EPA identified areas where additional revisions to part 98 would better align subpart W requirements with recently promulgated requirements in 40 CFR part 60 and part 62, allow facilities to use a consistent method to demonstrate compliance with multiple EPA programs (and thereby limit burden), and improve the emission calculations reported under the GHGRP subpart W. In regard to the proposed PHMSA regulation, the EPA notes that there is a fundamental difference between the proposed leak detection and repair requirements in the PHMSA proposal and the quantification of emissions under subpart W. We did not propose and are not finalizing any requirements related to leak detection and repair and comments related to implementation of the proposed PHMSA regulation are outside the scope of this subpart W rulemaking.

Commenter: GPA Midstream Association
Comment Number: EPA-HQ-OAR-2023-0234-0299
Page(s): 73-74

Comment 4: Effective Date of the Final Rule

The Spring 2022 Unified Agenda of Regularly and Deregulatory Actions lists November 2023 as the anticipated date of the final rule. The proposed rule, however, says that EPA "anticipates that the proposed changes may take effect on January 1, 2023, and would apply beginning with reports submitted for RY2023, which are required to be submitted to the EPA by April 1, 2024."[3]

If the final rule is indeed published in 2023, especially late 2023, the effective date should not be any earlier than January 1, 2024. The changes proposed are extensive and will require significant work to implement, work which cannot begin based on speculation while operators wait for the release of a final rule. Especially for midstream reporters, the GHGRP is an extremely complicated rule, and many midstream operators have had to build sophisticated data collection, calculation, and reporting systems to manage the huge workload this rule imposes and conduct thorough training in the field to ensure the data is properly collected. These data systems will have to be updated (and thoroughly tested) to accommodate the significant and substantial changes EPA has proposed for midstream operators. Further, due to the anticipated Securities and Exchange Commission ("SEC") rule relating to environmental, social and governance ("ESG") disclosures, changes to these systems will also require updates to provide stricter assurance and audit requirements. The SEC rule could have other implications when considering an appropriate effective date for this rule (for example, is BAMM allowable in the context of SEC disclosures?). In fact, even proposed changes intended to simplify or streamline requirements will require modifications to a reporter's GHGRP program and data systems. Many of the data system changes cannot be made until EPA releases final updated reporting forms and XML schema.

In addition, it is important to emphasize that even if a reporter may possess the raw data that will be required by a regulatory change, the necessary data collection, calculation, and reporting work will not be trivial. The opposite will in fact be true in many cases. Given these circumstances, EPA cannot reasonably expect companies to significantly change their GHG reporting programs based on speculation as to what may be included in a final rule, to change their systems retroactively, or to make rapid changes to complex reporting programs. This is unduly burdensome and costly. For these reasons, GPA requests that EPA apply a reasonable effective date and period for implementation of any final rule that will accommodate industry's needs to adapt to EPA's regulatory changes.

Footnote:

[3] 87 Fed. Reg. at 36,924.

Response 4: This comment was included as an attachment to the commenter's letter, but it is a comment on the 2022 GHGRP Proposal, which are not relevant to this final rule. The commenter also submitted comments on the 2023 Subpart W Proposal related to this issue, included earlier in this section.

27.3 Reporting Forms and Schema

Commenter: GPA Midstream Association
Comment Number: EPA-HQ-OAR-2023-0234-0299
Page(s): 16, 76

Commenter: Western Energy Alliance
Comment Number: EPA-HQ-OAR-2023-0234-0399
Page(s): 14

Commenter: American Petroleum Institute et al. (Part 1 of 2)
Comment Number: EPA-HQ-OAR-2023-0234-0402
Page(s): 72

Comment 1: Commenter 0299: **EPA should provide XML schema and revised reporting forms no later than October 31, 2024.**

GPA strongly encourages EPA to provide the draft XML schema and draft revised reporting forms to reporters for review and testing as early as possible—and not later than October 31, 2024.[40] Providing the draft XML schema and draft revised reporting forms early in the past has led to the identification of errors and resulted in significant improvements. Additionally, final forms and schema should be published at least 6 months prior to the due date of the first affected reports. Many midstream operators are reporting data for hundreds of assets and have thus developed automated processes for populating forms and/or schema, which will need to be updated to reflect the extensive changes EPA has proposed. On the occasions where EPA has not released schema until late January,[41] i.e., mere weeks before the reporting deadline, this has compounded challenges during the demanding annual reporting process, and GPA urges EPA to release the schema as early as possible.

…

Schema and Reporting Forms. GPA strongly encourages EPA to provide the draft XML schema and draft revised reporting forms to reporters for review and testing. In the past, doing so has led to the identification of errors and resulted in significant improvements. Additionally, final forms and schema should be published at least 6 months prior to the due date of the first affected reports. Many midstream operators are reporting data for hundreds of assets and have thus developed automated processes for populating forms and/or schema, which will need to be updated to reflect the extensive changes EPA has proposed. In the past, EPA has often not released schema until late January[16] i.e., mere weeks before the reporting deadline, which has compounded challenges during the demanding annual reporting process.

Footnotes:

[40] If finalized, the majority of the proposed revisions would become effective on January 1, 2025. Id. at 50,365. GPA agrees with this approach because, as discussed in this section, time is needed to develop and implement these new procedures.

[41] See, e.g., EPA, XML Reporting Instructions, https://ccdsupport.com/confluence/display/help/Archived+XML+Reporting+Instructions.

[16] https://ccdsupport.com/confluence/display/help/Archived+XML+Reporting+Instructions

Commenter 0399: Should EPA nevertheless persist, the Alliance recommends that EPA provide a draft template for review well in advance of reporting to ensure there are not delays with reporting.

Commenter 0402: Administrative Recommendations

Streamline Existing Reporting Forms to Reduce Duplicative Reporting and Reduce Unnecessary Submittal Errors

Due to the proposed requirement to report information on a more granular basis, the Industry Trades recommend the following streamlining efforts to reduce duplicative reporting, and to reduce the possibility of administrative error.

EPA should provide industry with a draft of the eGGRT form for review ahead of the reporting season (prior to January 1, 2026). The Industry Trades are concerned that the site-by-site reporting could cause these files to become very large and difficult to transmit and/or store.

Response 1: This comment on the development of draft XML schema and reporting forms published to the EPA's Greenhouse Gas Reporting Program website is outside the scope of the current rulemaking. The EPA may consider this suggestion in future updates to e-GGRT.

27.4 Report Revisions and Cessation of Reporting

Commenter: American Petroleum Institute et al. (Part 1 of 2)
Comment Number: EPA-HQ-OAR-2023-0234-0402
Page(s): 8, 17-18

Commenter: Offshore Operators Committee (OOC)
Comment Number: EPA-HQ-OAR-2023-0234-0409
Page(s): 14-15

Comment 1: Commenter 0402: **EPA must set a period over which submitted GHG reports are considered "final" now that reported emissions will be used as a basis for methane fees.** The Industry Trades are concerned about having to resubmit reports for administrative errors or small corrections in emissions given EPA's historical practice of continually submitting questions regarding previously submitted reports. This would lead to an unworkable situation where additional fees will have to be levied or credited for minor changes in emissions in a methane-fee environment. The Industry Trades recommend a 5% facility-wide reported methane emissions error threshold and only require corrections for emission inventories in the last three full data years.

…

Addressing "Substantive" Errors in a Methane-Fee Environment

A de-minimis threshold and timeframe must be established for errors to be considered substantive. The Industry Trades reiterate our October 2022 comment that a threshold must be developed by which an error is to be considered substantive. As currently codified, the definition of "Substantive Error" is overly broad; any change, including those that are administrative in nature that do not impact methane emissions, could trigger a re-submittal. Since it is likely that future rulemaking will result in operators paying a methane fee on emissions, it will become increasingly critical for EPA to:

1. Determine a de-minimis "substantive error" threshold for methane emissions that excludes administrative errors that would result in a re-submittal;
2. Limit the timeframe in which EPA can determine that a "substantive error" has occurred; and
3. Limit EPA's validation of re-submitted reports to only the initial potential error.

As methane fees become associated with submitted reports, it will become extremely burdensome to adjust previously submitted payments for changes in a report which could result in very small financial adjustments. Furthermore, as reported emissions result in more financial impacts, the required levels of burdensome review for a change in reported data will increase, even if a change does not result in a change in emissions. For these reasons, Industry Trades are recommending that EPA develop a de minimis threshold for "substantive errors" of 5% of an applicable facility's reported methane emissions. This 5% de minimis threshold for total GHG emissions is aligned with a level of emissions change that many companies use for updating their corporate emissions due to errors and/or acquisitions/divestitures in accordance with the

WRI/WBCSD GHG Protocol. While EPA may not know the scope of a possible error when initially requesting additional information, the reporter should have the option to not re-submit the report if an error is found to be below the de minimis threshold, and operators can provide the supporting information in their response to EPA through E-GGRT.

Finally, the Industry Trades are recommending a limit to the timeframe in which EPA can determine that a substantive error has occurred. The Industry Trades recommend that EPA limit the timeframe in which a "substantive error" can result in a requirement to resubmit a prior year's report to no more than three years, consistent with the record retention requirement in 40 CFR 98.3(g). Further, for re-submittals, EPA should limit the validation to the requested source(s) for which the substantive error was identified. This will avoid the burden of the current practice of EPA re-opening inquiries for other sources that previously have already been addressed by the reporter. This still allows EPA plenty of time for review and questions.

Commenter 0409: **Section/Paragraph Reference:** De-minimus threshold and timeframe must be established for errors to be considered substantive.

Proposed Text: Not applicable.

Comment: OOC supports section 2.2 in American Petroleum Institute's (API) Subpart W comment letter, which requests that a threshold be developed by which an error is to be considered substantive, in lieu of the current broad definition. Specifically, OOC is requesting that EPA:

1) Determine a de-minimus 'substantive error' threshold for methane emissions that excludes administrative errors that could result in a re-submittal. OOC suggests a threshold of 5% of facility-wide reported methane emissions.

2) Limit the timeframe in which EPA can determine that a 'substantive error' has occurred to no more than 3 years.

3) Limit EPA's validation of re-submitted reports to only the requested revision.

As methane fees become associated with submitted reports, it will become extremely burdensome to adjust previously submitted payments for changes in a report which could result in very small financial adjustments. The suggested timeframe of 3 years is consistent with the record retention requirement in 40 CFR 98.3.

Response 1: In addition to providing the mass of methane emissions used to compute charges under CAA section 136(e)(1), and as noted at 88 FR 50286 of this proposed rulemaking, the data collected under subpart W "are relevant to the EPA's carrying out of a variety of CAA provisions." To ensure the accuracy of data reported under subpart W of part 98, as a part of this rulemaking the EPA is not limiting when revised reports may be submitted or establishing a quantitative threshold for substantive errors below which correction would not be required pursuant to 40 CFR 98.3(h).

The EPA published a Notice of Proposed Rulemaking for the Waste Emissions Charge for Petroleum and Natural Gas Systems (WEC proposal) on January 26, 2024 (89 FR 5318) which proposed to codify the rule at 40 CFR part 99. Under the proposed rule, if the part 98 report for a facility subject to the proposed part 99 rule is revised resulting in an impact on the amount of WEC obligation owed (e.g., a change in the quantity of methane emissions reported to subpart W) the owner or operator of the facility would be required to submit a revised filing under part 99. The EPA recognizes that the association between reports submitted pursuant to subpart W of part 98 and the assessment of charges on methane emissions under proposed part 99 raises concerns not previously addressed with respect to part 98 resubmittals for purposes of WEC implementation. In consideration of these concerns, in that separate rulemaking the EPA has proposed a deadline of November 1 of the year following the reporting year for filings under part 99 (*e.g.*, for the 2024 reporting year, resubmitted WEC fillings would be required by November 1, 2025). Note that as part of this proposed approach the EPA would retain the authority to reevaluate charges after November 1 in certain situations, including following an EPA audit of facility data or in the cases where a facility's reported data is unverified as of November 1. Further, this proposed deadline would not apply to Clean Air Act section 111(b) or (d) compliance reports or revisions for the purposes of the regulatory compliance exemption. As part of the WEC proposal, the EPA requested comment on the proposed approach of setting a deadline for part 99 resubmissions, the proposed November 1 deadline, and alternative approaches. These comments will be considered and addressed under the separate part 99 rulemaking.

Commenter: Michigan Oil and Gas Association (MOGA)
Comment Number: EPA-HQ-OAR-2023-0234-0298
Page(s): 3

Comment 2: Off-Ramp Inclusion

MOGA applauds the EPA proposal to clarify the provisions allowing a temporary or final cessation of reporting when emission fall below the equivalent (mtCO2e) level or the 25,000 mtCO2 level for a subsequent number of years. However, MOGA is concerned with the potential costs associated with continued reporting during this timeframe. MOGA argues that emissions are tied to throughput and when throughput declines to marginal well levels, the proposed continued reporting will exacerbate the early plugging of wells by adding untenable costs. MOGA suggests the EPA should remove the subsequent reporting after off-ramping or, at minimum, reduce the reporting timeframe to two years to account for depletion.

Response 2: The EPA did not reopen and did not propose and is not taking final action in this rule to change the framework of the numeric years of the offramp provisions to cease reporting. As previously explained when adopting the existing requirements, the framework for GHGRP was adopted to help aid in comparing trends over time, with the off-ramping adopted as a method for facilities to move out of the reporting program due to reduced emissions over an extended period of time. As noted in the 2009 preamble, the EPA selected a 5-year offramp period to avoid situations where facilities or suppliers are constantly moving in and out of the reporting program due to small variations from one year to the next. The shorter 3-year period was adopted in acknowledgement that reporters below 15,000 $mtCO_2e$ would unlikely experience such variations from year to year (74 FR 56276-56277, Oct 30, 2009).

27.5 Public Availability of Reported Data

Commenter: Anonymous
Comment Number: EPA-HQ-OAR-2023-0234-0283
Page(s): 1

Comment 1: I have questions about the "delay in reporting for wildcat wells and delineation wells" section. EPA said before that these are types of exploratory wells and that this delay is because exploration data are "sensitive" for the first two years after a new well is drilled. It would be good if all the information could be posted, but if this special case is still needed, some of the changes in other parts of the rule don't match the parts where there's a delay.

1. Can a well be both a wildcat well and a delineation well, or is there a typo in the phrase "wildcat well and/or delineation well"?

2. EPA is moving to reporting by well, but there are places in the rule where they only get a delay in reporting "if the only wells in the sub-basin are wildcat and delineation wells". Why is that part required? If a single well is a wildcat or delineation well and information has to be reported by well, isn't the information sensitive regardless of whatever other wells are in the sub-basin, or basin?

3. Same question but different basis – if reporting is by well-pad, shouldn't there be a delay if the only wells on the well-pad are wildcat and delineation wells? Again, why does it matter what other wells are in the basin or sub-basin?

Response 1: See Section III.D of the preamble to the final rule for the EPA's response to this comment.

Commenter: Public Hearing Transcript
Comment Number: EPA-HQ-OAR-2023-0234-0224
Page(s): 54-55 (Katie Muth)

Commenter: National Tribal Air Association (NTAA)
Comment Number: EPA-HQ-OAR-2023-0234-0239
Page(s): 3, 4

Comment 2: Commenter 0224: The self-reporting method is a complete failure and allows for loopholes and dishonest data and a year delayed time frame here in Pennsylvania; we don't get emissions reporting until a year after the date of when a pollution event would've occurred. … also that there would be real time data implementation available if we can find where an Amazon package is located and look at the purple air monitor system with real time data, then our government should also provide real time data of the permits and the emissions that those permits pollute out into the air so we can see that in real time, not a year later.

Commenter 0239: The EPA should build on its already strong proposal by:

…

Ensuring that the GHGRP data is publicly accessible through the EPA's Facility Level Information on Greenhouse Gases Tool in a timely manner so that Tribes and Tribal members can access relevant information.

Response 2: This comment on changes to the publication of GHGRP data is outside the scope of the current rulemaking. The EPA may consider this comment in future updates to the process of verification and publication of the GHGRP data.

Commenter: Clean Air Council
Comment Number: EPA-HQ-OAR-2023-0234-0203
Page(s): 1

Commenter: Public Hearing Transcript
Comment Number: EPA-HQ-OAR-2023-0234-0224
Page(s): 13 (Alice Lu), 21 (Cheyenne Branscum), 27 (Arthur Gershkoff), 43 (Etta Albright), 44 (Shanna Edberg), 50 (Christina Digiulio), 54-55 (Katie Muth)

Commenter: American Lung Association
Comment Number: EPA-HQ-OAR-2023-0234-0335
Page(s): 1

Commenter: Damascus Citizens for Sustainability
Comment Number: EPA-HQ-OAR-2023-0234-0368
Page(s): 1

Commenter: Environmental Defense Fund et al.
Comment Number: EPA-HQ-OAR-2023-0234-0401
Page(s): 1

Comment 3: Commenter 0203: I urge EPA to strengthen its proposed rule in the following ways:

…

- Ensure data reported from all facilities – including those affected under the proposed revisions to onshore oil and gas production, gathering, and boosting industries – remain publicly available.

Commenter 0224: And finally, data from all facilities including those affected under the proposed revisions to onshore oil and gas production, gathering and boosting industries should remain publicly available and accessible.

…

And I really want to ensure that all data remains publicly available.

…

I applaud the EPA's goal of developing cooperative relationships with fossil fuel companies. The plan to treat certain data as confidential is an important component of this cooperation. However, the EPA may need to balance or modify confidentiality of certain data needed by communities in response to super emissions that threaten the health of communities, and which need to be investigated openly and publicly.

…

Because accurate reporting of the methane emission is critical to engage the public through knowledge and understanding of actions needed to contain global warming, such reports of emissions must be public information and not concealed. Such concealing of truth from the public is like the fracking industry not having to disclose the toxic chemicals used by the industry and remaining in our water, our air, and our soil. The EPA must fulfill the role of the agency to protect the environment, and thus the public, and not submit to the egregiousness of the industry.

…

And we also ask that reported data remain publicly available.

…

Reported data including those under the proposed revisions to the onshore and oil gas production and gathering and boosting industries should remain publicly available.

…

And make all information accessible to the public. There should be no confidentiality for this industry as they've hidden enough secrets that have caused a lot of harm. If it's not harmful, then why can't we all know the information is the question I would ask.

Commenter 0335: Once finalized, these revisions must require that all reported data, including those under the proposed revisions to the onshore oil and gas production, gathering, and boosting industries, remain publicly available.

Commenter 0368: We also would very much like to see the EPA provide all reported emissions data in publicly-accessible and easy to use formats. Verify the accuracy of reported emissions and that applicable facilities are properly identified.

Commenter 0401: Specifically, the EPA should adopt the following provisions:

…

- **Provide all reported emissions data in publicly-accessible and easy to use formats.** Verify the accuracy of reported emissions and that applicable facilities are properly identified.

Response 3: The EPA explained its proposed approach to evaluating the confidentiality status of data elements and proposed confidentiality determinations for new and revised data elements in the 2023 Subpart W Proposed Rule. In the Notice of Proposed Rulemaking for the Waste Emissions Charge for Petroleum and Natural Gas Systems (WEC proposal) on January 26, 2024 (89 FR 5318), the EPA re-proposed the confidentiality determination for one data element (the quantity of residue gas leaving that has been processed by the facility and any gas that passes through the facility to sale without being processed by the facility in the calendar year). As explained in section V of the preamble to the final rule, the EPA is finalizing the confidentiality determinations as proposed except for the quantity of residue gas leaving that has been processed by the facility and any gas that passes through the facility to sale without being processed by the facility in the calendar year, which we are not taking action on at this time. .

27.6 Consideration of Other Calculation and Reporting Programs

Commenter: Anonymous
Comment Number: EPA-HQ-OAR-2023-0234-0183
Page(s): 1-2

Commenter: Marcellus Shale Coalition (MSC)
Comment Number: EPA-HQ-OAR-2023-0234-0275
Page(s): 2-4

Commenter: Arkansas Independent Producers and Royalty Owners (AIPRO)
Comment Number: EPA-HQ-OAR-2023-0234-0382
Page(s): 8-9

Comment 1: Commenter 0183: The proposed rule does not address the potential overlap or duplication of reporting requirements between subpart W and other subparts of part 98, such as subparts C, D, K, O, U, HH, II, NN, OO, QQ, RR, SS, TT, UU, VV, WW, XX. The proposed rule should harmonize and streamline the reporting requirements for petroleum and natural gas systems facilities across different subparts of part 98, to avoid confusion and reduce reporting burden.

Commenter 0275: Background

The MSC notes its preparation of comments for the purpose of the GHGRP is to provide a source of data to identify opportunities for emission reductions and progress regarding these opportunities. The data should be useful for companies, the U.S. EPA states, cities, and communities. The U.S. EPA notes this purpose on its GHGRP website (https://www.epa.gov/ghgreporting/learn-about-greenhouse-gas-reporting-program-ghgrp):

The GHGRP (codified at 40 CFR Part 98) requires reporting of greenhouse gas (GHG) data and other relevant information from large GHG emission sources, fuel and industrial gas suppliers, and CO2 injection sites in the United States. This data can be used by businesses and others to track and compare facilities' greenhouse gas emissions, identify opportunities to reduce pollution, minimize wasted energy, and save money. States, cities, and other communities can use the U.S. EPA's greenhouse gas data to find high-emitting facilities in their area, compare emissions between similar facilities, and develop common-sense climate policies.

For companies, this has resulted in internal reduction goals or participation in industry programs such as the U.S. EPA's voluntary Natural Gas Star Program and Methane Challenge Program, API's The Environmental Partnership, ONE Future, and other initiatives. In addition, a growing number of companies have pursued third-party designations and affirmations as to their development processes, and as a result have achieved certifications for producing and transporting "Responsibly Sourced Gas". This heightened level of certification has become of increasing interest to stakeholders, investors and purchasers of natural gas, and often serves to provide recognition for an operators' processes – focused on efficiency, environmental stewardship, and other attributes – which the company was already adhering to as part of their own corporate ethos.

For regulatory bodies such as the U.S. EPA and the Pennsylvania Department of Environmental Protection (PADEP), it has provided a basis for discussion in the development of regulations and permit requirements. This includes the identification and control of sources of methane emissions for the oil and gas industry. The U.S. EPA has used this information in the development of New Source Performance Standards (NSPS) for the oil and gas industry. PADEP has developed its general permits (GP-5 and GP-5A) for the oil and gas industry which included state-defined Best Available Technology (BAT) controls through this process. Coupled with strong internal company standards for performance, efficiency, and environmental stewardship, these measures have contributed to Pennsylvania's operators – situated within the Appalachian Basin – being recognized for spearheading operations that have the lowest overall methane intensity of the nine largest hydrocarbon producing basins in the entire United States.[1]

In addition, it has spurred innovations in the use of existing developing technologies. Examples include optical gas imagining (OGI), LiDAR, drones, fixed emission monitors, satellite technology and other developing technologies.

…

GENERAL COMMENTS

The MSC again recommends that the final GHGRP recognize and not overlap, conflict or be redundant with requirements for sources under other programs.

The proposed rule includes revised emission factors, requirements for measurement and compliance, and contingency factors for determining greenhouse gas (GHG) emissions. Methane emissions are a focus of the proposed rule for the oil and gas industry. The calculation of volatile organic contaminants (VOC), organic hazardous air pollutants (HAPs), and other organic emissions are typically linked for the oil and gas industry.

Therefore, the U.S. EPA needs to address how the proposed regulation will impact accepted guidance and methods for emission quantification of organic emissions. This includes interaction with calculating potential and actual emissions associated with State Only Operating Permit Programs, Federal Title V Permit Programs, Prevention of Significant Deterioration/Non-Attainment New Source Review, New Source Performance Standards (NSPS) and National Emission Standards for Hazardous Air Pollutants (NESHAP), and in addition, Pennsylvania's annual emission inventory.

…

One specific example of guidance documents that should be addressed is the use of AP-42: Compilation of Emission Factors and the November 1995 Protocol for Equipment Leak Emission Estimates.

Footnote:

[1] Clean Air Task Force & Ceres: Benchmarking Methane & Other GHG Emissions (July 2022)

<u>Commenter 0382</u>: <u>Potential for "double-counting" of emissions from certain sources due to certain requirements</u>:

Under current GHGRP rules as well as proposed GHGRP revisions, there are multiple scenarios where emissions may be "double-counted", some of these include the following:

- Same reporter required to report under multiple GHGRP subparts due to operational makeup.

…

- Requiring indirect emissions (aka "Scope 2") reporting when other industry segments report the same emissions as direct emissions (aka "Scope 1").

AIPRO encourages EPA to identify and eliminate all potential double-counting scenarios.

AIPRO, again, welcomes the opportunity to collaborate with the agency on this effort.

Response 1: The EPA has previously addressed comments related to double-counting of emissions in the 2009 GHGRP final rule (74 FR 56260, October 10, 2009) and the responses to comments related to subpart C (see Volume 15 of USEPA Response to Public Comments on the Mandatory Greenhouse Gas Reporting Rule: Subpart C-General Stationary Fuel Combustion Sources, Docket Id. No. EPA-HQ-OAR-2008-0508). Per the requirements in 40 CFR part 98, subpart A (General Provisions), facilities have to report GHG emissions from all source categories located at their facility, including stationary combustion and process emissions. EPA does not intend that emissions be double reported, and part 98 provides specific methods for reporting sector-specific process emissions versus combustion emissions. To the extent that the EPA was aware of specific duplicative reporting requirements between subpart W and other GHGRP subparts, the EPA has sought to finalize amendments to remove these duplicative reporting elements. For example, see sections II.C and III.U.4 of the preamble to the final rule for discussion of the removal of the requirement to report certain data elements for facilities that also report under subpart NN (Suppliers of Natural Gas and Natural Gas Liquids). The commenter did not provide specific examples to evaluate and respond to the potential for duplicative reporting requirements between subpart W and subparts C, D, K, O, U, HH, II, OO, QQ, RR, SS, TT, UU, VV, WW, and XX.

Under this rulemaking, the EPA is finalizing amendments to improve the accuracy of reported emissions and incorporate empirical data under subpart W of the GHGRP. The EPA understands that the emissions monitoring, measurement, and quantification methodologies finalized in this rulemaking may be relevant to other regulatory programs; however, these interactions are not addressed under this rulemaking. Specifically, the interaction between emissions calculated and reported under subpart W of the GHGRP and the determination of potential and actual emissions associated with permitting programs, NSPS and NESHAP rules, or to individual state annual emission inventories are outside of the scope of this rulemaking.

With respect to comment regarding the reporting of indirect emissions, see Section III.A.4 of the preamble to the final rule for discussion of the proposed amendment under the GHGRP supplemental proposed rule on May 22, 2023 (88 FR 32852) to add subpart B (Energy Consumption) and the relationship of the proposal to this final subpart W rulemaking.

Commenter: Edison Electric Institute (EEI)
Comment Number: EPA-HQ-OAR-2023-0234-0379
Page(s): 3-4

Comment 2: EPA Should Be The Regulatory Agency That Directs GHG Reporting.

The natural gas and electricity industries have been reporting on and reducing GHG emissions. Across the Federal government, regulatory agencies are requiring GHG reductions and reporting as well. EPA has been given the statutory authority under the Clean Air Act (CAA) to require GHG emissions reporting from sources via the GHGRP; as such, the Agency has set the standard for agencies' GHG reporting requirements and could be the protocol used across the government. Given that the SEC is expected to issue climate disclosure rules for financial reporting purposes in the near future, we would be concerned if two or more Federal agencies promulgated disclosure requirements of a specific metric that varied in how they were computed. If that were to occur, it would increase the potential that users of the reports could be confused by inconsistent information or undermine confidence in either or both reporting systems. Therefore, EPA and the SEC should coordinate reporting requirements so that there is one approach. A uniform approach would help ensure that emissions reporting is consistent across agencies and reduce the potential that reporting entities would be required to maintain different accounting practices for the same underlying emissions. Moreover, as EPA is the agency with principal authority over emissions and significant experience with GHG reporting, it should be the lead agency on these reporting requirements.[3]

Footnotes:

[3] EPA is proposing to clarify that its proposed Subpart B regulations apply to Subpart W reporters. 88 Fed. Reg. at 50,296. EEI provided comments on EPA's prior Subpart B proposal and maintains its position that the Subpart B reporting should not be used as a mechanism for imposing emissions standards. See Comments of the Edison Electric Institute on the U.S. Environmental Protection Agency's Revisions and Confidentiality Determinations for Data Elements Under the Greenhouse Gas Reporting Rule Supplemental Notice of Proposed Rulemaking, EPA Dkt. No. EPA-HQ-OAR-2019-0424 (July 21, 2023).

Response 2: See Section III.A.4 of the preamble to the final rule for discussion of the proposed amendment under the GHGRP supplemental proposed rule on May 22, 2023 (88 FR 32852) to add subpart B (Energy Consumption) and the relationship of the proposal to this final subpart W rulemaking.

Commenter: Project Canary, PBC
Comment Number: EPA-HQ-OAR-2023-0234-0348
Page(s): 20

Commenter: Devon Energy
Comment Number: EPA-HQ-OAR-2023-0234-0360
Page(s): 5

Commenter: Duke Energy
Comment Number: EPA-HQ-OAR-2023-0234-0376
Page(s): 9

Commenter: Western Energy Alliance
Comment Number: EPA-HQ-OAR-2023-0234-0399
Page(s): 2-3

Commenter: American Petroleum Institute et al. (Part 1 of 2)
Comment Number: EPA-HQ-OAR-2023-0234-0402
Page(s): 5-6

Commenter: Atmos Energy Corporation
Comment Number: EPA-HQ-OAR-2023-0234-0406
Page(s): 8

Comment 3: Commenter 0348: **Conclusion**

We would be remiss if we did not add the broader point that Project Canary encourages the EPA to work with the rest of the Administration to support consistent, whole-of-government integration of advanced measurement technologies and incentives across other methane-related rulemakings by incorporating the NSPS OOOOb and EG OOOOc Alternative Test Method approval approach including:

- The PHMSA (Pipeline and Hazardous Materials Safety Administration) Pipeline Safety: Gas Pipeline Leak Detection and Repair Proposed Rule[45] which contemplates a similar measurement methodology approval approach.
- In the BLM (Bureau of Land Management) proposed rule on Waste Prevention, Production Subject to Royalties, and Resource Conservation[46], BLM proposes to incorporate "relevant advances in technology" as a factor for "reasonable measures to prevent waste." However, the proposed rule does not facilitate the adoption of advanced methane detection technologies for use at oil and gas operations on federal lands. The BLM should align its Final Rule with the EPA's proposed NSPS OOOOb and EG OOOOc approval process, allowing methodologies approved by EPA to fulfill BLM's "reasonable measures."
- The Department of Energy's differentiated natural gas Best Practices Framework initiative could also rely on EPA-approved measurement methodologies as a reliable source to ensure monitoring is best practice for purposes of verification, auditing, or buyer certainty for purchases of differentiated natural gas.
- Although the final SEC rulemaking is undergoing changes, as we understand it, it would also be advisable for the Administration to rely on EPA-approved measurement methodologies for corporate reporting as it can, again, provide a reliable source of assurance that methane measurement is best practice.
- It is also advisable for the Administration to adopt EPA-approved methane detection and quantification methodologies as best practice in the Federal Acquisition Regulation for Disclosure of Greenhouse Gas Emissions and Climate-Related Financial Risk[47] and the Federal Acquisition Regulation for Sustainable Procurement proposed rule. [48] It is important to encourage continued investment in the development of new methane measurement technologies and other innovations that may make these technologies more efficient, accessible, and affordable. We urge a technology-neutral approach in federal and state policies—laws and regulations should not dictate which technologies can be utilized. Instead, these policies should focus on quantifiable outcomes—specifically, a robust understanding of actual, on-the-ground emissions. This allows for the quick identification and remediation of emission sources and will encourage the adoption of more efficient and accurate technology as it is created.

By allowing sources of emissions to be informed by measurement-based and quantified emissions values, EPA will incentivize the investment in and adoption of advanced emissions detection technologies. In addition to these technologies providing the basis for a more accurate and robust GHG emissions inventory, they will also help to drive down emissions because operators are more likely to invest in emissions mitigation if they have confidence the resulting reductions will be reflected in their reported inventories. An accurate GHG emissions inventory also will result in more precise payments to the Treasury with respect to the methane fee. Through the use of EPA-approved measurement technologies in lieu of emission factors that are known to both under- and over-estimate emissions, operators are more likely to pay exactly what is owed regarding their emissions. Disincentivizing the adoption of advanced technologies would defeat the Agency's goals in this proposal and frustrate Congressional intent.

Footnotes:

[45] Docket No. PHMSA-2021-0039, RIN 2137-AF51. htps://www.regulations.gov/document/PHMSA-2021-0039-2101.

[46] BLM-2022-0003-0001. htps://www.regulations.gov/document/BLM-2022-0003-0001.

[47] FAR Case 2021-015. htps://www.regulations.gov/document/FAR-2021-0015-0037.

[48] FAR Case 2022-006, 88 Federal Register 51672 (August 3, 2023). htps://www.regulations.gov/document/FAR-2022-0006- 0001.

Commenter 0360: **EPA should ensure alignment across multiple EPA and other federal agency rulemakings.**

Methane and GHG emissions from the oil and gas industry are central to several ongoing rulemaking efforts across multiple federal agencies, including EPA, the Bureau of Land Management (BLM), and the Pipeline and Hazardous Materials Safety Administration (PHMSA). Misalignment within these rulemakings will create regulatory uncertainty and will hinder emissions reduction efforts. Where methane and GHG detection technologies are accepted in one rule, they should be accepted in the same manner and application across all rules. Where measurement and monitoring standards are deemed sufficient in one rule, they should be sufficient across all rules. The failure to recognize this fact will lead to unintended consequences that will hinder progress to reduce actual emissions. EPA must coordinate with other federal agencies to make sure it is not undermining or subverting the "whole of government" approach to mitigating methane and GHG emissions.

Commenter 0376: **It is vitally important that, whenever possible, federal agencies coordinate regulations where actions to reduce and measure emissions align with actions to operate safe natural gas transmission and distribution systems.**

In addition to the changes EPA is proposing in this docket, there are other federal and state agencies that are addressing greenhouse gas emissions and actions companies must take to reduce, eliminate, measure, and report these emissions. In some instances, these mandatory rules can create conflicts as well as redundancy for the companies trying to comply. For example, some of the EPA rules and the PHMSA rules overlap. In the PHMSA Pipes Act of 2020,[13] new and existing gas distribution pipeline operators will be required to use advanced leak detection technologies and practices through continuous monitoring on or along the pipeline, through periodic surveys with handheld equipment or equipment mounted on mobile platforms, or other means using commercially available technology. Duke Energy encourages EPA and PHMSA to work together to coordinate how companies can comply with both sets of regulations while providing safe, reliable, affordable gas service to our customers and reduce emissions.

Footnote:

[13] Protecting Our Infrastructure of Pipelines and Enhancement Safety Act of 2020, Sec. 113, Leak Detection and Repair.

Commenter 0399: **Harmonization of the Proposal with Other Rulemaking Efforts**

The Alliance urges EPA to carefully consider how this proposed rulemaking will interact negatively with other concurrent rulemakings at EPA and other federal agencies tasked with regulating emissions mitigation. For example, the Pipeline Hazardous Materials Safety Administration's Leak Detection and Repair rule and BLM's waste prevention rule also attempt to regulate methane emissions. As written, there would not only be several legal vulnerabilities, but also seemingly numerous conflicts in incentives and technologies to comply with the various sets of requirements. EPA should better coordinate with rulemaking efforts within the agency and the broader federal government to ensure the rulemaking efforts work in harmony with each other, instead of reimagining proper methods of emissions estimation and mitigation in each proposal.

Commenter 0402: Summary of Priority Items

In addition to our technical comments, the Industry Trades have identified four overarching priority items within the proposed rules that if satisfactorily amended, will allow industry to attain the maximum potential methane mitigation and reduce public confusion. These high priority items are as follows:

1. **Achieve greater [inter-agency] regulatory harmonization and coordination:**

There are multiple federal agencies and distinct departments within agencies that have pending or proposed regulations, guidance, or frameworks directly and indirectly related to methane emissions applicable to our industry, as listed below:

…

d. Treasury Department – Section 45V regulations for hydrogen production tax credit, with the treatment of differentiated natural gas

e. DOT/PHMSA – LDAR Rule

f. DOI/BLM – Waste Prevention Rule

g. DOE/Argonne – GREET Model, used as the basis for calculating GHGs associated with hydrogen production for eligibility for the Section 45V tax credit

h. DOE – Differentiated Gas Framework

i. State Department – International methane MRV standard (with DOE)

j. State Department – Global discussions on an EU Import standard and global methane policy

Across all of this methane-related policy making, the Industry Trades identify a potentially high risk for inconsistent methodologies or reporting structures.

…

We urge EPA to seek true alignment and harmonization with other federal regulatory requirements …

Commenter 0406: **EPA should harmonize Subpart W with Subparts OOOOb and OOOOc and the PHMSA leak detection and repair requirements when those rules are finalized.**

EPA should harmonize Subpart W with Subparts OOOOb and OOOOc and the PHMSA leak detection and repair requirements when those rules are finalized. Harmonizing monitoring and reporting requirements across the regulatory regimes will ease the already significant burden on operators and expedite the implementation of the new requirements. Accordingly, Atmos urges EPA to take the following steps to ensure consistency across all three programs.

First, given the potential for overlap between the OOOOb/OOOOc rules, PHMSA rules, and the Proposed Rule, EPA should provide a new opportunity for comment on Subpart W once the OOOOb/OOOOc[27] and PHMSA rulemakings[28] have concluded. At a minimum, EPA should ensure that any changes to the proposed OOOOb/OOOOc and PHMSA rules are also reflected in Subpart W.

Second, and of critical importance, EPA's proposed requirements for "other large release events" should align with other regulatory regimes. EPA is proposing to add a new emissions source, referred to as "other large release events," to capture reporting of "maintenance or abnormal emission events that are not fully accounted for using existing methods" in Subpart W.[29] EPA proposes to define a large release event as either an "instantaneous" CH4 emission rate of at least 100 kilograms per hour (kg/hr) or an exceedance of a "per event" threshold of 250 metric tonnes of carbon dioxide equivalent (mtCO2e).[30] EPA defines "other large release events" to include any planned or unplanned uncontrolled release, including those associated with maintenance activities, for which there are no emission calculation procedures in Subpart W.[31] As a result of these definitions, "other large release events" could include planned maintenance, shutdown, and startup activities that are short in duration and do not typically result in significant emissions. These events are also relevant to the ongoing PHMSA leak detection and repair rulemaking.[32] EPA should align its reporting requirements with PHMSA's rulemaking to avoid confusion and facilitate consistent, transparent emissions reporting.

Footnotes:

[27] EPA's semiannual agenda stated that EPA intended to issue the final rule in August 2023. 88 Fed. Reg. 48,598, 48, 603 (July 27, 2023).

[28] 88 Fed. Reg. 31,890 (May 18, 2023).

[29] 88 Fed. Reg. at 50,296.

[30] *Id.*

[31] *Id.*

[32] *See* e.g., 88 Fed. Reg. at 31,907.

Response 3: The EPA acknowledges and appreciates the information shared by commenter's regarding other methane-related rulemakings. To the extent that commenters provided specific comment regarding alignment between requirements under the proposed subpart W rule and other rulemakings, these comments are addressed in source- or topic-specific sections of this document. Regarding comment that the EPA work with other agencies to adopt EPA's Alternative Test Method approval approach, the EPA notes that this request is outside the scope of this rulemaking. With respect to the EPA's review of advanced technologies as part of this rulemaking, see Section II.B of the preamble to the final rule and Section 23 of this document for comments received regarding measurement approaches and their responses.

With respect to comment that the EPA should provide opportunity to comment on Subpart W following the conclusion of other rulemakings, the EPA disagrees. Each of the rulemakings referenced by the commenter are independent rulemakings and stakeholders were, or will be, provided the opportunity to submit any applicable comments to the respective docket for each rulemaking for consideration in the development of the final rules. See the response to Comment 2 in Section 28.4 of this document for more information regarding the information we provided in the 2023 Subpart W proposal regarding general alignment between Subpart W and the final NSPS OOOOb and EG OOOOc.

With respect to comments regarding alignment of requirements for other large release events with other regulatory programs, see Section III.B of the preamble to the final rule for discussion of the final amendments and response to comments concerning alignment with NSPS OOOOb and EG OOOOc. With respect to comments regarding alignment of specific requirements with NSPS OOOOb and EG OOOOc, see Section I.F, Section II.B, Section III.N, Section III.O and Section III.P of the preamble to the final rule for discussion of alignment of certain requirements with the timeline of implementation of the provisions of NSPS OOOOb and EG OOOOc.

Commenter: Edison Electric Institute (EEI)
Comment Number: EPA-HQ-OAR-2023-0234-0379
Page(s): 2-3, 4-5

Comment 4: EEI also supports efforts to ensure methane emissions from the entire natural gas supply chain are reduced as doing so is essential to the industry's ability to continue to use natural gas. EEI's members, together with members of the American Gas Association (AGA), were instrumental in organizing the Natural Gas Sustainability Initiative (NGSI), a voluntary, industry-led effort to advance best practices and to encourage continuous improvement in methane emissions reductions through company-level disclosure. NGSI is intended to complement and work in concert with regulatory standards from the EPA, which are critical to reducing emissions and providing certainty to both the regulated industry and its customers in the supply chain. NGSI also aims to provide consistency and comparability to these measurements throughout the supply chain.

…

EPA Should Leverage The Existing Reporting Under NGSI.

As noted above, EEI supports efforts to ensure methane emissions reductions and was instrumental in NGSI's formation. NGSI provides a methodology for companies to consistently calculate and report methane emissions intensity. The protocol, which is aligned with the ONE Future protocol,[4] is designed to support voluntary reporting by companies operating within the natural gas supply chain in the United States from onshore production through distribution. NGSI is intended to bolster and complement methane management efforts, including methane regulatory standards and direct methane measurement strategies, all of which are important elements for reducing emissions and providing certainty to both the regulated industry and its customers in the supply chain.

NGSI participants believe a coordinated effort—including voluntary reporting, benchmarking of continuous improvement, and expanded use of direct measurement technologies—is necessary to show that the entire supply chain manages natural gas in an increasingly safe, environmentally sound, and secure manner. NGSI's agenda for helping advance natural gas supply chain ESG efforts has been shaped by input gained through a robust stakeholder engagement process. NGSI has engaged with numerous companies representing all facets of the natural gas industry, investors and the broader financial community, and environmental nongovernmental organizations. This has included a series of webinars and a public workshop along with extensive outreach to individual companies and associations, during which stakeholders have provided valuable direction for NGSI's objectives, guiding principles, structure, and near-term agenda, and in the methane emissions intensity protocol.

EPA should leverage the significant reporting efforts under ONE Future and NGSI, recognizing the methane emission measuring protocols that have been developed to obtain more accurate empirical data and seek to align with such protocols as an option for regulated entities under Subpart W.

Footnote:

[4] Our Nation's Energy (ONE) Future, https://onefuture.us/.

Response 4: The EPA appreciates the information shared by the commenter and acknowledges the existence of voluntary programs to quantify and report emissions. While a comprehensive review of the ONE Future and NGSI protocols are outside of the scope of this rulemaking, the EPA notes that the GHGRP and the annual *Inventory of U.S. Greenhouse Gas Emissions and Sinks* (U.S. GHG Inventory) serve as the primary inputs to these protocols.[22] For discussion of revisions to address potential gaps in reporting to subpart W of the GHGRP, including review of the U.S. GHG Inventory, see Sections II.A and III.C.1 of the preamble to the final rule.

Commenter: Public Hearing Transcript
Comment Number: EPA-HQ-OAR-2023-0234-0224
Page(s): 17 (Laurie Anderson)

Commenter: Sensirion Connected Solutions
Comment Number: EPA-HQ-OAR-2023-0234-0293
Page(s): 17-18

Commenter: Western Energy Alliance
Comment Number: EPA-HQ-OAR-2023-0234-0399
Page(s): 9

Commenter: Bridger Photonics, Inc.
Comment Number: EPA-HQ-OAR-2023-0234-0407
Page(s): 3-4

Commenter: Differentiated Gas Coordinating Council (DGCC)
Comment Number: EPA-HQ-OAR-2023-0234-0415
Page(s): 3, 10

Comment 5: Commenter 0224: Colorado has been a national leader in fighting climate change by adopting strong policies to cut methane emissions from the oil and gas sector. Just recently, the Colorado air quality control commission finalized a rulemaking on reporting emissions for the GHG intensity verification rulemaking as we move toward direct measurement since pollution is often underreported. After so many years of basing pollution on calculated estimates, we will finally have critical measured data so the state and the industry can make better informed decisions on how to truly reduce pollution and hit our state's target GHG reductions. This rulemaking had unanimous support, including support from the industry. The protocols are still being developed, but we know that top-down basin-level data provides a broad view of total

[22] See, *e.g.*, NGSI. "NGSI Methane Emissions Intensity Protocol Version 1.0." February 2021. Available at https://www.aga.org/wp-content/uploads/2022/12/ngsi_methaneintensityprotocol_v1.0_feb2021.pdf ("Where possible, NGSI uses emission factors and estimation methodologies published and developed by the U.S. Environmental Protection Agency (EPA) as part of the Greenhouse Gas Reporting Program (GHGRP) or the Greenhouse Gas Inventory (GHG Inventory). In comments to NGSI, companies and organizations have identified several emission factors which may be over or underestimated in the GHGRP and the GHG Inventory, including leaks from distribution mains and services, emissions from pneumatic controllers, and methane slip from compressor engines. Instead of using alternative emission factors for these sources, NGSI references the GHGRP or the GHG Inventory to maintain consistency with data that is reported to EPA.")

emissions in the region, while site-level data can provide insight at a local level and combined will improve and enhance our understanding of reported emissions.

Commenter 0293: **The Proposed Rule's approach regarding continuous monitoring systems is inconsistent with leading state methane quantification policies.**

The approach in the Proposed Rule would put EPA off pace with leading state policies, which are moving toward intensity-based methane requirements and the use of advanced measurement technologies. Colorado finalized a rule in July 2023 that will require owners and operators of certain types of oil and gas facilities to directly measure their methane emissions on a facility-specific basis.[32] The state will use these calculations to derive state-wide emission inventories to assure compliance with the state's GHG intensity (emissions per unit output) thresholds. It is expected that facility owners will use advanced measurement technologies to comply with their direct measurement obligations.

The Colorado rule came about as the result of a comprehensive stakeholder dialogue involving industry, technology providers, and environmental groups. The Environmental Defense Fund issued a statement praising the rule as a "commonsense proposal to directly measure methane emissions in the field."[33]

Through the implementation of this rule, Colorado is fostering technology advancement and adoption as well as ensuring the operators in the state are utilizing empirical data to reduce their emissions and report the most accurate emissions data available. EPA should partner with Colorado, and other states considering similar approaches, to advance this mutual goal.

Footnotes:

[32] Colorado Dep't of Public Health, "Colorado Adopts First-of-its-Kind to Verify Greenhouse Gas Emissions From Certain Oil and Gas Sites" (July 2023), htps://cdphe.colorado.gov/press-release/colorado-adopts-first-of-its-kind-measures-to-verify-greenhouse-gas-emissions-from.

[33] Environmental Defense Fund, "Colorado Adopts Ground-breaking Methane Measurement Rule" (July 2023), htps://www.edf.org/media/colorado-adopts-groundbreaking-methane-measurement-rule.

Commenter 0399: EPA should consider how the Colorado Department of Public Health & Environment (CDPHE) has improved accuracy. The CDPHE Air Pollution Control Division, in its 2022 Production (Upstream) Emissions Inventory Instructions for Regulation No. 7, allows the use of site-specific emission factors that are included in the source permit. If the site-specific emission factor has not been incorporated into a permit it can be used in the emission inventory by providing the base sampling data and supporting emission factor development. This has resulted in a much more reliable and accurate emissions inventory for Colorado than currently exists in the GHGRP or if finalized as proposed.

Commenter 0407: Recommendation 1: Remove incentives to use less-effective emissions monitoring technology.

Instead of attempting to ensure that subpart W reporting is accurate by relying on a patchwork of unproven methodologies to capture more emissions events, we urge the EPA to follow the example set by Colorado's Greenhouse Gas Intensity Verification rule.[6] This rule scales bottom-up model reported emissions to make sure they match the measured methane emissions for the state. The rule was developed with broad stakeholder collaboration that included the Colorado Department of Public Health and Environment, academics, operators, API, and nongovernmental organizations. The central point of reference for this rule will be a robust measurement campaign to characterize methane emissions across the regulatory jurisdiction. Although the initial program only applies to production sites, Colorado plans to extend the measurement program to additional industry segments (e.g., gathering and boosting). Colorado expects to continue evaluating emissions on an annual basis and will retain flexibility in the analysis approach to make sure that the most current science is reflected in measurements. They will also provide operators with the option to use approved measurement-informed approaches to show reduced emissions for their infrastructure. Colorado's GHG emissions verification rule is well aligned with the intent of the IRA and better aligned than proposed subpart W revisions as they currently stand.

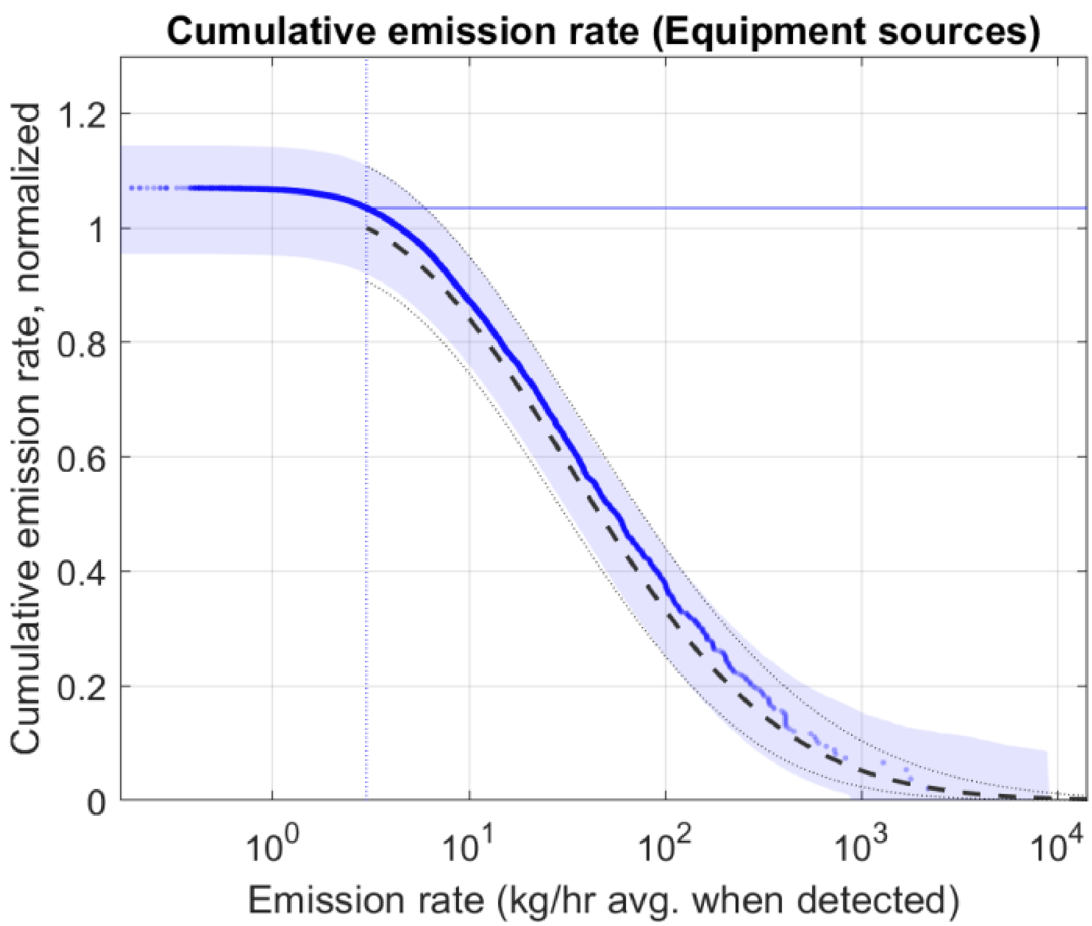

Figure 1 Equipment-level cumulative emission rate distribution from Gas Mapping LiDAR measurements at Permian Basin production facilities. In-depth discussion of this dataset is provided in the referenced publication[11]

If the EPA implements Colorado's regulatory approach, and there are considerable discrepancies between regional methane emissions inventories and the standard subpart W bottom-up model for emissions, we encourage the EPA to improve the bottom-up model accordingly. However, we urge the EPA to do so in in a way that:

- (a) Does not disincentive the use advanced monitoring technology, which can help us understand and effectively mitigate emissions (the goal of EPA air regulations in the first place);
- (b) Is systematic, consistent, and yields comparable results between operators;
- (c) Provides a pathway to improve the reporting data/methodologies so that reported emissions are relevant following changes in operations and infrastructure; and
- (d) Is validated against or developed from regional measurement-based methane emissions inventories.

Footnotes:

[6] https://cdphe.colorado.gov/press-release/colorado-adopts-first-of-its-kind-measures-to-verify-greenhouse-gas-emissions-from

[11] "Extension of Methane Emission Rate Distribution for Permian Basin Oil and Gas Production Infrastructure by Aerial LiDAR". https://doi.org/10.1021/acs.est.3c00229

Commenter 0415: **Executive Summary**

Lastly, the strides made at the state level in GHG emissions management deserve recognition. Colorado has incorporated advanced measurement technologies and introduced intensity-based methane requirements. A collaboration between the EPA and pioneering states can spearhead a cohesive and advanced national approach to emissions regulation.

…

EPA Should Collaborate with State-level Leadership

The approach in the proposed rule could put the EPA off pace with leading state policies that are moving toward intensity-based methane requirements and the use of advanced measurement technologies. States such as Colorado are leading the way by beginning to allow operators to utilize advanced technologies to meet the monitoring requirements of their leak detection and repair programs.

In July 2023, Colorado finalized a rule that will require owners and operators of certain types of oil and gas facilities to directly measure their methane emissions on a facility-specific basis.[16] The state will use these calculations to derive state-wide emission inventories to assure compliance with the state's GHG intensity (emissions per unit output) thresholds. It is expected that facility owners will use advanced measurement technologies to comply with their direct measurement obligations. By embracing advanced technologies for emissions quantification and management, states like Colorado are contributing to the development and application of innovative solutions in the emissions quantification space.

Through the implementation of this rule, Colorado is fostering technology advancement and adoption as well as ensuring the operators in the state are utilizing empirical data to reduce their emissions and report the most accurate emissions data available. EPA should ensure that its approach can align with states like Colorado, and other states considering similar approaches, to advance the mutual goal of rapid, sustained GHG emissions reductions.

Footnote:

[16] *See* Colorado Department of Public Health's "Colorado Adopts First-of-its-Kind to Verify Greenhouse Gas Emissions From Certain Oil and Gas Sites."

Response 5: The EPA acknowledges state and local rulemaking efforts related to monitoring, measuring, and reporting of GHG emissions, including the rulemaking finalized by the Colorado Department of Public Health and Environment in July 2023. With respect to the EPA's review of advanced technologies as part of this rulemaking, see Section II.B of the preamble to the final rule and Section 23 of this document for comments received regarding measurement approaches and their responses. The EPA will continue to assess continuous monitoring systems and other advanced technologies and may consider further updates to incorporate these approaches in a future rulemaking.

Commenter: Marcellus Shale Coalition (MSC)
Comment Number: EPA-HQ-OAR-2023-0234-0275
Page(s): 3-4

Commenter: American Petroleum Institute et al. (Part 1 of 2)
Comment Number: EPA-HQ-OAR-2023-0234-0402
Page(s): 5-7

Commenter: North Dakota Petroleum Council (NDPC)
Comment Number: EPA-HQ-OAR-2023-0234-0417
Page(s): 4-5

Comment 6: Commenter 0275: **GENERAL COMMENTS**

The MSC again recommends that the final GHGRP recognize and not overlap, conflict or be redundant with requirements for sources under other programs.

The proposed rule includes revised emission factors, requirements for measurement and compliance, and contingency factors for determining greenhouse gas (GHG) emissions. Methane emissions are a focus of the proposed rule for the oil and gas industry. The calculation of volatile organic contaminants (VOC), organic hazardous air pollutants (HAPs), and other organic emissions are typically linked for the oil and gas industry.

…

The MSC again points out that Pennsylvania has compiled an inventory of emissions since 2012 and expanded the scope of participating facilities over the years. It includes reporting of methane emissions from Oil and Gas facilities. The MSC requests that the U.S. EPA review Pennsylvania's annual emission programs (AES and OGRE) as a benchmark for its GHG inventory requirements for the Oil and Gas Industry. It provides an example of an established program with a detailed and reasonable approach for emission reporting. Accepted emission estimation methods include testing, manufacturers' emission estimates, fuel and other related usage rates, and recognized emission factors. The facilities reporting in these annual inventories are variable and require the use of these listed methods in conjunction with best engineering judgement to provide accurate emission statement. Such accuracy of Pennsylvania's emission inventory should be considered consistent with the statutory requirements of the Inflation Reduction Act.

Commenter 0402: Summary of Priority Items

In addition to our technical comments, the Industry Trades have identified four overarching priority items within the proposed rules that if satisfactorily amended, will allow industry to attain the maximum potential methane mitigation and reduce public confusion. These high priority items are as follows:

Achieve greater [inter-agency] regulatory harmonization and coordination:

…

In addition, many states – especially New Mexico and Colorado – have already implemented regulations to mitigate emissions across the oil and gas industry; these likely conflict with the final NSPS OOOOb, EG OOOOc and Subpart W reporting requirements.

Maintain EPA's GHGRP and Subpart W within it as the Authoritative Source of Reported Emissions:

There are increasing instances of conflict between Subpart W methodologies with those of permitting agencies, which also conflict with current and proposed LDAR requirements and other state and federal GHG reporting structures. EPA must strive for consistency across all GHG reporting frameworks in order to promote stakeholders' trust and confidence in the data.

Commenter 0417: In North Dakota and other regions of the U.S., produced natural gas is associated with or dissolved in the crude oil and cannot be produced independently from each other. The State of North Dakota already has regulations in place that:

- require a minimum of 91 percent of the associated gas be captured (not flared). See https://www.dmr.nd.gov/oilgas/112018GuidancePolicyNorthDakotaIndustrialCommission order24665_2.pdf. Operators are required to report gas capture data monthly, and many companies have independent goals that exceed 91 percent. This data is available to the public. The latest report from North Dakota's Department of Mineral Resources shows 96 percent gas capture in July 2023.

- prohibit the venting of natural gas unless it is flared or otherwise controlled as approved by the North Dakota Department of Environmental Quality (NDDEQ). See North Dakota Administrative Code, Title 33.1, Article 15, Chapter 7.
- require the control of vapors from storage tanks with the implementation of a control device prior to first production and a control device equipped and operated with an automatic igniter or a continuous burning pilot. See North Dakota Administrative Code, Title 33.1, Article 15, Chapter 7.
- regulate how Bakken oil is produced and processed at the well site through its Crude Conditioning Order. This was implemented in North Dakota in 2014 under North Dakota Industrial Commission (NDIC) Order No. 25417 and amended with Order No. 29398 in 2019. The Crude Conditioning Order uses NDIC's prescribed temperatures and pressures to produce a consistent product prior to shipping. It can be done with no additional footprint to the surface, and excess natural gas that is conditioned off the oil can be transported via pipeline to processing facilities for further handling.

In a state like North Dakota, inaccurate emissions calculation methodologies add costs and administrative burdens that significantly outweigh any perceived environmental benefits. The impact of inaccurate emission calculations on the Waste Emissions Charge also has the unintended consequence of sub-optimizing the industry's voluntary environmental programs, such that the focus could shift from true emission reductions to merely minimizing an unfavorable economic factor that is not based in reality.

Response 6: The EPA acknowledges that several state and local agencies, including those in New Mexico, North Dakota, and Pennsylvania, prescribe requirements related to GHG and methane emissions from sources in the oil and gas industry. The commenters did not provide specific instances of requirements in the proposed subpart W rule that they believe to be in conflict with these state and local requirements, and as such the EPA is not able to provide a direct response to those general comments in this document. As discussed in Section II of the preamble to the final rule, the final amendments in this rulemaking include revisions to accurately reflect total methane emissions reported to the GHGRP, to add emissions calculation methodologies to expand options to allow owners and operators to submit empirical emissions data and improve the accuracy of reported emission data, and to refine existing emissions calculation methodologies to reflect an improved understanding of emissions.

28 General Comments

28.1 Public Comment Period

Commenter: Project Canary, PBC
Comment Number: EPA-HQ-OAR-2023-0234-0182
Page(s): 1, 2

Commenter: GPA Midstream Association
Comment Number: EPA-HQ-OAR-2023-0234-0184
Page(s): 1-2

Commenter: Petroleum Alliance of Oklahoma, Independent Petroleum Association of America and Western Energy Alliance
Comment Number: EPA-HQ-OAR-2023-0234-0185
Page(s): 1-2

Commenter: Marcellus Shale Coalition (MSC)
Comment Number: EPA-HQ-OAR-2023-0234-0186
Page(s): 1-2

Commenter: Differentiated Gas Coordinating Council (DGCC)
Comment Number: EPA-HQ-OAR-2023-0234-0187
Page(s): 1

Commenter: American Exploration and Production Council (AXPC)
Comment Number: EPA-HQ-OAR-2023-0234-0188
Page(s): 1-2

Commenter: Kathryn Westman
Comment Number: EPA-HQ-OAR-2023-0234-0195
Page(s): 1

Commenter: Interstate Natural Gas Association of America (INGAA) et al.
Comment Number: EPA-HQ-OAR-2023-0234-0197
Page(s): 1-2

Commenter: Bridger Photonics, Inc.
Comment Number: EPA-HQ-OAR-2023-0234-0198
Page(s): 1

Commenter: State of Wyoming, Office of the Governor
Comment Number: EPA-HQ-OAR-2023-0234-0201
Page(s): 1-2

Commenter: Alaska Oil and Gas Association (AOGA)
Comment Number: EPA-HQ-OAR-2023-0234-0206
Page(s): 1-2

Commenter: American Petroleum Institute (API)
Comment Number: EPA-HQ-OAR-2023-0234-0207
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Commenter: GPA Midstream Association
Comment Number: EPA-HQ-OAR-2023-0234-0208
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Commenter: Public Hearing Transcript
Comment Number: EPA-HQ-OAR-2023-0234-0224
Page(s): 7 (Monica Prabhu), 14 (Lisa Beal), 21-22 (Cheyenne Branscum), 39 (Kathryn Westman), 45 (Scott Yager), 55 (Katie Muth)

Commenter: Energy Workforce & Technology Council
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Commenter: Tomas Rodriguez
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Commenter: National Federation of Independent Business, Inc. (NFIB)
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Commenter: Wyoming Department of Environmental Quality (WDEQ)
Comment Number: EPA-HQ-OAR-2023-0234-0388
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Commenter: The Petroleum Alliance of Oklahoma
Comment Number: EPA-HQ-OAR-2023-0234-0398
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Commenter: Lambda Energy Resources
Comment Number: EPA-HQ-OAR-2023-0234-0405
Page(s): 1

Commenter: Encino Energy (EAP Ohio, LLC)
Comment Number: EPA-HQ-OAR-2023-0234-0408
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Comment 1: Commenter 0182: Project Canary, PBC (Project Canary) appreciates the actions of the Environmental Protection Agency (EPA) to implement §60113 provisions in the Inflation Reduction Act pertaining to the Methane Waste Emission Fee and the associated Greenhouse Gas Reporting (GHFRP) Subpart W provisions. Given the deeply technical nature and the high degree of change contemplated by the proposed amendments to the rule, Project Canary respectfully requests a 30-day extension to the comment period to ensure that thorough and thoughtful comments can be provided to EPA.

…

We support EPA's efforts to enhance data transparency, broaden the scope of reported sources, and refine methodologies to ensure reported emissions are based on empirical data within these proposed amendments to the rule. The extensive nature of the proposed changes will take considerable time and resources to prepare meaningful comments. EPA has solicited comments on a significant number of issues within the proposal that require deep subject matter expertise across a wide range of topics. Due to the highly technical nature of the changes, we believe it is particularly important for commenters to thoroughly review the technical support document in conjunction with the proposed amendments to the rule. It is essential to understand how each newly proposed methodology and emission factor was derived and fits into the definition of empirical data. For these reasons, we believe a 30-day extension of the comment period is necessary. It will allow resource-constrained organizations sufficient time to digest the significant amount of information, and to fully understand the implications of the proposed amendments to the rule, ensuring that the Agency receives more meaningful and comprehensive comments on this significant proposal.

Commenter 0184: On June 30, 2023, the U.S. Environmental Protection Agency ("EPA") released a pre-publication notice of proposed rulemaking entitled "Greenhouse Gas Reporting Rule: Revisions and Confidentiality Determinations for Petroleum and Natural Gas Systems" ("Proposed Rule"). That document indicated that the Proposed Rule would be subject to a 60-day public comment period. In response, GPA Midstream ("GPA") submitted a July 13, 2023 request that EPA extend that public comment period by an additional 60 days. The Proposed Rule was published in the Federal Register on August 1, 2023, and it provides a 62-day comment period, with comments due on October 2, 2023. GPA continues to believe that an extension of the comment period is necessary.

…

As stated in GPA's July 13, 2023 letter, additional time is necessary for the public to develop meaningful comments on the Proposed Rule. The Proposed Rule is extraordinarily complex and builds on years of rulemaking proceedings related to greenhouse gas reporting. GPA is still analyzing the Proposed Rule and assessing the extent to which it responds to GPA's comments on previous revisions to Subpart W reporting requirements. GPA also needs to time coordinate with its members and to develop consensus positions among a range of companies that may be differently positioned with respect to the Proposed Rule's provisions. For these reasons, GPA respectfully renews its request for an additional 60 days to review and prepare comments on the Proposed Rule. At the very least, GPA believes an additional 30 days, accounting for the time between the release of the pre-publication version of the proposal and its publication in the Federal Register, would be appropriate.

Commenter 0185: The Petroleum Alliance of Oklahoma, the Independent Petroleum Association of America and Western Energy Alliance (collectively referred to as the Trades) request the Environmental Protection Agency (EPA) extend the public comment period by an additional 60-days for Docket Id. No. EPA-HQ-OAR-2023-0234, Greenhouse Gas Reporting Rule: Revisions and Confidentiality Determinations for Petroleum and Natural Gas Systems (Proposed Rule). In addition, we request EPA conduct a public hearing that includes a presentation on the proposed changes.

…

The Proposed Rule was published in the Federal Register on August 1, with a comment deadline of October 2. This Proposed Rule includes 160 pages of text along with 136 supporting documents that encompass hundreds if not thousands of pages of supporting material. The Trades do not think the 60-day comment period is adequate to fully review the Proposed Rule and supporting material and provide meaningful comments on such a short timeline.

EPA currently has three proposed Greenhouse Gas Reporting Rules (GHGRRs) that have not been finalized: EPA's initial proposed GHGRR (87 Fed. Reg. 36920, June 21, 2022), the Supplemental Proposed Rule (88 Fed. Reg. 32852, May 22, 2022) and this Proposed Rule for Subpart W for the petroleum and natural gas systems. In addition, EPA's proposed New Source Performance Standards for new and existing oil and gas sources (NSPS b/c), integral to the GHGRRs, are still not finalized, adding an additional level of complexity to the review process of the Proposed Rule. Taken together, these proposed rules are expansive and provide significant uncertainty as to how they collectively build upon and/or function together. The Trade's members need the additional 60-day review time to carefully review the Proposed Rule in context with the other proposed rules to better understand the cumulative costs impacts and requirements in order to provide fully informed comments.

EPA states its Proposed Rule revisions will improve the quality and consistency of the data collected under the rule, streamline and improve implementation, and clarify or propose minor updates to certain provisions that have been the subject of questions from reporting entities. The requested 60-day extension to the comment period will not cause hardship on the EPA nor will it create impacts on the environment or human health. Providing additional time will ensure the Trade's members have an opportunity to adequately review the information and provide useful comments that will benefit the EPA's decision-making process.

Finally, the Trade's request EPA conduct a public hearing and include a presentation on the proposed changes that would further the Trade's understanding of the Proposed Rule.

Given the consequences of the Proposed Rule on the Trade's members, and the breadth, depth, and complexity of the information involved, the Trades request EPA extend the comment period for the Proposed Rule by an additional 60-days and conduct a public hearing that includes a presentation of the proposed changes.

Commenter 0186: The MSC writes to respectfully request a 60-day extension for public comment regarding the above-referenced proposed rule beyond the current established deadline of October 2, 2023. Several reasons, outlined below, justify an extension of the public comment period to facilitate fully informed and constructive comments for review and response by the U.S. Environmental Protection Agency (USEPA).

First, the significant size and scope of the proposed rule will take considerable time and resources to allow for a full review and analysis by the regulated community. The proposed rule is almost 600 pages in length, including dozens of specific operational revisions, and raises several significant policy questions that merit public input. In addition, this proposed rulemaking will directly affect our members' operations and have a significant impact on the costs to deliver natural gas to American businesses and consumers. It is no small undertaking for the regulated community to analyze these significant policy change proposals, fully understand the potential impact on their operations, ensure conformance with applicable federal statutes relied upon by the USEPA, and construct meaningful comments for consideration.

Granting an extension of the public comment period will further the public interest by allowing for a full and proper vetting of the proposed rule and facilitate the delivery of constructive and informed comments to USEPA.

<u>Commenter 0187</u>: The Differentiated Gas Coordinating Council (DGCC) appreciates the actions of the Environmental Protection Agency (EPA) to implement section 60113 provisions in the Inflation Reduction Act pertaining to the Methane Waste Emission Fee and the associated Greenhouse Gas Reporting Program Subpart W provisions. Given the deeply technical nature and the high degree of change contemplated by the proposed amendments to the rule, the DGCC respectfully requests a 30-day extension to the comment period to ensure thorough and thoughtful comments can be provided to EPA.

…

The extensive nature of the proposed changes will take considerable time and resources to prepare meaningful comments and input. EPA solicited comments on a significant number of issues within the proposal that require deep subject matter expertise across a wide range of topics. It is essential to understand how each newly proposed methodology and emission factor was derived and fits into the definition of empirical data.

For these reasons, we believe a 30-day extension of the comment period is necessary. It will allow resource-constrained organizations sufficient time to digest the significant amount of information, and to fully understand the implications of the proposed amendments to the rule, ensuring that the Agency receives more meaningful and comprehensive comments on this significant proposal.

<u>Commenter 0188</u>: The American Exploration and Production Council (AXPC) is writing to respectfully request additional time for stakeholders to thoughtfully consider and respond to EPA's Proposed Greenhouse Gas Reporting Rule: Revisions and Confidentiality Determinations for Petroleum and Natural Gas Systems. We thank the Environmental Protection agency for its leadership in establishing industry-wide greenhouse gas (GHG) quantification methodologies. Given the importance of this program, we respectfully request a 60-day extension of the public comment period. We believe such an extension is warranted due to the extreme technical nature of the proposal and the need for thorough, complex analysis to understand the basis of the changes, any challenges or unintended consequences, and the potential impacts of proposed changes within the larger regulatory context.

…

We understand that improving the accuracy and reliability of the inventory of greenhouse gas emissions from the oil and gas sector are of national priority as evidenced by the recent inaugural White House Methane Summit. We are supportive of the Agency's goal to provide the public with high-quality, scientifically based GHG data as well as larger goals to reduce emissions from the oil and gas industry. We recognize that improvements to Subpart W are an important opportunity to improve this dataset and update the standard methodologies to be more reflective of emissions generated from US oil and gas industry operations today. It is similarly important that these changes be thoroughly analyzed and well supportive else we risk undermining the validity of the inventory that today represents the most consistently reported, comprehensive inventories in the world.

EPA's proposed changes are highly technical and extensive – over 600 pages of preamble, proposed rule, technical support documents and impact analysis. This in addition to another 175 documents in the docket. This rule also converges with several other rulemakings in development. Importantly, early review indicates there are some provisions in these changes to the GHGRP that do not appear to line up with the proposed revisions for the NSPS OOOOb/c rulemaking, and potential other methane related rulemakings, which when combined with the implementation of the Waste Emissions Charge in the Inflation Reduction Act has potential for significant unintended impacts to the industry and the economy. With so many rules changing at the same time affecting the same industry, analysis to understand how the rules will work together, where there is inconsistency or conflicts, and where there are unintended consequences all takes considerable time and complicated analysis. We fear that moving too quickly to finalize these policies before the public has ample time to respond to the proposals could be detrimental to the intent.

For these reasons, we believe and extension of the available time for public comment is well justified. We urge the EPA to extend the comment period for this proposal by 60 days in order to allow stakeholders the time necessary to conduct this extensive analysis and provide meaningful comments, which would serve only to improve the finalization of these rules.

<u>Commenter 0195</u>: I would like ti request a longer comment period in this vital subject of regulations. Perhaps there should also be another public hearing. I spoke a On 8/21/23 and was shocked all verbal comments could be held in one afternoon. Perhaps there should be more publicity to make the public aware of the comment period. And again asking it be extended.

<u>Commenter 0197</u>: The undersigned organizations, which represent a broad group of stakeholders across the gas and oil value chain, respectfully request a 45-day extension of the public comment period for the United States Environmental Protection Agency's ("EPA" or the "Agency") proposed rule entitled "Greenhouse Gas Reporting Rule: Revisions and Confidentiality Determinations for Petroleum and Natural Gas Systems" (hereinafter, "Proposed Rule").[1]

A proposal of this magnitude requires more than the 60 days currently allotted for public comment. The undersigned organizations need additional time to fully analyze and comment on the Proposed Rule due to its complexity and the volume of proposed new and revised data elements, new sources that would be required to report emissions, proposed revised emissions factors, and additional proposed data collection requirements. Stakeholders must conduct a careful evaluation of the anticipated impact of the Proposed Rule to ensure that their comments to the Agency are informed, well-reasoned, and accurate. Such an evaluation would be strained by the length of the comment period, as well as the high volume of other regulatory proposals with open or recently closed comment periods that are similarly relevant to the gas and oil industry.[2]

Furthermore, these proposed changes put more at stake than any prior revisions to the Greenhouse Gas Reporting Rule because they will underpin the framework for assessing the waste emissions charge under the Inflation Reduction Act. The waste emissions charge can have significant consequences for the gas and oil industry due to the financial liability attached to reported emissions that exceed the waste emissions threshold. The significance of these proposed changes requires more time for commenters to comprehend the details of EPA's Proposed Rule and how it would impact the waste emissions charge.

During EPA's virtual public hearing on August 21, 2023, speakers representing a variety of stakeholder interests—including various industry and environmental groups, tribal members, and a state legislator—consistently testified that the Proposed Rule's complexity and far-reaching impact necessitate an extension of the public comment period. Notably, none of the speakers at the hearing expressed opposition to such an extension.

This extension would enable stakeholders to compile detailed, useful comments to aid EPA's development of a final rule while still allowing ample time for the Agency to meet its statutory rulemaking deadline. For the foregoing reasons, the undersigned organizations request a 45-day extension to the public comment period for the Proposed Rule.

Footnotes:

[1] 88 Fed. Reg. 50,282 (Aug. 1, 2023).

[2] These include (but are not limited to) the following proposals from EPA and other federal agencies: Minerals Cost Recovery, 88 Fed. Reg. 38,416 (June 13, 2023); Marine Casualty Reporting on the Outer Continental Shelf, 88 Fed. Reg. 38,765 (June 14, 2023); Perchloroethylene (PCE); Regulation Under the Toxic Substances Control Act (TSCA), 88 Fed. Reg. 39,652 (June 16, 2023); Risk Management and Financial Assurance for OCS Lease and Grant Obligations, 88 Fed. Reg. 42,136 (June 29, 2023); Streamlining U.S. Fish and Wildlife Service Permitting of Rights-of-Way Across National Wildlife Refuges and Other U.S. Fish and Wildlife Service Administered Lands, 88 Fed. Reg. 47,442 (July 24, 2023); Endangered and Threatened Species; Designation of Critical Habitat for the Rice's Whale, 88 Fed. Reg. 47,453 (July 24, 2023); Fluid Mineral Leases and Leasing Process, 88 Fed. Reg. 47,562 (July 24, 2023); National Environmental Policy Act Implementing Regulations Revisions Phase 2, 88 Fed. Reg. 49,924 (July 31, 2023); Request for Comments on Proposed Guidance for Assessing Changes in Environmental and Ecosystem Services in Benefit-Cost Analysis, 88 Fed. Reg. 50,912 (Aug. 2, 2023); Revisions to the Air Emissions Reporting Requirements, 88 Fed. Reg. 54,118 (Aug. 9,

2023); Pipeline Safety: Safety of Gas Distribution Pipelines and Other Pipeline Safety Initiatives (released Aug. 24, 2023, publication forthcoming).

Commenter 0198: Bridger Photonics, Inc. ("Bridger") appreciates the opportunity to provide input on the proposed rulemaking notice that amends the Greenhouse Gas Reporting Program (GHGRP) for petroleum and natural gas systems (Subpart W) (88 FR 50282, "Proposed Rule"). Considering the highly technical nature of the Proposed Rule, the large number of proposed changes, and the far-reaching impact that the final rule will have, Bridger respectfully requests a 30-day extension of the public comment period.

…

To develop well-informed comments, significant resources must be devoted to understanding the Proposed Rule, exchanging knowledge with other stakeholders, and conveying our scientific knowledge within the context of Subpart W provisions. Other stakeholders will face similar challenges as they work to provide input to the rulemaking process. An extension in the public comment period would allow Bridger to better serve the EPA, the public, and the industry through our comments.

Commenter 0201: I respectfully request a comment period extension for EPA's proposed rulemaking, "Greenhouse Gas Reporting Rule: Revisions and Confidentiality Determinations for Petroleum and Natural Gas Systems," published in the Federal Register on August 1, 2023. The current deadline to submit comments is October 2, 2023. For reasons explained below, I ask your consideration that the deadline for comments be extended until after the oil and gas methane rule is final. In the alternative, I request a 90 day extension beyond October 2, 2023.

In recent months, EPA has proposed federal air quality regulations at such a pace that state regulatory agencies, such as the Wyoming Department of Environmental Quality (WDEQ), do not have adequate time to review, analyze and provide thorough, meaningful public comment. This proposed rule is yet another example on a growing list that also includes EPA's proposed Clean Power Plan 2.0, EPA's proposed revisions to the Air Emissions Reporting Requirements (AERR) rule, and many other proposed rules that impact Wyoming's economy and her industries. Our agencies evaluating those proposed regulations have labored to meet the comment deadlines for those rules at the cost of setting aside other standard regulatory matters. This comment fatigue is impacting the ability to respond to the degree that would be helpful to your agency.

This proposed rule is expansive and extremely technical. It will affect Wyoming's economy and her oil and gas industry, which ts the largest contributor to the economy. Furthermore, it contains many burdensome requirements that have an associated implementation cost far outweighing the nebulous environmental benefits. The proposed rule and accompanying preamble are 160 pages long. EPA's docket includes over 180 attachments that span over 27,000 pages of material pertinent to the proposed rule. EPA has given the public a mere 60 days to undertake the review and comment process for this proposed rule. Such a public comment period would require the public to undertake 450 pages per day of reading to cover the entirety of the material EPA has posted to the docket. This comment and review period does not provide remotely enough time for regulatory agencies, the regulated community, and the general public to thoroughly review the many complex requirements within the proposed rulemaking and evaluate its economic impacts and implementation challenges. Additionally, there are other simultaneously proposed rulemakings from other federal agencies, such as the Council on Environmental Quality's (CEQ) "Bipartisan Permitting Reform Implementation Rule," that have potential impacts on the oil and gas industry and require time and resources for review.

This proposed rule will have significant, far-reaching implications for affected sources and for state regulatory agencies that will be responsible for implementing a final rule. However, it is impossible in a 60-day comment period to determine what these impacts will be and what implementation challenges Wyoming may face. Furthermore, it is especially difficult to evaluate the proposed rule when EPA's "Standards of Performance for New, Reconstructed, and Modified Sources and Emissions Guidelines for Existing Sources: Oil and Natural Gas Sector Climate Review" (86 FR 63110) and its accompanying supplemental notice of proposed rulemaking (87 FR 74702) (EPA's oil and gas methane rule) have not yet been finalized. The lack of regulatory certainty that arises due to the still-proposed state of EPA' s methane rule and supplemental proposal, and how they fit together with the requirements of the proposed rule, makes the evaluation of the proposed rule almost impossible to complete. Seldom do proposed regulations of this magnitude become final without modifications. That is one of the reasons for a comment period. At this stage the public is being asked to evaluate how proposed rules affect other proposed rules. Clearly the ability to do so accurately is questionable and is basically assumptions on top of assumptions. The accelerated nature of the public comment period only compounds this issue.

For the above-listed reasons, I reiterate my request to extend the comment period on this proposal until 60 days after the effective date of EPA' s oil and gas methane rule.

Commenter 0206: AOGA commented on the Environmental Protection Agencies' 2022 New Source Performance Standards and Emissions Guidelines for Greenhouse Gas (GHG) Emissions proposed rule, and AOGA intends to submit comments for the 2023 Revisions and Confidentiality Determinations for Data Elements under the Greenhouse Gas Reporting Rule for the Petroleum and Natural Gas Systems. Comments are due on October 2, 2023. However, AOGA respectfully requests a 60-day extension of the public comment period, which will provide the public and stakeholders with a reasonable period for review and comment.

The newly proposed rule is comprehensive, encompassing a wide range of complex factors and criteria. Understanding and analyzing these aspects requires extensive time and effort from all stakeholders, including oil and gas producers. The rule, along with technical documents, is substantial and the public needs sufficient time to understand, analyze, and comment on these significant regularity changes. The current deadline does not provide adequate time for a thorough public review.

Access to the proposed rules supporting documents (i.e., Technical Supporting Document for Revisions and Confidentiality Determinations for Data Elements Under the Greenhouse Gas Reporting Rule; Proposed Rule – Petroleum and Natural Gas Systems) were not made available until the rule was published. The delayed release of these essential documents has substantially curtailed AOGA's ability to evaluate the proposed rules' practical implications. This delay further underscores the need for an extension.

Given the complexity and far-reaching consequences of the rule and considering the public's right to a comprehensive review and comment, AOGA strongly urges the EPA to grant this extension request. The additional time will allow for a more thoughtful, well-informed, and transparent process that will ultimately contribute to better regulatory outcomes.

<u>Commenter 0207</u>: The American Petroleum Institute (API) hereby respectfully requests a 60-day extension of the public comment period for EPA's Proposed 2023 Revisions and Confidentiality Determinations for Data Elements under the Greenhouse Gas Reporting Rule for the Petroleum and Natural Gas Systems, Reg. 14338, August 1, 2023. Comments are currently due October 2, 2023. However, because this is a large and complex rule with an impact on many different reporting segments within the oil and natural gas industry, API is requesting that the comment period be extended by 60 days to December 1, 2023, to ensure that API and all interested stakeholders have a full and fair opportunity to comment. This extension is necessary to allow API to present EPA with relevant information necessary to support an informed, reasoned, and defensible final rule. Given the importance of this proposal, API needs additional time and opportunity to review the extensive supporting documentation that has only just been made available in the Federal Register.

These supporting documents (e.g., *Technical Supporting Document for Revisions and Confidentiality Determinations for Data Elements Under the Greenhouse Gas Reporting Rule; Proposed Rule - Petroleum and Natural Gas Systems*) provide the scientific basis and details for revisions that EPA has proposed in the preamble. As such, these documents require close review and consideration to ensure that the data supports EPA's proposed revisions.

In light of the significant impact the proposed revisions could have on API members, a 60-day extension of the comment period is warranted and will provide the necessary time to provide detailed comments best-suited to assist EPA. We appreciate your prompt consideration of this request for an extension of the comment period.

<u>Commenter 0208</u>: On June 30, 2023, the U.S. Environmental Protection Agency ("EPA") released a notice of proposed rulemaking entitled "Greenhouse Gas Reporting Rule: Revisions and Confidentiality Determinations for Petroleum and Natural Gas Systems" ("Proposed Rule"). The Proposed Rule establishes a 60-day deadline for public comment. This letter is being sent on behalf of GPA Midstream Association ("GPA") to request that EPA extend this deadline by an additional 60 days from the date of publication of the Proposed Rule in the Federal Register.

…

Additional time is necessary for the public to develop meaningful comments on the Proposed Rule. As EPA undoubtedly knows, the Proposed Rule is extraordinarily complex, and builds on years of rulemaking proceedings related to greenhouse gas reporting. The Proposed Rule raises many substantial issues that require thorough analysis. Affected members of the public are only just beginning to undertake the analytical work necessary to understand and comment on the

Proposed Rule, and they cannot reasonably complete that important work within the current comment period. For that reason, GPA respectfully requests an additional 60 days to review and prepare comments on the Proposed Rule.

Because GPA and its members own and operate facilities that will be subject to the Proposed Rule, the ability to prepare comprehensive comments on these rules is of great importance to GPA.

Commenter 0224: I appreciate very much the EPA's work on this matter, and I want to acknowledge that although the public comment period is open until October, as of right now, the number of public comments that have been lodged in writing are very few. As far as I can tell, they're nearly all from the oil and gas industry, except for Project Canary. And I'd like to echo Project Canary's written remarks and ask for an extension to the public comment period because this is an extremely important, highly technical, complex proposal that has policy implications that are far-reaching. As a nontechnical person myself, I think I misunderstood exactly what those policy implications may be and the science behind the empirical inventories are just a very complex topic. So I want to acknowledge the work that the EPA is doing and thank you for that, and also to echo Project Canary's request for an extension. A number of groups I would like to see comments from have not lodged them yet, so I'll be watching for that, including the Environmental Defense Fund, the Clean Air Task Force, IGSD among them. If you have not received comments from these groups, I hope that the EPA can reach out to them and receive comments, as well as state air and environmental regulators from California, Colorado, New Mexico and others. I'd like to see their comments, and hopefully between now and October, we will see that.

…

I would just like to echo a few of the other speakers who have already said that additional 60 days extension time would be very helpful because this is a very important and impactful regulation.

…

And then the biggest ask is if your other speakers have asked, an extension on this comment period be made. This is a really complicated issue. This is a really complicated rule change, and if you're someone like me, your life is very busy and you're trying to survive day to day, and you don't have all of the time and luxury and education to process all of this. And I would love for people to have a little bit more time to understand and to relay comment on these huge things that are going to change them that affect them and their children.

…

I support the extension of the comment period and will submit my request.

…

We're still taking a look through the proposal to better understand the implications. There's a lot of nuance in the proposal that's taking us some additional time to think through and understand also. There are a number of other regulatory proposals out there in the air space as well that are taking a lot of bandwidth and time, so INGAA is requesting an additional 60 days to comment on the Subpart W proposal, understanding that EPA is trying to meet a Congressional deadline, which we can certainly appreciate. That deadline of August 24th, 2024, EPA would still be in line with meeting that deadline even with additional 60 days added to the public comment period so we would ask that you seriously consider granting that. That would allow us, INGAA and our members, to really put forward some insightful comments that are supported by data and helpful, I think, to the process.

…

I also would just reiterate the previous request to have an extension deadline for these comments because this is a very detailed change and it's an important one.

Commenter 0231: EPA's proposed changes are extensive, spanning over 600 pages of technical documents and impact analyses, with 175 additional documents in the docket. These changes intersect with other rulemakings, potentially causing unintended industry and economic impacts. Understanding how these rules align and identifying inconsistencies and conflicts is complex and time-consuming and we have heard directly from our membership that these rule intersections are making accurate reporting more difficult.

To ensure thoughtful public input and prevent hasty policy finalization, we request a 60-day extension of the comment period. This extension will allow stakeholders to perform comprehensive analyses and provide meaningful feedback, ultimately enhancing the rule finalization process.

Commenter 0277: This rule is very complex. Please add an additional 90 days to the comment period so that the oil and gas industry has time to understand how the rule affects their business.

Commenter 0336: The American people deserve more time to consider the proposed rules and submit comments on them to the EPA.

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The NPRM stated that EPA must receive any comments on the NPRM on or before October 2, 2023. NFIB joins the requests to EPA for a substantial extension of the deadline to submit comments on the NPRM made by letters to the EPA of the Governor of Wyoming (request of September 8, 2023); the Interstate Natural Gas Association of America, the American Gas Association, the American Public Gas Association, and the U.S. Chamber of Commerce (request of August 30, 2023); and the Petroleum Alliance of Oklahoma, the Independent Petroleum Association of America, and the Western Energy Alliance (request of August 7, 2023). If the EPA denies the request to extend the comment period, please note EPA's duty under 5 U.S.C. 555(e) to provide a statement of the grounds for denial.

Commenter 0388: The Wyoming Department of Environmental Quality (WDEQ) appreciates the opportunity to submit comments on EPA's proposed rulemaking, "Greenhouse Gas Reporting Rule: Revisions and Confidentiality Determinations for Petroleum and Natural Gas Systems," published in the Federal Register on August 1, 2023. The proposed rule is expansive, technically complex, and raises policy concerns that impact the State of Wyoming. Unfortunately, EPA only allocated the public with a mere 60 days to undertake the review and comment process, which was deeply insufficient considering the remarkable complexity and breadth of the proposed rule, and the abundance of other proposed federal air regulations that have overlapped with the public review period for this proposed rule. To this point, WDEQ respectfully requests that EPA further consider the comments submitted to EPA by Wyoming Governor Mark Gordon on September 8, 2023 (Docket No. EPA-HQ-OAR-2023-0234 and enclosed herewith), requesting a 90-day extension beyond October 2, 2023 to review the proposal. Put simply, the allocated public review and comment window was far too short for the public, state, local, and tribal regulatory agencies, and other stakeholders to undertake a comprehensive, meaningful review of the proposal and provide useful comments to EPA.

Commenter 0398: EPA currently has three proposed rules on the GHGRR that have not been finalized: EPA’s proposed rule (87 Fed. Reg. 36920, June 21, 2022)(200 pages), its Supplemental Proposed Rule (88 Fed. Reg. 32852, May 22, 2023) (96 pages) and this Proposed Rule (160 pages).[1] Taken together, the proposed GHGRRs are expansive and provide significant uncertainty has to how they collectively build upon the other, and EPA fails to clearly and concisely provide comprehensive cost impact information. EPA’s proposed NSPS OOOOb/c rules for new and existing oil and gas sources are not finalized but are integral to the GHGRR, adding an additional level of regulatory uncertainty. In addition, EPA has introduced more regulatory uncertainty by changing its GHGRR proposals over the past year creating confusion as to what is actually being proposed. Finally, EPA did not allow any extensions to the comment period for such a complex reporting rule that is interwoven with its other outstanding proposed rulemakings.

Action Requested: We request EPA provide supplemental information for comment and review that comprehensively outlines EPA’s GHGRR requirements and provide a comprehensive cost impact analysis so that our members can provide fully informed comments. As we have previously requested, EPA should allow an additional 60-day extension to the comment period that will provide our members additional time to review and understand the nuisances and complexities of EPA’s multiple rulemakings.[2]

Footnotes:

[1] The proposed rules and supporting information collectively span thousands of pages of information.

[2] The Petroleum Alliance of Oklahoma, the Independent Petroleum Association of America and the Western Energy Alliance requested a 60-day extension to the comment period on August 7, 2023. EPA denied this request.

Commenter 0405: The timeframe that EPA has provided for review and comment is too short to fully understand the new proposed requirements. The text In the rule Itself Is 160 pages long but with supporting documentation to review as well, there simply isn't enough time to comprehend everything a reporter would need to weigh in order to even provide proper comments on all the implications that affect a company like ours.

Commenter 0408: The 60-day comment period on the Subpart W proposal was not substantial enough to provide a comprehensive literature review of source material, relevant research, or offer answers to all or most questions asked by EPA in the proposal document which was over 600 pages long.

Response 1: The EPA considers the 60-day comment period that commenced upon publication of the proposal in the Federal Register to be appropriate and to provide a meaningful opportunity to comment on the proposed rulemaking. Consistent with Clean Air Act requirements, all data, information, and documents relied upon in the proposed rule were included in the docket on the date of publication of the proposed rule. Therefore, the EPA denied the requests for an extension to the comment period. We also note that the EPA posted a copy of the pre-Federal Register publication version of the notice on the EPA website on July 6, 2023, the same day the proposal was publicly announced. This provided the public with additional time to review the proposal's notice prior to publication in the Federal Register. Including this opportunity for pre-publication review, the total amount of time for review of the notice amounted to 88 days. In addition, the EPA also held a public hearing on August 21, 2023, for stakeholders to provide oral presentation of comments, data, and views on the proposed rulemaking. We believe these actions provided sufficient opportunity for stakeholders to provide their comments.

Commenter: GPA Midstream Association
Comment Number: EPA-HQ-OAR-2023-0234-0299
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Commenter: Wyoming Department of Environmental Quality (WDEQ)
Comment Number: EPA-HQ-OAR-2023-0234-0388
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Comment 2: Commenter 0299: **The extremely short comment period limits our ability to fully understand and meaningfully comment on the proposal.**

GPA has endeavored to create a technically sound and robust set of comments to assist EPA in this rulemaking process. We must express profound unease, however, regarding the limited and unreasonable timeframe provided for public comment for what is undeniably a substantial and complex set of revisions to an already complicated rule. Given the technical intricacies and far-reaching implications of the proposed amendments, it is imperative that all stakeholders have adequate time to comprehensively evaluate the potential impacts and offer meaningful feedback.

In response to our requests for a comment extension,[1] EPA cited the "pre-Federal Register publication version of the notice on the EPA website on July 6, 2023," and mentioned that the "total amount of time for review of the notice amounts to 88 days."[2] This response ignores, however, the important fact that this review period overlapped with another GHGRP proposal, to which GPA submitted substantial and data-rich comments on July 21.[3] This simultaneous timeline posed challenges in allocating adequate resources and focus to both proposals, potentially compromising the depth of our review. The decision to deny an extension now raises deep concerns, particularly when the proposed rule carries significant financial implications for reporting entities.

The intricacy of Subpart W necessitates a thorough and rigorous technical review, which requires ample time for stakeholders to:

- Carefully analyze the proposed changes and their implications on greenhouse gas reporting.
- Engage with technical experts within their organizations or consult with external experts.
- Consider the practical feasibility and implications of the proposed revisions on their operations and reporting practices.
- Collect and compile relevant data and evidence to support their comments.
- Collaborate and coordinate with other stakeholders to ensure a well-informed and balanced perspective.

GPA also notes that EPA included at least 77[4] discrete requests for comment in the rule preamble. A 60- day comment period, in this context, is simply inadequate and limits the opportunity for stakeholders to provide well-considered, evidence-based responses to those requests and other related comments (even considering the time between the proposal's release and publication in the Federal Register). Courts have said that Congress intended the Administrative Procedure Act's requirement[5] to provide notice and comment "(1) to ensure that agency regulations are tested via exposure to diverse public comment, (2) to ensure fairness to affected parties, and (3) to give affected parties an opportunity to develop evidence in the record to support their objections to the rule and thereby enhance the quality of judicial review."[6] The comment period for the proposed rule does not meet this legal standard because it fails to provide for meaningful participation. Moreover, it may inadvertently hinder the achievement of EPA's goals. As such, EPA should fairly consider additional materials and information provided after the close of the comment period.

Footnotes:

[1] GPA, Request for Extension of Comment Period, Docket ID No. EPA-HQ-OAR-2023-0234-0208 (July 13, 2023); GPA, Request for Extension of Comment Period, Docket ID No. EPA-HQ-OAR-2023-0234-0184 (Aug. 4, 2023).

[2] Letter from S. Lie, Director, Climate Change Division, EPA, to M. Hite, GPA Vice President of Government Affairs, Docket ID No. EPA-HQ-OAR-2023-0234-0204 (Aug. 15, 2023); Letter from S. Lie, Director, Climate Change Division, EPA, to M. Hite, GPA Vice President of Government Affairs, Docket ID No. EPA-HQ-OAR-2023-0234-0216 (Aug. 30, 2023).

[3] In addition to GHGRP comment efforts, during this same period of time, GPA members also prepared comments on EPA's proposed revisions to Subpart JJJJ of the New Source Performance Standards ("NSPS") and to Subpart ZZZZ of the National Emission Standards for Hazardous Air Pollutants ("NESHAP"). GPA Comments Re: 88 Fed. Reg. 41,361 (June 26, 2023) National Emission Standards for Hazardous Air Pollutants: Reciprocating Internal Combustion Engines and New Source Performance Standards: Internal Combustion engines; Electronic Reporting, Docket ID No. EPA-HQ-OAR-2022-0879-0043 (Aug. 25, 2023). At the same time, GPA members also submitted comments on a proposed rule issued by PHMSA. GPA Comments on Pipeline Safety: Gas Pipeline Leak Detection and Repair, Docket ID No. PHMSA-2021-0039-26350 (Aug. 16, 2023).

[4] Number of times each of these phrases appear in the preamble: "request comment" (38), "seek comment" (2), "seek information" (1), and "seeking comment" (37).

[5] The Administrative Procedure Act applies to this rulemaking because a rulemaking of this type is not one of the specified rulemakings listed under section 307(d) of the CAA. See CAA § 307(d), 42 U.S.C. § 7607(d).

[6] *Prometheus Radio Project v. FCC*, 652 F.3d 431, 449 (3d Cir. 2011); accord Idaho Farm Bureau Fed'n v. Babbitt, 58 F.3d 1392, 1404 (9th Cir. 1995) ("The purpose of the notice and comment requirement is to provide for meaningful public participation in the rule-making process.").

Commenter 0388: **EPA did not provide the public, State, Local, and Tribal agencies, and affected stakeholders with sufficient time to undertake a comprehensive review of the proposed rule.**

EPA' s allocated 60-day public comment period significantly shortchanged the public, State, Local, and Tribal agencies, and affected stakeholders of the opportunity to perform a necessary, comprehensive review of the proposed rule. In short, the proposed rule and its accompanying documents are far too expansive, technical, and intertwined with other federal air rules that have not yet been finalized for respondents to meaningfully assess its technical requirements and potential policy and economic implications in a 60-day timeframe. The proposed rule and accompanying preamble are 160 pages long. Furthermore, EPA's docket includes over 180 attachments that cumulatively span over 27,000 pages of material pertinent to the proposed rule. As noted by Wyoming Governor Mark Gordon in his comment extension request submitted to EPA on September 8, 2023:

Such a public comment period would require the public to undertake 450 pages per day of reading to cover the entirety of the material EPA has posted to the docket. This comment and review period does not provide remotely enough time for regulatory agencies, the regulated community, and the general public to thoroughly review the many complex requirements within the proposed rulemaking and evaluate its economic impacts and implementation challenges.

The already-heavy workload associated with reviewing the proposed rule within the allocated timeframe was further compounded by EPA's issuance of a slew of other proposed federal air regulations with coinciding public comment periods. Some of these federal air regulations have significant policy and economic implications for the State of Wyoming and it was necessary for WDEQ to undertake a simultaneous review of all proposed actions. Most notably, EPA' s proposed rules, "New Source Performance Standards for Greenhouse Gas Emissions From New, Modified, and Reconstructed Fossil Fuel-Fired Electric Generating Units; Emission Guidelines for Greenhouse Gas Emissions From Existing Fossil Fuel-Fired Electric Generating Units; and Repeal of the Affordable Clean Energy Rule" (88 FR 33240) and "Revisions to the Air Emissions Reporting Requirements" (88 FR 54118), have vast potential impacts for WDEQ to consider and have thus required particularly thorough reviews.

Altogether, those two proposed rules span 286 pages of complex preamble and regulatory text, as well as thousands of pages of supporting and related material like Regulatory Impact Analyses, Technical Support Documents, and Information Collection Requests. Their public comment periods overlapped directly with the public comment period of this proposed rule, essentially placing the infeasible burden upon state regulatory agencies of reviewing and responding to roughly 450 pages of proposed rules, and tens of thousands of pages of associated documents, within a 60-day comment period.

In short, EPA is promulgating exceptionally complex and extensive proposed rules at such a pace that it could not reasonably expect state regulatory agencies, affected stakeholders, and the general public to meaningfully engage with and respond to these proposed rules. EPA has repeatedly promulgated proposed rules, such as the supplemental proposal to the methane rule (87 FR 74702), in which it has focused on the concept of "meaningful engagement." In WDEQ's experience, EPA has not followed the principles of meaningful engagement, nor has it followed the meaningful engagement requirements it is proposing for state regulatory agencies to undertake, in the promulgation of its own rules. Furthermore, EPA' s actions are not consistent with the basic tenets of cooperative federalism.

The formulation of effective policy and regulation requires the thorough consideration of comments from stakeholders who have been afforded the opportunity to evaluate all potential concerns regarding a proposed rule. As has been the case with so many of EPA's other proposed federal air rules in the past 24 months, the provided public comment period for the proposed rule did not allow for such engagement and deliberation to take place. WDEQ respectfully requests that EPA consider the comment fatigue that state regulatory agencies and other affected stakeholders are grappling with and provide public comment periods of at least 90 days, or 120 days in the case of related proposals. It is essential that agencies, stakeholders, and the public have time to comprehensively review the proposed rules in order to provide EPA with valuable, important feedback that informs final rules and helps ensure that they can be more effectively implemented.

Response 2: In response to the comment that the comment period was not sufficient to review all the documentation due to the EPA’s denial of a comment extension request, the EPA reiterates that we considered the 60-day comment period to be appropriate and to provide a meaningful opportunity to comment on the proposed rulemaking. We note that the EPA posted a copy of the pre-Federal Register publication version of the notice on the EPA website on July 6, 2023, the same day the proposal was publicly announced. Including this opportunity for pre-publication review, the total amount of time for commenting amounted to 88 days. In addition, EPA offered to meet with stakeholders upon request about the proposal for the remainder of the comment period.

See Section VII.E of the preamble for EPA's response to comments regarding federalism.

Commenter: Offshore Operators Committee (OOC)
Comment Number: EPA-HQ-OAR-2023-0234-0409
Page(s): 2

Comment 3: OOC requests the right to add comments or revise these comments until such time that the implementation of Methane Emissions and Waste Reduction Incentive Program is finalized. Until that time, it is impossible to provide constructive comments on EPA's implementation.

Response 3: The WEC rulemaking is a separate rulemaking from this subpart W rulemaking and is outside the scope of this rulemaking. Comments submitted on this subpart W rulemaking after the comment period end date of October 2, 2023, were considered to be late comments. The EPA was able to consider late-filed comments through October 5, 2023.

Commenter: GPA Midstream Association
Comment Number: EPA-HQ-OAR-2023-0234-0299
Page(s): 13

Comment 4: GPA reiterates and reincorporates all of its comments on the 2022 Proposed Rule.

GPA submitted expansive comments on the 2022 Proposed Rule and also submitted comments to the pre-proposal rulemaking docket on the Methane Emissions Reduction Program.[24] The 2022 Proposed Rule was released prior to the enactment of the Inflation Reduction Act and the directive from Congress to revise Subpart W.[25] In its comments on the 2022 Proposed Rule, GPA asked that EPA not finalize that proposal but instead "issue one comprehensive subpart W rule package."[26] GPA appreciates that EPA has clearly stated that it "does not intend to finalize the revisions to subpart W that were in the 2022 Proposed Rule."[27] Unfortunately, even though EPA says it "considered … the concerns and information submitted by commenters in response to" the 2022 Proposed Rule in developing this proposed rule,[28] EPA did not release a response to comments document or provide any reaction to the comments in the preamble to this proposed rule. As a result, commenters on the 2022 Proposed Rule, including GPA, do not have a clear indication of what EPA's thinking was in response to those comments.

EPA notes that "[c]ommenters who would like the EPA to further consider in this rulemaking any relevant comments that they provided on the 2022 Proposed Rule … must resubmit those comments to the EPA during this proposal's comment period."[29] GPA is resubmitting its comments on the 2022 Proposed Rule in their entirety; those comments are included here as Attachment A and incorporated by reference. Similarly, GPA is also resubmitting its 2023 pre-proposal comments on the Methane Emission Reduction Program in their entirety; those comments are included here as Attachment B and incorporated by reference. GPA reiterates the comments that it made in these two prior sets of comments and expects a response from EPA to the points made therein.[30]

Footnotes:

[24] See GPA Comments on 2022 Proposed Rule; GPA Comments on Methane Emissions Reduction Program.

[25] 88 Fed. Reg. at 50,285.

[26] GPA Comments on 2022 Proposed Rule at 3.

[27] 88 Fed. Reg. at 50,285.

[28] *Id*.

[29] *Id*.

[30] The Supreme Court has held that "[a]n agency must consider and respond to significant comments received during the period for public comment." *Perez v. Mortgage Bankers Ass'n*, 135 S. Ct. 1199, 1203 (2015). The Ninth Circuit has described "significant comments" as "those which raise relevant points and which, if adopted, would require a change in the agency's proposed rule." *American Mining Congress v. EPA*, 965 F.2d 759, 771 (9th Cir. 1992). At a minimum, GPA expects a response to all of the comments it made that requested changes to the proposed rules.

Response 4: See the Introduction to this document for the EPA's response to this comment.

Commenter: Kirk Frost
Comment Number: EPA-HQ-OAR-2023-0234-0389
Page(s): 1-2

Comment 5: I noticed that all of the fossil fuel energy companies and entities representing the fossil fuel industry are all requesting an extension of time for comments. I do think that is a good idea, but I would not encapsulate the who proposed changes into 1 docket. I would separate it out into several dockets such as:

1. Section 1: Proposed Rule changes Scope – what facilities and functions are included and what are excluded.

2. Section 2: Proposed rule changes that mandate all facilities reporting comprehensive annual emissions of greenhouse gases, HAPs and VOCs. Specifying all source points and functions along with the associated types of emissions within the natural gas supply chain. This must include the mud methane degassing function.

3. Section 3: Data and Emissions Quantification Methods for reporting emissions of all facility and functions within the oil and natural gas supply chains.

4. Section 4: “Waste Emissions Charge” Criteria and Penalties.

5. Section 5: Reporting Compliance and Audit

I would suggest closing the comments up now, enacting the rules that have been proposed as quickly as possible and then follow up with the above mention sections as different dockets.

Response 5: The EPA generally establishes one rulemaking docket for each regulatory action. Here, the EPA has followed the rulemaking process required by CAA section 307(d), as this rulemaking is a CAA section 307(d) rule.

28.2 General Comments on Methane, Climate Change, and Public Health

The EPA received a substantial number of comments addressing the impacts of methane on climate change and public health. The EPA appreciates the participation of these commenters in the rulemaking process. The comments in this section are being published here to recognize all input received by the EPA, but they are not being responded to individually. The GHGRP is a reporting program and does not include provisions requiring the reduction of methane emissions; however, the EPA notes that methane does affect public health and welfare. Elevated concentrations of GHGs including methane have been warming the planet, leading to changes in the Earth’s climate that are occurring at a pace and in a way that threatens human health, society, and the natural environment. As a GHG, methane in the atmosphere absorbs terrestrial infrared radiation, which in turn contributes to increased global warming and continuing climate change, including increases in air and ocean temperatures, changes in precipitation patterns, retreating snow and ice, increasingly severe weather events, such as hurricanes of greater intensity, and sea level rise, among other impacts. Methane also contributes to climate change through chemical reactions in the atmosphere that produce tropospheric ozone and stratospheric water vapor. Major scientific assessments continue to be released that further advance the EPA’s understanding of the climate system and the impacts that methane and other GHGs have on public health and welfare both for current and future generations.

Commenter: Protect PT
Comment Number: EPA-HQ-OAR-2023-0234-0190
Page(s): 1-2

Comment: The proposed rule would cover gaps in the ways we currently measure methane emissions. Remember, methane is 82 times as potent a greenhouse gas as carbon dioxide. This rule would use remote sensing to measure the scale of the problem, giving EPA a tool and an argument for future restrictions on the proliferation of methane infrastructure. This rule would be one step along that long path.

Long term, the solution is to create such a burden on the industry to comply with the new rule that it reflects the true cost of doing business. The gas industry has been socializing costs and privatizing profits for a century and a half. If they are forced to account for the true costs of their business model, the industry will cease to be profitable - which is precisely the outcome we must seek if my community, or even our biosphere, is to survive.

Commenter: Protect PT
Comment Number: EPA-HQ-OAR-2023-0234-0190
Page(s): 2

Comment: My parents' drinking water, and that of 80,000 other people, comes from a reservoir called Beaver Run. You aren't allowed to fish there, or boat there, but if industry wants to frack right next to it, regulators roll out a red carpet. There are at least seven methane fracking wells located immediately next to the reservoir.

I will include pictures of this in my written comment. The images are horrific.

So I'm not going to mince words.

My parents are being poisoned. My parents are being killed. If you cannot hold their assailants liable criminally, as I personally believe they ought to be, then at least pass regulations to make the assailants admit to what they are doing to people, to the planet, and to my parents.

To the industry shills who joined this call arguing for less frequent measurements and less stringent rules: if you are still listening, or reading this comment in the federal register, I hope you quit your jobs and stop carrying water for the industry that is poisoning mine. It's not too late to walk away and save what is left of your soul.

Fig. 1: oil and gas wells around Beaver Run Reservoir, where my parents and 80,000 other people get their drinking water. Red dots are fracking wells.

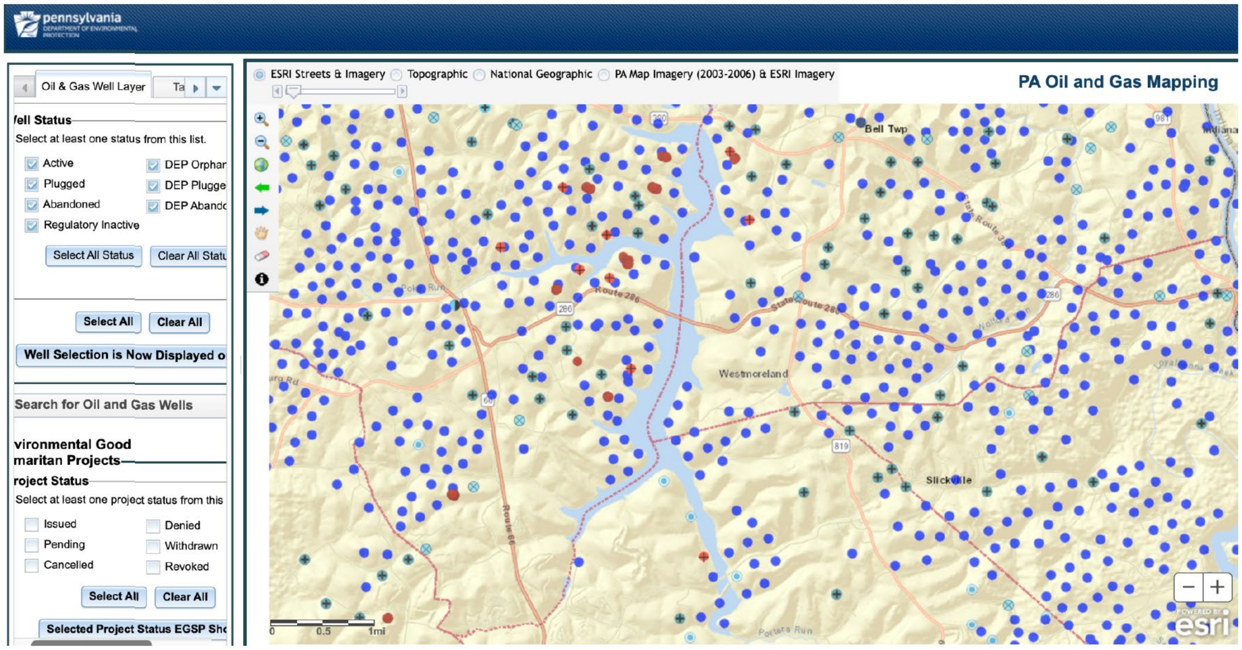


Fig. 2: The Dearmitt fracking well immediately next to Beaver Run Reservoir.

Commenter: Physicians for Social Responsibility Pennsylvania (PSR)
Comment Number: EPA-HQ-OAR-2023-0234-0192
Page(s): 1

Comment: The harmful effects fracking has on the public health of our communities are detrimental. By reducing methane emissions and advocating for methane safeguards, we can improve air quality, water quality, and our health.

It is essential to place emphasis for those living nearby oil and gas operations– that methane emissions can increase risk of: heart disease, lung disease, asthma, infertility for men and women, cancers such as: (Acute Lymphatic Leukemia & Ewing Sarcoma) , eczema, and reduced life longevity in comparison to those that do not live within a close proximity to an oil and gas site according to: the Compendium published by PSR and Concerned Health Professionals of New York with Scientific, Medical, and Media Findings Demonstrating Risks and Harms of oil and gas drilling.

Commenter: John Sonin
Comment Number: EPA-HQ-OAR-2023-0234-0193
Page(s): 1-2

Comment: "The social abuse of supply-side economics has inverted priorities in civil enterprise, for all production, but insidiously so for independent contractors!

… as a domesticate in nature, I am a fervent servant of civil humanity. I work from dawn to dusk as an essayist, maintenance man, and street cleaning trash collector. This energy imbalanced capitalistic economy is availing ecological disaster due to valueless energy transfer of monetary representations that are not representative of the complex-atomic-construction's (energy!) they're meant to symbolize. We must do with what we have to correct this ecological-engineering anomaly, while we still can! Below is my conviction.

Any public necessity privatized is demeaned! Each private capitalist devalues the synergistic gains gleaned of civil relationships when community is producing/creating together. When that venture is detracting from Earth's system dynamics without a reciprocal addition of energy, in whatever form of human effort equitable, the result is evidenced in our current climate conflagration! The legacy loss of this reciprocity must be reconciled for the Planet to achieve a neutralized magnetic polarity! Methane pollution from the oil and gas sector is accelerating the pace of climate change and harming the health of our families and communities and even our fresh waterways, across the country but it is the extractive industry, from oil, coal and gas, to mining and atomic conversion, which is hastening that demise.

Privatized ownership of what our mind's recognize/imagine being part of our own body, decimating via spills, pollution or toxic spread, of any and ALL planetary elements, especially oil and coal, depleting the essential human requisites like air and water resources, or the denigration of our nutritional needs by dismembering our food-chain, wiping-out links without flinching—instigated and emboldened by the “profit-maximization” technique to innovate through capitalism (which then only reinforces an educational system to "crystallize" our innate intolerance of adolescence, ergo creating an adulthood of medieval-style — Machiavellian! — inter-personal relationships; right from the get-go!) is an embattlement that has become a Sisyphus-like challenge for me, personally, but it is one for the whole of our human condition to persist and succeed with publicly!

Commenter: Public Hearing Transcript
Comment Number: EPA-HQ-OAR-2023-0234-0224
Page(s): 10-11 (Don Schreiber)

Comment: I'm in the other famous basin in New Mexico, the San Juan basin in the northwest corner of our state. We're home to 30,000 gas and oil wells, major gas processing facilities, compressor plants and stations, thousands of points where methane can and does occur in emissions. And we have the infamous methane hot spot over our heads to prove it. We're surrounded by 122 gas wells on and near our ranch. Thirty-three of those are within a mile of our home and 10 of them you can see from our front yard. So I've offered my comments to you in the past many times over the years, and every time I'm telling you about what I'd seen daily here on the Devil Springs Ranch for the last 23 years and still see today. When I comment, I'm speaking on behalf of front-line families like mine who most often suffer the effects of methane pollution that finds its way on to our doorsteps and into the faces of those of us most vulnerable to methane pollution, like the elderly. My wife and I are in our mid-70s. Like the very young, we have 10 grandchildren. And like those already suffering from pre-existing health conditions. You have already heard and will hear again comments regarding potential positive results for the Greenhouse Gas Reporting Rule and the Methane Emissions Reduction Program that's the subject of today's hearing. GHGRP and MERP are full of opportunities to make a direct impact on front-line communities like ourselves and to help prevent further methane pollution that is so devastating to our climate. But for those of us who live with the impacts of oil and gas every day, it is our obligation to speak out about operators who do not always follow the rules, no matter how well intended or written they are. Unfortunately, for us here in the San Juan basin, the dominant operator is Hilcorp Energy of Houston, Texas who, according to analysis of your 2021 methane emission data, is the largest methane polluter in the United States, despite the fact that they are only 13th in overall methane production. GHGRP and MERP are only going to be as good as the self-reported company data is. And EPA must be vigilant that companies will report in the interest of methane reductions, not in their own self-interest. When New Mexico was writing its own methane waste and emission rules, New Mexico Oil Conservation Director Adrian Sandoval said some companies live within the exceptions, not the rules. After so many years of state and federal efforts to reduce methane pollution, we cannot let the opportunities that GHGRP and MERP present be lost because of oil and gas operators that seek to profit at the expense of front-line communities and at the expense of a climate changing so dramatically for the worse.

Commenter: Public Hearing Transcript
Comment Number: EPA-HQ-OAR-2023-0234-0224
Page(s): 11-12 (Morgan King)

Comment: No one should have to worry if air they breathe is safe or if climate disaster will take their home or business. As the climate emergency worsens, it is more important than ever to rapidly reduce greenhouse gases to avoid the worst impacts of our warming world.

…

Appalachians and West Virginians are among the most at risk due to the many active and abandoned oil and gas wells in the region. Over half of West Virginians live within half of a mile of an active gas and mile well. Also, there are approximately 6500 abandoned and orphaned oil and gas wells in our state leaking methane. As a region, Appalachia has over 180,000 low producing oil and gas wells responsible for half of all well site methane pollution in the country, and the region, with the highest concentration of these sites. My own county, Kanawha County, has over 3,000 of these types of wells in my home state, which is the highest number of wells in a single county in the state. Needless to say, pollution from the oil and gas industry is a problem in West Virginia. West Virginians have dealt with the brunt of pollution and cumulative impacts for too long from extractive industries. Given the high concentration of oil and gas operations in West Virginia, there is an increased health impact here. The volatile organic compounds released alongside methane during operations worsen respiratory disease, increase the risk of cancer and cardiovascular disease. West Virginia ranked first in the nation in the prevalence of heart attack and coronary heart disease and has the second highest cancer mortality rate. With an overall aging population, this puts our West Virginians at an even greater risk from these pollutants.

Commenter: Public Hearing Transcript
Comment Number: EPA-HQ-OAR-2023-0234-0224
Page(s): 12 (Alice Lu)

Comment: The United States oil and gas industry produce what is equal to 312 million tons of carbon dioxide in 2021. That's equivalent to driving 70 million gas-powered cars for an entire year. Methane, a potent greenhouse gas, is a major pollutant emitted by this industry and is often released alongside other toxic and carcinogenic air pollutants. Reducing emissions would tackle the climate crisis and protect the health of Americans.

…

Ensuring that the proposed update effectively accounts for total greenhouse gas emissions will be crucial for tackling the climate crisis and protecting human health.

Commenter: Public Hearing Transcript
Comment Number: EPA-HQ-OAR-2023-0234-0224
Page(s): 15 (Jessica Moerman)

Comment: First, I want to thank you on behalf of my children for taking methane pollution seriously. Medical research shows that children are among the most at risk for developing life-threatening conditions from exposure to fossil fuel pollution, and that fossil fuel combustion is a leading environmental threat to children's health. Many studies link living in proximity to natural gas development and methane production to birth defects, including to the brain, spine, and spinal cord, and to lower birth weight. As an evangelical pastor, I take seriously what the bible says in Proverbs 13:22, that it's our duty to leave a good inheritance to future generations. Birth defects and severe health complications are no inheritance to leave to our children. The good news is, is because of methane’s significantly stronger warming punch and shorter lifespan in the atmosphere, reducing methane emissions is the fastest way to slow global warming while defending the health of all God's children. However, with inadequate monitoring and reporting of methane emissions and leaks, we face what former defense secretary Donald Rumsfeld referred to as a “known unknown.” We know that leaks are out there, but we don't know where and how much.

Commenter: Public Hearing Transcript
Comment Number: EPA-HQ-OAR-2023-0234-0224
Page(s): 16 (Luke Metzger)

Comment: To avoid the worst impacts of global warming, we must drastically cut climate pollution, but we can only do that with the best data on where the pollution is coming from and how much. So these changes to Subpart W are critical to preserving a livable climate. Texas is ground zero for global warming. We're both the top polluter and home to some of its worst impacts; according to an analysis by the Texas Tribune, in the last decade here in Texas, there were 1,000 more days of record-breaking heat than a normal decade, and that's had deadly consequences. Last year, at least 300 people died of heat-related causes. Scientists have estimated that the persistent dangerous heat that we're experiencing was made at least five times more likely by climate change. So, cutting pollution and accurately measuring that pollution will save lives.

Commenter: Public Hearing Transcript
Comment Number: EPA-HQ-OAR-2023-0234-0224
Page(s): 21 (Cheyenne Branscum)

Comment: I am a single mom and like I said, I’m a tribal citizen, so I really feel that if climate change isn't going to affect me, it will affect my children. We are very much the face of front-line communities, and the people that will be impacted by the decision that you make.

Commenter: Public Hearing Transcript
Comment Number: EPA-HQ-OAR-2023-0234-0224
Page(s): 22 (Cyrus Reed)

Comment: While here in Travis County, we don't have hundreds of oil and gas wells or much production, as an organization, we work with hundreds of communities and thousands of members and supporters who are impacted by pollution from oil and gas wells and associated equipment, and right here in Austin, we are seeing the ravages of climate change. We're on day 45 of 100 degrees or higher, first time in our history, and certainly some of that climate change is caused by methane emissions.

Commenter: Public Hearing Transcript
Comment Number: EPA-HQ-OAR-2023-0234-0224
Page(s): 23 (Camilla Fiebelman)

Comment: I facilitate our New Mexico methane table, which represents dozens of community and environmental groups in New Mexico that have worked since the discovery of the methane hot spot over the four corners to eliminate methane waste and pollution. And the health impacts of co-pollutants that emit with methane. Rules like these are key to truly protecting our communities from the devastating heat of climate change and the deep impacts of air pollution. We're grateful to our Governor, Michele Grisham, for establishing methane and ozone precursor rules, but, and I apologize to my fellow Sierra Club director to the east, with neighbors like Texas, we need to ensure that industry is following a nationwide standard for reporting their waste and pollution, especially since it so badly impacts our border communities in the heat of Permian basin extraction.

Commenter: Public Hearing Transcript
Comment Number: EPA-HQ-OAR-2023-0234-0224
Page(s): 25 (Joan Brown)

Comment: We all are experiencing this summer as unprecedented in terms of heat, drought, fires, et cetera, and it may be a tipping point. In our state and region, we often say that our state and many areas in our state and region have been targeted as sacrifice zones for extractivism. I think we have moved into a new place where we knowingly now are choosing to create a planetary sacrifice zone of the entire planet. So we have a great ethical, moral, and spiritual responsibility to address this. We must work for the common good to choose life and not a planetary sacrifice zone. Women, children, men, species, and the vulnerable are at stake as we all are in our common home.

Commenter: Public Hearing Transcript
Comment Number: EPA-HQ-OAR-2023-0234-0224
Page(s): 25-26 (Bill Midcap)

Comment: Rocky Mountain Farmers Union stands in support of greater protections to curb methane pollution from the oil and gas sector. Folks, farmers, and ranchers are on the front-lines of climate change, and that puts our nation's food supply at risk. Global warming has already cost producers hundreds of millions of dollars that will never be recovered. Severe storms and drought related to climate change have farmers and ranchers guessing about their future. As temperatures increase, producers are experiencing declining yields and declining quality in the food that they supply to consumers in America and all over the world. Climate change is expected to have negative effects on most crops and livestock. As temperatures increase, crop production areas may shift to follow the temperature range for optimal growth and yield, though production in many given locations will be more influenced by the availability of adequate moisture during the growing season. Today producers spend over 15 billion, with a "b", a year on pesticides to control weeds and insects. Those costs are only expected to rise with increasing temperatures and emissions attributed to climate change. … As the EPA drafts regulations to reduce methane pollution from the oil and gas industry, please keep in mind that these protections are needed more now than ever to protect our health, our safety, our food security, and our planet.

Commenter: Public Hearing Transcript
Comment Number: EPA-HQ-OAR-2023-0234-0224
Page(s): 27 (Arthur Gershkoff)

Comment: I'm concerned about the health and well-being of our citizens and our nation. Fossil fuel extraction, processing, and distribution are associated with releases, emissions containing methane and other volatile gases, that can cause illness and increased risk of cancer, respiratory system disease, and other ailments. People who live and work close to extraction wells and processing facilities are at major risk of deteriorated health. Neighborhoods near such sites are often communities of color and often poorer families that can't afford to live elsewhere.

Commenter: Public Hearing Transcript
Comment Number: EPA-HQ-OAR-2023-0234-0224
Page(s): 27-28 (Rebecca Edwards)

Comment: It is a core tenet of my faith that humans are called to care for their neighbors. What's more, we are called to offer our particular care for neighbors who are the most vulnerable. Methane pollution is harmful to our neighbors in several ways, from the health impacts of air pollution to the consequences of climate change. Because the impacts of these environmental problems are most severe for people who are already vulnerable, and because climate change impacts are borne by the people least responsible for greenhouse gas emissions, people of faith care deeply about mitigating the causes of climate change. In summary, Texans of faith feel called to advocate for a healthy environment, where all people can thrive. Reducing methane emissions is a critical part of ensuring a healthy environment. That starts with appropriate quantification of methane releases from the oil and gas sector. In service of the goal of reducing or eliminating those emissions.

Commenter: Public Hearing Transcript
Comment Number: EPA-HQ-OAR-2023-0234-0224
Page(s): 30 (Ann McCartney)

Comment: As a person of conscience, I am concerned about how we as a country take responsibility for our impacts on our air, our atmosphere, and the impacts of methane and other gas releases from oil and gas production on people. I have visited the Permian basin in New Mexico and seen the dirty methane flares and heard from the people who live and work there about the health impacts they have experienced living in an area saturated with greenhouse gas emissions from oil and gas production. Because of the air quality issues from gas emissions, my organization, New Mexico Interfaith Power and Light, together with Citizens Caring for the Future, are buying air purifiers for some of the most critically impacted residents of the Permian basin. So the need for more precise and comprehensive reporting of greenhouse gas emissions is great.

Commenter: Public Hearing Transcript
Comment Number: EPA-HQ-OAR-2023-0234-0224
Page(s): 30 (Marlene Perrotte)

Comment: I am a citizen of New Mexico, and I stand in solidarity with the Permian basin especially and also the San Juan basin. We have the ethical imperative and moral responsibility to care for our home, planet Earth. We have to ensure we are doing all we can to improve air quality, health, and address climate chaos. I'm no specialist, I'm just a concerned citizen.

Commenter: Public Hearing Transcript
Comment Number: EPA-HQ-OAR-2023-0234-0224
Page(s): 31-32 (Tracy Sabetta)

Comment: Moms Clean Air Force has engaged for years in debate around reducing methane and other emissions from oil and gas facilities. As a public health advocate and lifelong resident of the Buckeye State, I know what a profound impact reducing and accurately reporting methane pollution would have on states like Ohio. We are currently home to more than 103,000 oil and gas production facilities. We rank second in the nation for total residents living within a half mile of these facilities and second for students attending a school, daycare, or college within a half mile. … Increased methane pollution and resulting climate impacts are already hitting us in Ohio and bringing along their own costs. According to the bird polar and climate research center at the Ohio State University, one severe climate impact currently being seen in Ohio is a rise in overnight temperatures. Records for overnight temperatures were recently broken in four major Ohio cities, with Toledo, Akron, Mansfield and Findlay setting records for average minimum summer temperatures. These widespread temperature increases bring with them a strain on cooling systems, electric bills, and people's health, specifically in front-line communities across the state. Now add the power outages experienced by many into the mix and you have a climate change recipe for disaster. … Scientists have known for decades that air pollution is harmful to health and this is especially true for vulnerable populations such as older adults, people with underlying health conditions, communities of color, pregnant women, and children. Air pollution from the oil and gas industry can cause respiratory diseases, asthma attacks and increased hospitalizations. That is why strengthening the proposed rule is so critical. On behalf of the 89,000 members of Moms Clean Air Force in Ohio, we believe the changes to the Greenhouse Gas Reporting Program are off to a really good start, and we hope that you will consider the proposed suggestions for strengthening the requirements. This is an important step toward addressing the climate crisis and protecting the health and safety of children and families across Ohio, and across the country.

Commenter: Public Hearing Transcript
Comment Number: EPA-HQ-OAR-2023-0234-0224
Page(s): 33 (Margeret Bell)

Comment: New Mexico along with Texas as part of the Permian basin is at the nation's largest methane emitter. Methane emissions have played a dominant role in our state's mega drought, and then the horrific wildfires that have destroyed hundreds of thousands of acres of forests and damaged acequias, which are local community irrigation networks, streams and aquifers, resulting in loss of water resources we cannot afford to lose. The damage has been so catastrophic that the forests, lands, ecosystems, waters and multigenerational communities in northern New Mexico may never fully recover. We are beyond a climate crisis. We are in a climate catastrophe.

Commenter: Public Hearing Transcript
Comment Number: EPA-HQ-OAR-2023-0234-0224
Page(s): 34 (Dr. Dakota Raynes)

Comment: … third the United States is currently working toward exporting our approach to methane reporting, measuring, and mitigation to the rest of the world therefore, if we get this wrong, the consequences will not just impact our country, our communities and our little sliver of the environment, rather, the consequences will be felt around the world. If we get this wrong, we run the risk of continuing to overestimate our progress and our chances of survival.

Commenter: Public Hearing Transcript
Comment Number: EPA-HQ-OAR-2023-0234-0224
Page(s): 34 (Dr. Dakota Raynes)

Comment: The accuracy of Subpart W data is even more important now for several reasons. First as others have mentioned, we are quickly running out of time to ensure that we are on track with the commitments made in the Paris Climate Accord and the target set by the Intergovernmental Panel on Climate Change.

Commenter: Public Hearing Transcript
Comment Number: EPA-HQ-OAR-2023-0234-0224
Page(s): 36-37 (Sarah Bradley)

Comment: Almost two years ago, I had the opportunity to join a pilgrimage and immersion to the Permian basin in southeast New Mexico, which is one of the most productive oil and gas basins in the country and the world. There I got to meet residents of the region and learn about the enormous challenges that the oil and gas industry is causing in the region, especially in their struggle for environmental justice and healthy air, soil, and water. We drove through lands covered with fracking and drilling pipelines and rigs as far as the eye could see, and under a consistent brown haze of pollution, for miles and miles, we drove by constant illegal flaring and in the towns of Hobbs and Carlsbad, we met mothers, daughters, and wives who are watching their loved ones who work in the oil and gas industry fall sick, watching their bodies deteriorate. They worry about the health of their families, seeing the clear connection between exposure to pollutants and long-term health impacts such as pulmonary and heart disease, asthma, chronic bronchitis, cancers, leukemia, and birth defects. Walking around in a neighborhood that had a well right next to a children's park, residents could point to multiple houses where long term residents died from rare cancers that are proven to be connected to oil and gas pollutants. In the Permian basin, organizers dedicated to protecting their community's health faced enormous push back and silencing. It's David and Goliath out there, as the oil and gas companies employ a large portion of the residents and control everything in town, from community program funding to political leaders; so many everyday people are literally afraid for their lives, they're afraid for their health, but are afraid to speak out in their local towns, knowing that standing up could result in them losing their jobs and facing attacks from many sectors. So given the imbalance of power in these kinds of places where the oil and gas industries are so strong, we need regulatory agencies to live up to their charge and protect the people and the environment and the planet as a whole. The EPA has a responsibility to protect front-line communities and we cannot protect anyone if we are not effectively and thoroughly monitoring what is going on in the air, ground and waters. … Accurate monitoring and holding companies accountable for these [inaudible] activities is the bare minimum we need to be doing in a time of climate collapse, and what the EPA does now is going to have a global impact in terms of mitigating the climate catastrophe. It's my belief that political leaders and government officials in the U.S. today are not protecting our communities and our futures enough and I implore you to do more. We have an ethical and moral responsibility to ensure we are doing all we can to safeguard front-line communities and make sure we have a livable climate future.

Commenter: Public Hearing Transcript
Comment Number: EPA-HQ-OAR-2023-0234-0224
Page(s): 38 (Liz Scott)

Comment: Climate change is a health emergency, and we cannot afford to pass off the health impacts of climate change as future problems because there is no shortage of climate disasters like flooding, wildfires, excessive heat, and storms threatening lives and livelihood right now. These extreme weather patterns are being fueled by climate change, which is being fueled in part by methane emissions. This is why the Lung Association was glad to see the inclusion of the Methane Emissions Reduction Program in the Inflation Reduction Act. … Volatile organic compounds like benzene are emitted alongside methane and can worsen asthma symptoms and increase the risk of cancer, developmental, and neurological disorders. VOCs can also react to form harmful ozone pollution or smog. Smog can increase the risk of premature death, contribute to asthma attacks, and aggravate existing lung and heart problems.

Commenter: Public Hearing Transcript
Comment Number: EPA-HQ-OAR-2023-0234-0224
Page(s): 41-42 (Glenn Wikle)

Comment: New Mexico has one of the highest poverty rates in the U.S., and it's this hot spot of oil and gas activity right now on both ends of our state. We've heard about both basins where there's drilling … These people are exposed to high levels of dangerous emissions from ever growing oil and gas wells. Just when we need oil and gas production to ramp down here in New Mexico, it's ramping up. Since everyone here is being so calm and so orderly, at least most of us, it's important to frame this context of the global crisis which is now clearly unfolding around the world. We shouldn't forget that extreme events caused by climate change are killing people and taking away thousands of homes. This summer is just the beginning. The amount of suffering will increase as decades go by. We all have a duty to do more to mitigate our country's contribution to the global climate crisis. Everyone at the EPA has a duty to do more to mitigate this worldwide crisis. Everyone at the EPA has a duty to resist pressure from operators to do less.

Commenter: Public Hearing Transcript
Comment Number: EPA-HQ-OAR-2023-0234-0224
Page(s): 42-43 (Etta Albright)

Comment: I am a retired registered nurse whose career was serving a population then labeled mentally retarded. Among the many causes of those permanently damaged with lifelong malfunctioning of brain and neurocognitive processing was unknown prenatal influences. I now recognize the influences as epigenetic. Commonalities in all epigenetic influences are air, water, and soil - Earth origin. There is outstanding evidence of the adversarial impact industry has had on the air, water, and soil in Pennsylvania. And the subsequent impact on public health, well-being, and safety. Fast forward to the present reality of the impact on human and environmental health by the fossil fuel industry by greenhouse gas emissions and the subsequent exacerbation of global warming and climate change.

Commenter: Public Hearing Transcript
Comment Number: EPA-HQ-OAR-2023-0234-0224
Page(s): 49-50 (Christina Digiulio)

Comment: As a part of my work as a Field Scientist, I'm working on air monitoring and impacted communities across the state, and optical gas imaging of facilities here in Pennsylvania in order to help others understand what is released into the air in order to correlate the health outcomes related to methane exposure caused by oil and gas drilling or fracking in Pennsylvania. … So basically the harmful effects of fracking -- has on public health of our communities are detrimental, as we've seen here in Pennsylvania. By reducing methane emissions and advocating for methane safeguards we can improve air quality, water quality, and our health, and especially for those living nearby oil and gas operations, these methane emissions can increase the risk of heart disease, lung disease, asthma, infertility for men and women, cancer such as lymphatic leukemia, Ewing's sarcoma and reduce life, longevity in comparison to those who do not live within close proximity to an oil and gas site according to the compendium that was published by PSR and Concerned Health Professionals of New York with scientific medical and medical and media findings demonstrating risk and harms of the oil and gas drilling. Climate change is a health issue and the agency must use all of the scientific knowledge that's currently available and prioritize protecting the health and safety of the public and our environment above all else.

Commenter: Public Hearing Transcript
Comment Number: EPA-HQ-OAR-2023-0234-0224
Page(s): 51 (Liz Anderson)

Comment: These emissions, as Lisa mentioned, affect immediately, due to living near oil and gas extraction activities, and then also the secondary impact of climate change, which affects all of us.

Commenter: Public Hearing Transcript
Comment Number: EPA-HQ-OAR-2023-0234-0224
Page(s): 52 (Bill Sabey)

Comment: There are more than 200 similar volunteers in southeast Pennsylvania advocating for clean air and clean energy. It is vitally important for the survivability of our planet and humanity that we eliminate all sources of methane emissions to the atmosphere. Recent reports of natural tipping points of carbon and methane emissions from melting and previously frozen tundra, peat, and other underground caverns that are now finding their way to the surface, it is vitally important that we eliminate any man-made methane emissions that we can.

Commenter: Public Hearing Transcript
Comment Number: EPA-HQ-OAR-2023-0234-0224
Page(s): 54-55 (Katie Muth)

Comment: … while my district is in southeastern Pennsylvania, currently where there are no actual frack pads which are high methane emitters, we have gas and oil infrastructure galore via pipelines, pump stations, pigging stations, all sorts of infrastructure for the cradle to grave process of oil and gas, as Pennsylvania is the number two producer in the nation and also one of the most polluted states in the country. I also grew up in Westmoreland County, so I have lived on the other side of the state for over two decades before I went to Penn State and now I'm on the other side of the state, and currently my elementary school that I attended also which would be in the Franklin Regional School District has a frack pad near it, another one recently approved, so to the previous speaker who's in Gibsonia, I appreciate her mentioning that. I've spoken to dozens of Pennsylvania families, property owners, farmers, all who have had their quality of life, their property, their health, and their drinking water ruined by the Marcellus Shale industry, and its also associated partners in the petrochemical industry. Oil and gas is one of the leading sources of methane pollution in the United States emitting roughly 16 million metric tons of methane every year and that's just what is reported as mentioned by a previous speaker. … We know that methane traps about 80 times as much heat, more heat as carbon dioxide on average and over the first 20 years after it reaches the atmosphere, it's responsible for approximately one-third of the warming from greenhouse gases occurring today. The international energy agency estimates that methane is responsible for about 30% of the rise in global temperature since the industrial revolution in rapid and sustained reduction in methane emissions are the absolute critical key and imperative factor to limit near-term warming and improve air quality. To be blunt, if the EPA does not take action immediately and put more stringent regulations on methane, the existential threat of climate change in this climate crisis is no longer a threat but a reality. And we know that 80% of people may endure heat waves, we've seen floods, we've seen wildfires, we had the deadliest wildfire in this country's history in over a hundred years in Maui, and with hundreds of people missing and over a hundred killed. We know that it impacts croplands and our ability to produce food, and every level of government should be working to reduce all greenhouse gas emissions, but what I hear lately on the state level is hydrogen hubs galore and carbon capture, carbon capture, carbon capture - and what carbon capture does not capture is methane.

Commenter: Physicians for Social Responsibility Pennsylvania (PSR)
Comment Number: EPA-HQ-OAR-2023-0234-0226
Page(s): 1

Comment: The harmful effects fracking has on the public health of our communities are detrimental. By reducing methane emissions and advocating for methane safeguards, we can improve air quality, water quality, and our health.

It is essential to place emphasis for those living nearby oil and gas operations– that methane emissions can increase risk of: heart disease, lung disease, asthma, infertility for men and women, cancers such as: Acute Lymphatic Leukemia & Ewing Sarcoma, eczema, and reduced life longevity in comparison to those that do not live in close proximity to oil and gas sites according to the *Compendium on Scientific, Medical, and Media Findings Demonstrating Risks and Harms of oil and gas drilling* published by PSR and Concerned Health Professionals of New York.

Commenter: Ceres, Inc.
Comment Number: EPA-HQ-OAR-2023-0234-0236
Page(s): 1-2

Comment: Methane emissions from oil and gas infrastructure represent safety and reputational risks, additional GHG emissions, wasted natural resources, and a failure to monetize a product that would otherwise add value to oil and gas value chain companies in investment portfolios.

Addressing methane emissions is one of the fastest, most cost-effective means of limiting global warming. But methane emissions need to be measured correctly to be managed adequately. Scientific studies have shown that methane pollution from oil and gas facilities in the U.S. is far worse than current, self-reported estimates suggest. Actual emissions have been found to be between 50 and 100% higher than emissions reported to the EPA. This means that current standards for methane emissions reporting are insufficient to provide assurances of accuracy to external stakeholders and to support mitigation efforts.

For the past three years, Ceres has partnered with the Clean Air Task Force and ERM to produce an annual report benchmarking oil and natural gas company methane and other GHG emissions performance using EPA data (see publications in 2021, 2022 and 2023). This work has made clear to us that: 1. Investors and lenders take a strong interest in both the relative and absolute performances of oil and gas companies on managing methane emissions. The benchmarking analysis has been used by both banks and institutional investors in their engagements with oil and gas companies to encourage improved methane emissions mitigation. 2. The EPA's current approach to GHG reporting for the oil and gas sector, while providing valuable data, has several shortcomings that limit its usefulness to stakeholders. An updated and modernized approach to the GHGRP will find a ready audience among financial as well as other stakeholders.

Commenter: Interfaith Center on Corporate Responsibility (ICCR)
Comment Number: EPA-HQ-OAR-2023-0234-0242
Page(s): 1-2

Comment: Investors are concerned about all aspects of sustainability for the energy sector but are especially concerned about methane as it is such a powerful climate change forcer. As long-term and diversified investors, we are deeply concerned about the impact of climate change on the broader economy, on the companies in which we are invested, and on communities across the world, particularly low-income, vulnerable communities, which are bearing the worst impacts of climate change. ICCR's membership includes faith-based health systems and congregations with ministries in communities affected by oil and gas operations, so we are additionally concerned about the harmful impacts of methane and VOC emissions on public health.

Climate change poses severe and systemic risks to the economy, financial systems, and society at large. While we appreciate voluntary efforts from leading members of the oil and gas industry to curb methane waste and improve data reporting, robust government regulations are needed to address this systemic risk by reducing greenhouse gas emissions in a uniform manner across operators, enhancing transparency, and supporting companies' net-zero transitions.

Methane emissions from oil and gas infrastructure represent wasted natural resources, increased warming impact, safety and reputational risks, and a failure to capture valuable product that would otherwise add value to the oil and gas value chain for companies in investment portfolios.

Addressing methane emissions is one of the fastest, most cost-effective means of limiting global warming, but you cannot manage what you don't measure. Studies continue to show that current standards for methane emissions reporting are insufficient to provide assurances of accuracy to external stakeholders and to support mitigation efforts. A comprehensive study released in 2018 found emissions to be 60% higher than EPA estimates.1

Footnote:

1 Alvarez, et al., Assessment of methane emissions from the U.S. oil and gas supply chain. Science. 2018, Vol. 361, Issue 6398, pp.186-188.
https://www.science.org/doi/10.1126/science.aar7204

Commenter: Ronald Gulla
Comment Number: EPA-HQ-OAR-2023-0234-0259
Page(s): 1

Comment: It is long overdue for Oil&Gas Industry to be held accountable for emissions. My farm in Hickory, Washington County was a major science project for the Industry. Emissions were incredibly horrific. Health issues started happening and the Industry with their lawyers covered the problems. … I have been fighting this Industry since 2005, when Range Resources polluted and destroyed my 142 acre farm. My wife has been diagnosed with Acute Myeloid Leukemia in September of 2022. Range Resources has caused her health issues and has shortened her life. My wife is only 53 years old, also I'm still in litigation since July 2007.

Commenter: Paul Roden
Comment Number: EPA-HQ-OAR-2023-0234-0270
Page(s): 1

Comment: The green house gas emissions should be monitored, recorded and made available to the government and the public. We need to hold any company accountable for the green house gas emissions. There should be competition to see what company or corporation can get to "net zero," in their use of energy. We need an "Apollo Moon Race" type mission to get the nation & world off fossil fuel & nuclear power to save the planet, its ecosystems & lifeforms from extinction now. Fossil fuel & nuclear power are both too dangerous, too expensive and totally unnecessary for our energy needs.

If anybody still thinks we need fossil fuel, natural gas as a "transition fuel" or nuclear power to save us from the impact of the burning of fossil fuel, until renewable enery is ready, I suggest you go the the websites of The Solutions Project and the Rocky Mountain Institute, to read about the plans for transitioning to renewable energy now with just solar, wind, geothermal & hydroelectric energy. They have plans for all 50 states and 146 countries all over the world and pilot projects demonstrating the feasibility to do so now.

All we lack is the political will to do so because of the unlimited, anonymous PAC campaign donations buying the votes of our elected representatives in the Congress and State Legislatures from both political parties. We will not "starve and freeze in the dark," nor "wreck our economy in the process of transitioning to a renewable energy economy."

Monitor greengas emissions and stand up to the fossil fuel industry and protect our environment now.

Commenter: Paul Roden
Comment Number: EPA-HQ-OAR-2023-0234-0306
Page(s): 1

Comment: The EPA should have the authority to regulate green house gas emissions. The dying profit addicted fossil fuel industry must cease and desist from drilling, digging, extracting, refining, shipping, & distributing their planet environment killing product. We have the technology and natural resources to transition to renewable energy by 2030. Go to https://thesolutionsprotect.org/ We need to stop the use of fossil fuel and the fossil fuel industry,, impose their control of government regulations all for short term profits.

Commenter: Wendy Schroeder
Comment Number: EPA-HQ-OAR-2023-0234-0311
Page(s): 1

Comment: Please reduce the methane and other hazardous and carcinogenic air pollutants that are being released by the use of gas and oil. We need solutions to climate change so future generations can live healthy lives on our unique and precious planet.

We need more wind and solar energy being used instead. It may be a substantial undertaking, but it will be worth it.

Commenter: Paul Palla
Comment Number: EPA-HQ-OAR-2023-0234-0315
Page(s): 1

Comment: It's very simple. FOSSIL FUELS = DEATH AND YOU KNOW IT! STOP HELPING THEM KILL US!!

Commenter: Laura Horowitz
Comment Number: EPA-HQ-OAR-2023-0234-0328
Page(s): 1

Comment: Thank you for the opportunity to comment on this proposal.

Although this proposed update would improve the accuracy of emissions reported by oil and gas facilities, there are still a number of ways EPA can strengthen it.

The oil and gas industry in the United States is a large emitter of climate-heating GHGs, producing emissions in 2021 that were equivalent to driving nearly 70 million gasoline-powered cars for an entire year. Methane is a major pollutant emitted by the oil and gas industry and is often released alongside other hazardous and carcinogenic air pollutants. Reducing methane emissions from the oil and gas sector would tackle the climate crisis and better protect the health of Americans.

The fossil fuels industry has shown consistently that it has no interest in honest reporting of the damage it does to the environment. If they won't own up, we must make them do so. Their profits are not the priority here. Environmental and human health are.

Commenter: American Lung Association
Comment Number: EPA-HQ-OAR-2023-0234-0335
Page(s): 1

Comment: However, these changes to Subpart W must go further to protect our most vulnerable citizens. In 2019 following a spate of cancer diagnosis among children and pregnant women in southwestern Pennsylvania, the State Department of Health partnered with the University of

Pittsburgh to study the possible health risks of our oil and gas industries. In three reports released just last week, the relationship between adverse outcomes and the proximity to gas operations has become more clear. [i]Children living within a mile of a well had a 500-700% greater risk of developing lymphoma and other cancers than their counterparts. [ii]Also, they found a "strong link" between natural gas development and "severe exacerbations, emergency department visits and hospitalization for asthma in people living within 10 miles of one or more wells producing natural gas." [iii]Finally, the research concluded that mothers gave birth to smaller babies when living in proximity to active wells, compressor stations and waste facilities. Pennsylvania's studies join a growing body of scientific and medical evidence that shows adverse health impacts on people living nearby oil and gas activities.

Footnotes:

[i] Report_Cancer_outcomes_2023_August (pitt.edu)

[ii] Report_Asthma_outcomes_Revised_2023_July (pitt.edu)

[iii] Report_Birth_outcomes_Revised_2023_July (pitt.edu)

Commenter: California State Teachers' Retirement System CalSTRS
Comment Number: EPA-HQ-OAR-2023-0234-0347
Page(s): 1

Comment: CalSTRS believes climate change is one of the greatest threats to our future, with undeniable links to business and financial investments. Climate change impacts health and safety, the environment, and the global economy, which puts the CalSTRS investment portfolio at risk. Virtually all companies and assets in our portfolio are affected by climate risk and must prepare for the transition to a low carbon economy.

Commenter: Stephen Gliva
Comment Number: EPA-HQ-OAR-2023-0234-0353
Page(s): 1

Comment: Reducing methane emissions from the oil and gas sector would tackle the climate crisis and better protect the health of Americans

Commenter: Tika Bordelon
Comment Number: EPA-HQ-OAR-2023-0234-0358
Page(s): 1

Comment: The U.S. Environmental Protection Agency (EPA) has proposed to amend a part of the Greenhouse Gas Reporting Program to ensure that operators of certain oil and gas facilities more accurately report their climate-heating greenhouse gas (GHG) emissions. Studies have shown that methane emissions calculated and reported by the oil and gas industry are greatly underestimated.

Stop polluting our world!

Commenter: Gerard Tessier
Comment Number: EPA-HQ-OAR-2023-0234-0361
Page(s): 1

Comment: I've been around methane pipelines in SW PA.

I'd like to see the EPA ensure leaks are reported. Also ensure that companies monitor wells long after they are done using them as they can leak way into the future if not sealed.

Not only are carcinogenic molecules released at these sites, Methane is a very potent GHG and these sites need to be monitored.

I think it is very important that the EPA passes what it has so far, but I truly believe that further monitoring, especially of Methane in our communities and natural areas, needs to be mandated.

Commenter: Evangelical Environmental Network (EEN)
Comment Number: EPA-HQ-OAR-2023-0234-0371
Page(s): 1

Comment: Medical research shows that children are among the most at risk for developing life-threatening conditions from exposure to fossil fuel pollution and that fossil fuel combustion is a leading environmental threat to children's health.[1] A multitude of studies link living in proximity to natural gas development and methane production to birth defects to the brain, spine, and spinal cord[2,3] and to lower birth weight.[4]

As an evangelical pastor, I take seriously what the Bible says in Proverbs 13:22: that it's our duty to leave a good inheritance to future generations. Birth defects and severe health complications are no inheritance to leave to our children.

The good news is because of methane's significantly stronger warming punch and shorter lifespan in the atmosphere, reducing methane emissions is the fastest way to slow the escalating rate of global warming while defending the health of all God's children.

However, with inadequate monitoring and reporting of methane emissions and leaks, we face what former Defense Secretary Donald Rumsfeld referred to as a "known unknown". We know that leaks are out there but we don't know where and how much.

Footnotes:

[1] Perera F. (2017) Pollution from Fossil-Fuel Combustion is the Leading Environmental Threat to Global Pediatric Health and Equity: Solutions Exist. *Int J Environ Res Public Health*. 2017;15(1):16. doi:10.3390/ijerph15010016

[2] Lisa M. McKenzie, Ruixin Guo, Roxana Z. Witter, David A. Savitz, Lee S. Newman, and John L. Adgate, Birth Outcomes and Maternal Residential Proximity to Natural Gas Development in Rural Colorado, Environmental Health Perspectives doi:10.1289/ehp.1306722.

[3] Casey J.A., et al., "The association between natural gas well activity and specific congenital anomalies in Oklahoma, 1997-2009," Environment International, Volume 122, January 2019, 381-388, https://www.sciencedirect.com/science/article/pii/S0160412018317999?via=ihub

[4] Stacy SL, Brink LL, Larkin JC, Sadovsky Y, Goldstein BD, Pitt BR, et al. (2015) Perinatal Outcomes and Unconventional Natural Gas Operations in Southwest Pennsylvania. PLoS ONE 10(6): e0126425. doi:10.1371/journal.pone.0126425

Commenter: Miller/Howard Investments, Inc.
Comment Number: EPA-HQ-OAR-2023-0234-0380
Page(s): 1

Comment: Methane emissions from oil and gas infrastructure represent wasted natural resources, increased emissions, safety and reputational risks, and a failure to monetize a product that would otherwise add value to the oil and gas value chain companies in investment portfolios.

Addressing methane emissions is one of the fastest, most cost-effective means of limiting global warming, but you cannot manage what you don't measure. Studies continue to show that current standards for methane emissions reporting are insufficient to provide assurances of accuracy to external stakeholders and to support mitigation efforts. A comprehensive study released in 2018 found emissions to be 60% higher than EPA estimates.[1]

Footnote:

1 Alvarez, et al., Assessment of methane emissions from the U.S. oil and gas supply chain. Science. 2018, Vol. 361, Issue 6398, pp.186-188.
https://www.science.org/doi/10.1126/science.aar7204

Commenter: Environmental Defense Fund et al.
Comment Number: EPA-HQ-OAR-2023-0234-0401
Page(s): 1

Comment: Methane pollution is a dangerous climate change accelerant responsible for at least 25% of the global warming we're dealing with today. Studies based on observed, measured emissions at the regional level show that current emissions inventories are significantly underestimating methane pollution.

Commenter: Differentiated Gas Coordinating Council (DGCC)
Comment Number: EPA-HQ-OAR-2023-0234-0415
Page(s): 3

Comment: Background

The DGCC is a coalition of stakeholders across the natural gas value chain dedicated to expanding the differentiated natural gas market. The DGCC's goal is to facilitate a pathway for regulators, utilities, and gas consumers to utilize differentiated gas as an important option to meet their climate goals. We believe adopting differentiated gas is the best way to rapidly reduce methane emissions in the oil and gas sector—a win for energy producers, energy consumers, and the climate.

Differentiated gas, also known as certified gas or responsibly sourced gas, is natural gas that is marketed and sold based on its verifiable environmental attributes, particularly the cumulative intensity of methane emissions throughout the production and transportation value chains.[2] In a world seeking to reconcile climate change and the continued use of fossil fuels, energy products with smaller GHG footprints will inevitably gain a competitive edge. The reliable verification of a cleaner product means that such a product can be sold at a premium by stakeholders who seek a trusted and transparent method of verifying emissions reductions.[3] To participate in this market, natural gas producers and buyers must track, quantify, and communicate their methane and carbon dioxide emissions to investors, customers, and regulators.

According to a recent report by the International Energy Agency, more than 70% of methane emissions in oil and gas operations are avoidable, and 45% are avoidable at no net cost.[4] Energy companies can detect and stop leaks as they occur, minimize routine flaring, improve flare efficiency, and identify and replace problematic equipment. In 2019, oil and gas companies operating on U.S. public and tribal lands leaked, vented, or flared approximately 163 billion cubic feet of natural gas into the atmosphere, resulting in nearly $500 million of lost potential revenue.[5] Differentiated gas can help create competitive pathways for operators to adopt advanced methane monitoring and measuring technologies and invest in commercially available mitigation solutions, developing a cleaner and more transparent industry in the eyes of domestic and international buyers.

Within the natural gas sector, cutting-edge methane-measuring sensors and systems are catalysts for transparency by facilitating precise quantification of methane emissions. The availability of such data, combined with mounting ESG (environmental, social, and governance) financial and regulatory drivers, holds the potential to spur the growth of a differentiated natural gas market in the United States. However, the development of such a market is contingent upon the implementation of policies that acknowledge and incentivize high-performing operators and those dedicated to comprehensive emissions quantification and disclosure. Without sufficient data, the transactability of differentiated natural gas based on emissions attributes will remain challenging, therefore limiting the emissions reductions that can be realized. The establishment of presumptive emissions rates by the EPA would inadvertently dissuade well-intentioned actors in the natural gas sector from embracing the most advanced technologies available.

The dynamic landscape of the oil and gas industry requires adaptive, clear, and well-coordinated regulatory measures to ensure both safety and environmental sustainability. The DGCC is deeply engaged in this evolution, collaborating on technological advancement while advocating for pragmatic regulatory solutions.

Footnotes:

[2] *See* Differentiated Gas Coordinating Council's (DGCC) "What is Differentiated Gas."

[3] *See* Bloomberg Law's "U.S. Can Ensure Climate Security With Differentiated Natural Gas."

[4] *See* International Energy Agency's "Slashing methane emissions is crucial for the climate."

[5] *See* Environmental Defense Fund's, "New Study Quantifies Natural Gas Wasted on U.S. Public and Tribal Lands.

Commenter: Protect PT
Comment Number: EPA-HQ-OAR-2023-0234-0422
Page(s): 1-2

Comment: During the public comment session on a proposed rule, I was invited by an EPA official to pass along local air monitoring data to EPA. We primarily do air quality monitoring for VOCs and particulate matter, and we work with other local organizations when the need arises to monitor methane. Below is a writeup from Melissa Ostroff with Earthworks, who has done methane monitoring in our region.

On November 3, 2021 between approximately 2:15 and 2:45pm, Melissa Ostroff, an Infrared Training Center (ITC) certified optical gas imaging (OGI) thermographer employed by Earthworks, filmed fugitive emissions at the "Penn Trafford Sch Dist 1" well located behind Trafford Elementary School in Trafford, Westmoreland County, owned by Kriebel Acquisition Co LLC. The emissions were leaking from a joint near the base of the wellhead, and an odor of hydrocarbons was also present. The resulting video, filmed using a Forward Looking Infrared (FLIR) GF320 optical gas imaging camera, can be viewed at: https://www.youtube.com/watch?v=Ts1khTBYFQY

Given the location of this well, directly next to an elementary school, we [Earthworks] filed a complaint with PA DEP and requested they immediately investigate the situation and take appropriate action to remedy this complaint.

Our complaint appeared to be lost in DEP's system after we followed up by phone in early December. By mid-Decemeber, a DEP inspector visited the site and found several leaks. He contacted the operator, who said they would repair the equipment. In late December, the operator repaired a hammer union and fitting under the production chart. The inspector returned and did not find any additional leaks.

On July 16, 2022 at approximately 3:30 PM, Ostroff returned to the site and found new emissions. The resulting video, filmed using a Forward Looking Infrared (FLIR) GF320 optical gas imaging camera, can be viewed at: https://www.youtube.com/watch?v=ziCyb5ZM1-E. The camera documented hydrocarbon emissions being continuously released from diaphragm valves at the base and top areas of a vertical separator. Continuous emissions from the valves are indicative of a potential malfunction. Exposure to the pollutants observed in this video represents a serious potential health hazard for children as they return to school in the coming weeks. We filed a complaint with PA DEP and urged the agency to investigate the situation described above immediately and to take appropriate action to remedy this complaint.

A month later, a DEP inspector told us his gas meter didn't detect gas around the separator, but that he believed the valve on top of the separator was leaking. The operator replaced the valve. They also tightened some parts where the inspector's gas meter found methane at other points around the well.

On April 16, 2023 at approximately 1:15 PM, Ostroff returned to the site and again filmed emissions -- the same malfunction found in July 2022 that we had been told was repaired. The resulting video, filmed using a Forward Looking Infrared (FLIR) GF320 optical gas imaging camera, can be viewed at: https://www.youtube.com/watch?v=9PHPY9bYUfk. The camera documented hydrocarbon emissions being continuously released from diaphragms at the base and top areas of a vertical separator. Continuous emissions from these diaphragms are indicative of a malfunction, as they are designed to vent intermittently, not continuously. We filed another complaint and urged the agency to investigate the situation described above immediately and to take appropriate action to remedy this complaint.

About one month later, a DEP inspector contacted Earthworks and told us the operator had done "a good bit of work" at the site. The gas reading on his detector was lower than threshold for action and intermittent when he inspected the site. He believes the operator must have tightened the bottom and/or top of the separator diaphragms. The inspector agreed that the site deserves frequent inspections due to its proximity to the elementary school.

28.3 General Support or Opposition

The comments in this section are general comments that are being published here to recognize all input received by the EPA, but they are not being responded to individually. Some of the comments express general support for the proposed rule, and the EPA acknowledges the support of those commenters. Some comments generally indicate that the EPA should not finalize the rule as proposed and/or provide general suggestions for improvements to the proposal. To the extent that the comment letters also provide suggestions for improvements to specific calculation methodologies for specified source types, responses to those comments are provided either in the preamble to the final rule or elsewhere in this document. The last type of comments in this section are brief summaries of the commenter's more detailed comments. Responses to those detailed comments are provided either in the preamble to the final rule or elsewhere in this document.

Commenter: Differentiated Gas Coordinating Council (DGCC)
Comment Number: EPA-HQ-OAR-2023-0234-0187
Page(s): 1

Comment: We support EPA's efforts to enhance data transparency, broaden the scope of reported sources, and refine methodologies to ensure reported emissions are based on empirical data within these proposed amendments to the rule.

Commenter: Protect PT
Comment Number: EPA-HQ-OAR-2023-0234-0190
Page(s): 1-2

Comment: We support the rule as written, but we would also like to see the EPA incorporate the revisions suggested by the Environmental Defense Fund. The strongest possible version of this rule should be passed.

…

Abandoned wells are not the only sources of methane leaks. All gas infrastructure leaks to some extent, and industry standard operating practice is to ignore leaks that are deemed to be "insignificant".

Right now, my organization is doing air monitoring instead of the EPA or PA Department of Environmental Protection, DEP, handling it. These agencies are publicly charged with safeguarding public health, but both are falling short. We are an eight-person non-profit and cannot fill the gap left by a regulatory agency. You must step in and do this.

In Pennsylvania, we are granted the right to clean air and water under Article 1, Section 27 of the State Constitution. The State of Pennsylvania has not delivered on their obligations under our state constitution. While we recognize that EPA is a federal agency, because of the inaction and harmful actions of our state government, we must request that EPA take this small step toward filling the gap the state has left by passing these rules as proposed.

…

For the reasons enumerated, Protect PT supports the rule as written, and would be even more heartened to see the EPA incorporate the revisions suggested by the Environmental Defense Fund. We shouldn’t have to settle for “good enough”, and this rule can be made stronger by taking the EDF’s suggestions.

Please pass the strongest possible version of this rule.

Commenter: Peter Furcht
Comment Number: EPA-HQ-OAR-2023-0234-0191
Page(s): 1

Comment: I am … deeply concerned with the health of the global environment, with the extent to which human activities are disrupting the climate, and especially with the way the fossil fuel industrial complex continues exploiting both the environment and often marginalized populations and are still being given free passes to emit green house gas pollution without cost. This must stop, now.

Look, I’m not so naive that I think the fossil fuel industrial complex will or even should go away anytime soon. The truth is, we will need the industry for the foreseeable future. But not at any cost to humanity. It is well passed time for the fossil fuel industrial complex to stop behaving badly by denying climate disruption, by acting as if they are owed the right to discharge green house gas pollution without cost or concern, by operating as if the global environment is unaffected by their activities, by acting as if their profits are more important than the health of those living and working within the environment directly impacted by their activities, by acting as if they are being disadvantaged if their activities are not subsidized with free passes to emit green house gas and other pollutants into OUR environment.

If I could have my way, I would write these Greenhouse Gas Reporting rules to such an extent that the entire fossil fuel industrial complex is required, regardless of business size, profitability, product, segment, classification, you name it, to report every single GHG emission, anything bigger than an individual human’s flatulence, no other exceptions.

Yes, the first step in controlling emissions is to have complete and accurate reporting of all emissions and confirmation of the accuracy of said reports must be frequent, regular, and explicit. There must be significant and meaningful penalties for transgressions.

Of course, the industry is going to complain that it is too costly for them to produce these reports. Well, yes, that's right, there is a cost to emitting, they just haven't been paying those costs or had to pay for them. I have been paying that cost; my neighbors have been paying that cost; we are all paying that cost, for every emission. As such, we have the right to know who is doing the emitting and exactly how much they are emitting.

Yes, WE are all paying indirectly for these emissions with our healthcare expenses, with our increased costs for flood insurance, if we can get it anymore, with our air conditioning bills (if we can afford it) or with our discomfort and sleepless nights during longer and hotter summers, with our taxes for storm damage remediation and future storm and climate induced flooding prevention projects, with burning forests, rapidly increasing extinctions, and reduced opportunities for the pleasures brought on by the beauty of nature, and with our own anxiety as we contemplate the world our children and their children will be inheriting. This is so messed up. I don't even use a company's products yet I pay for their emissions. The fossil fuel industrial complex should be paying for emitting, directly, not us, the general population, indirectly. Get over it and start reporting, accurately.

And yes, once we have accurate reporting in place, legislators can implement various pay-to-emit programs and we can put all the cost of emitting, not just the cost for reporting on emitting, on the producers where the cost belongs.

On a side note, I am not so naive as to think that the industry will not pass these emission reporting costs and eventual pay-to-emit costs on to the consumer. Of course they will. They are still going to worship their profit gods. But now as consumers, we can choose how much and which products we buy and therefore we can control our costs related to emissions.

I fully support the EPA's new reporting rules and encourage the EPA to tighten them even further. Now is the time for drastic change and bold steps to prevent further climate damage.

Commenter: Physicians for Social Responsibility Pennsylvania (PSR)
Comment Number: EPA-HQ-OAR-2023-0234-0192
Page(s): 1-2

Comment: I ask that the following changes be finalized:

1. EPA proposes to require reporting of **large release events** defined as the emission events are currently not reflected in Subpart W reporting and can be large events, harming our health.

2. EPA move towards improved **updated emission factors** that will better capture intermittent emission and provide more accuracy for reporting

3. EPA will require operators to report higher emissions on **malfunctioning equipment** as subpart W does not accurately account for emissions from equipment malfunctions.

Commenter: Planetary Emissions Management Inc.
Comment Number: EPA-HQ-OAR-2023-0234-0194
Page(s): 1

Comment: PEM Inc. supports EPA's revisions to Subpart W-—particularly the focus on accuracy, empirical data, and direct measurement …

Commenter: Public Hearing Transcript
Comment Number: EPA-HQ-OAR-2023-0234-0224
Page(s): 9 (Edwin LeMair)

Comment: Avoiding the most catastrophic consequences of global warming requires limiting the world's temperature rise to 1.5 degrees Celsius. Doing so requires dramatically cutting greenhouse gas emissions. The GHGRP and Subpart W is a fundamental underpinning of U.S. climate policy. Understanding the sources of emissions is critical for informing approaches to mitigation. And ensuring the accuracy of information reported through the GHGRP is necessary for achieving the Biden administration's commitment to reducing domestic greenhouse gas emissions by 50 to 52% over 2005 levels by 2030. EDF strongly supports updates to Subpart W and we urge EPA to strengthen key provisions. In adopting the Methane Emission Program, Congress recognized the importance that accurate and empirically based methane reporting would have effectuating the methane waste emissions charge. That is because the waste charge is only assessed on methane emissions reported to EPA through Subpart W. If that reporting is not accurate and does not capture all of the emissions actually occurring, then the waste charge will not be as effective in incentivizing reductions as Congress intended. There are three components of the directive to update Subpart W included in Clean Air Act section 136(h). The first is that reporting be based on empirical data, the second is that reported emissions accurately reflect the total methane emissions from reporting facilities, and the third is that owners and operators of reporting facilities be allowed to submit data in a manner to be prescribed by EPA. EPA's proposed updates to Subpart W include important improvements to enhance the accuracy of reported emissions. These include the reporting of large release events and new emission factors based on recent measurement studies. We strongly support these updates.

Commenter: Public Hearing Transcript
Comment Number: EPA-HQ-OAR-2023-0234-0224
Page(s): 11-12 (Morgan King)

Comment: The West Virginia Rivers Coalition supports the EPA in proposing updates to Subpart W of the Greenhouse Gas Reporting Program. Including improvements to enhance the accuracy of reported emissions from the oil and gas industry. Cutting methane emissions and other greenhouse gas emissions within the oil and gas sector is the quickest and most impactful way to limit global warming, given how potent methane is as a greenhouse gas. … Because most operators calculate their emissions using EPA's default assumptions for pollution from different types of equipment, it's critical that these emission factors accurately reflect real pollution. We support EPA moving toward major equipment-based emissions factors that use recent real-world data adjusted for infrequent large emitters. These improved emission factors will better capture intermittent emissions and provide more accurate reporting for simplifying calculations. And finally, we support EPA's proposal for multiple changes that would require operators to report higher emissions when they discover malfunctioning equipment. … We urge EPA to finalize other improvements it's proposed to enhance the accuracy of emissions including requirements to report large release events and new emission factors based on recent measurement studies.

Commenter: Public Hearing Transcript
Comment Number: EPA-HQ-OAR-2023-0234-0224
Page(s): 15 (Jessica Moerman)

Comment: At EEN, we support the proposed changes to Subpart W for accounting for the reporting of large release events; the move towards major equipment-based emission factors that use real world data and adjusted for infrequent large emitters; and multiple changes that would require operators to report higher emissions when they discover malfunctioning equipment.

Commenter: Public Hearing Transcript
Comment Number: EPA-HQ-OAR-2023-0234-0224
Page(s): 16-17 (Luke Metzger)

Comment: Industry is the largest source of climate pollution in Texas with petroleum and natural gas systems making up about one fifth of reported industrial emissions. But the studies show, of course, that current emissions inventories are underestimating the methane pollution and the oil and gas companies know it. A report last year from the House Committee on Science, Space, and Technology found that the company's own internal data show that their methane emissions in the Permian Basin are likely significantly higher than official data. In particular, large release events which can make up most of total methane emissions are not currently reflected in Subpart W reporting. A 2021 survey of the -- aerial survey of the Permian conducted by Carbon Mapper found 533 methane super emitters. According to the Associated Press, one of those was the Mako compressor station which was observed releasing as much methane as the climate equivalent to burning seven tanker trucks full of gasoline every day, but the total reported emissions to the EPA in 2020 by the company that operates Mako from all of its boosting and gathering operations combined were just 1/12th of what Carbon Mapper documented billowing from that Mako site alone. So we strongly support EPA's proposed reporting updates, including requiring reporting of other large release events, updated emissions factors to accurately reflect real pollution, and changes that would require operators to report higher emissions when they discover malfunctioning equipment.

Commenter: Public Hearing Transcript
Comment Number: EPA-HQ-OAR-2023-0234-0224
Page(s): 20 (Antoinette Reyes)

Comment: I'm speaking today in support of the proposed changes to Subpart W of the Greenhouse Gas Reporting Rule.

Commenter: Public Hearing Transcript
Comment Number: EPA-HQ-OAR-2023-0234-0224
Page(s): 22 (Cyrus Reed)

Comment: Also as conservation director, I frequently advocate at the Texas legislature as well as state agencies like the railroad commission and TCEQ, and on the whole, our political leadership in Texas has not been supportive of more rigorous reporting or lower methane emissions which means this rulemaking is very important. So first, I want to thank you all for this very good proposal. We think it should be improved but there's a lot of good in this proposal. Here in Texas, we are the top oil and gas producer in the country. I can give you a bunch of statistics, but for a time, I won't. We also have lots of so-called orphaned and abandoned wells that are also likely leaking methane emissions. And we don't actually have an accurate way to know how much methane emissions there are. There's a lot of uncertainty as you know in reporting, and venting, flaring that's not correctly done, blowouts of fugitive emissions are very common here. We don't believe our regulators have done a good job to make sure they don't happen, and a number of studies other folks have mentioned have shown that methane emissions are likely much higher than what's been reported in the current Subpart W. So there are some aspects of this rule we very much support. As others have mentioned, we very much support the accounting for super emitting events, requiring reporting of other large release events, we think that's a good part of this rule. We appreciate the updated emission factors that we think will be more accurate to move towards equipment-based factors that use real world data adjusted for infrequent large emitters and obviously we support the equipment malfunctions and the multiple changes that you would have operators make to report higher emissions.

Commenter: Public Hearing Transcript
Comment Number: EPA-HQ-OAR-2023-0234-0224
Page(s): 23-24 (Camilla Fiebelman)

Comment: For our methane reductions efforts to work, we need to be sure that we're measuring the extraction correctly. That's especially true here in New Mexico where we're the second most prolific oil extractor in the country, and where our rural oil and gas extracting counties get D and F grades on ozone from the American Lung Association. In November of 2022, the publication Capital & Maine as reported by Jerry Redfern published that NASA's Jet Propulsion Labs ground scan camera found a massive methane leak from what appeared to be a gas well 10 miles southeast of Carlsbad, New Mexico with a plume extending two miles. But this wasn't even the express purpose of the camera or the project. The researcher described the methane results as a side effect or something that he could mine for the benefit of our communities, and yet caught the venting of more than 43,000 pounds of methane per hour. This is the type of event that we want to avoid, and that may make the totals that we see emitted quite inaccurate. So in summary on this rule, EPA's proposed updates to Subpart W of the Greenhouse Gas Reporting Program include improvements to enhance the accuracy of reported emissions from oil and gas industry, including requirements to report large release events and new emission factors based on recent measurement studies. … EPA should finalize other important improvements it has proposed to enhance the accuracy of reported emissions including requirements to report large release events and new emissions factors based on recent measurement studies. And I'll close by saying that, at least in New Mexico, the large majority of extraction is taking place on public lands, private industry is extracting publicly held resources off our public lands, and in many cases failing to truly report the cost and impact to our communities. I thank you for bringing that practice to an end, and I think you can do that by slightly improving this rule.

Commenter: Public Hearing Transcript
Comment Number: EPA-HQ-OAR-2023-0234-0224
Page(s): 24 (Joan Brown)

Comment: Regarding this issue of pollution, air pollution, oil and gas industry, methane, we have worked closely with those in those regions in our state but particularly in the Permian basin for over a decade. We're grateful for these rules, but we believe they need to be stronger to ensure that the emissions are based on real world measurements with correct data, and also that incidences of larger intermittent emissions need to be included.

Commenter: Public Hearing Transcript
Comment Number: EPA-HQ-OAR-2023-0234-0224
Page(s): 26 (Arthur Gershkoff)

Comment: I greatly appreciate and value these EPA regulations to promote obtaining accurate data and to develop strategies and incentives to reduce emissions over time.

Commenter: Public Hearing Transcript
Comment Number: EPA-HQ-OAR-2023-0234-0224
Page(s): 26 (Bill Midcap)

Comment: Rocky supports updated emission factors; most operators calculate their emissions using EPA's default assumptions for pollution from different types of equipment. This is critical that these emission factors accurately reflect real pollution.

Commenter: Public Hearing Transcript
Comment Number: EPA-HQ-OAR-2023-0234-0224
Page(s): 28 (Rebecca Edwards)

Comment: Subpart W of the Greenhouse Gas Reporting Program offers the public transparency on climate pollution from oil and gas facilities; however observational studies reveal that significant amounts of methane continue to be released without being included in Subpart W reporting. Accurately recorded emissions data is foundational for effective climate policy and environmental quality.

Commenter: Public Hearing Transcript
Comment Number: EPA-HQ-OAR-2023-0234-0224
Page(s): 30 (Ann McCartney)

Comment: I strongly encourage the EPA to strengthen the reporting requirements in the final rule you are considering, to improve the accuracy of reported emissions from the oil and gas industry. These are technical rules, but they have real life importance for our state and our country.

Commenter: Public Hearing Transcript
Comment Number: EPA-HQ-OAR-2023-0234-0224
Page(s): 30 (Marlene Perrotte)

Comment: I also support EPA's proposal to update emission factors. It is critical that these emission factors accurately reflect real pollution. This will better capture intermittent emissions and provide more accurate reporting.

Commenter: Public Hearing Transcript
Comment Number: EPA-HQ-OAR-2023-0234-0224
Page(s): 31-32 (Tracy Sabetta)

Comment: Grateful for EPA's proposed improvements to Subpart W of the Greenhouse Gas Reporting Program that would enhance the accuracy of reported emissions from the oil and gas industry, including requirements to report large release events and new emissions factors based on recent measurement studies. … We support the changes being proposed in the Greenhouse Gas Reporting Program, particularly those that ensure large release events are reflected in Subpart W. The movement toward major equipment-based emission factors that use real world recent data adjusted for infrequent large emitters, and changes that account for emissions from equipment failures and malfunctions. Subpart W of the Greenhouse Gas Reporting Program provides the public critical insight on climate pollution from oil and gas facilities. This reported emissions data is foundational for climate policy.

Commenter: Public Hearing Transcript
Comment Number: EPA-HQ-OAR-2023-0234-0224
Page(s): 33 (Margeret Bell)

Comment: I am grateful to the EPA for the changes you're making to Subpart W, and I support those changes which include large release events, emissions from malfunctioning equipment, and updated emission factors.

Commenter: Public Hearing Transcript
Comment Number: EPA-HQ-OAR-2023-0234-0224
Page(s): 34 (Dr. Dakota Raynes)

Comment: Congress directed the EPA to update Subpart W to ensure that reporting is based on empirical data and accurately reflects total methane emissions from applicable facilities. Hence, we are pleased that the EPA's proposed updates include a variety of improvements that could enhance the accuracy of reported emissions such as requirements to report large release events.

Commenter: Public Hearing Transcript
Comment Number: EPA-HQ-OAR-2023-0234-0224
Page(s): 37 (Sarah Bradley)

Comment: The EPA should also finalize other important improvements that it has proposed including requirements to report large release or super emitter events, using major equipment-based emission factors which use real world data will help with accurate reporting as well. Operators also need to be accountable for equipment malfunctions and report higher emissions when they know equipment is not working properly. While such rules may be technical, together they are part of life and death importance to our human communities and life everywhere.

Commenter: Public Hearing Transcript
Comment Number: EPA-HQ-OAR-2023-0234-0224
Page(s): 38 (Liz Scott)

Comment: The American Lung Association strongly supports accurate accounting of emissions. Under Subpart W of the Greenhouse Gas Reporting Program, owners and operators of certain oil and gas facilities are required to report annual methane emissions using various methods. Unfortunately, the methods used have been shown to underestimate the total emissions. Getting this part right is crucial to achieving the emissions reduction needed to stave off even more catastrophic impacts of climate change and at the same time to clear the air of the co-pollutants often leaking alongside methane. … Revising the requirements under Subpart W to ensure that the reporting accurately reflect the total methane emissions from facilities is necessary to set up further tactics and strategies to reduce those methane emissions. We support the proposed requirement to better report large intermittent emissions events. These events are currently not reflected in Subpart W reporting, and expanding the requirement for their inclusion will help capture some potentially large emission events that are being missed otherwise. We also strongly support the proposed changes to deal with malfunctions. When equipment malfunctions occur, it is likely that emissions levels will be higher and requiring operators to report those higher emissions will lead to more accurate emissions data gathering.

Commenter: Public Hearing Transcript
Comment Number: EPA-HQ-OAR-2023-0234-0224
Page(s): 39 (Kathryn Westman)

Comment: I testify as a registered nurse, as I call for tighter monitoring of the oil and gas industry, and call attention to the ongoing negative health effects of this industry. And as a grandmother of three children, as I call for leading a healthy and sustainable and equitable future for all children. Today I also speak as a person of faith, called to be a good steward of the Earth. I am a member of the southwest Pennsylvania Synod of the Evangelical Lutheran Church in America, Creation Care Team of Lampa, which is the Lutheran Advocacy Ministry in Pennsylvania, and also Interfaith Power and Light of Pennsylvania. From speaker group 3, Joan Brown highlighted many ethical and moral reasons that people of faith call to your attention, and I do too. The current calculations and reporting methods underestimate their total emission. Taking the liberty to misquote Greta Thunberg and Nero, I tell you, our house is on fire and we just keep fiddling. I appreciate and support the amendments, encourage making them even stronger. A speaker from group 1, Alice Lu, listed Clean Air Council's recommendations to strengthen the proposal. In the interest of time, I would like to say I fully support all of the suggestions of the Clean Air Council and believe they all must be implemented, as soon as possible.

Commenter: Public Hearing Transcript
Comment Number: EPA-HQ-OAR-2023-0234-0224
Page(s): 40 (Kayley Shoup)

Comment: I live in Carlsbad, New Mexico in the heart of the most active oil field in our country, the Permian basin. I often rear to the Permian as the wild, wild west because it's so vast and busy that oil companies can get away with breaking the rules quite easily, simply because there's no one there to call them out. Every time I drive out in the field, I'm reminded of the fact that we haven't even began to truly quantify the amount of methane pollution coming from my region. This is why I think that Subpart W of the Greenhouse Gas Reporting Program is absolutely crucial.

Commenter: Public Hearing Transcript
Comment Number: EPA-HQ-OAR-2023-0234-0224
Page(s): 43 (Etta Albright)

Comment: Thank you for what you do, and know that I support many organizations that are on the path to hopefully be able to contain global warming. We know we cannot stop it but we must do all we can to contain it, and we are all stakeholders. The industry is a stakeholder. We are, I especially, am very grateful for the comforts and pleasures and conveniences that have been provided me and afforded me throughout my lifetime, but that was without recognizing this consequence that we must face now collectively as global warming and climate change. It going to take many partnerships, and the public has to understand that. So all the information relevant to greenhouse gases, and that that is responsible for this condition, which we're all contributing to, must be made known, must be made public, and must seek the cooperation of the public to do their part.

Commenter: Public Hearing Transcript
Comment Number: EPA-HQ-OAR-2023-0234-0224
Page(s): 44 (Shanna Edberg)

Comment: We are grateful to the EPA for adding new reporting requirements for large release and super emitter events, updating emissions factors that will better capture intermittent emissions, and accounting for emissions from equipment failures and malfunctions. … It is really critical that oil and gas companies reported emissions reflect their actual real world pollution in order for us to address it. Our health is at risk and it will only worsen as emissions from oil and gas development continues. For that reason, we are urgently requesting the EPA to set a strong and comprehensive reporting rule without loopholes and allowances before our climate and our families run out of time.

Commenter: Public Hearing Transcript
Comment Number: EPA-HQ-OAR-2023-0234-0224
Page(s): 48-49 (Lisa Finley-DeVille)

Comment: Transparency and clear communications from industry to my community has never been good. So I am pleased to see some of the updates in this proposal. Anything that improves accuracy of information coming from industry regarding large releases and everyday emissions will be an improvement. … Changes I would like to see include EPA requiring reporting of other large release events, as these emissions are not reflected in Subpart W. I support EPA moving toward major equipment-based emission factors that use recent real world data adjusted for frequent large emitters. This would simplify an increased accuracy of the reporting. Finally I'd like to have the higher emissions due to malfunctioning equipment be required because currently Subpart W does not accurately account for emissions from equipment malfunctions or failures.

Commenter: Public Hearing Transcript
Comment Number: EPA-HQ-OAR-2023-0234-0224
Page(s): 50 (Christina Digiulio)

Comment: The issues we're supporting are actually the emissions must have -- emission factors have to have an empirical basis. Also the incidence of large emissions being included is, -- large events or super emitters can be a significant source of GHG-- will be required to be reported, that is something we are thankful for having as an addition.

Commenter: Public Hearing Transcript
Comment Number: EPA-HQ-OAR-2023-0234-0224
Page(s): 51 (Liz Anderson)

Comment: "We, at Dakota Resource Council, just installed air monitors within the boundaries of Fort Berthold and they are the first to go in within tens of miles, probably 50s of miles because the state and the federal government do not have any monitoring. And so this, to reduce emissions and to track what emissions industry is reporting to make sure that it's verified are really important tools. … I feel that the proposed updates to Subpart W are going to increase accuracy of the reported emissions and would include requirements to report large releases. That absolutely should happen and we know from imaging from airplanes and satellite that what is being reported by companies is an underestimation, and that just makes sense. They're not going to accurately report what they're emitting unless they have to. So I want to see these changes, and strict policies and guidelines for how they report it, how they're checked on, and what locations they're reporting from. … So I appreciate the accountability for super emitter events. It's a really important addition. They are not currently reflected, and a lot of them are really large, and basically go unnoticed by the public. The update of emission factors, industry can calculate their emissions using the default assumptions for pollution from different types of equipment, and it's critical that these emission factors accurately reflect real pollution, because that is what real people are really breathing. And this is all about the people. We need to move away from supporting industry and start supporting the health and well-being of the people directly affected. And frankly all of us are going to be affected by these greenhouse gases as climate change becomes more and more real. The proposal of multiple changes that would require operators to report higher emissions when they discover malfunctioning equipment such as a stuck dump valve or open hatches, that's important too, we support the changes because Subpart W does not currently address, as you know, doesn't address emissions from equipment failures and malfunctions. So I appreciate this effort. I think there are some good pieces and I look forward to seeing what the final rule is, and I just urge you all to keep people in proximity to these operations in the forefront of your mind as you're making these rules. "

Commenter: Public Hearing Transcript
Comment Number: EPA-HQ-OAR-2023-0234-0224
Page(s): 52 (Bill Sabey)

Comment: I fully support the rule improvements that tracking - that are proposed and in addition, I would like to see the Clean Air Council's recommendations included, and they have previously submitted those so I won't repeat them, but there were two additions to the rule they recommend and eight strengthening rule improvements.

Commenter: Public Hearing Transcript
Comment Number: EPA-HQ-OAR-2023-0234-0224
Page(s): 52 (Pattrice Tomcik)

Comment: I support the EPA's proposed updates to Subpart W of the Greenhouse Gas Reporting Program that would improve the tracking of greenhouse gas emissions from the oil and gas industry. … In summary, I support the EPA's proposed updates to Subpart W of the Greenhouse Gas Reporting Program that would improve the tracking in greenhouse gas emissions from the oil and gas industry.

Commenter: Public Hearing Transcript
Comment Number: EPA-HQ-OAR-2023-0234-0224
Page(s): 56 (Jozee Zuniga)

Comment: High oil export areas like the Permian basin could greatly benefit from the Greenhouse Gas Reporting Program. In Carlsbad alone, since the beginning of 2023, we have surpassed the nationwide limit for pollution multiple times over, meaning Carlsbad is an unsafe area for citizens with such high pollution levels. When we've seen from the various PFAS reports that these chemicals being released into our air are unsafe for citizens. Holding these companies accountable by reporting unsafe levels will keep New Mexicans and others living in front-line areas safe.

Commenter: Physicians for Social Responsibility Pennsylvania (PSR)
Comment Number: EPA-HQ-OAR-2023-0234-0226
Page(s): 1-2

Comment: We ask that the following changes be finalized:

1. EPA proposes to require reporting of **large release events** defined as the emission events are currently not reflected in Subpart W reporting and can be large events, harming our health.

2. EPA move towards improved **updated emission factors** that will better capture intermittent emission and provide more accuracy for reporting

3. EPA will require operators to report higher emissions on **malfunctioning equipment** as subpart W does not accurately account for emissions from equipment malfunctions.

Commenter: Ceres, Inc.
Comment Number: EPA-HQ-OAR-2023-0234-0236
Page(s): 2

Comment: As a result, Ceres supports EPA's proposed rule to ensure that reporting is based on real-world, empirical data, aligns with top-down aerial observations, and accurately and credibly reflects total methane emissions from oil and gas facilities. That way, EPA can address the well-known problem of underreported emissions. More accurate and empirically based reporting is also needed to ensure that the MERP's waste emissions charge is assessed on the industry's real-world pollution and leads to real-world emissions reduction and associated health outcomes. In addition, ensuring accuracy in reporting would equip investors with reliable data to better assess company-specific performance and methane-related risk across the entire industry, and to build investor confidence in such data by creating a centralized, government-run database. It would also ensure that U.S. companies can remain competitive in global markets, including export markets where methane is a growing concern.

Commenter: National Tribal Air Association (NTAA)
Comment Number: EPA-HQ-OAR-2023-0234-0239
Page(s): 3

Comment: The NTAA supports the EPA's current proposal updating the greenhouse gas reporting requirements for petroleum and natural gas systems.

As we have stated in the past, the EPA must recognize that its obligations with respect to measuring and controlling methane and other harmful pollutants from petroleum and natural gas systems must include assistance and resources, including funding, to Tribes, if they want it, to monitor emissions that impact Tribal lands and Tribal members. Additionally, with respect to any Tribe that is subject to the GHGRP, the EPA should continue its work to promote ease of implementation.

We commend EPA's proposed requirements to address the important task of measuring (and regulating) waste emissions, including from equipment malfunction. We also applaud the EPA's proposal to include emissions from "other large release events" to capture large emissions events and super-emitters in the subpart W reporting program. The NTAA also supports the EPA's decision to require emitters to use EPA or third-party notifications of potential super-emitter emissions events as a trigger to calculate and report emissions from those events if they are not already accounted for. As noted in our February 13, 2023, letter on the proposed New Source Performance Standards for the oil and natural gas operations, the NTAA strongly supports the EPA's Super Emitter Response Program to address super-emitter events through third-party monitoring.

Commenter: Kairos Aerospace
Comment Number: EPA-HQ-OAR-2023-0234-0240
Page(s): 2, 16

Comment: Executive Summary

Kairos supports the incorporation of measurement data into EPA's Greenhouse Gas Reporting Program (GHGRP) to better understand the sources and amounts of greenhouse gas emissions from the oil and natural gas sector. A variety of highly effective, low cost methane measurement solutions are commercially available today that can help facility owners and EPA quantify methane emissions from a range of sources.

Peer-reviewed scientific studies examining large-scale measurement campaigns of methane emissions from the oil and gas sector have identified discrepancies between calculated emissions under the GHGRP and measurement campaign results.3,4,5 In some instances, measured total emissions may be 6.5 times higher than reported EPA Inventory emissions.6 And while the inventory often fails to capture the magnitude of total emissions, it also does not necessarily accurately represent where emissions are coming from either. In many cases, measured emissions from particular source categories may be substantially different from emission factor-based calculations.7

Relying on widespread, high-quality measurement data will drastically improve the accuracy of EPA's Inventory, which in turn will lead to better policy outcomes. We do have several recommendations for EPA to consider, which we believe will further improve the quality of data collected under the GHGRP.

…

At a high level, the Proposed Rule will more directly incorporate empirical data and methane measurement into the Greenhouse Gas Reporting Program. We see this as an important step to satisfying Congressional intent in the Inflation Reduction Act. It is also realistic and feasible, as measurement technology has evolved rapidly and is already being deployed at scale across the oil and natural gas industry today. This next generation of methane measurement tools are capable of greatly enhancing our understanding of methane emissions in the field, which often appear quite different from the current Greenhouse Gas Inventory.

Footnotes:

[3] Daniel H. Cusworth, Riley M. Duren, Andrew K. Thorpe, Winston Olson-Duvall, Joseph Heckler, John W. Chapman, Michael L. Eastwood, Mark C. Helmlinger, Robert O. Green, Gregory P. Asner, Philip E. Dennison, and Charles E. Miller 2021. Intermittency of Large Methane Emitters in the Permian Basin. Environ. Sci. Technol. Lett. 2021, 8, 7, 567–573 https://pubs.acs.org/doi/10.1021/acs.estlett.1c00173 ("Cusworth et al. 2021")

[4] Sherwin et al. "Quantifying oil and natural gas system emissions using one million aerial site measurements" https://www.researchsquare.com/article/rs-2406848/v1 2023 In Revision.

[5] Chen et al. 2022

[6] Id.

[7] Johnson, M.R., Conrad, B.M. & Tyner, D.R. Creating measurement-based oil and gas sector methane inventories using source-resolved aerial surveys. Commun Earth Environ 4, 139 (2023). https://doi.org/10.1038/s43247-023-00769-7

Commenter: Interfaith Center on Corporate Responsibility (ICCR)
Comment Number: EPA-HQ-OAR-2023-0234-0242
Page(s): 1, 2, 3

Comment: We support the agency's efforts to update the methane reporting protocols to ensure reporting is based on real -world empirical data and accurately reflects total oil and gas emissions, but we would argue that more can be done to improve the proposal.

…

We support EPA's proposed rule to ensure that reporting is based on empirical data and accurately reflects total methane emissions from oil and gas facilities. By updating these protocols so reporting is based on real-world empirical data and aligns with top-down aerial observations, EPA can address the well-known problem of underreported emissions. More accurate and empirically based reporting is also needed to ensure that the MERP's waste emissions charge is assessed on the industry's real-world pollution, and to equip investors with reliable data to better assess company-specific performance and methane-related risk across the entire industry. The costs to improve the accuracy of reporting are reasonable, especially when balanced with the considerable benefits to policy making, transparency and market efficiency resulting from improved monitoring and reporting.

Ensuring accuracy in reporting would have the added benefits of building investor confidence by creating transparency around companies' emissions performance through a centralized, government-run database and by ensuring that U.S. companies can remain competitive in global markets.

…

EPA's proposal can set a standard reporting structure across the industry, which will provide long-term certainty, improve data quality, and help to mitigate climate and transition-related risks for investors. We encourage your agency to move swiftly to finalize the proposed rule.

Commenter: Jesse Crouse
Comment Number: EPA-HQ-OAR-2023-0234-0249
Page(s): 1

Comment: The oil and Gas industry should be held to the highest standards in the GHG reporting.

Commenter: Lucyna de Barbaro
Comment Number: EPA-HQ-OAR-2023-0234-0291
Page(s): 1

Comment: I am a long-time environmentalist and a Ph.D. in physics recipient. Since my time in academia, in the nineties, I have followed climate science and, over time, felt a growing despair over how little our government and society is doing to curb global warming emissions. Thank you for this effort to strengthen the GHG reporting regulation. I strongly support the following parts of the proposal and urge EPA to maintain them in the final rule:

- Requirements for air pollution inspections at all gas wells, regardless of size.

- Requirements for air pollution inspections until a gas well is plugged, which will address the pervasive threat of abandoned gas wells constantly leaking pollution across the country

- The zero emission standards for several types of oil and gas equipment.

I urge the U.S. Environmental Protection Agency to strengthen the rules by:

- Eliminate all pollution from routine flaring (burning of excess gas).

- Reducing emissions from storage tanks by making the standards apply to more tanks.

Commenter: Sensirion Connected Solutions
Comment Number: EPA-HQ-OAR-2023-0234-0293
Page(s): 1-2

Comment: Sensirion Connected Solutions Inc. (SCS), appreciates the actions and effort put forth by the Environmental Protection Agency (EPA or "the Agency") in proposing updates to the requirements of the Greenhouse Gas Reporting Program (GHGRP) for the petroleum and natural gas systems source category (hereafter referred to as "Subpart W") to ensure that Subpart W reporting is based on empirical data and accurately reflects the total methane emissions from the applicable facilities, and to allow operators the option of using empirical emissions data to demonstrate the amount of Methane Waste Emissions Charge to be paid in accordance with Clean Air Act (CAA) section 136.

SCS has several concerns that will prevent the Agency from achieving their goal of reducing methane emissions and stifle innovation in the energy sector through the usage of advanced alternative technologies – particularly, continuous monitoring technologies - slowing down the positive impact potential to the environment. This effect can impact current investments both by operators in the space as well as technology enablers such as SCS by several years that we cannot afford to incur as a planet.

The Inflation Reduction Act (IRA) demonstrated the importance felt by Congress to enable technologies such as continuous monitoring, in the space to unlock a new era of BESR practices (section 136). This would enable the needed usage of "empirical" methods that bring down methane emissions at a steeper curve proven through scientific and academic studies. SCS did not see this in the Proposed Rule nor a framework for how any advanced measurement technology could be brought forward to approval. A discrepancy such as this between the Proposed Rule and the IRA would render the final rule vulnerable to legal enforcement. SCS does not want the actions of the EPA to result in a disconnect preventing the ultimate goal of methane emissions reductions. For these reasons, SCS strongly urges the EPA to consider its position on the benefit and usage of advanced alternative technologies.

Commenter: American Exploration and Production Council
Comment Number: EPA-HQ-OAR-2023-0234-0295
Page(s): 1

Comment: AXPC appreciates EPA's efforts to update quantification methodologies and emission factors in an attempt to improve the accuracy and completeness of GHG emissions reports for the oil and gas sector and is cognizant of the Agency's directive from Congress under the Inflation Reduction Act (IRA) to revise Subpart W to ensure that reporting (and associated calculation of waste emission charges) is based on empirical data. A highly credible, robust GHG inventory set forth by Subpart W is in the best interest of our business and all our stakeholders, and we appreciate the opportunity to collaborate with the EPA to refine the calculation, estimation, and measurement methodologies set forth by Subpart W.

To the extent that the IRA mandate states that EPA shall revise Subpart W to ensure the reporting is "based on empirical data… (and) accurately reflect(s) the total methane emissions … from the applicable facilities", AXPC has significant concerns with many aspects of the proposed changes which do not align with that directive.

Further, the proposed changes would introduce additional complexity in terms of the calculation methodology hierarchy, with significantly more onerous measurement requirements for certain source categories. Not only will the cost of compliance be substantial, but because many aspects of the Proposal either overlap or are contradictory to requirements of the pending proposed NSPS Subpart OOOOb/c regulations, operators are faced with regulatory uncertainty and ambiguity, leading to significant business risk.

With Subpart W playing an integral role in determining a company's waste methane emissions charge liabilities, it is imperative that the final rule be clearly written and aligned with best industry operating practices as well as EPA's (and Congress's) intent to minimize and reduce methane emissions.

AXPC is providing detailed comments in the attachment that expands on these general themes as well as many other matters. AXPC appreciates the opportunity to provide these comments and looks forward to working with EPA in its continued development of these rules.

Commenter: Anonymous
Comment Number: EPA-HQ-OAR-2023-0234-0296
Page(s): 1

Comment: I appreciate the attention directed towards the proposed changes in subpart W. The aim is to capture all of the methane emissions, especially considering significant emission sources currently without estimation methods or reporting requirements within 40 CFR Part 98. Including the "other large release events" category is a good idea, helping to note unexpected things like well blowouts and other large, atypical release events. I value the commitment to the accuracy using real measurements, engineering estimates, or other available best data. Introducing calculation methodologies and stipulating requirements to report GHG emissions from new sources, including nitrogen removal units, highlights the thoroughness of this approach. The revisions in calculating combustion emissions, notably for components like RICE and gas turbines, reflect a determination to enhance precision. By looking at more parts of the industry, this rule is aiming to cover all the bases. I really value the hard work in making sure we know about all major methane sources.

Commenter: National Association of Manufacturers (NAM)
Comment Number: EPA-HQ-OAR-2023-0234-0297
Page(s): 1-2

Comment: Petroleum and natural gas make up over two thirds of power generated in the U.S. according to the Energy Information Administration.[1] Manufacturers rely on dependable and stable power delivery for everyday operations. The EPA's targeting of petroleum and natural gas industries could jeopardize two of the major sources that U.S. businesses and manufacturers rely on.

Technical and Economic Feasibility

As has been the case with other recent EPA regulatory proposals, this proposed rule would set standards for petroleum and natural gas production that are neither technically nor economically feasible. Rather than engage with manufacturers and industry, the EPA has again proposed standards for unachievable efficiency standards with no acknowledgment of economic impact. The cascading impact of jeopardizing the production of two critical power-source fuels into the gaps and lapses of power production and transmission are absent from the EPA's analysis and proposal. The EPA should acknowledge the criticality of all fuel and energy sources, including petroleum and natural gas, and pursue emissions and efficiency standards that promote all-of-the-above energies that are economically and technically reachable.

Conclusion

Manufacturers are committed to being excellent environmental stewards, creating well-paying jobs and improving the quality of life for everyone. Our industry is prepared to work closely with the EPA on emission and efficiency standards to ensure there are not gaps or lapses in energy supply.

Footnote:

[1] https://www.eia.gov/energyexplained/us-energy-facts/#:~:text=U.S.%20total%20annual%20energy%20production,primary%20energy%20production%20in%202022.

Commenter: GPA Midstream Association
Comment Number: EPA-HQ-OAR-2023-0234-0299
Page(s): 16-17

Comment: GPA supports many of EPA's proposed changes to the GHGRP.

GPA has worked extensively with EPA over the years on potential revisions to the GHGRP, and GPA appreciates that a significant number of the changes EPA has proposed reflect approaches consistent with positions for which GPA has advocated technical data and other information GPA has developed and supplied to EPA. GPA is pleased to have been a part of this productive process and encourages EPA to finalize those provisions, consistent with these comments, that GPA believes will provide for a more effective and efficient GHGRP.

Commenter: Lee Schondorf
Comment Number: EPA-HQ-OAR-2023-0234-0300
Page(s): 1

Comment: Please strengthen monitoring and penalties for greenhouse gas emissions!

Commenter: Carbon Mapper and RMI
Comment Number: EPA-HQ-OAR-2023-0234-0301
Page(s): 3

Comment: We support EPA's updates to the major equipment-based emission factors, based on more recent, real-world data. Updated emission factors are based on approximately 3,700 direct measurements from peer-reviewed research, Rutherford et al. (2021). EPA should finalize these emission factors and establish a process to periodically update default emission factors, using newly published empirical data. We also support EPA's proposed changes to better account for equipment malfunctions that result in higher emissions, such as combustion slips, open thief hatches, and stuck dump valves.

Commenter: American Lung Association
Comment Number: EPA-HQ-OAR-2023-0234-0335
Page(s): 1

Comment: The American Lung Association strongly supports accurate accounting of emissions. We also support the proposed changes to deal with malfunctions and the proposed requirement to better report large intermittent emissions events.

Commenter: Independent Petroleum Association of New Mexico (IPANM)
Comment Number: EPA-HQ-OAR-2023-0234-0337
Page(s): 1-2

Comment: We support EPA's efforts that lead to responsible, balanced regulations that protect the environment and human health while also supporting the safe extraction of the abundant oil and gas resources on federal lands in New Mexico.

The EPA in the Proposed Rule explains it is amending the petroleum and natural gas system source category requirements of the Greenhouse Gas Reporting Rule "to ensure that reporting is based on empirical data, accurately reflects the methane emissions and waste emissions from applicable facilities, and allows owners and operators of applicable facilities to submit empirical emissions data that appropriately demonstrate the extent to which a charge is due." Proposed Rule, 88 Federal Register 50282. While we share EPA's goal to report empirical emissions data, based on our experience we believe that some of the new requirements will result in inaccurate results, conflict with existing regulations or impose too great a burden on New Mexico oil and gas operators. As EPA appreciates, onshore oil and gas production in states like New Mexico occurs over vast areas, far from population centers and in many cases without infrastructure like electricity. IPANM has specific concerns about the Proposed Rule requirements for pneumatic devices; pneumatic pumps; tanks; flares; reciprocating compressors; equipment leaks; and large release events that are detailed below. We appreciate the opportunity to comment on the Proposed Rule.

Commenter: Antero Midstream Corporation
Comment Number: EPA-HQ-OAR-2023-0234-0338
Page(s): 3

Comment: Antero supports and appreciates EPA' s efforts to increase the reliability of greenhouse gas reporting under Subpart W. Antero appreciates EPA's consideration of its comments on the Proposed Rule as part of these efforts.

Commenter: Enerplus Resources (USA) Corporation
Comment Number: EPA-HQ-OAR-2023-0234-0342
Page(s): 1

Comment: Enerplus Resources (USA) Corporation (Enerplus) submits the following comments on the Environmental Protection Agency's (EPA) proposed rules to Subpart W of the Greenhouse Gas Reporting Rule for Petroleum and Natural Gas Systems published on August 1, 2023 (88 Fed. Reg. 50,282). Enerplus is focused on reducing greenhouse gas emissions (GHGs) from our operations and supports effective and reasonable revisions to the Greenhouse Gas Reporting Rule that balance the goal of improving the completeness and accuracy of GHG reports without imposing significant additional burden on reporters for minimal value. To that end, Enerplus is in favor of revisions to Subpart W that allow operators to use empirical data and credible information to estimate GHG emissions wherever such data is available. Finally, given the interrelatedness of this rulemaking with other substantial pending rules impacting the industry (i.e., NSPS Subparts OOOOb/c, IRA, PHMSA Pipes Act), Enerplus urges EPA to seek alignment of the final Subpart W language with key impactful elements of those rules (e.g., definitions, monitoring requirements, and measurement methods) in order to minimize ambiguity, avoid conflicting requirements, and reduce the cost and complexity of compliance for operators. We believe this alignment is necessary to ensure that the final rule does not have the unintended consequences of disincentivizing operators from employing the best practices and latest technology to minimize, measure, and monitor GHG emissions.

Commenter: Permian Basin Petroleum Association (PBPA)
Comment Number: EPA-HQ-OAR-2023-0234-0346
Page(s): 2-3

Comment: Perhaps most troubling is that the proposed rule, regardless of what operation it applies, is based on faulty, and scientifically flawed, modeling, data, and analysis that will fail to achieve its intended purpose, with no benefit to the environment and the economy. Therefore, the rule should be withdrawn and revised to ensure it conforms to the IRA related provisions and the intent of Congress.

As expressed in the proposal, EPA's aim is "to ensure that reporting is based on empirical data, accurately reflects total methane emissions and waste emissions from applicable facilities, and allows owners and operators of applicable facilities to submit empirical emissions data that appropriately demonstrated the extent to which a charge is owed."1 PBPA supports that aim. After all, reported emissions will drive the magnitude of our members' methane fees. But if finalized as proposed, EPA would instead compel reporting of unrealistic, inflated emission totals through (a) disincentivizing use of monitoring technologies and (b) imposition of unrealistic emission factors.

A defensible reporting rule must incent the use of proven monitoring technologies. Throughout the proposal, EPA links revisions to those proposed for NSPS OOOOb and EG OOOOc. But while EPA's OOOOb/c (and state analogs) incorporate use of monitoring technology, this proposal does not. EPA's proposal, if finalized, would actually deter oil and gas companies from investing in the types of technologies that produce more empirical data.

Also, a defensible reporting rule must not compel the use of unrealistic emission factors or default emission durations where actual data exists. For instance, the proposal arbitrarily assigns an assumed 92% destruction removal efficiency to unmonitored flares—the same efficiency assumed for explosion-related combustion. And as a general matter, EPA's proposed emission factors do not account for the variability that exists in source-level emissions based on differences in operations, basins, and industry sectors. Unrealistic assumptions beget unrealistic emissions reporting.

These two defects alone will result in reporting of unrealistic, inflated emission totals. That not only counters EPA's express aim, but it also would significantly impact PBPA members both in terms of reputation (through unrealistic yet publicly-disclosed emissions data) and finances (through inflating methane fees). Indeed, a PBPA member compared emissions totals as calculated under the existing rule to those calculated under the proposal, and reports that leak emissions would increase total company methane emissions by 240%. On its face, that level of variability reflects arbitrary defects in the proposal.

PBPA appreciates this opportunity to comment on EPA's proposal. These and other comments are further detailed below. To better align with EPA's expressed aim and to address these material defects, PBPA requests that the EPA revise the proposal as described to ensure that reporting is based on empirical data that reflects actual methane emissions.

Footnote:

[1] Proposed Rule at 50282.

Commenter: California State Teachers' Retirement System CalSTRS
Comment Number: EPA-HQ-OAR-2023-0234-0347
Page(s): 1-2, 3

Comment: <u>We support the agency's efforts to update the methane reporting protocols to ensure reporting is based on real-world empirical data and accurately reflects total oil and gas emissions.</u>

…

Addressing methane emissions from oil & gas operations is one of the fastest, most cost-effective means of limiting global warming. These emissions also represent wasted natural resources, safety and reputational risks, and a failure to monetize a product that would otherwise add value to oil & gas companies in our portfolio.

However, you can't manage what you don't measure. We support the EPA's proposed rule to ensure that reporting is based on empirical data and accurately reflects total methane emissions from oil and gas facilities. By updating the methane reporting protocols, the EPA can address the well-known problem of underreported emissions.

More accurate and empirically based reporting is also needed to ensure that the MERP's waste emissions charge is assessed on the industry's real world emissions, and to equip investors with reliable data to better assess company-specific performance and methane-related risk across the industry.

Ensuring accuracy in reporting would have the added benefits of building investor confidence by creating transparency around companies' emissions performance through a centralized government-run database, and support the competitiveness of U.S. companies in global export markets.

…

The EPA's proposal can set a standard reporting structure across the industry, which will provide long-term certainty, improve data quality, and help to mitigate climate and transition-related risks for investors. We encourage the Agency to move swiftly to finalize the proposed rule.

Commenter: Project Canary, PBC
Comment Number: EPA-HQ-OAR-2023-0234-0348
Page(s): 1

Comment: Project Canary, PBC ("Project Canary"), appreciates the Environmental Protection Agency (EPA or "the Agency") the proposed revisions to the requirements of the Greenhouse Gas Reporting Program (GHGRP) for the petroleum and natural gas systems source category (hereafter referred to as "Subpart W") to ensure that Subpart W reporting is based on empirical data and accurately reflects 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 to demonstrate the extent to which a Methane Waste Emissions Charge is owed under Clean Air Act (CAA) Section 136.1

However, Project Canary has significant concerns about the Proposed Rule.

Commenter: Taxpayers for Common Sense (TCS)
Comment Number: EPA-HQ-OAR-2023-0234-0351
Page(s): 1-3, 6

Comment: TCS supports EPA's proposed rule designed to fill existing gaps in the current Greenhouse Gas Reporting Rule (40 CFR 98, subpart W). Increasing the quantity and quality of greenhouse gas (GHG) emissions data reported to EPA benefits taxpayers. Greenhouse gas emissions intensify the increasingly frequent and destructive effects of climate change felt by American taxpayers. The emissions of private companies have a direct impact on taxpayers and the federal budget. Moreover, private companies often receive public funds through federal subsidies and contracts, so taxpayers have a right to know how their tax dollars may be supporting actions that exacerbate the taxpayer costs of climate change and create long-term liabilities.

This rule is also an important part of the greater Methane Emission Reduction Program (MERP), or section 136 of the Clean Air Act established by the Inflation Reduction Act. Accurate GHG emissions data are necessary for successful application of the methane waste emissions charge.

Methane Waste Costs Taxpayers

Methane, the primary component of unprocessed natural gas, is 80 times more potent than CO2 during its first 20 years in the atmosphere. The Intergovernmental Panel on Climate Change (IPCC) has stressed that strong, swift, and sustained methane reductions are critical to mitigating near-term climate disruptions and to complementing reductions in other GHGs to limit the severity of climate change and its destructive impacts. 1

These destructive impacts include enormous immediate costs and growing future liabilities for taxpayers. Federal emergency spending must address immediate and future costs of climate-induced extreme weather events. The National Oceanic and Atmospheric Administration (NOAA) reports that natural disasters are increasing in number and are becoming more costly, with a record number of billion-dollar weather-related disasters occurring in 2020. 2 Over the past five years, taxpayers have borne an average annual cost of approximately $62 billion (about $190 per person in the U.S.), a 35 percent increase over the preceding five-year average, for various programs aimed at combating and mitigating climate impacts. 3

Natural gas and petroleum systems account for 32 percent of all U.S. emissions in 2020, according to the EPA U.S. Greenhouse Gas Inventory data.4 The oil and gas sector is the largest industrial source of methane emissions in the U.S., discharging an estimated 403.4 billion cubic feet (bcf) of methane in 2021 through venting, flaring, and leaks.5 This lost gas could have powered 4.3 million households for a year and, according to EPA estimates, represents a potential industry loss of over $871 million. 6

In addition to the climate costs of GHG emissions, gas waste also poses financial losses for taxpayers and consumers when it is not captured and sold. For gas released from federal lands, the absence of clear guidelines on when royalties should be applied results in lost revenue for taxpayers. Using Oil and Gas Operations Report (OGOR-B) data, TCS found that 300 billion cubic feet (Bcf) of natural gas was wasted on federal lands alone from FY2012 to FY2021. Taxpayers should have received $119 million in royalties at a rate of 12.5 percent. Instead, the Office of Natural Resources Revenue (ONRR) reported collecting only $43 million in royalties on vented or flared gas over the decade, approximately one-third of the potential royalties.7 These estimates are likely conservative, as OGOR-B data relies on self-reporting from operators and there is little or no incentive for operators to estimate the volume of lost gas accurately given the limited oversight by the Department of the Interior (DOI).

Using satellite data on top of production data, another study commissioned by Environmental Defense Fund and TCS calculated that approximately 163 Bcf of natural gas was lost on federal and tribal lands in 2019 alone, far more than the operator self-reported volume. This wasted gas was worth roughly $509 million and could have met the annual energy needs of 2.2 million households.8 The wasted gas also represented a combined loss of $64 million in federal, tribal, and state royalty revenues.

Public Accessibility of Emissions Data Must be Improved

The proposed rule would greatly increase the quality and quantity of data available to the public on GHG emissions from the oil and gas sector. TCS supports EPA's efforts to increase the frequency and level of detail included in monitoring and measuring requirements, in addition to expanding the types of sources covered under the GHG Reporting Rule.

Increasing the amount and breadth of data available on GHG emissions in the oil and gas sector is advantageous to taxpayers. The decisions of private companies affect taxpayers, as these firms benefit from public subsidies, execute federally funded projects, and create financial liabilities that may strain public finances. Consequently, taxpayers have a vested interest in information about the operations of private companies, particularly those activities contributing to climate change, such as greenhouse gas emissions.

Improving the quality and quantity of publicly accessible data on GHG emissions will deepen the public's understanding of how companies and entire industries contribute to climate change. This enhanced understanding will enable better tracking of how firms receiving federal funding contribute to climate-related costs borne by taxpayers. Armed with knowledge of who contributes to climate change, policymakers can work to ensure that the responsible parties, rather than taxpayers, bear the costs of their impacts on communities and individuals.

…

Conclusion

The proposed rule would improve transparency and accountability in the oil and gas sector by improving both the quantity and quality of publicly accessible GHG emissions data. These emissions directly impact taxpayers and contribute to the rising taxpayer costs associated with climate change. Increasing the availability of data on GHG emissions will improve the public's understanding of the processes and policies driving climate change and better inform decisions that ensure emitters, not taxpayers, are accountable for the long-term costs and liabilities created through GHG emissions.

Footnotes:

[1] IPCC, "Climate change widespread, rapid, and intensifying – IPCC," August 9, 2021. https://www.ipcc.ch/2021/08/09/ar6-wg1- 20210809-pr/

[2] NOAA National Centers for Environmental Information (NCEI) U.S. Billion-Dollar Weather and Climate Disasters (2023). https://www.ncei.noaa.gov/access/billions/

[3] TCS, "Paying the Price," June 7, 2023. https://www.taxpayer.net/climate/paying-the-price/

[4] EPA, U.S. Greenhouse Gas Inventory Data Explorer, https://cfpub.epa.gov/ghgdata/inventoryexplorer/#energy/naturalgasandpetroleumsystems/allgas/gas/all

[5] EPA, "Greenhouse Gas Reporting Rule: Revisions and Confidentiality Determinations for Petroleum and Natural Gas Systems," 88 FR 50282 (proposed August 1, 2023) https://www.federalregister.gov/d/2023-14338/p-752

[6] EPA, Greenhouse Gas Equivalencies Calculator, https://www.epa.gov/energy/greenhouse-gas-equivalencies-calculator

[7] TCS, “Gas Giveaways II,” Aug 30, 2022. https://www.taxpayer.net/energy-natural-resources/gas-giveaways-ii-methane-wasteon-federal-lands-is-business-as-usual/

[8] Olivia Griot et. al., “Onshore Natural Gas Operations On Federal and Tribal Lands in the United States: Analysis of Emissions and Lost Revenue,” Jan. 20, 2023. (”Synapse”) htps://blogs.edf.org/energyexchange/files/2023/01/EMBARGOED_EDFTCS_Public_Lands_Analysis.pdf

Commenter: Devon Energy
Comment Number: EPA-HQ-OAR-2023-0234-0360
Page(s): 1-2

Comment: Devon believes a meaningful reduction in methane and greenhouse gas (GHG) emissions is central to managing climate-related risks and opportunities and has taken a comprehensive approach to mitigate methane and GHG emissions across its operations.

…

Devon supports a path toward a legally durable and effective framework for regulating and reporting methane and GHG emissions that encourages innovation and operational flexibility and supports revisions to Subpart W to the extent those revisions incentivize and afford the ability to accurately characterize the actual methane and GHG emissions emitted to the atmosphere.

However, without key changes as outlined below, Devon is concerned that these revisions will not result in more accurate reporting by limiting the use of empirical data, disincentivizing the use of advanced methane detection technologies, and improperly defining industry segment boundaries, all of which could unfairly penalize operators since reporting under Subpart W is used to determine the charge owed under the forthcoming Methane Emissions Reduction Program (MERP).

Commenter: Encino Environmental Services
Comment Number: EPA-HQ-OAR-2023-0234-0364
Page(s): 2-3

Comment: Encino agrees with the EPA on the decision to include in this proposed Subpart W revision the OGI-based monitoring method proposed in Appendix K of the NSPS OOOOb and EG OOOOc proposed rule. This will effectively streamline the processes and allow reporters to comply with the proposed subpart W requirement by means of utilizing data derived from NSPS OOOOb surveys.

Encino acknowledges that concurrent proposed rules by other federal agencies incorporate the newest monitoring technologies. Some of these new advanced technologies allow for the identification, localization, and quantification of each individual leak. Optical gas imaging (OGI) cameras and continuous emission monitoring systems (CEMS) now provide accurate quantification at ground level. Some satellite systems not only have the advantage of frequent revisitations but allow for source allocation and quantification of larger leaks along the extents of pipelines and oil and gas infrastructure. Hence, Encino applauds the inclusion of advanced measurement technologies, as well as the recognition that those technologies will not be a replacement for other calculation methodologies.

Encino recognizes that this proposed rule is relevant due to its expanding approach on measurement and on empirical data to provide more representative inventories. This will allow greater granularity across supply chains since emissions now will be reported at individual facility level. In addition, this proposed rule aims to improve inventory estimates by including data from super emission events, reducing the bias towards underestimation of the emissions.

Commenter: Anonymous
Comment Number: EPA-HQ-OAR-2023-0234-0366
Page(s): 1

Comment: EPA is improving the consistency in calculation methods for emissions to the atmosphere and those “routed to flares, combustion, or vapor recovery systems,” which is good. However, there are a few places that still need to be updated.

Commenter: Damascus Citizens for Sustainability
Comment Number: EPA-HQ-OAR-2023-0234-0368
Page(s): 1

Comment: We, Damascus Citizens for Sustainability (DCS), a PA-NY-Delaware River basin non-profit organization, founded in 2008 to fight oil gas drilling, pollution, etc has had a vital interest in GHG tracking and reporting for all our existence. We strongly support the U.S. Environmental Protection Agency’s (EPA’s) proposed edits to Subpart W of the Greenhouse Gas (GHG) Reporting Rule that include improvements for tracking GHG emissions from the oil and gas industry. It is very good that this amendment would add requirements to report emissions from previously-excluded GHG sources, update calculation methods for total emissions based on empirical data, and verify facilities’ reported emissions. The global climate disintegration, fueled by both advancing levels of atmospheric carbon and destructive land use policies, has reached levels of unpredictability, of horror and terror for human and all the other world inhabitants that not acting to further control emissions becomes criminal.

Commenter: Evangelical Environmental Network (EEN)
Comment Number: EPA-HQ-OAR-2023-0234-0371
Page(s): 2

Comment: We support the proposed changes to Subpart W for accounting for super-emitting events and the reporting of "other large release events," the move towards major equipment-based emission factors that use recent real-world data adjusted for infrequent large emitters, and multiple changes that would require operators to report higher emissions when they discover malfunctioning equipment.

Commenter: EOS at Federated Hermes Limited (EOS) (United Kingdom)
Comment Number: EPA-HQ-OAR-2023-0234-0372
Page(s): 1-2

Comment: We support the agency's efforts to update GHGRP Subpart W's methane reporting protocols to ensure reporting more accurately depicts company-specific and total oil and gas sector methane emissions that will become the basis of MERP-mandated methane fee assessments that will be detailed in a separate regulation to be proposed at a later date.

…

We commend your agency's efforts to improve methane emissions reporting accuracy. We believe that better reporting will not only equip investors with higher-quality data to assess company-specific performance and material financial risks including from the methane fee but will also point companies to economic opportunities to reduce methane emissions, enhance the US oil and gas sector's global competitiveness and resultant economic and geopolitical benefits, and help mitigate health, safety, and environmental concerns.

We express support for the EPA to continue to work with the oil and gas sector, the largest industrial source of methane emissions, and to develop a final rule that carefully considers the cost of any reporting obligations to ensure that the US industry is able to meet customer demands in an economically viable fashion, particularly as customers in Europe and Asia seek alternatives to Russian supply following its invasion of Ukraine; these same customers increasingly prefer low methane emission suppliers.[4]

Our reasons are outlined below:

- More accurate reporting is critical to helping investors discern company-specific risks, including as related to emissions and methane fees, safety, and reputation.
- Russia's invasion of Ukraine created a unique window of opportunity for US-based suppliers to meet demand of countries seeking new sources of reliable, affordable, and environmentally conscious energy. The EPA can play a constructive role enhancing the US oil and gas sector's global competitiveness by setting standards that enhance data quality and transparency that elevate average US-wide methane performance.

- Some leading operators have already voluntarily taken technically viable and cost effective actions to improve methane reporting and methane emissions performance. For example, members of the Oil and Gas Climate Partnership (OGMP) 2.0, including a range of large and small, publicly traded and privately-owned companies have improved their methane disclosures.

Our position on the proposed rule is that it should be principles based, including:

- Enhance reporting transparency, credibility, and comparability.
- Promote best operating practices.
- Improve public health and safety and human rights and further value chain regulatory oversight and transparency.

We believe this letter in support of strong methane emissions reporting enhancements standards is consistent with our fiduciary responsibility to our clients and their beneficiaries. We encourage your agency to move swiftly to finalize the proposed rule …

Footnote:

[4] In July 2023, the EU, Japan and South Korea, who are all large liquified natural gas (LNG) customers, along with the US and Australia, participated in a joint statement affirming the importance of transparency for methane emissions data in the fossil fuel energy sector and supporting accelerated methane reduction in the LNG value chain. Big LNG buyers and producers to tighten methane monitoring | Financial Times (ft.com)

Commenter: Marathon Oil Company
Comment Number: EPA-HQ-OAR-2023-0234-0378
Page(s): 1-2

Comment: Marathon Oil is focused on reducing greenhouse gas emissions (GHGs) from our operations and supports effective and reasonable revisions to the Greenhouse Gas Reporting Rule that balance the goal of improving the completeness and accuracy of GHG emission reports without imposing significant additional burden on reporters for minimal environmental value. While we appreciate EPA' s efforts to update quantification methodologies and emission factors in an attempt to improve the accuracy and completeness of GHG emissions reports for the oil and gas sector, we are concerned that these changes include requirements that significantly increase the burden on reporters without commensurate environmental benefit.

Further, the Subpart W revisions do not align with EPA's directive from the Inflation Reduction Act (IRA) that operators be allowed to submit empirical emissions data to demonstrate the extent to which a charge is owed. Given Subpart W's dramatic shift in purpose from a reporting tool to a methodology for assessing a waste emissions charge pursuant to the IRA, there must be a pathway for all emissions source categories to demonstrate individual company performance using empirical data. As currently drafted, these pathways do not exist for all sources (including flare destruction efficiency calculations, gathering pipeline leak calculations, combustion slip and the duration of large release events), which will operate as a disincentive to emission reduction innovation, or will actually serve to increase emissions- the opposite of the stated goal of the rule.

…

In light of the limited time for review, Marathon Oil notes that its failure to provide specific comments in all areas of the proposal should not indicate support and should not reflect that there are not outstanding concerns with substantive requirements. We have prioritized the issues of greatest concern…

Commenter: Edison Electric Institute (EEI)
Comment Number: EPA-HQ-OAR-2023-0234-0379
Page(s): 3

Comment: EEI supports the EPA's efforts to develop a reporting rule that is based on empirical data,[2] where possible, to accurately reflect the total methane emissions and provides the comments below aimed at ensuring reporting is accurate and consistent across regulatory regimes.

Footnote:

[2] Section 136(h) of the Inflation Reduction Act amended the Clean Air Act to direct the Administrator to promulgate regulations "to allow and operators of applicable facilities to submit empirical emissions data." Inflation Reduction Act, Pub. L. No. 117-169, 136 Stat. 1818.

Commenter: Miller/Howard Investments, Inc.
Comment Number: EPA-HQ-OAR-2023-0234-0380
Page(s): 1-2

Comment: We support the agency's efforts to update the methane reporting protocols to ensure reporting is based on real-world empirical data and accurately reflects total oil and gas emissions.

…

We support EPA's proposed rule to ensure that reporting is based on empirical data and accurately reflects total methane emissions from oil and gas facilities. By updating these protocols so reporting is based on real-world empirical data and aligns with top-down aerial observations, EPA can address the well-known problem of underreported emissions. More accurate and empirically-based reporting is also needed to ensure that the MERP's waste emissions charge is assessed on the industry's real-world pollution, and to equip investors with reliable data to better assess company-specific performance and methane-related risk across the entire industry. Ensuring accuracy in reporting would have the added benefits of building investor confidence by creating transparency around companies' emissions performance through a centralized, government-run database and by ensuring that U.S. companies can remain competitive in global markets.

…

EPA's proposal can set a standard reporting structure across the industry, which will provide long-term certainty, improve data quality, and help to mitigate climate and transition-related risks for investors. We encourage your agency to move swiftly to finalize the proposed rule.

Commenter: Endeavor Energy Resources, L.P.
Comment Number: EPA-HQ-OAR-2023-0234-0381
Page(s): 1-4, 22

Comment: As part of the Onshore Natural Gas Production reporting segment, Endeavor is experienced with reporting under EPA's current Greenhouse Gas Reporting Program ("GHGRP"). While Endeavor supports improving the quality and consistency of the data collected under the GHGRP, such as through greater integration of direct measurement of emissions where feasible and alongside other forms of measurement and calculation, we are concerned that many aspects of the Subpart W Proposal will present significant implementation challenges, or in some cases will be simply unworkable in practice, without corresponding benefits in the accuracy or consistency of data collection and reporting. We write to outline these concerns and provide information and examples related to industry experience to demonstrate why certain aspects of the Subpart W Proposal need to be withdrawn or materially revised before EPA issues a final rule.

EPA is required by the Inflation Reduction Act of 2022 ("IRA") to update Subpart W of the GHGRP in order to gather accurate emissions data from the oil and natural gas industry as a whole to inform its implementation of the Clean Air Act ("CAA"), as well as to calculate "waste emissions charges" on excess methane emissions from Subpart W-covered facilities, which will take effect beginning with emissions reported under the GHGRP for calendar year 2024.[2] Accordingly, the IRA requires EPA to revise Subpart W to ensure that emissions reporting and the calculation of methane charges "are based on empirical data" and "accurately reflect the total methane emissions and waste emissions from the applicable facilities."[3] Although the Subpart W Proposal advances the IRA's mandate for accurate, empirical data and flexibility in measurement methods in some respects, Endeavor believes that other aspects are counterproductive to, or conflict with, the IRA's mandate or could go further to advance the goals of accuracy, consistency, and flexibility in emissions reporting. Given the costs associated with the IRA's methane charges—reaching $1,500 per ton in excess of the applicable threshold for emissions reported for 2026 and beyond—it is critical that Subpart W produces consistent and accurate data based on a facility's true emissions, not simply rough approximations. In addition to containing provisions that would hinder, rather than further, Congress's directive and EPA's stated goal of improving the accuracy of emissions reporting within the industry,[4] the Subpart W Proposal also creates new burdens without any corresponding benefits, including by placing an increased emphasis on site-specific or equipment-specific reporting. Given the increased difficulty in accurately measuring emissions at increasing levels of granularity, EPA's approach here would not lead to more accurate reporting when extrapolated to the facility or industry levels. It will simply generate more work for companies as they re-categorize emissions that are already being collectively reported.

Reporting rules that are not clear or that force owners and operators to make inaccurate reports also create unfair enforcement risks for reporters seeking to comply with the new requirements. Just last week EPA's Assistant Administrator for Enforcement and Compliance Assurance issued a memorandum directing EPA's enforcement staff to focus on "compliance activities to reduce emissions of Greenhouse Gases" including by prioritizing enforcement actions such as "compliance with the Greenhouse Gas Reporting Rule."[5] Endeavor therefore requests that EPA resolve the ambiguities in the Subpart W Proposal further described in this letter in order to avoid potential due process concerns related to such enforcement.

…

Our industry has already faced significant regulatory uncertainty and costs with respect to methane emissions over the past few years. Aside from the IRA and EPA's ongoing revisions to the GHGRP, there is also EPA's still-pending proposed rulemaking on New Source Performance Standard ("NSPS") Subparts OOOOb and OOOOc ("Methane Proposal").[7] With so many moving parts, it is critical that EPA reconcile and resolve any potential inconsistencies or incongruities before implementation of its suite of proposed rulemakings. By creating a practical and durable regulatory regime that recognizes operational realities for owners and operators like Endeavor, EPA can help to encourage environmentally sound and economically viable domestic oil and gas production. However, if EPA issues an unworkable and legally unsupportable final rule, it will invite challenges under the CAA and Administrative Procedure Act ("APA"), leading to continued regulatory uncertainty and substantial harm to our domestic production; this, in turn, would drive up energy prices for consumers and likely have the perverse outcome of forcing consumers to turn to foreign sources of energy which are not subject to anywhere close to the same stringency of environmental regulation as domestic U.S. production.

…

Conclusion

Endeavor supports efforts to improve the accuracy of the GHGRP and appreciates the opportunity to provide comment on EPA's Subpart W Proposal. We respectfully submit these comments for EPA's consideration as it develops the GHGRP to effectuate Congress's intent for accurate, empirical emissions reporting under Subpart W while at the same time taking into account the costs and burdens associated with such reporting. Endeavor appreciates your time in reviewing and considering these comments.

Footnotes:

[2] See Inflation Reduction Act of 2022, Pub. L. No. 117-169, § 60113(c)–(h), 136 Stat. 1818, 2076 (codified at 42 U.S.C. § 7436(c)–(h)).

[3] *Id.* § 60113(h) (codified at 42 U.S.C. § 7436(h)).

[4] *See, e.g.*, 88 Fed. Reg. at 50,284 ("The EPA is also proposing several revisions to add new or revise existing calculation methodologies to improve the accuracy of reported emissions, incorporate additional empirical data and to allow owners and operators of applicable facilities to submit empirical emissions data . . . .").

[5] David M. Uhlmann, EPA's Climate Enforcement and Compliance Strategy 3 (Sept. 28, 2023).

[7] *See* Standards of Performance for New, Reconstructed, and Modified Sources and Emissions Guidelines for Existing Sources: Oil and Natural Gas Sector Climate Review, 87 Fed. Reg. 74,702, 74,746–55 (Dec. 6, 2022) [hereinafter Methane Proposal]. Endeavor provided comments on EPA's Methane Proposal, and wishes to reiterate our concerns with many aspects of the proposal. *See* Endeavor Energy Resources, LP Comments on Standards of Performance for New, Reconstructed, and Modified Sources and Emissions Guidelines for Existing Sources; Oil and Natural Gas Sector Climate Review, Docket ID EPA-HQ-OAR-2021-0317 (Comment ID EPA-HQ-OAR-2021-0317-2283) (Feb. 15, 2023), https://tinyurl.com/fauf299j [hereinafter Endeavor Methane Comments].

Commenter: Arkansas Independent Producers and Royalty Owners (AIPRO)
Comment Number: EPA-HQ-OAR-2023-0234-0382
Page(s): 16

Comment: In conclusion, the task mandated to EPA by Congress requires the agency to comprehensively review, revise and validate its Subpart W regulations to make them accurate and reliable because of the role their implementation will play in determining methane taxes under the IRA. Congress' deadline of EPA's action failed to reflect the reality of the task. EPA, faced with the choice of meeting a deadline or meeting its mandate to comprehensively revise Subpart W, chose the deadline and produced a wholly inadequate proposed revision of the current Subpart W regulations. At best, the Subpart W proposal collects revisions to the current calculation process that EPA failed to validate as either accurate or appropriate. At worst, the proposed revisions to Subpart W are a thinly disguised effort to purposefully increase IRA methane taxes through the careful selection of higher emissions factors and overly burdensome & unworkable calculation procedures. As such, EPA should withdraw the current Subpart W proposal and execute its mandate to make it accurate, including taking the necessary steps to validate the emissions factors or emissions calculation procedures that it ultimately puts in place.

Commenter: Pioneer Natural Resources USA, Inc.
Comment Number: EPA-HQ-OAR-2023-0234-0385
Page(s): 1, 2

Comment: Pioneer appreciates EPA's efforts to update quantification methodologies and emission factors that are intended to improve the accuracy and completeness of GHG emissions reports for the oil and gas sector and is cognizant of the Agency's directive from Congress under the Inflation Reduction Act ("IRA") to revise Subpart W to ensure that reporting (and associated calculation of waste emission charges) is based on empirical data. As a member of the Oil and Gas Methane Partnership 2.0 ("OGMP"), Pioneer supports the improvement and transparency of emissions inventories. Pioneer strives to be an industry leader in minimizing emissions from operations, promoting best practices, piloting innovative leak detection technologies, and seeking out other voluntary ways to improve the Company's emissions footprint.

…

Pioneer appreciates the opportunity to contribute to this important rulemaking and intends these comments to provide valuable operator insight into this proposal.

Commenter: Kirk Frost
Comment Number: EPA-HQ-OAR-2023-0234-0389
Page(s): 1

Comment: Docket EPA–HQ–OAR–2023–0234 is quite striking, especially with all of the studies and documentation included exemplifying that many emission sources and events are not accounted for by oil and gas facility owners in annual emissions reports that facility owners are to provide to the EPA. Further exacerbating the methane emission in the natural gas supply chain, is that EPA studies demonstrate these emissions occurring from facilities in all parts of the natural gas supply chain (wells, processing plants, gathering pipelines, transmission pipelines, distribution segments, industry endpoints, electric generation endpoints and export endpoints). I wasn’t aware of plastic pipelines nor mud methane degassing function post hydraulic fracturing. All in all, the studies and papers included in the docket tell the story of a fossil fuel infrastructure that is leaking at every point and in many cases 100,000s of tons of methane that isn’t being captured into the EPA greenhouse gas emissions database.

I want to thank the EPA for taking a ‘hard review’ of the current state of greenhouse gas reporting within the oil and gas supply chains. I have been trying to escalate to EPA Region 2 and NJDEP pertaining to specific examples over the past 20 years, where natural gas facility owners in New Jersey have been falsifying their emissions down to impossible methane emission amounts. And I have not seen corrective action take place. I have seen NJDEP acknowledge that they were not aware of the specifications that facility owners provide to FERC, which detail emissions sources and specifications of those emissions that are 100s of times greater than what the facility owner reports annual in emissions to NJDEP and EPA.

As I have learned more about the loopholes, such as blowdown reporting is only required if the VOC emissions exceeds 2,000 pounds in one blowdown event, I have come to recognize that the natural gas facility owner/operator use all available means to purposely underreport emissions. For example, if a blowdown does occur that exceeds 2,000 pounds of VOC emissions, the owner/operator never specifies the correlating methane emission (2,000 pounds of VOC means more than 500 tons of methane was emitted) nor any other air pollutant emissions associated with that blowdown event is reported. Nor are those emissions included in the annual estimate emissions the facility owner/operator provides to EPA and NJDEP. Further, all blowdowns, venting and fugitives that emit 2,000 pounds of VOCs or less are not reported at all in any form or fashion. Yet, these owners/operators inform FERC that many venting events occur each and every year, and they provide FERC an estimated amount of venting for each year necessary to keep natural gas flowing through the facility. Venting is used as an easy method to purge natural gas that is obstructing flow.

I have to admit, I have not completed reading through the proposed requirements document. I was sidetracked several times to the additional extensive documentation that the EPA provided as supplementary data. I really enjoy the frank solicitation for comments the EPA engages throughout the document. I wish I could enumerate all of them and respond to each one. This is the approach I usually take with other dockets that lay out the comment input questions posed. However, with this EPA document, there isn’t the time to do that. I think a summary of sections and comment inputs for each section may have helped elicit more input from the public. Additionally, since the rules and regulations are established across numerous sections of the Clean Air Act codes (40 CFR part 98, 40 CFR part 98 subpart A, 40 CFR part 98 subpart C, 40 CFR part 98 subpart W and section 136), it quickly becomes a maze of rules and regulations. However, I really appreciated how the proposed rule changes document is laid out.

…

We have a substantial gap and issue between what EPA has been reporting for methane emissions versus actual emissions and quantification of all natural gas facilities across the United States. I am grateful that the EPA is proposing new rules that close that gap, but I am sure that the energy industry will work with congress to lessen the rules. So it is incredibly important that EPA use all of the studies and data that folks like myself provide to EPA to start an awareness campaign to Congress and to the American People. The Environmental Protection Agency was created to protect the people from toxic industries overtaking rural America. Yet, that is what has occurred with the oil and gas industry.

Commenter: MiQ
Comment Number: EPA-HQ-OAR-2023-0234-0392
Page(s): 1-2, 12

Comment: Executive Summary

After reviewing the revised regulatory language and other documentation in the docket, MiQ expresses its support for EPA's efforts to update Subpart W. EPA's efforts to substantially add calculation methodology options that reflect actual operating conditions for most material sources of emissions update requirements around calculating and reporting methane emissions to address gaps that have led many peer-reviewed studies over the past decade to conclude that the 40 CFR Part 98 is systemically underestimating methane emissions from the oil and gas sector. Overall, EPA strikes a practical balance in both providing updates to key assumptions and emission factors based on more up-to-date sources of empirical data and provides optionality to operators in many instances to use primary, site-specific data to calculate emissions.

MiQ presents comments, suggestions and requests for clarifications to EPA from the proposed language in this rule. MiQ agrees with EPA's general approach to structure emissions reporting methodological options as follows for individual sources.

1) Add methodologies for direct measurement where feasible

2) Provide requirements for the use of actual operating conditions in engineering calculation methods, or conservative defaults

3) Where emission factor methodologies are retained, revise emission factors where more recent data exists to better reflect the state of understanding around poorly measured or calculated methane emission sources.

MiQ's mission includes differentiating oil and gas operations based on best practices of methane management and quantification. Critics of the existing Subpart W regulation point to calculation methodologies significantly underestimating emissions from most regions and that emissions reported to Subpart W cannot be utilized to meaningfully analyze differences in operations. We believe that EPA's proposed rule significantly helps to address both criticisms. Providing options for operators to calculate emissions using their actual, reliable operational data such as flow metering data, air emissions testing data, and results of source or site-level measurement campaigns significantly helps give operators who simply want to comply that option, but also gives the option to operators to pursue other specific quantification methodologies. Additionally, EPA's efforts to correct methane emission sources that are suspected to lead to most observed discrepancies, including unlit or poorly operating flares and venting from over-pressurization caused by malfunctioning separator dump valves, clogged waste gas lines, or poorly designed facilities should result in operator-level emissions that agree more accurately with regional emission studies.

The onset of proposed OOOOb and OOOOc regulations that operators will eventually be required to utilize calculation methodologies utilizing data from inspections and process monitoring equipment that will eventually be required at scale. However, in the interim, accurate emission factors reflected by more recent studies and other assumptions in the proposed rule will provide incentives for operators to explore calculation methodologies that are based on actual operational and measurement data.

MiQ is concerned that the lack of specific guidance for some reporting requirements of actual operational data could lead to substantial data quality issues including variations of reporting of critical operational data. We provide EPA with the specific regulatory text, and in cases where we have experience, suggestions for how EPA can improve their requirements. MiQ also believes the proposed use of advanced methane monitoring and measurement technologies will lead to inconsistencies between operators. The proposed rule provides clear disincentives for the use of advanced monitoring and measurement technologies that have been found to consistently detect larger emission sources than traditional fugitive emission inspection methods more reliably. We provide EPA with examples of discrepancies that this regulation may unwittingly allow, and suggestions based off the MiQ Standard for how EPA can re-consider requiring or incentivizing the use of advanced monitoring and measurement technologies to ultimately help assure operator-level emission inventories. To ensure the data reported to EPA is consistent with the intent of these proposed requirements, MiQ additionally suggests the EPA implement third-party verification requirements.

…

MiQ supports the proposed changes by EPA to 40 CFR Part 98, Subpart W. Consistent with MiQ's mission, these proposed changes give operators the opportunity to quantitatively display their differentiated emissions performance moreso than current emissions reporting requirements, using empirical data. These revisions should have the effect of more meaningfully differentiating performance between exceptional, responsible operators and lagging operators. The full effects of this rule, however, can only be realized if EPA further strengthens reporting requirements, more directly incentivizes or requires the usage of advanced monitoring and measurement technologies, and strengthens verification requirements.

Commenter: Range Resources Corporation
Comment Number: EPA-HQ-OAR-2023-0234-0397
Page(s): 1-2

Comment: As a leader in the industry, Range believes that collection of accurate and representative data is imperative for credible reporting and identifying opportunities for reducing GHG emissions. For that reason, Range is encouraged by the direction provided by the U.S. Congress to the Environmental Protection Agency ("EPA") that reporting under the regulations at 40 C.F.R. Part 98, Subpart W is based on empirical data and accurately reflects emissions.

Over the past several years, Range has provided comments to EPA in an effort to improve the Subpart W reporting program and ensure that the regulations result in accurate reporting of emissions. Range appreciates that EPA has incorporated many of Range's comments into this Proposed Rule but believes that further improvements are necessary to accomplish the goal of obtaining emissions reporting that is based on empirical data and which accurately reflects actual emissions. Range hopes that EPA will consider the attached comments and incorporate them into the final rule.

We are grateful for EPA's consideration of our comments and we welcome the opportunity to meet with EPA to discuss our comments and to provide additional information that EPA might find helpful.

Commenter: Chesapeake Energy Corporation
Comment Number: EPA-HQ-OAR-2023-0234-0400
Page(s): 1

Comment: We support EPA's efforts to improve the quality of greenhouse gas emissions data collected under the Greenhouse Gas Reporting Rule but encourage EPA to revise its Proposed Rule to improve transparency, accuracy, verifiability, and implementability, and to harmonize this rule with other reporting regimes.

Commenter: Environmental Defense Fund et al.
Comment Number: EPA-HQ-OAR-2023-0234-0401
Page(s): 1, 2

Comment: We support the U.S. Environmental Protection Agency's effort to improve the accuracy of oil and gas emission inventories under Subpart W of the Greenhouse Gas Reporting Program.

…

As we all work to tackle climate change, these proposed updates are an essential step forward in more comprehensively assessing the scope of emissions from the oil and gas sector and ensuring that the necessary reductions are achieved to slow the rate of climate change happening now.

Commenter: American Petroleum Institute et al. (Part 1 of 2)
Comment Number: EPA-HQ-OAR-2023-0234-0402
Page(s): 5

Comment: Summary of Priority Items

The Industry Trades support certain aspects of the proposed revisions to Subpart W and remain committed to working with the Environmental Protection Agency (EPA) and the Administrator to improve the accuracy of Subpart W reporting in a cost-effective manner, while encouraging continued progress toward reducing greenhouse gas (GHG) emissions. The Industry Trades support accurate emissions reporting for many reasons, however it is particularly important given that reported emissions will form the basis of assessed methane fees as a Waste Emissions Charge (WEC), implemented under the Inflation Reduction Act (IRA). As such, these proposed changes create a potentially significant financial impact on the Industry Trades. Therefore, the Industry Trades provide these comments with a goal of improving accuracy of reported emissions through requirements that are appropriate, implementable, and reflective of actual emissions.[1] The comments herein focus on technical and feasibility challenges with specific provisions that EPA included in the proposed Subpart W rule revisions, while providing viable alternatives that support accurate emissions reporting.

The Industry Trades continue to strongly encourage EPA to find ways to make Subpart W less prescriptive and therefore better poised to not just accommodate but encourage the use of rapidly evolving technologies to detect and minimize emissions.

Footnote:

[1] Citations provided in this comment letter refer to the proposed rule, unless indicated otherwise. The structure and order of our comments does not necessarily reflect the individual comments' importance to the Industry Trades and their members. The Industry Trades believe all of its comments will help ensure the rule's integrity and deserve serious consideration.

Commenter: Atmos Energy Corporation
Comment Number: EPA-HQ-OAR-2023-0234-0406
Page(s): 1

Comment: Atmos Energy Corporation (Atmos Energy) appreciates the opportunity to comment on EPA's proposed rule entitled Greenhouse Gas Reporting Rule: Revisions and Confidentiality Determinations for Petroleum and Natural Gas Systems, 88 Fed. Reg. 50,282 (August 1, 2023), (Proposed Rule). Atmos Energy supports improving the accuracy of reported greenhouse gas (GHG) emissions data under the Greenhouse Gas Reporting Rule (Reporting Rule) and encourages EPA for further streamline requirements by taking advantage of existing data and considering on-the-ground implementation challenges. EPA should not finalize proposed elements that impose great costs without providing a meaningful return on data improvements.

Commenter: Differentiated Gas Coordinating Council (DGCC)
Comment Number: EPA-HQ-OAR-2023-0234-0415
Page(s): 1

Comment: The DGCC applauds the EPA for its proposal and its effort to bring the Greenhouse Gas Reporting Program (GHGRP) into the 21st Century. The DGCC shares the EPA's goal of drastically reducing greenhouse gas (GHG) emissions throughout the oil and gas sector. However, the DGCC believes the EPA can significantly improve the Proposed Rule, particularly as it relates to aligning with Congressional intent, encouraging the expansion of the differentiated gas market, and encouraging state-level leadership in emissions reporting.

Transitioning from estimate-based emissions factors toward empirical data is a significant advancement in our drive for precise, actionable environmental data. As the value of emissions data increases, stakeholders will inherently demand data that is high in quality. Direct measurement technologies can unlock data of much higher accuracy than scientifically informed estimates (i.e., emission factors). This high-fidelity, verifiable data will provide the trust and transparency needed to ensure the continued growth, evolution, and maturation of the differentiated gas market both domestically and internationally.

We urge the EPA to incorporate our feedback, ensuring that the final rule reflects the growth in both the industry's emissions mitigation efforts and the nation's environmental ambitions.

Commenter: American Gas Association (AGA) and American Public Gas Association (APGA)
Comment Number: EPA-HQ-OAR-2023-0234-0418
Page(s): 1

Comment: The American Gas Association ("AGA") and the American Public Gas Association ("APGA") (jointly, "the Associations") appreciate the opportunity to comment on the U.S. Environmental Protection Agency's ("EPA" or "Agency") proposed rule titled "Greenhouse Gas Reporting Rule: Revisions and Confidentiality Determinations for Petroleum and Natural Gas Systems" ("Proposed Rule"), which was published in the Federal Register on August 1, 2023.[1] The Associations support certain concepts in the Proposed Rule—particularly the proposal to allow the development of site-specific emission factors and emissions reporting based on direct measurements—however, the Associations have a number of recommendations to improve the accuracy and ease of reporting by local distribution companies ("LDCs")[2] under Subpart W of the Greenhouse Gas Reporting Program ("GHGRP"), which would in turn incentivize methane emission reductions.

Footnotes:

[1] Proposed Rule, 88 Fed. Reg. 50,282 (Aug. 1, 2023).

[2] Most AGA members are investor-owned LDCs, and APGA members are municipal or publicly owned utilities. Consistent with the definition of "natural gas distribution" under Subpart W, *see* 40 C.F.R. § 98.230(a)(8), the term "LDC" is used throughout these comments to refer to both publicly and privately owned natural gas distribution entities *(i.e.*, members of both AGA and APGA)

Commenter: Planetary Emissions Management Inc. (PEM)
Comment Number: EPA-HQ-OAR-2023-0234-0419
Page(s): 1

Comment: PEM applauds the EPA's proposed revisions to the requirements under 40 CFR Part 98, subpart W and respectfully submits the enclosed comments identifying how the EPA can leverage advanced emissions measurement technologies to meet those directives set forth under the Clean Air Act (CAA). As the preamble acknowledges, there is a need "to address potential gaps in the total CH4 emissions reported per facility to subpart W."[1] While we support the EPA's efforts to address these gaps, further revisions are necessary to effectively fulfill CAA section 136(h)'s statutory mandate "to ensure that reporting of CH_4 emissions under subpart W (and corresponding waste emissions charges under CAA section 136) is based on empirical data, accurately reflects the total CH_4 emissions (and waste emissions) from applicable facilities, and allows owners and operators to submit empirical emissions data, in a manner prescribed by the Administrator . . . ."[2]

Footnotes:

[1] https://www.regulations.gov/document/EPA-HQ-OAR-2023-0234-0001

[2] Id.

28.4 General Alignment with NSPS/EG

Commenter: Kairos Aerospace
Comment Number: EPA-HQ-OAR-2023-0234-0240
Page(s): 13-14

Commenter: Occidental (Oxy)
Comment Number: EPA-HQ-OAR-2023-0234-0276
Page(s): 4

Commenter: North Dakota Petroleum Council (NDPC)
Comment Number: EPA-HQ-OAR-2023-0234-0417
Page(s): 7

Commenter: The Petroleum Alliance of Oklahoma
Comment Number: EPA-HQ-OAR-2023-0234-0398
Page(s): 2

Commenter: Chesapeake Energy Corporation
Comment Number: EPA-HQ-OAR-2023-0234-0400
Page(s): 15

Commenter: American Petroleum Institute et al. (Part 1 of 2)
Comment Number: EPA-HQ-OAR-2023-0234-0402
Page(s): 5

Commenter: Devon Energy
Comment Number: EPA-HQ-OAR-2023-0234-0360
Page(s): 5-6

Commenter: Marcellus Shale Coalition (MSC)
Comment Number: EPA-HQ-OAR-2023-0234-0275
Page(s): 3-4

Comment 1: Commenter 0400: **E. To the extent there is overlap, EPA should harmonize the Subpart W requirements with the requirements in Subparts OOOOb and OOOOc when those rules are finalized.**

Two key areas of overlap between the Proposed Rule, NSPS OOOOb, and EG OOOOc are the measurement requirements for reciprocating compressor rod packing emissions[53] and the new "super emitter" or "other large release event" reporting obligations.[54]

As described above, EPA has attempted to align Subpart W, NSPS OOOOb, and EG OOOOc to avoid inconsistency. However, these topics have also been subject to significant public comment[55] and the nuances are likely to change when OOOOb and OOOOc are finalized. To the extent EPA makes changes, these changes should also be reflected in Subpart W anywhere doing so creates efficiencies. Ensuring that monitoring and reporting requirements are harmonized across the regulatory regimes will ease the already significant burden on operators while expediting implementation of the new requirements.

Footnotes:

[53] See 88 Fed. Reg. at 50,341.

[54] See 88 Fed. Reg. at 50,290.

[55] See e.g., Kinder Morgan, Inc. Comments, EPA-HQ-OAR-2021-0317-2282 (Feb. 14, 2023) (which proposed clarifying language to the OOOOb rod packing regulatory text); Berkshire Hathaway Energy Company Comments, EPA-HQ-OAR-2021-0317-2366 (Feb. 14, 2023) (which argued for changes to the emissions threshold, methods to validate new technology, and operator qualifications).

Commenter 0402: Summary of Priority Items

In addition to our technical comments, the Industry Trades have identified four overarching priority items within the proposed rules that if satisfactorily amended, will allow industry to attain the maximum potential methane mitigation and reduce public confusion. These high priority items are as follows:

1. Achieve greater [Intra- agency] regulatory harmonization and coordination:

There are multiple federal agencies and distinct departments within agencies that have pending or proposed regulations, guidance, or frameworks directly and indirectly related to methane emissions applicable to our industry, as listed below:

a. EPA – New NSPS OOOO b/c regulations

b. EPA – Revisions to GHG Subpart W methane reporting

c. EPA – Pending Methane Emissions Reduction Plan (MERP) implementation regulations

…

Across all of this methane-related policy making, the Industry Trades identify a potentially high risk for inconsistent methodologies or reporting structures.

…

We urge EPA to seek true alignment and harmonization with other federal regulatory requirements, particularly the NSPS OOOOb and EG OOOOc "Methane Rules" and the GHGRP itself.

Commenter 0240: VI. EPA Should Consider Strategies to Harmonize its Approach with Other Regulations and Standards

We appreciate EPA's decision to align the changes outlined within the Proposed Rule with other relevant regulatory requirements, notably the OOOOb and OOOOc rules. We believe that harmonizing the GHGRP requirements with those other standards will increase consistency and provide certainty for the regulated community, technology developers, and the regulators themselves.

Commenter 0360: **IV. EPA should ensure alignment across multiple EPA and other federal agency rulemakings.**

Within EPA itself, there are multiple ongoing rulemakings that are inextricably connected. The proposed NSPS OOOOb and OOOOc rules, the IRA mandated revisions to Subpart W, and the forthcoming MERP framework, must all work together in order to incentivize and achieve actual emissions reductions, and therefore facilitate the overall climate related goals of Devon, the broader oil and gas industry, and this Administration. A fundamental misstep in any of these rulemakings will put that progress at risk. Although Devon appreciates the fact that there are various factors that prevent these rulemaking timelines from being optimally positioned for perfect alignment, it encourages EPA to take the time necessary to ensure fundamental misalignment does not occur. Ideally, NSPS OOOOb and OOOOc would be finalized, establishing emissions limitations, work practice standards, and alternative test methods for advanced methane detection technologies that would then be appropriately recognized and characterized within the Subpart W reporting requirements, which would then lead to the most accurate accounting of methane emissions intensity within the MERP framework in order to establish a proper and fair waste emissions charge as mandated by the IRA.

Commenter 0276: III. EPA's final rule should ensure reporting is not duplicative of other federal regulations.

EPA should avoid promulgating duplicative regulations or regulations that are inconsistent with other federal regulatory programs. Oxy's concern is that, with duplicative rules, the EPA may be administering, and operators may then need to comply with two sets of requirements (standards set in NSPS and reporting in GHGRP) that are intended to achieve similar goals but are not aligned. Oxy specifically asks EPA to consider their proposal in light of the existing and proposed NSPS as well as within the current reporting structure of GHGRP. A streamlined rule will ensure industry and EPA have a seamless transition into the new reporting structure.

Commenter 0398: The Alliance is concerned that the Proposed Rule includes differing and/or conflicting requirements (e.g., monitoring, sampling, and inspection) for various emission sources as compared to EPA's proposed New Source Performance Standards (NSPS) OOOOb/c rules. This will only lead to confusion and non-compliance. For consistency and regulatory certainty, EPA should align its requirements with its proposed NSPS OOOOb/c rules.

Action Requested: We request EPA align its requirements for each emission source by incorporating by reference to NSPS OOOOb/c rules.

Commenter 0240: VI. EPA Should Consider Strategies to Harmonize its Approach with Other Regulations and Standards

We appreciate EPA's decision to align the changes outlined within the Proposed Rule with other relevant regulatory requirements, notably the OOOOb and OOOOc rules. We believe that harmonizing the GHGRP requirements with those other standards will increase consistency and provide certainty for the regulated community, technology developers, and the regulators themselves.

Commenter 0417: The proposed Subpart W requirements expressly reference and/or are directly related to a number of other pending regulations or legislation, namely CAA Section 111(b) standards of performance for certain new, reconstructed, and modified oil and natural gassources (40 CFR Part 60, Subpart OOOOb, herein referred to as "NSPS OOOOb"), emissions guidelines under CAA Section 111(d) for certain existing oil and natural gas sources (40 CFR Part 60, Subpart OOOOc, herein referred to as "EG OOOOc"), and the Inflation Reduction Act Section 60113 methane emissions reduction program's waste emission charge for oil gas facilities, herein referred to as "MERP WEC." Significant portions of the proposed Subpart W requirements are inherently intertwined with critical compliance aspects of these other programs, which have not yet been finalized.

NDPC requests that the EPA develop and communicate its plan to ensure all associated regulations are coordinated and implemented consistently. To mandate separate emission factors solely for GHG reporting does not benefit the environment and only serves to

unnecessarily inflate the Waste Emissions Charge.

Commenter 0275: **GENERAL COMMENTS**

1. The MSC again recommends that the final GHGRP recognize and not overlap, conflict or be redundant with requirements for sources under other programs.

The proposed rule includes revised emission factors, requirements for measurement and compliance, and contingency factors for determining greenhouse gas (GHG) emissions. Methane emissions are a focus of the proposed rule for the oil and gas industry. The calculation of volatile organic contaminants (VOC), organic hazardous air pollutants (HAPs), and other organic emissions are typically linked for the oil and gas industry.

…

Monitoring and other requirements should align in these programs and not conflict with existing federally enforceable requirements in both federal and state operating permits. Specific examples of potential regulatory conflicts include control efficiencies and monitoring requirements in NSPS OOOO, OOOOa, proposed NSPS OOOOb and Emission Guidance OOOOc, and NESHAP HH. Areas of concern include the control efficiencies and other requirements for flares and other combustion control devices, fugitive emission monitoring programs, frequency of sampling and performing gas analyses, and the use of flow meters and online analyzers.

Response 1: We agree with commenters that is important to align subpart W requirements with other EPA regulations, where appropriate. See Section I.F and Section II.B of the preamble to the final rule for our discussion of the alignment of the final rule with the final NSPS OOOOb and EG OOOOc. As discussed in Section I.F of the preamble to the final rule, the EPA identified areas where additional revisions to part 98 would better align subpart W requirements with recently promulgated requirements in 40 CFR part 60 and part 62, allow facilities to use a consistent method to demonstrate compliance with multiple EPA programs (and thereby limit burden), and improve the emission calculations reported under the GHGRP subpart W. On March 8, 2024, the final NSPS OOOOb and EG OOOOc rule published in the Federal Register (89 FR 16820) and references to that final rule have been updated in this final rule to ensure alignment between the two rules.

Commenter: Michigan Oil and Gas Association (MOGA)
Comment Number: EPA-HQ-OAR-2023-0234-0298
Page(s): 1-2, 3-4

Commenter: GPA Midstream Association
Comment Number: EPA-HQ-OAR-2023-0234-0299
Page(s): 74-75

Commenter: Ascent Resources, LLC
Comment Number: EPA-HQ-OAR-2023-0234-0339
Page(s): 2

Commenter: Enerplus Resources (USA) Corporation
Comment Number: EPA-HQ-OAR-2023-0234-0342
Page(s): 3

Commenter: Permian Basin Petroleum Association (PBPA)
Comment Number: EPA-HQ-OAR-2023-0234-0346
Page(s): 8

Commenter: Ovintiv Inc.
Comment Number: EPA-HQ-OAR-2023-0234-0350
Page(s): 2

Commenter: Marathon Oil Company
Comment Number: EPA-HQ-OAR-2023-0234-0378
Page(s): 2

Commenter: Arkansas Independent Producers and Royalty Owners (AIPRO)
Comment Number: EPA-HQ-OAR-2023-0234-0382
Page(s): 7, 9

Commenter: Wyoming Department of Environmental Quality (WDEQ)
Comment Number: EPA-HQ-OAR-2023-0234-0388
Page(s): 1-2, 3-4

Commenter: Range Resources Corporation
Comment Number: EPA-HQ-OAR-2023-0234-0397
Page(s): 3

Commenter: American Petroleum Institute et al. (Part 1 of 2)
Comment Number: EPA-HQ-OAR-2023-0234-0402
Page(s): 8

Commenter: Lambda Energy Resources
Comment Number: EPA-HQ-OAR-2023-0234-0405
Page(s): 1

Comment 2: Commenter 0298: MOGA's original intent was to file a public comment requesting an extension based on the overwhelming complexity and integration of proposed modifications to Subpart W and the IRA, Methane Emissions Reduction Act (MERP), the proposed New Source Performance Standards ("NSPS") for new, reconstructed and modified sources under 40 CFR Part 60, Subpart OOOOa and future proposals for "Emissions Guidelines" ("EG") for existing sources under 40 CFR Part 60, Subpart OOOO(b) & Subpart OOOO(c). MOGA reviewed the published EPA denial letters for the request for extensions and decided to attempt sufficient comment. Unfortunately, MOGA and our constituents came to the same conclusion as other submitters regarding the inability to understand the potential interconnectedness of unfinalized and proposed regulations that would likely impact potential comments regarding revisions to Subpart W.

For this reason, MOGA supports fellow submitters regarding finalization of parallel regulations prior to requesting comments with regards to the revision to calculations that may have potential tax implications to very small and small businesses. MOGA supports other commentors who called for the withdrawal of the proposed rule until finalization of other co-mingled and unfinalized regulations.

MOGA urges the United States Environmental Protection Agency ("EPA") to listen to the concerns of our small business industry segment prior to creating and finalizing technically and financially infeasible regulations. The ability for very small and small businesses to read, understand and implement regulations is paramount to achieve compliance success. The current state of proposed regulations has become interrelated and difficult to understand, let alone provide adequate foundation for sufficient comment on the potential impacts to the industry.

…

MOGA appreciates the opportunity to comment on the proposed Subpart W modifications but found the timing of the proposed regulations inconsistent with unfinalized proposed concurrent regulations that may impact the current proposed regulations. MOGA recommends the EPA withdraw the proposed Subpart W regulations until further clarification and finalization of parallel proposed regulations are complete.

Commenter 0299: *Reliance on Proposed Standards under Section 111.* As a general matter, the proposed rule's reliance on aspects of the proposed new source performance standards ("NSPS") and emissions guidelines for existing oil and natural gas sources under section 111(b) and 111(d), respectively referred to as proposed subpart OOOOb and proposed subpart OOOOc, create logistical and legal concerns for the proposed rule.[4] The proposed rule explains that EPA is "proposing revisions to certain requirements in subpart W relative to the requirements proposed for NSPS OOOOb and the presumptive standards proposed in the EG OOOOc (which would inform the standards to be developed and codified under 40 CFR part 62)."[5] Those revisions include the subpart W calculation methodologies for natural gas pneumatic devices and equipment leak surveys, as well as the reporting requirements for "other large release events."[6] EPA further explains that at least some of these proposed revisions "would not apply to individual reporters unless and until their emission sources are required to comply with either the final NSPS OOOOb or an approved state plan or applicable Federal plan in 40 CFR part 62 …. [and that] [i]n the meantime, reporters would comply with the applicable provisions of subpart W for sources not subject to NSPS OOOOb or 40 CFR part 62."[7]

The Clean Air Act ("CAA") and the most fundamental tenets of administrative law require EPA to propose revisions to the GHGRP that provide adequate notice to interested parties. The Administrative Procedure Act ("APA"), for instance, requires that a notice of proposed rulemaking include "either the terms or substance of the proposed rule or a description of the subjects and issues involved."[8] Under this standard, an agency's proposal must fairly apprise interested persons of the subjects and issues of the rulemaking.[9]

Section 307(d)(3) of the CAA imposes even more stringent requirements than the APA. It requires a notice of proposed rulemaking to include "the factual data on which the proposed rule is based;" "the methodology used in obtaining the data and in analyzing the data;" and "the major legal interpretations and policy considerations underlying the proposed rule."[10] The D.C. Circuit has explained that the CAA thus requires EPA to issue a proposed rule and to provide a detailed explanation of its reasoning at the proposed rule stage.[11]

Until EPA's OOOOb and OOOOc requirements have been made final, any proposed rule that relies on their requirements cannot reasonably provide notice of "the terms or substance of the proposed rule" or "the major legal interpretations and policy considerations underlying the proposed rule." On the contrary, the references in the proposed revisions to the GHGRP are in effect mere placeholders for whatever law or policy is ultimately made in the related proposals for OOOOb and OOOOc.

Even as a practical matter, EPA should refrain from taking final action on its proposed revisions to subpart W until it has finalized OOOOb and OOOOc and allowed interested parties with an opportunity to fully comment on how those final rules requirements might be reflected in or impact implementation of the GHGRP. Acting to finalize the GHGRP revisions first risks predetermining (or giving the appearance of predetermining) the outcome of the methane and volatile organic compounds ("VOCs") rulemaking or premising the revisions at issue in this rulemaking on provisions that remain subject to change. Either alternative is problematic.

EPA can avoid these issues entirely by taking final action on OOOOb and OOOOc prior to finalizing this rulemaking. Should the OOOOb or OOOOc requirements change in any substantive respect relevant to the GHGRP, EPA should reopen these proceedings for additional public comment. Taking such an approach will ensure that EPA complies with the law and adopts sound public policy.

Footnotes:

[4] *See id*. at 36,962.

[5] *Id*.

[6] *Id*.

[7] *Id*.; *id*. at 36,977-79; 36,983-84.

[8] 5 U.S.C. § 553(b).

[9] *See, e.g.*, *Am. Iron & Steel Inst. v. EPA*, 568 F.2d 284, 293 (3d Cir. 1977).

[10] CAA § 307(d)(3), 42 U.S.C. § 7607(d)(3).

[11] See, e.g., *Small Refiner Lead Phase-Down Task Force v. EPA*, 705 F.2d 506, 519 (D.C. Cir. 1983).

Commenter 0339: **Timing/Interrelatedness of Proposed Changes with Other Federal Regulations**

The proposed Subpart W requirements expressly reference and/or are directly related to a number of other pending regulations or legislation, namely CAA Section 111(b) standards of performance for certain new, reconstructed, and modified oil and natural gas sources (40 CFR Part 60, Subpart OOOOb, a.k.a. "NSPS OOOOb"), emissions guidelines under CAA Section 111(d) for certain existing oil and natural gas sources (40 CFR Part 60, Subpart OOOOc, a.k.a. "EG OOOOc"), and the Inflation Reduction Act Section 60113 methane emissions reduction program's waste emission charge for oil gas facilities ("MERP WEC"). Significant portions of the proposed Subpart W requirements are inherently intertwined with critical compliance aspects of these other programs, which have not yet been finalized. Ascent requests that EPA develop and communicate their plan to ensure all associated regulations are coordinated and in sync.

Commenter 0342: Timing/Interrelatedness of Proposed Changes with Other Federal Regulations

The proposed Subpart W requirements expressly reference and/or are directly related to a number of other pending regulations or legislation, namely CAA Section 111(b) Standards of Performance for Certain New, Reconstructed, and Modified Oil and Natural Gas Sources (40 CFR Part 60, Subpart OOOOb, a.k.a. "NSPS OOOOb"), emissions guidelines under CAA Section 111(d) for certain existing oil and natural gas sources (40 CFR Part 60, Subpart OOOOc, a.k.a. "EG OOOOc"), and the Inflation Reduction Act Section 60113 methane emissions reduction program's waste emission charge for oil gas facilities ("MERP WEC"). Significant portions of the proposed Subpart W requirements are inherently intertwined with critical compliance aspects of these other programs, which have not yet been finalized. Enerplus requests that EPA develop and communicate their plan to ensure all associated regulations are coordinated and in sync.

Commenter 0346: EPA's Proposed Rule Incorporates Portions of Other Rules Which Have Not Been Finalized

EPA should not propose a rule (GHGRP) that incorporates portions of another proposed rule that is not yet final (OOOOb/OOOOc). Significant portions of the Proposed Rule are contingent upon the finalization of a rule that is not only in the middle of its own comment review period and subject to change, but that could likely be the subject of multi-year litigation. Any changes that are made by the EPA to the OOOOb/OOOOc rules in response to comments or changes that may be required by the courts, will necessarily impact the implementation of the proposed GHGRP.

Specifically, EPA states that the final Subpart W amendments "would reference the final version of the method(s) in the NSPS OOOOb and EG OOOOc."[9] This is presumptive rulemaking at best, and would likely violate the Administrative Procedures Act, because the final version of OOOOb and OOOOc have not been published or referenced in the GHGRP proposal. Of course, this assumes that these rules are actually finalized. Any reference to these final rules is presumptive and cannot be relied upon by the regulated community because no one, at least not in the public, actually knows what the final rule will look like.

Footnote:

[9] Proposed Rule at 50288.

Commenter 0350: Timing/Interrelatedness of Proposed Changes with Other Federal Regulations

The proposed Subpart W requirements expressly reference and/or are directly related to a number of other pending regulations or legislation, namely CAA Section 111(b) standards of performance for certain new, reconstructed, and modified oil and natural gas sources (40 CFR Part 60, Subpart OOOOb, a.k.a. “NSPS OOOOb”), emissions guidelines under CAA Section 111(d) for certain existing oil and natural gas sources (40 CFR Part 60, Subpart OOOOc, a.k.a. “EG OOOOc”), and the Inflation Reduction Act Section 60113 methane emissions reduction program’s waste emission charge for oil gas facilities (“MERP WEC”). Significant portions of the proposed Subpart W requirements are inherently intertwined with critical compliance aspects of these other programs, which have not yet been finalized. Ovintiv requests that EPA develop and communicate their plan to ensure all associated regulations are coordinated and in sync.

Commenter 0378: The provisions of Subpart W must be harmonized with other regulations.

Careful consideration should be given to harmonizing the provisions of all of the EPA and BLM rules that have been proposed (or will be proposed) that touch upon emissions from the oil and gas industry to minimize ambiguity, avoid conflicting requirements and reduce the cost and complexity of compliance for operators. The proposed Subpart W requirements expressly reference and/or are directly related to a number of other pending regulations or legislation, namely CAA Section 111 (b) standards of performance for certain new, reconstructed and modified oil and natural gas sources (40 CFR Part 60, Subpart OOOOb, a.k.a. NSPS OOOOb), emissions guidelines under CAA Section 111 (d) for certain existing oil and natural gas sources (40 CFR Part 60, Subpart OOOOc, a.k.a. EG OOOOc) and the Inflation Reduction Act Section 60113 methane emissions reduction program's waste emission charge for oil gas facilities (MERP WEC). Significant portions of the proposed Subpart W requirements are inherently intertwined with critical compliance aspects of these other programs, which have not yet been finalized. Marathon Oil requests that EPA develop and communicate their plan to ensure all associated regulations are coordinated and in sync. We believe this harmonization is necessary to ensure that the final rule does not have the unintended consequence of disincentivizing operators from employing the best practices and latest technology to minimize, measure and monitor GHG emissions. Thus, we urge EPA to delay taking final action on the proposed Subpart W revisions until EPA finalizes NSPS OOOOb, EG OOOOc, and the yet to be proposed regulatory framework for administering the MERP WEC.

Commenter 0382: “Advanced Notice of Proposed Rulemaking” NOT a “Proposed Rule”:

EPA’s proposed revisions to its GHGRP do not satisfy the requirements of a “Proposed Rule” as it references requirements from NSPS OOOOb and EG OOOOc, which are not final rules. And, in the case of EG OOOOc, no regulatory text has been provided for and presumably doesn’t yet exist. EG OOOOc specifically will require states to develop and gain approval from EPA for implementation plans and rules, which will likely take years to accomplish.

As such, affected stakeholders, such as the regulated community, are unable to review and provide adequate comments on the proposed GHGRP revisions.

Again, AIPRO strongly encourages EPA to withdraw the current proposed GHGRP revisions at Docket ID No. EPA–HQ–OAR–2023–0234 …

…

AIPRO reiterates its objection to proposed GHGRP - Subpart W revisions referencing and incorporating requirements of proposed NSPS OOOOb and EG OOOOc. Reporters subject to Subpart W requirements are unable to adequately review and interpret the impacts and appropriateness of the proposed revisions to Subpart W, because OOOOb and OOOOc are not yet finalized and proposed regulatory text has not yet been provided. This contradicts the procedural requirements EPA must follow when promulgating new rules, and therefore should not be allowed unless and until proposed OOOOb and EG OOOOc become final rules.

<u>Commenter 0388</u>: The many challenges of reviewing the proposed rule are further magnified by the landscape of regulatory uncertainty under which the proposal operates. When jointly taken into consideration with the abundance of overlapping proposed rules affecting oil and natural gas facilities that have not yet been finalized by EPA (such as the proposed methane rule and supplemental proposal), or have yet to be published in the Federal Register (the forthcoming Waste Emissions Charge proposal), this proposed rule exists in a regulatory labyrinth that is almost impossible for state regulatory agencies or operators of affected sources to navigate. WDEQ and other state regulatory agencies can merely grasp at hypothetical straws when attempting to determine how this proposed rule interfaces with, overlaps with, or expands upon the myriad of other regulatory requirements for oil and natural gas that EPA has proposed but not yet finalized. WDEQ considers that EPA has put the proverbial cart before the horse in soliciting comments on a proposed rule with requirements that potentially dovetail with the Waste Emissions Charge, Super-Emitter Response Program, and other provisions of proposed, but not finalized, OOOOb and OOOOc regulations that are still up in the air, themselves.

…

EPA's promulgation of the proposed rule prior to the finalization of other complimentary proposed rules for affected oil and natural gas sources has resulted in a landscape of regulatory uncertainty that has made evaluating the impacts of the proposed rule almost impossible.

In addition to the unworkable public comment deadline, WDEQ has also significantly grappled with evaluating the potential impacts of the proposed rule because so many regulations that apply to the same category of affected sources in the oil and natural gas industry are also still in proposed status. Regarding the Greenhouse Gas Reporting Rule, there are two previous iterations of proposals (87 FR 36920, proposed on June 21 , 2022, and 88 FR 32852, proposed on May 22, 2023) that have not yet been finalized. These proposals are significant-totaling nearly 300 pages in preamble and regulatory text - and cross-reference other proposed regulations (the proposed new source performance standards (NSPS) OOOOb and emissions guidelines (EG) OOOOc) that have not been finalized either. Furthermore, the supplemental proposal to the Greenhouse Gas Reporting Rule (88 FR 32852) also includes numerous revisions to emissions calculation methodologies and global warming potentials. EPA's web of proposed revisions that is interwoven by the nearly 500 cumulative pages of text across the three iterations of revisions to the Greenhouse Gas Reporting Rule is tangled and difficult to navigate.

Additionally, EPA has not yet finalized its proposed NSPS and EG included in "Standards of Performance for New, Reconstructed, and Modified Sources and Emissions Guidelines for Existing Sources: Oil and Natural Gas Sector Climate Review" (86 FR 63110) - also known as the proposed methane rule - and the supplemental proposal to the methane rule (87 FR 74702). This pairing of proposed rules contains the revisions to NSPS OOOOa, as well as the newly proposed NSPS OOOOb and EG OOOOc. These proposed NSPS and EG proposed new requirements with immense implications for the oil and natural gas industry who will also have to respond to the reporting requirements in this proposed rule. Some of the OOOOb and OOOOc requirements even potentially interface with or directly overlap with the requirements of this proposed Greenhouse Gas Reporting Rule. However, it is essentially impossible to anticipate what the finalized requirements of those two proposed rules will be, especially given that EPA has not yet responded to the comments submitted on the proposed methane rule and the supplemental proposal. If EPA finalizes the OOOOb and OOOOc requirements as proposed, it would create extraordinary compliance and monitoring-related burdens for affected sources, as WDEQ and many other entities raised in their comments on the proposed methane rule. However, when considering this proposed rule, it is difficult to evaluate the full extent of resource constraints and potential economic implications from the added greenhouse gas reporting burdens without knowing with certainty the extent of the associated burdens tied to the proposed OOOOb and OOOOc requirements.

In short, EPA has overfilled its plate of proposed regulations pertaining to the oil and natural gas industry without first responding to comments and finalizing, or withdrawing, some of the complimentary regulations that it has proposed. Evaluating the potential impacts of this proposed rule is an unreasonably difficult task because of the landscape of regulatory uncertainty EPA has created. EPA should respond to comments and perform meaningful engagement with state agencies on previously proposed rules, like the proposed NSPS OOOOb and EG OOOOc, prior to issuing follow-up rules like this proposed Greenhouse Gas Reporting Rule that overlaps and interfaces with the requirements of other rules that have not yet been finalized. Otherwise, performing an accurate evaluation of the cumulative economic and implementation impacts of the proposals is unreasonably challenging because affected stakeholders can only make hypothetical assumptions about what certain final requirements will be. Regulatory certainty pertaining to other previously promulgated, complimentary rulemakings is crucial for evaluating impacts of later proposed rules, such as this one, and EPA has not afforded commenters such certainty in this proposed rulemaking.

Commenter 0397: **Comment #1: EPA inappropriately incorporates by reference rulemakings that have not yet completed the administrative rulemaking process.**

EPA has proposed new standards of performance for certain new, reconstructed, and modified oil and natural gas sources at 40 C.F.R. part 60, subpart OOOOb. EPA has also proposed new emissions guidelines for certain existing oil and natural gas sources at 40 C.F.R. part 60, subpart OOOOc. Neither of these proposed regulations have been adopted by EPA and there is significant concern with portions of the proposed regulations that hopefully will be addressed before the regulations become final. Accordingly, it is unlawful and inappropriate for EPA to adopt concepts in a rulemaking that have yet to complete the administrative rulemaking process. Moreover, it is unclear when EPA's proposed subparts OOOOb and OOOOc will become final, making compliance with the various related rulemakings complicated and confusing.

<u>Commenter 0402</u>: Furthermore, the Industry Trades suggest that EPA not finalize changes to Subpart W until such time that NSPS OOOOb and EG OOOOc have been finalized, and give another opportunity to provide comments on the proposed updates to Subpart W. It is important to the Industry Trades that there is consistency as opposed to conflicting requirements between the GHGRP and future and current rulemaking under other air quality regulatory programs.

<u>Commenter 0405</u>: Additionally, the New Source Performance Standards for new and existing oil and gas sources OOOO b/c have not even been finalized as of yet. Since so much of what is in OOOO b/c dictates Greenhouse Gas reporting, it seems only logical to wait for one rule to be finalized before implementing another.

We request that an additional comment period follow the finalization of OOOO b/c before implementing these rules.

Response 2: The EPA disagrees that the proposed rule for this subpart W revision was premature, or substantively and procedurally flawed. This final rule is focused on aligning the subpart W requirements, to the extent possible, with the final NSPS OOOOb and EG OOOOc. As we explained in Section II of the preamble to the 2023 Subpart W Proposal, the proposed amendments would also allow facilities to use a consistent method to demonstrate compliance with multiple EPA programs. We also explained that the proposal would limit burden for subpart W facilities with affected sources that would also be required to comply with the proposed NSPS OOOOb or a State or Federal plan in part 62 implementing EG OOOOc by allowing them to use data derived from the implementation of the NSPS OOOOb or EG OOOOc to calculate emissions for the GHGRP rather than requiring the use of different monitoring methods. Consistent with that goal, the EPA stated in the 2023 Subpart W Proposal that the EPA expects that the final amendments to subpart W would reference the final version of the method(s) in the NSPS OOOOb and EG OOOOc. We explained that these amendments would also improve the emission calculations reported under the GHGRP. We then more specifically explained that we were proposing amendments to the subpart W calculation methodologies for flares, centrifugal and reciprocating compressors, and equipment leak surveys related to the proposed NSPS OOOOb and presumptive standards in EG OOOOc, and were proposing new reporting requirements for ''other large release events'' as defined in subpart W that would reference the NSPS OOOOb and approved state plans or applicable Federal plan in 40 CFR part 62. Further detail on those proposed provisions was provided in sections III.B, N, O, and P of the preamble to the 2023 Subpart W Proposal. We also clearly explained in the proposal our intention that, if finalized, the provisions of these proposed amendments that reference the NSPS OOOOb and approved state plans or applicable Federal plan in 40 CFR part 62 would not apply to individual reporters unless and until their emission sources are required to comply with either the final

NSPS OOOOb or an approved state plan or applicable Federal plan in 40 CFR part 62. We also explained that, in the meantime, under our proposal reporters would have the option to comply with the calculation methodologies that would be required for sources subject to NSPS OOOOb or 40 CFR part 62, or they would comply instead with the applicable provisions of subpart W that apply to sources not subject to NSPS OOOOb or 40 CFR part 62. Thus, the proposed rule provided adequate notice and opportunity to comment on how the rule will affect stakeholders, including providing a detailed explanation of the EPA's reasoning at the proposed rule stage, and this rulemaking is in compliance with the relevant requirements of CAA section 307(d), including CAA section 307(d)(3) and relevant caselaw. Commenters also cited the Administrative Procedure Act (APA), including 5 U.S.C. 553(b)(3), which requires that a notice of proposed rulemaking shall include "either the terms or substance of the proposed rule or a description of the subjects and issues involved." The EPA notes that our process is also consistent with the notice and comment requirements of the APA, 5 U.S.C. 551–559. In the preambles to the proposed and final rule, as well as elsewhere in this document, the EPA describes at length the statement and purpose of the revisions, provides explanations for any changes in the rule, and responds to all comments submitted.

Specifically, in regards to the proposed rule referencing the then proposed NSPS OOOOb and EG OOOOc monitoring method(s),[23] the EPA disagrees that the proposed rule did not give adequate notice and therefore the EPA did not re-propose or re-open the comment period for this action. The proposed rule clearly laid out the EPA's proposal and requested comment regarding alternatives, as well as the detailed reasoning behind and goals of the proposal. The EPA provided this detailed explanation to ensure that commenters had ample notice of the revisions under consideration, and provided 60 days for the public comment period. This process accords with proper notice and comment procedure. Commenters posit that referencing the then proposed NSPS OOOOb and EG OOOOc standards in the Subpart W proposed rule renders this notice premature and inadequate, and the EPA respectfully disagrees. First, in proposing to reference the NSPS OOOOb and EG OOOOc provisions, the EPA was not proposing to require any new collection of data under subpart W, as the data would already be collected to meet the requirements of NSPS OOOOa or EG OOOOc. Instead, the EPA proposed to add use of these methods and data under subpart W so that reporters would be required to use, for the purpose of compliance with the proposed mandatory subpart W calculation, and reporting requirements, whatever data would already be collected as a result of complying with certain provisions that would be finalized in the NSPS OOOOb and EG OOOOc. As such, the substance of the NSPS rulemaking provisions was not at issue for purposes of subpart W within these revisions, as that process took place within the NSPS OOOOb and EG OOOOc rulemaking. Rather, the EPA ensured that reporters were provided notice of the proposal to add use of methods and data that would result from compliance with the final NSPS OOOOb and EG OOOOc, provided notice of the proposed additional subpart W monitoring, calculation, and reporting requirements for sources subject to the NSPS OOOOb or EG OOOOc, and made clear that the intent of these revisions was to align the programs so that reporters would use the data gathered in complying with the finalized NSPS OOOOb or EG OOOOc to comply with their subpart W requirements. As noted earlier, the proposed rule further explained the purpose behind this proposed revision, as detailed in the proposed rule (88 FR 50282; August 1, 2023). In fact, the proposed rule for subpart W clearly detailed the NSPS OOOOb and EG OOOOc proposed provisions the EPA

[23] The NSPS OOOOb and EG OOOOc rule has since been finalized. 89 FR 16820 (March 8, 2024).

intended to require alignment with and furthermore explained that any provisions aligned with in this final subpart W action would be those that were finalized in the NSPS OOOOb and EG OOOOc.

This final rule incorporates alignment with certain provisions finalized in the NSPS OOOOb and EG OOOOc with some changes from proposal, including those resulting from the EPA's own reasoned consideration and its assessment of public comment. To the extent the specifics of how this final subpart W rule is including requirements in alignment with the NSPS OOOOb and EG OOOOc that differ from the specifics in the subpart W proposal, as explained further in Section III of the preamble to the subpart W final rule, these changes are consistent with the purpose detailed in the proposed and are a logical outgrowth of the proposal. The proposed rule need not reflect the precise components that will comprise the final rule anticipated or ultimately promulgated by the agency, provided the final rule is a "logical outgrowth" of the materials provided at proposal, which this final rule is.

The changes from the proposed to final NSPS OOOOb and EG OOOOc did not, in many cases, result in substantive changes to this final Subpart W rule. Where substantive changes occurred from the proposed to final NSPS OOOOb and EG OOOOc that impacted the Subpart W rule (e.g., changes to the Super Emitter Program), the changes were made after consideration of comments similar to the ones submitted by commenters on this rule. While other substantive changes occurred to the NSPS OOOOb and EG OOOOc requirements from proposal to final in that separate rulemaking, those changes are out of scope of the subpart W rulemaking provisions that are intended to align with the final NSPS OOOOb and EG OOOOc requirements; however, commenters were provided full notice and opportunity to comment within that NSPS OOOOb and EG OOOOc rulemaking, as fully explained within those proposed and final preambles, the EPA's response to comments, and the docket of that action.[24]

See Sections III.B, N, O, and P of the preamble to the final rule for additional discussion of specific changes from the proposed to final Subpart W rule for alignment with provisions finalized in the NSPS OOOOb and EG OOOOc.

Commenter: GPA Midstream Association
Comment Number: EPA-HQ-OAR-2023-0234-0299
Page(s): 13-14

Commenter: Permian Basin Petroleum Association (PBPA)
Comment Number: EPA-HQ-OAR-2023-0234-0346
Page(s): 8-9

Comment 3: Commenter 0299: **The GHGRP serves an informational purpose only—to report emissions—and it cannot be used to mandate control or reduction of greenhouse gas emissions.**

[24] Docket ID No. EPA-HQ-OAR-2021-0317.

The GHGRP serves an informational purpose only—the reporting of greenhouse gas emissions from certain sources. Indeed, when the rule was initially promulgated in 2009, EPA explicitly stated that "[t]he rule does not require control of greenhouse gases, rather it requires only that sources above certain threshold levels monitor and report emissions."[31] While GPA supports the reduction of methane emissions, any emission reduction or control requirements must be imposed under other provisions of the CAA, such as the NSPS and emission guidelines under section 111.

Unfortunately, some provisions of the proposed rule stray unlawfully into the territory of emission regulation, and these provisions should not be finalized. Many of the provisions are appropriately proposed as part of EPA's proposed NSPS OOOOb and EG OOOOc rulemaking and should not give rise to additional requirements in Subpart W. Examples of this include EPA requesting comment on the need to establish additional requirements for third-party notifiers and the verification of third-party notifications.[32] EPA requested comment on this issue in the NSPS OOOOb and EG OOOOc rulemaking;[33] it should not repeat that here. Nor should there be requirements as part of this informational reporting rule on reporting "[t]he total number of intermittent bleed natural gas pneumatic devices detected as malfunctioning in any pneumatic device monitoring survey during the calendar year,"[34] flare pilot monitoring,[35] or tank thief hatch inspections.[36] Finally, aspects of this proposal (such as proposed requirements related to flare DRE) could impact air permitting. Subpart W—a greenhouse gas reporting rule—should not be the driver on how to permit criteria and hazardous air pollutant emissions.

Footnotes:

[31] 74 Fed. Reg. 56,260 (Oct. 30, 2009).

[32] 88 Fed. Reg. at 50,300.

[33] See 87 Fed. Reg. 74,702, 74,750 (Dec. 6, 2022).

[34] 88 Fed. Reg. at 50,419.

[35] Id. at 50,429.

[36] Id. at 50,326.

[37] Id. at 50,286.

[38] Id. at 50,289.

Commenter 0346: EPA is Attempting to Incorporate Requirements in this Reporting Rule that Belong in Other Regulations

PBPA recommends that EPA refrain from including operational requirements that may have been left out of the OOOOb and OOOOc proposal into the Proposed (Reporting) Rule.

Specifically, it appears EPA is attempting to bootstrap requirements into this rule that it failed to include in the OOOOb and OOOOc proposal when it states:

Because the proposed standards in NSPS OOOOb and the proposed presumptive standards in EG OOOOc are not the same as the requirements in subpart W, the EPA is proposing a few additional requirements under subpart W for compressors subject to the proposed standards in NSPS OOOOb or standards in an applicable approved state plan or applicable Federal plan codified in 40 CFR part 62. Subpart W requires measurement of compressor sources that would not be required to be measured under the proposed standards in NSPS OOOOb and the proposed presumptive standards in EG OOOOc (e.g., blowdown valve leakage through the blowdown vent). The EPA is proposing that reporters conducting measurements of compressors under NSPS OOOOb or the applicable approved state plan or applicable Federal plan in 40 CFR part 62 would conduct measurements of any other compressor sources required to be measured by subpart W at the same time.

The Proposed Rule also includes a massive new set of recordkeeping requirements (as well as reporting obligations) for operators of produced water tanks. EPA should have included those recordkeeping requirements in the OOOOb proposal instead of trying to squeeze them into a reporting rule.

Response 3: The EPA does not agree with the commenter's assertion that the proposed rule strayed unlawfully into the territory of emission regulation. As discussed in sections I.B, II.B, and II.C of the preamble to the final rule, CAA section 136(h) requires that the EPA shall revise the requirements of subpart W to ensure the reporting under that subpart and calculation of charges under CAA section 136(e) and (f) are based on empirical data, accurately reflect the total CH_4 emissions and waste emissions from the applicable facilities, and allow owners and operators of applicable facilities to submit empirical emissions data, in a manner prescribed by the Administrator, to demonstrate the extent to which a charge is owed. The focus on empirical data and reporting of accurate total facility emissions that is the foundation of this final rule was mandated by Congress in the IRA. The EPA is finalizing several changes to the reporting requirements in this final rule to ensure the accuracy of reported emissions and improve the verification process. The accuracy of reported emissions is predicated on accurate inputs to emissions calculations. We have addressed comments related to inclusion of specific new calculation and reporting requirement mentioned in these comments, as follows:

- For responses to comments and discussion of the final rule requirements related to measurements of compressors and alignment with NSPS OOOOb and EG OOOOc, see Section III.O of the preamble to the final rule.
- For responses to comments related to produced water tanks, see Section 4.3 of this document.
- For responses to comments and discussion of the final rule requirements related to emissions from flares and alignment with NSPS OOOOb and EG OOOOc, see preamble Section III.N of the preamble to the final rule.

Commenter: American Petroleum Institute et al. (Part 1 of 2)
Comment Number: EPA-HQ-OAR-2023-0234-0402
Page(s): 7-8

Comment 4: Monitoring, measurement or inspection requirements (e.g., flare monitoring, etc.) included in Subpart W should be consistent across other air quality programs. The Industry Trades are concerned with potentially conflicting monitoring or other compliance requirements between the Greenhouse Gas Reporting Program (GHGRP) and future air quality rulemaking under New Source Performance Standards (NSPS) or other air quality programs under EPA's office of Air and Radiation. The Industry Trades are recommending that EPA remove prescriptive monitoring, sampling or inspection requirements from the GHGRP and instead reference data made available through requirements in other existing regulations. … Finally, the Industry Trades wish to make clear that monitoring methods should not define emission reporting parameters.

Response 4: As discussed in Section I.F of the preamble to the final rule, the EPA is finalizing revisions to certain requirements in subpart W relative to the requirements finalized for NSPS OOOOb and the presumptive standards in EG OOOOc (which will inform the standards to be developed and codified at 40 CFR part 62). As in the 2016 rule, the final amendments also allow facilities to use a consistent method to demonstrate compliance with multiple EPA programs. These final standards will limit burden for subpart W facilities with affected sources that are also required to comply with the NSPS OOOOb or a State or Federal plan in part 62 implementing EG OOOOc by allowing them to use data derived from the implementation of the NSPS OOOOb to calculate emissions for the GHGRP rather than requiring the use of different monitoring methods.

Commenter: GPA Midstream Association
Comment Number: EPA-HQ-OAR-2023-0234-0299
Page(s): 2, 15

Comment 5: More extensive comments are provided in this letter, but to highlight our key areas of concern the following summary is provided:

…

- Alignment with Other Federal Regulations – EPA has attempted but failed to properly incorporate requirements from other federal regulations. This is most notable with the "Other Large Release Events" source category, which provides an avenue to circumvent the requirements of EPA's proposed "Super Emitter Response Program" ("SERP") under the Clean Air Act's ("CAA") new source performance standards provisions and is misaligned with the incident reporting thresholds of the Department of Transportation's Pipeline and Hazardous Materials Safety Administration ("PHMSA"). Further misalignment can be found with additional requirements for compressor vent measurements and flare requirements. GPA notes that methane reduction and reporting requirements have been proposed or are being contemplated across many federal agencies and departments. Inconsistency between these requirements will simply be untenable for operators and will not support data transparency.

…

The GHGRP is misaligned with certain other EPA programs.

For sources subject to NSPS OOOOb and EG OOOOc, EPA says "the proposed amendments would also allow facilities to use a consistent method to demonstrate compliance with multiple EPA programs."[39] Unfortunately, however, as GPA has noted in its comments, the proposed rule introduces inconsistencies between the two EPA programs, which are listed here:

- Measurement of isolation and blowdown valves leakage for compressors subject to NSPS OOOOb or EG OOOOc. This is discussed further below in Comment 64.
- Proposed NSPS OOOOb identifies optical gas imaging ("OGI") as the best system of emission reduction ("BSER"), but Subpart W OGI emission factors are higher than those for Method 21. This is discussed further below in Comment 67.
- Inconsistencies between measurement requirements for leak surveys under Subpart W and other EPA fugitive component monitoring requirements. This is discussed further below in Comment 70.
- Duplicative reporting requirements for super emitter events and notifications. This is discussed further below in Comment 17.

Footnote:

[39] Id. at 50,288.

Response 5: We discuss alignment with NSPS and EG OOOOc related to the specific areas identified in these comments in Sections III.O, III.P, and III.B of the preamble to the final rule, as well as the response to Comment 6 in Section 3.4 of this document.

28.5 Implementation of WEC

Commenter: Public Hearing Transcript
Comment Number: EPA-HQ-OAR-2023-0234-0224
Page(s): 17-18 (Laurie Anderson), 24-25 (Joan Brown), 32 (Tracy Sabetta), 34 (Dr. Dakota Raynes)

Commenter: National Federation of Independent Business, Inc. (NFIB)
Comment Number: EPA-HQ-OAR-2023-0234-0336
Page(s): 2

Commenter: Permian Basin Petroleum Association (PBPA)
Comment Number: EPA-HQ-OAR-2023-0234-0346
Page(s): 1-2

Comment 1: Commenter 0224: The accuracy of subpart W data is even more important now that the Inflation Reduction Act's methane fee, an important tool for incentivizing pollution reductions, is based on the emissions reported to this program.

…

Second the methane fee structure outlined in the Inflation Reduction Act relies on emissions data reported via this greenhouse gas program.

…

However, as these comments relate to the Methane Emissions Reduction Program, which cuts methane from oil and gas operations through a charge on wasteful pollution, it is critical that the amount of pollution is verifiable so the MERP waste charge is assessed on the true volume of pollution created by the oil and gas industry and, through this charge, operators are further compelled to reduce wasteful emissions.

…

In addition, I know that technical comments are being held in high esteem but I believe also that ethical moral values, implications need to also be held equally. Moneys from the Methane Reduction Program that are collected from excess methane emissions need to go for further monitoring emissions tracking to ensure adequate reporting and other needs for our front-line communities. Some new technology including aerial monitoring could assist in detection in quantifying of emissions in hard to reach and isolated areas.

Commenter 0336: (1) Section 60113 of the Reconciliation Act of 2022 (informally called the Inflation Reduction Act) (Public Law 117-169, August 16, 2022) enacted a new section 136 of the Clean Air Act (42 U.S.C. 7436). Section 136(c) requires the EPA Administrator to impose a charge on "methane emissions that exceed an applicable waste emissions threshold under subsection (f)" from an owner or operator of a covered petroleum or natural gas facility that "reports more than 25,000 metric tons of carbon dioxide equivalent of greenhouse gases emitted per year pursuant to subpart W of part 98 of title 40, Code of Federal Regulations, regardless of the reporting threshold under that subpart." The charge is a tax. Given the relative inelasticity of demand for fossil-fuels, the result of the tax is an increase of the cost to consumers of fossil-fuel energy.

Commenter 0346: Before discussing the specific major technical and policy flaws in the proposed rule, it is critical to provide context for its existence and likely impact broadly. First and most important, the proposed rule, in conjunction with efforts to incorporate elements of the the-not-yet-final New Source Performance Standards ("NSPS") and Emissions Guidelines for Greenhouse Gas Emissions from Existing Crude Oil and Natural Gas Facilities ("EG") OOOOb/c pending rule, will dramatically increase the scope and breadth of activities and oil and gas operators that will be subjected to methane emissions reporting requirements. As a result, the intended effect will be to dramatically increase those operations subject to the charge for emissions above 25,000 metric tons of CO2 or its equivalent as established in the Inflation Reduction Act ("IRA").

Utilization of the rulemaking process in this manner is not consistent with the IRA. In fact, the author of the methane charge legislation, Sen. Joe Manchin (D-WV), the Chairman of the Senate Energy and Natural Resources Committee, has made clear that his intention is that only those operations that were subject to Subpart W on the date of enactment are to be subject to the charge. He was particularly concerned about the impact on small to medium producers. In his June 6, 2023, letter to the Environmental Protection Agency ("EPA") regarding concerns over implementation of the charge he wrote:

The statute clearly intends to exempt marginal wells and smaller producers from the fee. EPA must make it clearly understood that those entities not subject to the current Subpart W Greenhouse Gas Reporting Program are not subject to EPA fees under MERP.

Our comments will show in great detail how the requirements under the proposed rule will dramatically increase the number of small and mid-sized operations subject to the charge.

Response 1: The EPA acknowledges these comments and reiterates that the WEC is being addressed through a separate rulemaking. Implementation of the WEC is addressed in the Notice of Proposed Rulemaking for the Waste Emissions Charge for Petroleum and Natural Gas Systems (WEC proposal) published on January 26, 2024 (89 FR 5318), and comments related to implementation of WEC are outside the scope of this subpart W rulemaking.

Commenter: Independent Petroleum Association of America (IPAA)
Comment Number: EPA-HQ-OAR-2023-0234-0265
Page(s): 1-3

Commenter: American Exploration and Production Council
Comment Number: EPA-HQ-OAR-2023-0234-0295
Page(s): 31-32

Commenter: GPA Midstream Association
Comment Number: EPA-HQ-OAR-2023-0234-0299
Page(s): 11

Commenter: BP America Inc.
Comment Number: EPA-HQ-OAR-2023-0234-0345
Page(s): 6-7

Commenter: Wyoming Department of Environmental Quality (WDEQ)
Comment Number: EPA-HQ-OAR-2023-0234-0388
Page(s): 4-6

Commenter: American Petroleum Institute et al. (Part 1 of 2)
Comment Number: EPA-HQ-OAR-2023-0234-0402
Page(s): 15-16

Comment 2: Commenter 0265: Subpart W Mandate

Initial efforts to revise Subpart W were included in 2022 as a part of a similarly titled proposal – Revisions and Confidentiality Determinations for Data Elements under the Greenhouse Gas Reporting Rule; Docket No. EPA-HQ-OAR-2019-0424. However, enactment of the Inflation Reduction Act (IRA) mandated that EPA revise Subpart W because of its use as the emissions basis for inclusion in and the calculation of the Methane Emissions Reduction Program (MERP) methane tax. In fact, no action taken now to revise Subpart W cannot be evaluated without considering and understanding its implications under the methane tax.

The mandate to revise Subpart W is no small task. The history of Subpart W demonstrates that its accuracy was never intended to be the basis for use as a taxing mechanism. Generally, its emissions factors were developed from limited emissions studies that were never structured to develop precise emissions estimates. The Inflation Reduction Act mandate requires EPA to:

Not later than 2 years after August 16, 2022, the Administrator shall revise the requirements of subpart W of part 98 of title 40, Code of Federal Regulations, to ensure the reporting under such subpart, and calculation of charges under subsections (e)[1] and (f)[2] of this section, are based on empirical data, including data collected pursuant to subsection (a)(4)[3] , accurately reflect the total methane emissions and waste emissions from the applicable facilities, and allow owners and operators of applicable facilities to submit empirical emissions data, in a manner to be prescribed by the Administrator, to demonstrate the extent to which a charge under subsection (c)[4] is owed.

The current proposal fails to remotely meet this mandate regarding either time or substance.

One obvious element of the MERP is that its timelines for action are completely inconsistent with reality. It initiates the methane tax in 2025 based on 2024 emissions reporting while falsely promising that compliance with federal Subpart OOOO, OOOOa, OOOOb, and OOOOc regulations and emissions guidelines will void the tax when these regulations will not be fully implemented until at least 2028. Regarding the Subpart W revisions, it requires EPA to finish its revisions by August 2024. The scope of actions that must be undertaken for the full revision of Subpart W, as described in the Inflation Reduction Act, cannot be completed in a two-year window. However, rather than execute its mandated task, EPA proposes a thinly disguised cosmetic rework of the same material that has existed for years with little or no validation by EPA – and, even then, EPA does not apply its changes for a year after its mandated deadline.

If Congress intends to impose millions of dollars of taxes on methane emissions from the petroleum and natural gas industries, potentially crippling the production of millions of barrels and cubic feet of these American products, its mandate to EPA to revise the appallingly inaccurate emissions tools of Subpart W must be read as a serious and thorough methodological effort.

Such an effort would have several key elements. First, it must recognize the nature of emissions particularly from petroleum and natural gas production and production related emissions. Second, it must recognize that some emissions can be measured and others will continue to need emissions estimates from factors; these decisions will be particularly influenced by the economic status of the facility operator. Third, it must recognize that EPA will need to validate these measurement tools and the emissions factors.

Emissions from petroleum and natural gas systems are characterized by leaks from pieces of equipment that cannot be readily or continuously measured. They differ by an array of numerous factors – crude oil versus natural gas, associated gas or low volatility crude, wet or dry gas wells. All wells decline as they produce, changing the volume and composition of their production. Studies have shown that low production wells differ from high volume wells. The economics of production differs between high and low production wells, frequently an indication of the capitalization of the operations. The amount of active equipment at a facility changes with production. Some facilities have gathering and compression equipment on site; others do not. Many low production wells do not operate daily. Many small natural gas wells have booster compressors to suck natural gas from the well bore. Emissions analyses show that 90 percent of emissions come from about 10 percent of facilities, with storage tanks and some pneumatic controllers accounting for the predominant percentage of these emissions.

Because so many of the potential emissions sources from petroleum and natural gas production facilities are diverse components like valves, flanges, storage tanks, connectors, and controllers that are individually small, there are not straightforward methods to routinely monitor these emissions. Studies that have been conducted have used methods like bagging equipment to collect emissions for a short period of time. This technique is infeasible for routine operations. Newer facilities with higher volumes of production and more equipment at a site have been able to collect emissions from equipment like pneumatic controllers and pneumatic pumps and route them to vapor capture or combustion. However, such technology is limited if not impossible for older, low production facilities. Consequently, while EPA has been directed to expand the use of actual facility-based emissions data to quantify emissions, there will continue to be a certain need for emissions factors for emissions that are too difficult to measure or too expensive to collect for low production operations.

Perhaps most importantly for EPA and where EPA has failed most clearly in this proposal is the need to produce validated emissions calculations and validated emissions factors for Subpart W. Subpart W presents a long history of relying on limited studies from the 1990s appended using questionable analyses by environmental lobbyists to produce reports on petroleum and natural gas production facilities. Many of these same analyses have been used for the development of EPA methane regulations in Subpart OOOO, OOOOa, OOOOb and OOOOc. Missing from all these EPA actions is careful, thorough validation of the analyses by EPA and replication of these analyses. Many of these studies have been based on a small number of facilities, based on drive-by analysis with no information on facilities' operation, based on recalibrating data in different ways without any new information, based on applying statistical manipulation to produce headline grabbing allegations. Congress' mandate to EPA is connected to very real methane tax consequences. EPA cannot meet this mandate without collecting and analyzing its own data to develop sound, robust emissions calculation methods and emissions factors. This proposal fails completely to meet this essential test.

These challenges for EPA to meet its Subpart W mandate demonstrate clearly that it cannot be done properly in the two-year window of the MERP timeline. For EPA to do it job right, it needs to get changes made to the Inflation Reduction Act to make its timelines for both Subpart W and the completion and implementation of the Subpart OOOOb regulations and OOOOc emissions guidelines to complete these actions before collecting methane taxes from American producers.

Footnotes:

[1] Emissions charge amount

[2] Waste emissions threshold

[3] Direct and indirect costs required to administer this section, prepare inventories, gather empirical data, and track emissions

[4] Waste emissions charge

Commenter 0295: **EPA's Proposal conflicts in key aspects with the text and purpose of new CAA § 136.**

First, as explained above, CAA Section 136(h) directs EPA to ensure that the calculation of the MERP charge under other provisions in Section 136 is accurate and based on empirical data. But, by irrationally and without authority severing this rulemaking from its forthcoming rulemaking implementing the charge program. The fact that the methane charge will be phased in through three escalating stages, see CAA § (e)(2)(A)-(C), does not change the fact that Congress directed to revise so that the MERP charge program could be properly implemented. Because, as explained above, EPA cannot legally or rationally keep this Subpart W-revisions rulemaking separated from its forthcoming MERP charge rulemaking, the Agency needs to provide sufficient opportunity for review of both proposals and accept comment in that rulemaking both on its own provisions and on the provisions in this Proposal in light of the interaction between the two. Notwithstanding that neither proposal should incorporate proposed but not yet finalized components of the developing CAA 111 rulemakings as discussed in more detail above. Only that will ensure that Congress's direction in CAA § 136 is carried out lawfully, rationally, and harmoniously. Any other approach is destined to sow confusion and frustrate the new statutory section's goals of accurate reporting and proper implementation of the charge program for the purpose of incentivizing emission reduction.

Commenter 0299: **The proposed changes to Subpart W cannot be properly assessed independently of the Waste Emissions Charge.**

EPA states that it "intends to undertake one or more separate actions in the future to implement the waste emissions charge" and as a result, it believes "implementation of the waste emissions charge is outside the scope of this rulemaking."[16] This position does not make sense. The revisions to Subpart W (the subject of this rulemaking) are intertwined with the waste emissions charge and commenting independently is problematic. Indeed, section 136(h), which directs EPA to undergo this rulemaking to revise Subpart W, references both "the reporting under [Subpart W], and calculation of charges under subsections (e) and (f)."[17] These two provisions go hand in hand, and separating this rulemaking on the revision of Subpart W from the rulemaking on the implementation of the waste emissions charge creates an artificial barrier that Congress did not intend. At a minimum, EPA should consider any comments made in this rulemaking that involve the waste emissions charge that are tied to the proposed revisions to Subpart W. To do otherwise would be arbitrary and capricious.

GPA also urges EPA to reopen the comment period for this proposal following the publication of any proposed rules related to implementing the waste emission charge.

Footnotes:

[16] 88 Fed. Reg. at 50,286.

[17] CAA § 136(h), 42 U.S.C. § 7436(h) (emphasis added).

<u>Commenter 0345</u>: **Longer-term stability of GHGRP is paramount given the importance of the program to the Methane Waste Emissions Charge.**

Given the significant monetary consequences for methane emissions introduced by the methane charge, it is important to establish stability in the scope of GHG reporting that may be subject to that fee. As explained in the preamble to the initial GHGRP rule in 2009, the rule was originally established as an information gathering mechanism in order to better inform policymakers, regulators, industry, and other stakeholders.[17] EPA stated that it would use this information to inform the development of future policies and regulations under the CAA, such as whether to include new sources under "New Source Performance Standards."[18] Subpart W itself was incorporated into the GHGRP for this purpose as well — including, for example, to "assist[] in the development of emissions reduction regulations in the petroleum and natural gas industry."[19]

The GHGRP is a critical information-disclosure and policymaking tool, which benefits from continuous improvement and updates to produce accurate and reliable information. However, because it was not established as a program with direct regulatory or financial consequences, frequent changes in definitions and methodologies did not create direct monetary ramifications for reporters nor explicitly impact decisions concerning long-term investments in infrastructure and technology.[20]

For the first time, however, the methane charge will shift the purpose of the GHGRP beyond just information-gathering, and establish a direct monetary charge based on the emissions reported under Subpart W.[21] Given the significance in this shift in the nature and consequences of Subpart W reporting, and the investments and operational planning decisions that will be made by facility operators in relation to the methane charge, it is important that there is long-term stability regarding the types of sources covered by Subpart W and how emissions calculations are performed going forward. We hope EPA considers this as it develops the final Subpart W rule and with respect to the implementation of the methane charge.

Footnotes:

[17] See 74 FR at 56,264-56,265, 56,279 (stating, for example, that "[t]he goal of this rule is to collect accurate and consistent data of sufficient quality to inform future CAA policy and regulatory decisions").

[18] See 74 FR at 56,265; see also 74 FR 16,446, at 16,456 (Apr. 10, 2009) (preamble to the GHG reporting proposed rule) (stating that the purpose of establishing the GHGRP is to "[o]btain data that is of sufficient quality that it can be used to support a range of future climate change policies and regulations…").

[19] See Mandatory Reporting of Greenhouse Gases: Petroleum and Natural Gas Systems, 75 FR 74,458, at 74,460 (Nov. 30, 2010).

[20] See EPA, "Subpart W Rulemaking Resources," https://www.epa.gov/ghgreporting/subpart-wrulemaking-resources (listing the thirteen rulemakings to revise Subpart W since it was first incorporated into the GHGRP in 2010).

[21] See 42 U.S.C. § 7436(c).

Comment 0388: **WDEQ anticipates that there could be significant adverse impacts to Wyoming's economy resulting from the proposed rule, but the full extent of those adverse impacts are impossible to evaluate without EPA's promulgation, or withdrawal, of the Waste Emissions Charge rule.**

EPA' s proposed rule repeatedly references Section 60113 of the Inflation Reduction Act in its Executive Summary and, specifically, the "Waste Emissions Charge" that will be applied to sources that exceed waste thresholds of more than 25,000 metric tons of carbon dioxide equivalent. The proposed rule will invariably impact Wyoming's oil and natural gas industries because of this threshold and the expanded domain of sources that are subject to reporting, consequently resulting in a greater possibility of sources that will be subject to the Waste Emissions Charge. Additionally, there will be economic impacts associated with the potentially significant training and equipment costs that the regulated community will incur in attempting to comply with the significantly expanded reporting requirements in this proposed rule, as well as other associated rules such as EPA's proposed OOOOb and OOOOc requirements.

However, commenters such as WDEQ are unable to fully evaluate adverse economic impacts associated with this proposed rule, and the proposed methane rule and supplemental proposal, until EPA releases its proposed Waste Emissions Charge rule. EPA has provided some preliminary information on what it may include in its proposed Waste Emissions Charge - such as the price per metric ton for the Waste Emissions Charge to apply in 2024, 2025, 2026, etc. - but the manner in which the Charge will function in relation to this proposed rule, and the proposed methane rule and supplemental proposal, is quite ambiguous. Essentially, a crucial piece of the proverbial puzzle is missing because the Waste Emissions Charge rule has not yet been proposed and, as such, it is impossible to evaluate the full scale of economic impacts. It is WDEQ's experience, in performing preliminary outreach on the proposed rule, that other states' regulatory agencies and affected stakeholders are also struggling with this dilemma.

As one of the nation's top producers of oil and natural gas, Wyoming may bear a disproportionate burden to implement this rule compared to other affected states. As of October 2022, Wyoming ranked eighth nationally in oil production[1] and, for the 2021 calendar year, Wyoming ranked ninth in marketed production of natural gas.[2] Furthermore, Wyoming has 16 of the nation's 100 largest natural gas fields, including the Pinedale and Jonah fields, which rank among the top 10.[3] According to the Wyoming State Geological Survey summary report published in January 2023, Wyoming operators were on track to produce about 90 million barrels of oil in 2022.[4] The importance of oil and gas development to the State is further captured by the Wyoming State Geological Survey:

> Oil and gas severance taxes and royalties contribute funding to state highway and county road construction and maintenance; water projects; local governments; school districts, scholarships, and the University of Wyoming and community colleges; and state-government agencies. Combined, oil and natural gas brought in more than $372,000,000 in severance taxes for the state coffers during fiscal year 2021.[5]

Wyoming's oil and gas industry is also responsible for the direct and indirect employment of tens of thousands of workers, as cited in the summary report:

> In 2019, when Wyoming oil production was at an all-time high, these oil and gas extraction and support workers received upwards of $1.1 billion in total wages to spend in their communities.[6]

It is quite evident that the State of Wyoming will experience adverse economic impacts occasioned by EPA's proposed rule and other associated proposals pertaining to the oil and natural gas industry. However, WDEQ and other state regulatory agencies, as well as affected stakeholders, cannot reasonably determine the extent of those impacts until EPA has promulgated its Waste Emissions Charge proposed rule. EPA should extend the public comment period for this proposed rule until EPA has promulgated the Waste Emissions Charge rule and given the public time to review and evaluate how it overlaps with this proposal.

Footnotes:

[1] U.S. Energy Information Administration, https://www.eia.gov/state/rankings/#/series/46

[2] U.S. Energy Information Administration, https://www.eia.gov/state/rankings/#/series/47

[3] U.S. Energy Information Administration, Wyoming State Profile and Energy Estimates, http://www.eia.gov/state/analysis.php?sid=WY

[4] Wyoming State Geological Survey, Erin A. Campbell, Director and State Geologist, “Oil & Natural Gas Resources in Wyoming,” January 2023 Summary Report

[5] Wyoming State Geological Survey, Erin A. Campbell, Director and State Geologist, “Oil & Natural Gas Resources in Wyoming,” January 2022 Summary Report

[6] Wyoming State Geological Survey, Erin A. Campbell, Director and State Geologist, “Oil & Natural Gas Resources in Wyoming,” January 2022 Summary Report

Commenter 0402: Subpart W and the Waste Emissions Charge Program

Reporting requirements under Subpart W must be reconsidered in light of the role that Subpart W will play in implementing the Waste Emissions Charge Program.

As noted above, key elements of the Proposed Rule are not adequately explained or supported because EPA failed to assess or explain how the proposed new reporting requirements square with the various elements of the WEC. A fundamental aspect of this issue is the fact that the information generated under Subpart W will be used for wholly different purposes under the WEC than it previously was under Subpart W alone. In particular, the emissions information reported under Subpart W will have new and significant legal ramifications because it will be used to determine the applicability of fee determinations under the WEC. So, Subpart W will be extended from a program that provides emissions data for informational purposes to support the development of the national Greenhouse Gas Inventory by EPA into a program that also serves as the compliance assurance component of the WEC. Simply put, this change in the rule now has financial implications for companies.

That expansion in the basic purpose of Subpart W is highly relevant to the Proposed Rule and in meeting EPA’s obligation to revise Subpart W to “allow owners and operators of affected facilities … to demonstrate the extent to which a charge under subsection (c) is owed.”[11] For example, as explained above, the extent to which “other large release events” should be reported under Subpart W must be established with an eye toward the relevance of the reported information in assessing the applicability and substantive requirements under the WEC program. The same is true of the other “gaps” in Subpart W that EPA proposes to fill in the Proposed Rule.

…

Also, emissions information from oil and gas operations is developed to satisfy a wide range of regulatory and non-regulatory obligations beyond the WEC – including to show compliance with the NSPSs and NESHAPs for such operations and to satisfy emissions reporting obligations (e.g., the SEC’s proposed disclosure rule). EPA must clearly specify the information needed to implement the WEC and prevent collateral challenges to WEC compliance based on information generated for other purposes under other regulatory programs.

In short, Subpart W is now unique among the GHGRP subparts in that emissions information submitted under Subpart W will serve regulatory purposes not shared by other industries that report under other subparts. As a result, EPA now must consider the implications under the WEC program of all Subpart W requirements and explain how Subpart W and the WEC will be integrated into a consistent, coherent, and workable program. EPA's failure to do so in the Proposed Rule constitutes a failure to consider a highly important aspect of the proposal and prevents interested parties from fully understanding, assessing, and commenting on the proposal.

Footnote:

[11] Id.

Response 2: The EPA disagrees with the commenters' positions that the subpart W and WEC rulemakings must be combined, that comments to this rulemaking must be considered under the WEC proposal, and that subpart W revisions should be reproposed after the WEC rulemaking. Subpart W and WEC are related; the EPA recognizes that the data reported under subpart W (*e.g.*, emissions and hydrocarbon throughput), as required by Congress, are inputs into the WEC calculations and that Congress therefore required the EPA to revise subpart W consistent with the directives in CAA section 136(h). The EPA has done so. In this rulemaking, the EPA is finalizing revisions to ensure reporting is based on empirical data under subpart W and to ensure reported emissions accurately reflect total facility methane emissions. However, while the subpart W requirements for reporting result in data that will be used in calculation of the WEC, revising subpart W consistent with CAA section 136(h) is separate from the EPA taking action on implementation of the WEC. The EPA therefore believes it is reasonable and appropriate to address the subpart W revisions and WEC through two separate rulemakings, including after taking into consideration the statutory deadline provided in CAA section 136(h) for the subpart W rulemaking revisions. The EPA also notes that stakeholders will be able to submit any applicable comments to the docket for the WEC proposal for consideration in the development of the final WEC rule. We note that where the EPA determined upon review that aspects of the proposal were closely tied to WEC implementation (*e.g.* see Section III.A.1.b of the preamble to the final rule), we did not take final action at this time and intend to do so on a timeline similar to the WEC final rule.

Regarding comments that the EPA was required to produce validated emissions calculations and emissions factors for subpart W and failed to do so, the EPA disagrees. We note that CAA section 136(h) does not require the development of an emission factor for each source, but rather requires that the reporting and calculation of methane and waste emissions are based upon empirical data. The emissions calculation methodologies prescribed in subpart W include emission factors, as well as direct emissions measurement, the combination of measurement with engineering calculations, and approaches based upon engineering calculations. As discussed in Section II.B of the preamble to the final rule, in consideration of the mandate under CAA section 136(h), we re-evaluated existing methodologies for each source to determine if they are likely to accurately reflect methane and waste emissions at an individual facility, whether the existing methodologies used empirical data (*e.g.*, direct emissions measurements or monitoring of methane emissions; measurement of associated parameters), and whether the existing methodologies should be modified or replaced or if new optional calculation methodologies should be added to meet CAA section 136 directives.

In cases where our re-evaluation of existing methodologies identified data sufficient to develop new or revised emission factors, these factors have been promulgated under the final rule. The review of underlying studies or data sources and derivation of these emission factors are discussed in the TSD to the final rule.

Commenter: Arkansas Independent Producers and Royalty Owners (AIPRO)
Comment Number: EPA-HQ-OAR-2023-0234-0382
Page(s): 2-3

Commenter: Ute Indian Tribe of the Uintah and Ouray Reservation
Comment Number: EPA-HQ-OAR-2023-0234-0421
Page(s): 3

Comment 3: Inflation Reduction Act ("IRA") and Associated "Waste Emissions Charge"

… To compound the issue, reporters will soon be subject to waste emissions charges/methane taxes, under the IRA, which are calculated based on the inaccurate emissions data.

Another obvious issue with the proposed Subpart W revisions, in relation to the IRA, is that its timelines for action are completely inconsistent with reality. The IRA initiates the methane tax in 2025 based on 2024 emissions reporting while falsely promising that compliance with federal Subpart OOOO, OOOOa, OOOOb, and OOOOc regulations and emissions guidelines will void the tax when these regulations will not be fully implemented until at least 2028. Further, the IRA requires EPA to finish its revisions of Subpart W by August 2024. The scope of actions that must be undertaken for the full revision of Subpart W, as described in the Inflation Reduction Act, cannot be completed in a two-year window. However, rather than execute its mandated task, EPA proposes a thinly disguised cosmetic rework of the same material that has existed for years with little or no validation by EPA. And, even then, EPA does not apply its changes for a year after its mandated deadline. If Congress intends to impose millions of dollars of taxes on methane emissions from the petroleum and natural gas industries, potentially crippling the production of millions of barrels and cubic feet of these American products, its mandate to EPA to revise the appallingly inaccurate emissions tools of Subpart W must be read as a serious and thorough methodological effort.

As such, AIPRO strongly encourages the EPA to withdraw the proposed revisions in Docket ID No. EPA–HQ–OAR–2023–0234

Commenter 0421: **Timing**

The Tribe has identified a number of timing issues presented by the Proposed Rule. The EPA published the Proposed Rule in the Federal Register on August 1, 2023. Comments are due by October 2, 2023. The changes to Subpart W are scheduled to take effect on January 1, 2025, and must be used for calculating emissions starting in Reporting Year ("RY") 2025; with an exception for oil and gas sent to sale from each well plugged and abandoned in 2024, which is required to be reported in RY 2024 pursuant to the Methane Emission Reduction Program ("MERP").

It is critical to note that the timing for Subpart W reporting does not align with timing for MERP reporting. The result is that reported emissions will likely see a significant increase between RY 2024 and RY 2025 via the use of revised reporting and calculation methodologies, while available off-ramps will not become effective until at least 2027 or 2028. These timing discrepancies both in terms of implementation and relief threaten to create a scheme of regulatory incoherence that will have real impacts on our Tribe's bottom line.

Response 3: The EPA does not agree with the commenter's assertion that the subpart W proposal should be withdrawn. As noted in the comments, Congress established a deadline of August 2024 for finalization of revisions of subpart W and required that the waste emissions charge first go into effect for the 2024 reporting year. The EPA intends to meet this timeline. With respect to the effective date of new calculation methodologies, see Section 27.2 of this document and Section IV of the preamble to the final rule for discussion of the availability of optional new calculation methodologies for reporting year 2024. We note that the implementation of the Waste Emission Charge and the timeline of the associated exemptions are out of scope for this rulemaking; however, with the availability of all identified empirical data methods appropriate for the reporting year 2024 provisions as options methodologies, facilities will have the necessary tools to demonstrate accurate emissions for which a charge is owed.

Commenter: Riverside Energy Group
Comment Number: EPA-HQ-OAR-2023-0234-0230
Page(s): 2

Commenter: Michigan Oil and Gas Association (MOGA)
Comment Number: EPA-HQ-OAR-2023-0234-0298
Page(s): 3

Comment 4: Commenter 0230: Furthermore, EPA is granting exemptions on NSPS OOOO regulations, which are not finalized. Those regulations should be finalized prior to the WEC & Proposed Subpart W so the oil/gas community can analyze any exemptions before a fee is charged.

Commenter 0298: 5. Clarification of Exemptions proposed in NSPS OOOOb & OOOOc and the IRA

The EPA has repeatedly proposed exemptions in proposed NSPS OOOOb, NSPS OOOOc and the IRA. MOGA constituents have commented that the exemptions they have in these proposed rules are not clear or have not specifically been outlined. MOGA attempted to develop specific comments related to the proposed revisions to Subpart W calculations, but co-mingled proposed and unfinalized regulations make commenting impractical at this time. MOGA recommends that the EPA specify exemptions prior to requesting comments on modifications to the Subpart W calculations that may have financial implications.

Response 4: The EPA disagrees with the commenter's assertion that commenting on the modifications to subpart W is impractical without a proposed language for implementation of

WEC exemptions. Subpart W is being revised, as mandated by Congress, to ensure the reporting under subpart W and calculation of charges are based on empirical data, accurately reflect the total methane emissions and waste emissions from applicable facilities, and allow owners and operators of applicable facilities to submit empirical data in a manner prescribed by the Administrator, to demonstrate the extent to which a charge is owed. Implementation of the WEC is outside the scope of this rulemaking. The EPA's proposed approach for implementation of WEC exemptions is discussed in the WEC proposal published in the Federal Register on January 26, 2024 (89 FR 5318). We note that the final NSPS OOOOb and EG OOOOc rules were published in the Federal Register on March 8, 2024 (89 FR 16820).

Commenter: Ute Indian Tribe of the Uintah and Ouray Reservation
Comment Number: EPA-HQ-OAR-2023-0234-0421
Page(s): 3

Comment 5: Notwithstanding the inclusion of such off-ramps and implementation extensions, the Tribe also encourages the EPA to fully distribute the $1.55 billion set aside in the MERP to assist operators with emission reduction efforts before implementing fee assessments.

Response 5: The EPA is moving expeditiously to implement the incentives for methane mitigation and monitoring and anticipates; however, those steps are outside the scope of this rulemaking. For current information on the funding opportunities under the Methane Emissions Reduction Program, stakeholders should visit: https://www.epa.gov/inflation-reduction-act/methane-emissions-reduction-program.

Commenter: EnerVest Operating, LLC
Comment Number: EPA-HQ-OAR-2023-0234-0229
Page(s): 6

Comment 6: Facility Definition

EnerVest urges the EPA to limit the definition of "facility" for oil and natural gas operations, when used to calculate the lower limit for exceptions to the Methane Tax, to the following definition: a facility for oil and natural gas operations shall be defined as a well pad site, whether for a single well or multiple wells, for the purposes of calculating any Methane Tax due under the Inflation Reduction Act. We believe the definition, if not modified, could include an entire basin as one facility. An operator in any one basin can have many wells that are disconnected from each other, which may or may not share the same production pipelines, and are therefore certainly not one facility. Each well pad site is its own facility. Limiting the definition as we propose would help operators who have marginal wells and would still enable EPA to accomplish the goals of the act by targeting those well pad sites with significant emissions. As such, we urge the EPA to limit the definition of facility as outlined.

Response 6: The EPA did not reopen the definition of the "Onshore petroleum and natural gas production" industry segment, and as such the request to change this definition is outside the scope of this rulemaking.

Commenter: Williams Companies, Inc.
Comment Number: EPA-HQ-OAR-2023-0234-0394
Page(s): 3, 16-20

Comment 7: Finally, Williams urges the EPA to address what we believe is a notable gap in the Proposed Rule regarding the phrase "gas sent to sale" in the context of the natural gas transmission industry segment.

…

The EPA needs to address the term "Gas Sent to Sale" prior to promulgating the calculation of methane intensity for the Inflation Reduction Act Waste Emissions Charge.

The revisions to Subpart W set forth in the Proposed Rule mark the EPA's first step towards implementing Section 60113 of the Inflation Reduction Act of 2022 (IRA). Section 60113 added Section 136 to the Clean Air Act (CAA), "Methane Emissions and Waste Reduction Incentive Program for Petroleum and Natural Gas Systems." Section 136 directs the EPA to impose a fee on methane emitted from each applicable oil and natural gas facility that reports CO2e emissions over 25,000 MT pursuant to the Greenhouse Gas Reporting Program (GHGRP).

The revisions in the Proposed Rule are focused on improving how the empirical data for each source category are identified and collected. Knowing these revisions will have a significant impact on how the Waste Emissions Charge (WEC) calculation[37] (yet to be proposed by EPA[38]) could be developed and impact industry, Williams closely examined whether the Proposed Rule sufficiently addresses some questions left open in the IRA. Accordingly, Williams had to examine the various ways the methane intensity and the WEC could be calculated in a manner consistent with the IRA.[39] Through this exercise, Williams identified an important concern in the Proposed Rule. The Proposed Rule, following the language of the IRA, creates a complication for the interstate natural gas pipeline industry segment because "Gas Sent to Sale" does not conceptually correspond with our business model and without clarification in the Subpart W revision could result in a methodology that does not fully reflect the intent of Congress.

Williams proposes "Natural Gas Sent to Sale" for both the Onshore Natural Gas transmission compression and transmission pipeline segments be limited to the quantity of gas transferred to third parties as per 40 C.F.R. §98.236(aa)(11)(iv). Using the quantity of gas transported through the transmission compressor station, data required by 40 CFR §98.236(aa)(4)(i) to be reported related to throughput, to represent gas "sent to sale from or through such facility" pursuant to the IRA can lead to double counting of "Natural Gas Sent to Sale". Results from Williams' hypothetical calculation show compressor station methane intensities, for a vast majority of stations, to be well below the 0.11% methane intensity fee threshold Congress used in the IRA. When netted with other compressor facilities along the pipeline route, the methane intensity continues to shrink. This result suggests the Agency needs to closely examine how it needs to modify or define the phrase "Gas Sent to Sale" to better reflect the functionality and transportation of onshore natural gas transmission systems and yield methane intensity values comparable to the methane intensity contained in the IRA.

To better illustrate why this distinction of "Natural Gas Sent to Sale" is important, Williams must share a simple yet workable solution or formula for the methane fee. The formula below is based on data already gathered by the EPA in the GHGRP, or simple additional information to be reported in the GHGRP:

$$\$ = (I_a - I_{IRA}) \times NG \times 1000 \times \rho_{CH4} \times 10^{-3} \times Fee_{MT}$$

Where:

$ = Fee amount for a specific facility
I_a = Calculated actual methane intensity, in thousand standard cubic feet of methane per thousand standard cubic feet of natural gas throughput at the facility
I_{IRA} = Methane intensity threshold for applicable industry segment. Use 0.11% for Transmission, Storage, Transmission Pipeline, LNG Import/Export and 0.05% for Gathering & Boosting, Processing
NG = Natural gas sent to sale, i.e., throughput of natural gas for the facility, in thousand standard cubic feet
1000 = Conversion factor from thousand standard cubic feet to standard cubic feet
ρ_{CH4} = Density of methane; 0.0192 kg/ft^3 at 60 °F and 14.7 psia
10^{-3} = Conversion factor from kilograms to metric tons
Fee_{MT} = Emissions fee, in dollars per metric ton of methane. Use $900 for RY2024, $1200 for RY2025, $1500 for RY2026 and after

For the Onshore Natural Gas Transmission Compression Segment, a methane intensity (Ia) calculation methodology consistent with the language in the 2022 IRA law *could be* expressed as the quotient of

$$I_a = \frac{\frac{Facility\ Scope\ 1\ Emissions\ (MT)}{year}}{\frac{Facility\ Natural\ Gas\ Throughput}{year}}$$

Total Scope 1 CH4 (MT) Emitted from a Facility per year and Gas Transported through the same Facility per year:

For an interstate natural gas pipeline system, like Williams' Transcontinental Gas Pipe Line, natural gas is transported linearly along the system through several compressor stations before it is delivered to a third party. A simplified representation is show in the table below:

Facilty A	
Total Scope 1 CH4 (MT) per Year Emitted = A1	Gas Transported through Facility per Year = A2
Facility B	
Total Scope 1 CH4 (MT) per Year Emitted = B1	Gas Transported through Facility per Year = B2
Facility C	
Total Scope 1 CH4 (MT) per Year Emitted = C1	Gas Transported through Facility per Year = C2
Facility D	
Total Scope 1 CH4 (MT) per Year Emitted = D1	Gas Transported through Facility per Year = D2
Facility E	
Total Scope 1 CH4 (MT) per Year Emitted = E1	Gas Transported through Facility per Year = E2

Inserting the linear natural gas transmission system concept into the Facility Methane Fee Equation shown earlier, the formula is expanded as follows:

$$\$ = \frac{A1}{A2} - I_{IRA} \cdots + \frac{B1}{B2} - I_{IRA} \cdots + \frac{C1}{C2} - I_{IRA} \cdots + \frac{D1}{D2} - I_{IRA} \cdots + \frac{E1}{E2} - I_{IRA} \cdots$$

where … = $\times NG \times 1000 \times \rho_{CH4} \times 10^{-3} \times Fee_{MT}$.

In this example, A2, B2, C2, D2, and E2 are all roughly equal, large volumes of natural gas being moved from compressor station to compressor station along a pipeline route and the volume consists of largely the same natural gas molecules being moved from compressor station to compressor station (i.e., natural gas transported through a pipeline from Station A, to Station B, to Station C, and so forth). The drawbacks to this methodology are: (1) the large volumes of natural gas being transported between compressor stations cannot be reasonably characterized as "Natural Gas Sent to Sale" as they are not delivered to third parties; and (2) a double counting of the natural gas transported between the compressor stations occurs in the denominators (i.e., A2 and B2 volumes are largely comprised of the same gas molecules but treated as additive; B2 and C2 volumes are largely comprised of the same gas molecules but treated as additive; and so forth).

To avoid these drawbacks, Williams proposes calculating the methane intensity for the Onshore Natural Gas Transmission Compression segment using the same denominator as the Onshore Natural Gas Transmission Pipeline segment. Accordingly, the Proposed Rule must be modified for the Asset Level for the Onshore Natural Gas Transmission Compression segment so that "Natural Gas Sent to Sale" for a compressor station in a pipeline system is the same as the pipeline system itself, avoiding the double counting of natural gas being compressed from one compressor station to another:

Methodology	Industry Segment	Intensity Numerator	Intensity Denominator	Asset Level
Consistent with the IRA	Onshore Natural Gas Transmission Compression	Compressor Station total scope 1 methane emitted per year (MT CH4/yr)	Quantity of gas transported through the compressor station (mscf/yr)	Compressor Station
	Onshore Natural Gas Transmission Pipeline	Pipeline total scope 1 methane emitted per year (MT CH4/yr)	Quantity of gas transported through the pipeline system (mscf/yr)	Pipeline
Modified Asset Level	Onshore Natural Gas Transmission Compression	Compressor Station total scope 1 methane emitted per year (MT CH4/yr)	**Quantity of gas transported through the pipeline system (mscf/yr)**	**Pipeline**
	Onshore Natural Gas Transmission Pipeline	Pipeline total scope 1 methane emitted per year (MT CH4/yr)	Quantity of gas transported through the pipeline system (mscf/yr)	Pipeline

Adapting the example above, considering Facilities A-E are part of the same onshore natural gas transmission pipeline, the methane fee calculation for the Onshore Natural Gas Transmission Compression becomes:

$$\$ = (I_a - I_{IRA}) \times NG \times 1000 \times \rho_{CH4} \times 10^{-3} \times Fee_{MT}$$

Where:

$$I_a = \frac{A1 + B1 + C1 + D1 + E1}{X}$$

and

X = the quantity of natural gas transported through the pipeline facility and transferred to third parties such as LDCs or other transmission pipelines in thousand standard cubic feet, per 40 CFR §98.236 (aa)(11)(iv)

The methane fee calculation for the Onshore Natural Gas Transmission Pipeline would then be the pipeline emissions outside of the boundary of these compressor station emissions divided by the same quantity of gas transferred to third parties per 40 C.F.R. §98.236 (aa)(11)(iv). Williams anticipates that the methane fee for Onshore Natural Gas Transmission Compression and Onshore Natural Gas Transmission Pipeline would then be netted together along with the methane fees from other applicable industry segments in accordance with Subsection 136(f)(4) to arrive at a final total fee charge.

To summarize, Williams proposes "Natural Gas Sent to Sale" for both the Onshore Natural Gas transmission compression and transmission pipeline segments be limited to the quantity of gas transferred to third parties as per 40 C.F.R. §98.236(aa)(11)(iv). This approach accounts for the linear nature of the transportation of natural gas along a pipeline system whereby large volumes of the same natural gas molecules are moved from compressor station to compressor station along a pipeline route. Making this revision in the Subpart W Proposed Rule will help ensure future proposed methodologies for the WEC do not double count "Natural Gas Sent to Sale".

Additional recommended revisions to the Proposed Rule in order to implement the WEC as intended by Congress include:

- Adding a new data field in e-GGRT for "Pipeline System Throughput", the quantity of natural gas transferred to third parties such as LDCs or other transmission pipelines for the entire pipeline system, on each Onshore Natural Gas Transmission Compression form. Therefore, each compressor station reported to the GHGRP will have its individual compressor station methane emissions and associated pipeline system throughput, both to be used for the methane fee calculation. Additional fields needed in e-GGRT for netting transparency include a "Netted?" ("YES" or "NO") selection and a calculated methane intensity output.

Footnotes:

[37] See Proposed Rule, 88 Fed. Reg. at 50,284 ("CAA Section 136(h) requires that the EPA shall, within two years after the date of enactment of section 60113 of the IRA, revise the requirements of subpart W to ensure the reporting under subpart W (and corresponding waste emissions charges under CAA section 136) is based on empirical data, accurately reflects the total CH4 emissions (and waste emissions) from the applicable facilities, and allow owners and operators of applicable facilities to submit empirical emissions data, in a manner to be prescribed by the Administrator, to demonstrate the extent to which a charge is owed under CAA section 136.").

[38] See EPA Unified Agenda, Methane Emissions and Waste Reduction Incentive Program for Petroleum and Natural Gas Systems (Spring 2023).

[39] Williams acknowledges that the EPA considers comments concerning "the implementation of the waste emissions charge outside the scope of this rulemaking." Proposed Rule, 88 Fed. Reg. at 50,285. Williams intends to provide comment to the Agency as part of that forthcoming rulemaking and provide more discussion and input around the calculations proposed by EPA to determine facility methane intensity and the waste emissions charge. Meanwhile, Williams and

others in the industry need to plan ahead and examine how the fee could be calculated in order to better ascertain the impact of the Proposed Rule revisions.

Response 7: The issues discussed in these comments are addressed in the EPA's separate WEC proposal and are largely out of scope for this rulemaking. In that separate rulemaking, the EPA proposed specific subpart W throughput metrics that would be used within each industry segment for the purpose of the WEC calculations and that the EPA WEC proposal aligned with the requirements in CAA section 136(f)(1) through (3). We note that the commenters' requested approach for throughput would combine throughput for the transmission compression and transmission pipeline industry segments. The EPA did not reopen the definition of these subpart W industry segments and this request is outside the scope of this rulemaking.

Commenter: Ute Indian Tribe of the Uintah and Ouray Reservation
Comment Number: EPA-HQ-OAR-2023-0234-0421
Page(s): 2

Comment 8: Notwithstanding this threat to our sovereignty, the inclusion of Other Large Release Events along with combustion slip, crankcase emissions, mud degassing, produced water tanks and other sources as new additional sources presents an economic threat to our Tribe. These new sources along with revised calculation methodologies will function to subject almost half of the upstream segment and all of the midstream segment of the oil and gas industry on the Reservation to fees via increased reported emissions.

Significant increases in reported emissions, translated as significant increases in fees calculated for reported emissions, will expose operators to potentially millions of dollars in fee payments. In response, operators will likely opt to plug and abandon producing wells and divert future development investments outside of the Reservation to avoid fees and noncompliance. The result of such operator "flight" would have a significant impact on the Tribe's economy as a result of lost production and divestment.

The Tribe is also concerned that the Proposed Rule fails to consider the practicalities of retrofitting outdated equipment to bring sources within emission compliance. These operator efforts which are currently taking place, if allowed to continue unimpeded, would ultimately result in reduced emissions and cleaner air. These efforts do not and cannot take place overnight. Resource constraints such as equipment supply chain and skilled labor shortages restrict operators' ability to retrofit equipment and/or conduct emission identification and mitigation efforts. Such efforts are further complicated when outdated equipment is in a difficult to reach location and rendered impossible during significant periods of the year owing to inaccessibility due to weather and ground conditions on the Reservation.

Despite the constraints described above, operators continue to advance these emission reduction efforts, in most cases voluntarily. As discussed above, the Proposed Rule will result in an increase in fees. Instead of going toward actual emission reduction and sustainable development goals, the fees collected will go to the Treasury with no progress having been made in the pursuit of cleaner air. Without taking these practicalities into account, the Proposed Rule threatens to be punitive rather than constructive and threatens to undermine the federal government's obligation as our trustee to promote Tribal self-determination and economic development.

Response 8: These comments are substantially related to implementation of the WEC and are outside the scope of this rulemaking. The WEC proposal and its impacts are addressed under a separate rulemaking conducted in accordance with EPA's tribal consultation policy. For our response to comments related to the addition of new sources and discussion of the provisions of the final rule related to the addition of new sources, see Section III.B and Section III.C of the preamble. For our response to comments related to tribal impacts from this subpart W rulemaking, refer to Section 26 of this document. For our response to comments related to the effective date and time needed to implement the provisions of this rule, see Section 27 of this document.

Commenter: Williams Companies, Inc.
Comment Number: EPA-HQ-OAR-2023-0234-0394
Page(s): 20

Comment 9: Additional recommended revisions to the Proposed Rule in order to implement the WEC as intended by Congress include:

…

- Methane fees should be netted on a parent company basis, and not an owner basis, operator basis, or reporter basis. The parent company is identified in the e-GGRT report submitted to EPA each year. Netting on a parent company basis is consistent with how GHG emissions are reported to EPA and published by EPA in their FLIGHT and Envirofacts databases which are made available to the public.
- If a gathering and boosting, transmission, or storage compressor station is subject to OOOO/OOOOa/OOOOb/OOOOc regulation, that facility should automatically be exempted from the IRA carbon fee program, before netting calculations are performed. Voluntary compliance with OOOO/OOOOa/OOOOb/OOOOc regulations by a company should not exempt the facility from the IRA carbon fee program.
- For the Gathering and Boosting and Natural Gas Processing Segments, the natural gas throughput should be based on gas leaving the facility, not gas entering the facility. For the Underground Natural Gas Storage Segment, the throughput should be based on the sum of gas being injected into and withdrawn from the storage cavern(s).

Response 9: These comments are related to implementation of the WEC and are outside the scope of this rulemaking.

28.6 Other General Comments

Commenter: Interstate Natural Gas Association of America (INGAA)
Comment Number: EPA-HQ-OAR-2023-0234-0387
Page(s): 15-16

Comment 1: Estimates should account for reductions that occur via vapor recovery, combustion, thermal or other control for all sources.

The Proposed Rule should be clarified to ensure that emissions reductions or control and vapor recovery are clearly included in emission estimates and related terms are defined. This appears to be EPA's intent, but additional clear definitions are needed to improve clarity.

The Proposed Rule includes revisions to related text, such as deleting the term "thermal oxidizer" from several sections. In its place, the Proposed Rule refers to flares and "combustion devices." A definition is included in Subpart A and Subpart W for "flare", but other control technology, including "combustion device" are not defined. It may not be clearly understood that a thermal oxidizer is a "combustion device," and other control technology such as catalytic reduction should not be precluded.

EPA should ensure that Subpart W clearly accounts for control of methane emissions that result from routing emissions to a process or device that reduces the methane content of the stream before emitting to atmosphere. Definitions should be added for "combustion device" that clearly identify candidate technologies such as thermal oxidizers, and other types of potential control options, such as catalytic control should also be included in emission estimates. Thus, "control device" and/or "other control device" (i.e., non-combustion) should also be defined. In addition, EPA should consider an offramp or simplification of ongoing monitoring, reporting, and recordkeeping requirements if a source clearly demonstrates zero or reduced emissions from control.

Response 1: For the emission source types that may be routed to a flare, combustion, or a vapor recovery system, the final amendments specify that the emissions to be reported for that source type are only those emissions vented directly to the atmosphere. If the source is routed to a flare, the emissions should be calculated as specified in 40 CFR 98.233(n) and reported as flared emissions according to 40 CFR 98.236(n). Similarly, if the source is routed to a stationary combustion device, the emissions should be calculated as specified in 40 CFR 98.233(z) or subpart C, as applicable for the source type, and reported as combustion emissions according to 40 CFR 98.236(z) or subpart C, respectively and as applicable for the source type. The final amendments also specify that if the source is routed to vapor recovery, emissions are not required to be reported under subpart W (except in cases where the vapor recovery system is bypassed, in which case the emissions are venting directly to the atmosphere). See Section III.F.1 for more information on the EPA's assessment of sources routed to vapor recovery systems.

We disagree with the commenter that a thermal oxidizer should be defined as a "combustion device." For facilities that report under subpart W, if the thermal oxidizer meets the definition of flare in subpart W, the emissions should be reported under subpart W as flare emissions. For reference, per 40 CFR 98.238, "Flare, for the purposes of subpart W, means a combustion device, whether at ground level or elevated, that uses an open or closed flame to combust waste gases without energy recovery."

Regarding other definitions, for industry segments for which the combustion emissions are reported under Subpart C, stationary fuel combustion sources are defined in 40 CFR 98.30(a). For industry segments that report combustion emissions under Subpart W, stationary combustion equipment is described in 40 CFR 98.232(c)(22), (i)(7), or (j)(12), as applicable for the industry segments. A thermal oxidizer that does not meet the definition of a flare in 40 CFR 98.238 of subpart W may be a stationary combustion unit under one of those definitions. Vapor recovery system is defined in 40 CFR 98.6.

Commenter: Clean Air Council
Comment Number: EPA-HQ-OAR-2023-0234-0203
Page(s): 1

Commenter: Public Hearing Transcript
Comment Number: EPA-HQ-OAR-2023-0234-0224
Page(s): 12 (Alice Lu), 17 (Luke Metzger), 23 (Cyrus Reed), 42 (Glenn Wikle), 44 (Shanna Edberg), 50 (Christina Digiulio)

Commenter: American Lung Association
Comment Number: EPA-HQ-OAR-2023-0234-0335
Page(s): 1

Commenter: Damascus Citizens for Sustainability
Comment Number: EPA-HQ-OAR-2023-0234-0368
Page(s): 1

Commenter: Offshore Operators Committee (OOC)
Comment Number: EPA-HQ-OAR-2023-0234-0409
Page(s): 3-4

Comment 2: Commenter 0203: The U.S. Environmental Protection Agency's (EPA's) proposed edits to Subpart W of the Greenhouse Gas (GHG) Reporting Rule include improvements for tracking GHG emissions from the oil and gas industry. The rule, however, can still be strengthened to improve data accuracy and hold the oil and gas sector accountable for GHG emissions. I urge EPA to strengthen its proposed rule in the following ways:

- Reduce the current reporting limit and methane emissions charge threshold of 25,000 metric tons of CO2 equivalent (CO2e) to 10,000 metric tons CO2e, as originally proposed in the Build Back Better Act.

Commenter 0224: While the proposed update has several notable improvements, the rule can still be strengthened, so first , the reporting and methane emissions charge thresholds of 25,000 metric tons of CO_2 equivalent should be reduced to 10,000 metric tons of CO_2 equivalent as originally proposed in draft legislation. This would promote accountability and accuracy without being prohibitively strict, so in Pennsylvania, for example, lowering the threshold would only increase the number of reporting facilities from 53 to 57 by 2021 reports. But this would account for an additional 100,000 metric tons of CO_2 equivalent.

…

We also urge the EPA to strengthen the final rule, including by … reducing the current reporting limit in methane emissions threshold of 25,000 metric tons of CO_2 equivalent to 10,000 metric tons …

…

Still as others have already mentioned, there are some ways to strengthen this rule … lowering the reporting requirements from 25,000 tons of CO_2 equivalent to 10,000…

…

The EPA is in a position of global leadership. Many other countries will follow what the EPA does. To follow through on your leadership position, I ask you to reduce the greenhouse gas reporting limit to 10,000 metric tons of carbon dioxide equivalent, as was specified in the Inflation Reduction Act,

…

We recommend EPA reduce the current reporting limit and methane emissions charge threshold to 2,000 metric tons of CO_2e as originally proposed in the Build Back Better Act.

…

And we also support reduce, to reduce the current reporting limit and methane emissions charge threshold of 25,000 metric tons of CO_2 equivalent or CO_2e to 10,000 metric tons of carbon dioxide equivalents CO_2e as originally proposed in the Build Back Better Act.

Commenter 0335: Furthermore, we encourage EPA to reduce the current reporting limit and methane emissions charge threshold of 25,000 metric tons of CO_2 equivalent (mt CO_2e) to 10,000 metric tons of carbon dioxide equivalent (CO_2e), as originally proposed.

Commenter 0368: We urge that you significantly reduce the reporting limit to the lower level originally proposed in the Build Back Better Act to include a larger number of sources reporting more accurate data.

Commenter 0409: **Section/Paragraph Reference:** §98.2(a)

Proposed Text: The GHG reporting requirements and related monitoring, recordkeeping, and reporting requirements of this part apply to the owners and operators of any facility that is located in the United States or under or attached to the Outer Continental Shelf (as defined in 43 U.S.C. 1331) and that meets the requirements of either paragraph (a)(1), (a)(2), or (a)(3) of this section; and any supplier that meets the requirements of paragraph (a)(4) of this section:

(1) A facility that contains any source category that is listed in Table A–3 of this subpart. For these facilities, the annual GHG report must cover stationary fuel combustion sources (subpart C of this part), miscellaneous use of carbonates (subpart U of this part), and all applicable source categories listed in Tables A–3 and A–4 of this subpart.
(2) A facility that contains any source category that is listed in Table A–4 of this subpart and that emits 25,000 metric tons CO2e or more per year in combined emissions from stationary fuel combustion units, miscellaneous uses of carbonate, and all applicable source categories that are listed in Table A–3 and Table A–4 of this subpart. For these facilities, the annual GHG report must cover stationary fuel combustion sources (subpart C of this part), miscellaneous use of carbonates (subpart U of this part), and all applicable source categories listed in Table A–3 and Table A–4 of this subpart.
(3) A facility that in any calendar year starting in 2010 meets all three of the conditions listed in this paragraph (a)(3). For these facilities, the annual GHG report must cover emissions from stationary fuel combustion sources only.
(i) The facility does not meet the requirements of either paragraph (a)(1) or (a)(2) of this section.
(ii) The aggregate maximum rated heat input capacity of the stationary fuel combustion units at the facility is 30 mmBtu/hr or greater.
(iii) The facility emits 25,000 metric tons CO2e or more per year in combined emissions from all stationary fuel combustion sources.

Comment: OOC supports maintaining the 25,000 mtCO2e reporting threshold to remain consistent with the provisions of the Inflation Reduction Act.

Response 2: The EPA did not reopen the subpart W reporting threshold; it remains at 25,000 metric tons CO_2e. We note that the reporting threshold for the GHGRP was originally selected based on the level at which the incremental emissions reporting between thresholds is the highest for the lowest increase in number of facilities between the same thresholds. A full discussion of the threshold analysis is found in (EPA-HQ-OAR-2009-0923-0027).

While outside the scope of this rulemaking, we note that CAA section 136(c) Waste Emission Charge states: "The Administrator shall impose and collect a charge on methane emissions that exceed an applicable waste emissions threshold under subsection (f) from an owner or operator of an applicable facility that reports more than 25,000 metric tons of carbon dioxide equivalent of greenhouse gases emitted per year pursuant to subpart W of part 98 of title 40, Code of Federal Regulations, regardless of the reporting threshold under that subpart."

Commenter: Riverside Energy Group
Comment Number: EPA-HQ-OAR-2023-0234-0230
Page(s): 2

Commenter: Michigan Oil and Gas Association (MOGA)
Comment Number: EPA-HQ-OAR-2023-0234-0298
Page(s): 2

Commenter: Lambda Energy Resources
Comment Number: EPA-HQ-OAR-2023-0234-0405
Page(s): 2

Comment 3: Commenter 0230: We would also like to request that the EPA should avoid the use of metric units in calculating methane emissions and consider the use of imperial units only. The proposed rule provides calculations for methane emission using metric units ((kilograms per hour (kg/hr)) The majority, if not all, field equipment, meters, gauges, and other devices for measuring and recording data used for calculating emissions use imperial units, i.e., pounds per hour (lbs/hr), cubic feet per hour (cf/hr), etc. Converting imperial units into metric, for the sake of data collection and reporting, when complicated formulas are used, introduces possibility for multiple errors, and will result in inaccurate data. With fees being charged for methane emissions, and waste emissions, it is critical that reported data is representative of the actual emissions, so that reporters under Subpart W avoid excessive emission charges.

Commenter 0298: Imperial vs. Metric

The United States oil and gas industry has historically used Standard Cubic Feet per Hour (scf/hr) and not Kilograms per hour (kg/hr). Most field equipment including gauges, meters and other associated equipment report in pounds per hour (lb/hr) and standard cubic feet per hour (sch/hr). All proposed regulations should utilize accepted methodologies and cater to the least common denominator with regards to raw data collection. Any data collection efforts with unnecessary conversions will likely result in an incorrect data set and lead to improper conclusions.

Commenter 0405: Also adding to the confusion in these rules is switching from scf/hr to kg/hr to quantify emissions. Measurement of kg/hr is unusual to almost everyone as the gas and oil business generally measures gas in standard cubic feet per hour. We would like the EPA to keep the standard measurement.

Response 3: The majority of the provisions in Subpart W specify measurements in imperial units and the calculation of emissions in units of metric tons is performed as a last step, as metric tons are the standard units of measure for greenhouse gas emissions. It is unclear from the comment which provision the comment applies to, however, the commenters may be referencing the threshold for other large release events, which is in kilograms per hour and was chosen, in part, for consistency with NSPS OOOOb. However, reporters may perform measurements in imperial units and then convert the emissions rate to kg/hr to determine whether the event exceeded the threshold to be reported.

Commenter: American Petroleum Institute et al. (Part 1 of 2)
Comment Number: EPA-HQ-OAR-2023-0234-0402
Page(s): 72

Comment 4: Administrative Recommendations

Streamline Existing Reporting Forms to Reduce Duplicative Reporting and Reduce Unnecessary Submittal Errors

Due to the proposed requirement to report information on a more granular basis, the Industry Trades recommend the following streamlining efforts to reduce duplicative reporting, and to reduce the possibility of administrative error.

…

Remove all requirements to report a count of equipment or events when there is a requirement to report on an equipment- or site-level basis. Requiring a count of an item that is already provided on a line-by-line basis does not improve the reported data quality, does not increase EPA's ability to validate the reported data, and introduces potential errors that will flag unnecessary follow between reporters and EPA.

Response 4: The EPA has determined that the data elements finalized in this rulemaking are necessary for the verification of reported data and that the verification process improves reported data quality and accuracy of total emissions reported by the facility.

Commenter: Protect PT
Comment Number: EPA-HQ-OAR-2023-0234-0190
Page(s): 1

Commenter: Public Hearing Transcript
Comment Number: EPA-HQ-OAR-2023-0234-0224
Page(s): 54 (Katie Muth)

Comment 5: Commenter 0190: Our organization is based in Southwestern PA. We live in an industry-designated sacrifice zone. In our region, there are thousands of abandoned and orphaned wells documented by EPA and the PA Department of Environmental Protection. From personal experience, I can also assure you there are even more that are not on the books.

Emissions from these sources are serious. Methane is 82 times as potent at trapping heat than carbon dioxide.

Commenter 0224: Pollution from small wells is also a problem, we know we have many, many abandoned wells here in Pennsylvania and some that apparently the DEP and other regulators aren't aware if they're abandoned or still active. In fact, while low producing wells account for just 6% of production nationwide, these wells are responsible for over 50% of [inaudible] at these oil and gas well sites. You drive down the Pennsylvania turnpike, get off a few exits, you can see some of these abandoned structures all along the roadways. According to data by the Clean Air Council, the north or east region of the United States, these wells emit 1.2 million tons of methane annually.

Response 5: The EPA acknowledges that abandoned wells contribute to the overall methane emissions from the oil and gas industry. See, for example, recent updates made to the annual *Inventory of U.S. Greenhouse Gas Emissions and Sinks* (U.S. GHG Inventory)[25] to better characterize abandoned well counts and emissions from these sites. Requirements related to closure requirements for abandoned wells are outside the scope of this rulemaking. However, the EPA notes several recent rulemakings related to these wells. In the Notice of Proposed Rulemaking for the Waste Emissions Charge for Petroleum and Natural Gas Systems (WEC proposal), published in the Federal Register on January 26, 2024 (89 FR 5318), the EPA proposed requirements to implement Clean Air Act section 136(f)(7) related to the exemption of methane emissions from plugged wells from the WEC. For facilities that are subject to the WEC, the EPA expects that this exemption will incentivize operators to permanently shut-in and plug wells in accordance with all applicable closure requirements. Additionally, the final NSPS OOOOb and EG OOOOc rules, published in the Federal Register on March 8, 2024 (89 FR 16820), include requirements related to the closure of wells including the requirement to complete a survey following the completion of well closure activities to verify that there are no emissions. In addition to these rulemakings, the EPA notes that the Bipartisan Infrastructure Law, signed November 15, 2021, allocated $4.7 billion in funding for the plugging of orphaned wells on federal, Tribal, state, and private lands. The implementation of this program is through the Department of the Interior's Orphaned Wells Program Office.[26]

Commenter: Anonymous
Comment Number: EPA-HQ-OAR-2023-0234-0183
Page(s): 1

Commenter: Damascus Citizens for Sustainability
Comment Number: EPA-HQ-OAR-2023-0234-0368
Page(s): 1

Commenter: Kirk Frost
Comment Number: EPA-HQ-OAR-2023-0234-0389
Page(s): 2

Commenter: CrownQuest Operating
Comment Number: EPA-HQ-OAR-2023-0234-0393
Page(s): 255

[25] U.S. EPA. Inventory of U.S. Greenhouse Gas Emissions and Sinks 1990-2020: Updates for Abandoned Oil and Gas Wells. April 2022. Available at https://www.epa.gov/system/files/documents/2022-04/2022_ghgi_update_-_wells.pdf.
[26] https://www.doi.gov/orphanedwells

Comment 6: Commenter 0183: The proposed rule does not explain why different definitions of "facility" and "facility segment" are needed for subpart W, and how they differ from the general definitions in subpart A of part 98. The proposed rule should provide more rationale and examples of how these definitions are applied and reported for petroleum and natural gas systems facilities.

Commenter 0368: So good as far as the proposed rule goes, it can be strengthened and we urge EPA to do the following;

- to include as aggregated sources all the emitters in an area - not allowing a single compressor station, for example, to be considered alone when there are, for example, other compressor stations, wells, processing facilities, etc. nearby. - yes, distance limits need setting - half or one mile perhaps, and to include not just one company's facilities.

Commenter 0389: Get rid of the label "applicable facility" since all facilities must be included. Redefine facility to also include pipeline segments and distributed valve / pig entrance points along pipeline segments.

Commenter 0393: The definition of facility is highly confusing, and the EPA is asking for data but are not actually asking for anything.

Response 6: These comments are outside the scope of this rulemaking, as the referenced terms are either not relevant to subpart W or were not reopened in this rule. The EPA notes that we considered how to define industry segments and facilities for Subpart W in the 2010 rulemaking. Please refer to Section 4.c.i, Facility Definition Characterization, in the 2010 Background Technical Support Document (EPA-HQ-OAR-2009-0923-0027). Additionally, the EPA further considered the definition of industry segments and facilities for subpart W when two new segments were added in the 2015 rulemaking. Please refer to EPA-HQ-OAR-2014-0831-0188 for a discussion of the facility definition for the Onshore Petroleum and Natural Gas Gathering and Boosting and Onshore Natural Gas Transmission Pipeline segments.

Commenter: Anonymous
Comment Number: EPA-HQ-OAR-2023-0234-0183
Page(s): 1

Commenter: Michigan Oil and Gas Association (MOGA)
Comment Number: EPA-HQ-OAR-2023-0234-0298
Page(s): 2

Comment 7: Commenter 0183: The proposed rule does not specify how reporters can request and obtain approval for an engineering calculation method for any emission source within any facility segment of an onshore production facility, as required by section 98.234(f)(6). The proposed rule should provide more details and procedures for requesting and obtaining approval for an engineering calculation method, such as how to submit a request, how long it will take for the Administrator to review and approve or deny a request, what criteria will be used to evaluate a request, and what recourse reporters have if their request is denied.

<u>Commenter 0298</u>: Approval of Independent Engineering Calculations for Emission Determination

MOGA applauds the EPA for allowing independent emission determination using alternative procedures and calculation. However, MOGA's constituents are concerned with the lack of clarification, definition of procedures and response time for the EPA's approval process for independent emission determination calculations. Prior to providing sufficient comment on the revisions to Subpart W calculation methodologies, the public must have a detailed process and procedure including a specified time for approval. Without this information, it is impossible to provide specific comment on the proposed regulations and the potential impacts to the industry.

Response 7: It is unclear from the comment which provision the commenters are referencing, and as such, the EPA cannot provide a substantive response to these general comments. Commenter 0298 did not specify a paragraph reference, and the paragraph referenced by Commenter 0183, 40 CFR 98.234(f)(6), does not exist in either the existing or the proposed rule. 40 CFR 98.234(f) was proposed and is being finalized to be reserved and does not contain any requirements. Since the comment does not specifically address the proposed rule, the comment is beyond the scope of this rulemaking. If this is a comment on the alternative monitoring provisions for fugitive emissions in NSPS OOOOb, those comments are also beyond the scope of this rulemaking.

Commenter: Kirk Frost
Comment Number: EPA-HQ-OAR-2023-0234-0389
Page(s): 2

Comment 8: Eliminate all loopholes that enable a facility owner and or function from reporting accurate emissions.

a. Mandate that all emission sources and types must be included in the annual emissions report.

b. Venting, which takes place routinely must be included.

c. Blowdowns, which takes place either through planned and or unplanned emergency events, must be included in the reporting of methane, HAPs and VOCs.

d. Fugitive leaking, which occurs 100% of the time must be included in annual emissions reporting.

e. All methane emission events, whether planned or unplanned, need to be included for all facilities in the natural gas supply chain. This must even include methane emissions from holding ponds used for the hydraulic fracture waste slurry.

Response 8: The *Mandatory Greenhouse Gas Reporting Rule Subpart W – Petroleum and Natural Gas: EPA's Response to Public Comments* for the original 2010 rulemaking states that the EPA determined that the source types in the Greenhouse Gas Reporting Program are an optimal balance of emissions coverage and cost burden. For that rulemaking, the EPA focused on sources within each segment that contributed significantly to the segment emissions based on information available at the time. Since then, the EPA has added industry segments and source types to Subpart W as information has become available indicating that there are potentially significant sources of GHG emissions for which there are no current emission estimation methods or reporting requirements within Subpart W, including the sources that we are finalizing in this rulemaking. Finally, we note that the GHGRP is a reporting program for greenhouse gas emissions; emissions of non-GHGs are outside of the scope of the program.

Commenter: Independent Petroleum Association of America (IPAA)
Comment Number: EPA-HQ-OAR-2023-0234-0265
Page(s): 3-4

Commenter: Environmental Defense Fund, et al.
Comment Number: EPA-HQ-OAR-2023-0234-0413
Page(s): 42-43

Comment 9: Commenter 0265: *New Implications of Subpart W*

When Subpart W was solely related to filing under the GHGRP, determining whether a facility needed to file and the accuracy of submitted information carried limited further scrutiny. However, because the MERP imposes a methane tax, all filing decisions now become auditable and subject to penalties under the enforcement provisions of the Clean Air Act (CAA). These new burdens compel EPA to address them in Subpart W, but it does not.

Both the MERP and Subpart W establish a filing threshold of 25,000 mt/year of CO_2eq. This threshold was set initially by EPA when it initiated Subpart W reporting to limit the burden on small businesses while maintaining reporting by the preponderance of emissions sources. It was specifically retained in the MERP legislation. At issue then is the challenge to small producers to determine whether they are subject to the Subpart W filing requirements without compelling them to complete a costly full-blown inventory that is unnecessary. EPA provides no simple estimating procedure to determine whether small producers are near the 25,000 mt/year threshold. Both EPA and Congress have shown that small producers are not the target of the methane tax; however, EPA must now provide a mechanism to easily exclude them without the threat of audit and enforcement by the Office of Enforcement and Compliance Assurance (OECA).

Commenter 0413: 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 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.

Response 9: Since the comment does not specifically address the proposed rule, the comment is beyond the scope of this rulemaking. However, the EPA may consider the commenter's suggestions as part of the implementation of these final amendments. For example, the EPA plans to update the Optional Calculation Spreadsheets to reflect the new source types and the new and revised calculation methods.

Commenter: CrownQuest Operating
Comment Number: EPA-HQ-OAR-2023-0234-0393
Page(s): 247

Commenter: Western Energy Alliance
Comment Number: EPA-HQ-OAR-2023-0234-0399
Page(s): 5-9

Comment 10: Commenter 0393: We performed calculations internally using the new proposed emission factors. The calculations were compared to our 2022 GHG Subpart W calculations. We used the proposed emission factors for natural gas pneumatic devices, flare stacks and equipment leak surveys and population counts. The increase in the total emissions estimates is significant and they seem to come with no rhyme or reason. These factors cannot be blanketed across basins based off a couple of studies. Results from our calculations are below:

Total percentage increase in "Total Reported CH4 Emissions (mt CH4)
- pneumatics: 47.5% increase
- flare stacks: 300% increase
- equipment leak surveys and population counts: 77% increase

*For all sources combined we would see a 121% increase in total reported CH4 emissions in mt CH4.

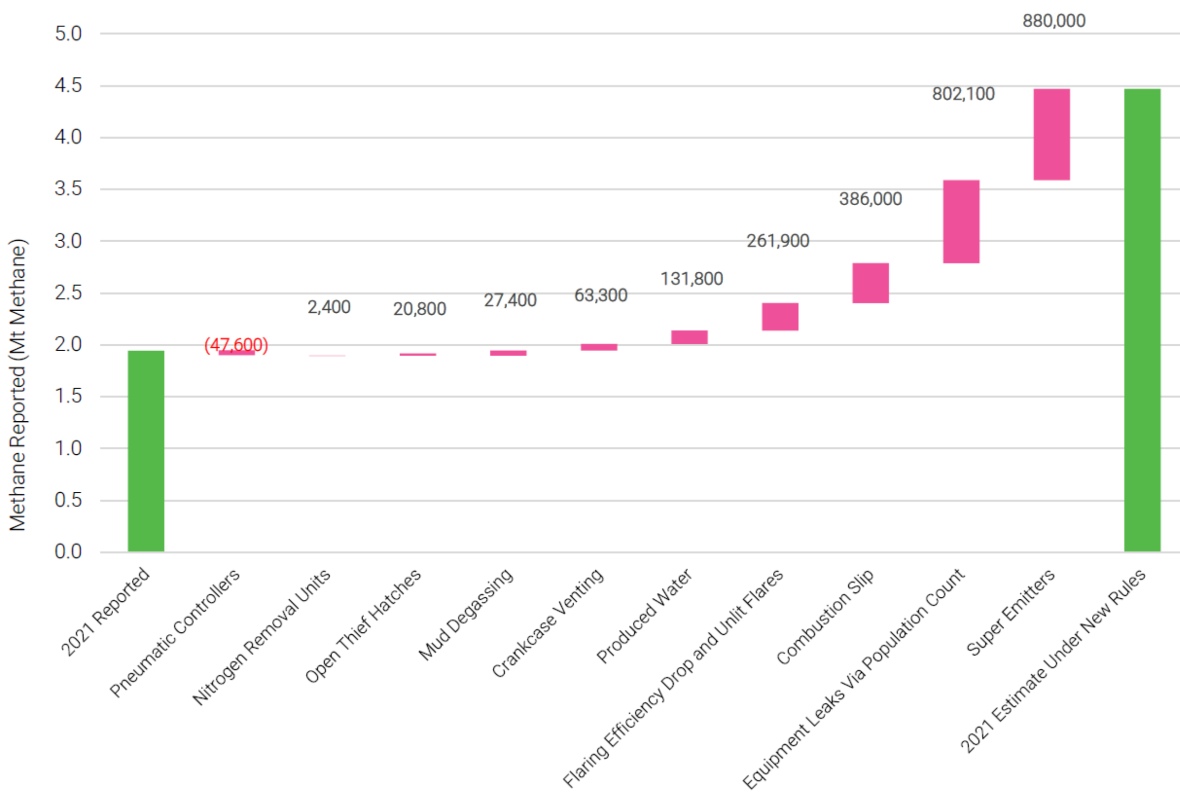
As you can see, these proposed emission factors have a profound effect on reportable emission sources.

Commenter 0399: Overestimation of Emissions

The proposed rule would result in inaccurate and overestimated emissions from the upstream sector. Enverus Intelligence Research conducted an analysis of the relative impact of EPA's Subpart W proposed rule changes by recalculating upstream and gathering emissions for 2021 using the proposed emissions factor updates and other provisions. Enverus estimates that, all things else being equal, 2021 methane emissions would have been 130% higher and CO_2e emissions would have been 41% higher (an increase of 73 MMt), as shown in Figures 2 and 3 from the Enverus report below.[2] While these percentage increases cannot be directly extrapolated to what will be reported for 2025 under the new Subpart W rule, as other EPA regulations such as NSPS OOOOb will go into effect, their estimates are a good indication of the impact of the proposed rule.

Enverus finds that 92% of the methane increase (2.3 million metric tons of the total 2.5MMt increase from the rule) is due to the super-emitter event category, higher emission factors for equipment leaks, updates to combustion slip from engines, and lowered flaring efficiencies. Other new or modified emission source categories account for less than about .2 MMt.

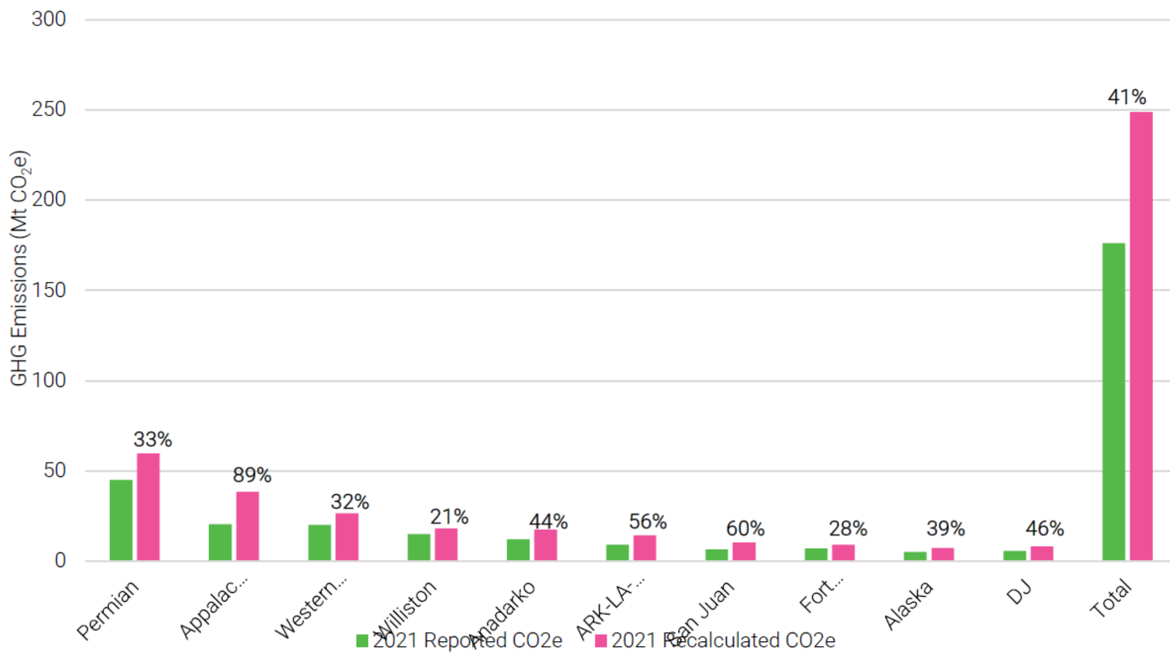
FIGURE 2 | 2021 Estimated Increase in Methane by Source Under Proposed Rules



Source | Enverus Intelligence® Research, Enverus ESG Analytics, EPA

Enverus estimates that the proposed rule would push more facilities above the 25,000 tons of CO_2e threshold for Subpart W reporting and increase liability for the methane tax, with well over half of upstream assets and all gathering assets now exposed, versus an estimated 30% and 34% respectively without the proposed rule changes. See Figures 4 and 5 below from the Enverus report. Enverus also finds that the proposed rule would triple the methane tax from $1.1 billion to $2.9 billion based on a hypothetical application of the tax to 2021 emissions reported under the previous versus the proposed rule. Overall the tax would equate to about $.18 per barrel of oil equivalent (boe) and $.12 per boe for the upstream and gathering sectors, respectively. Lower-producing assets would bear a disproportionate share of the tax.

FIGURE 3 | Estimated Change in Overall Reported CO2e Emissions by Basin



Source | Enverus Intelligence® Research, Enverus ESG Analytics, EPA

FIGURE 4 | Upstream Methane Intensity vs. Cumulative Gas

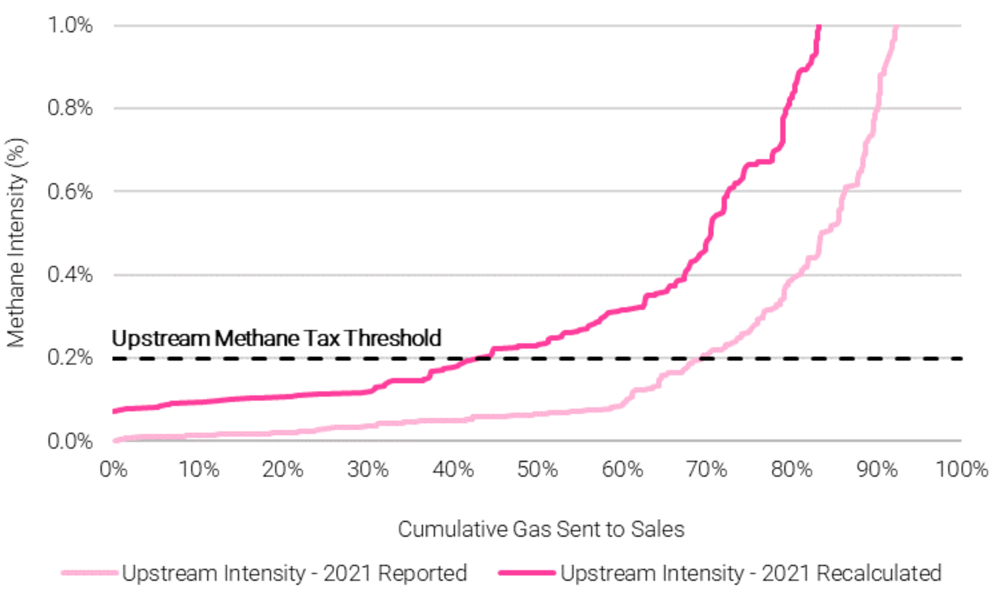
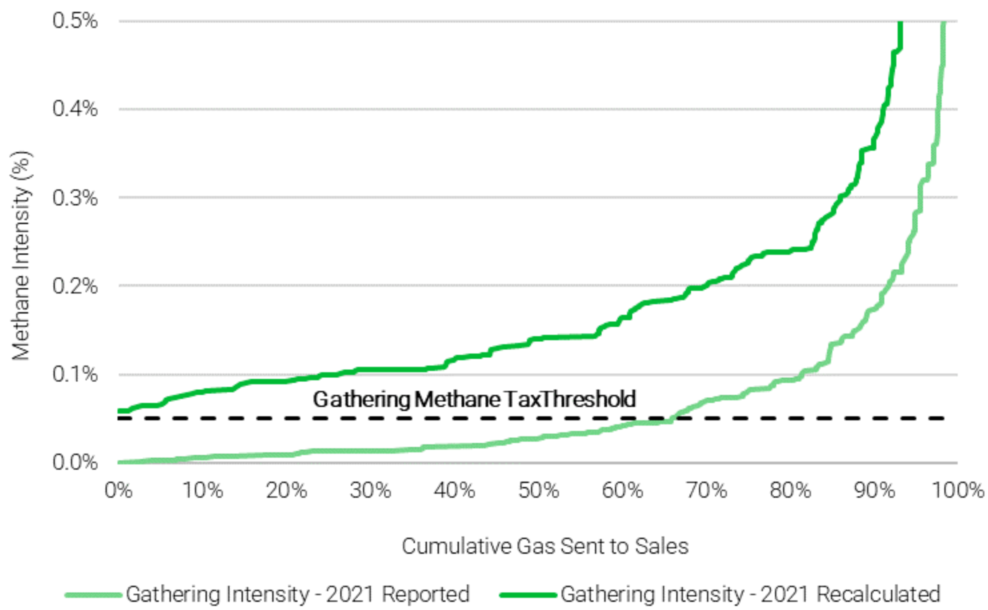


FIGURE 5 | Upstream Methane Intensity vs. Cumulative Gas



Source | Enverus Intelligence® Research, Enverus ESG Analytics, EPA

The Alliance hopes EPA finds these data from Enverus, a neutral energy analytics firm, to be useful. However, we believe even Enverus' high percentage increase is too conservative. One of our member companies ran estimates for 2022 reporting using this rule and finds it would have increased reported methane emissions by about 3.5 times and total CO2e emissions by about 40%, despite the fact that the there were no physical changes in the field that would cause emissions to increase.

Footnotes:

[2] *EPA's Emissions Revisions: More Rules, Double the Methane, Triple the Tax*, Enverus Intelligence Research, September 7, 2023.

Response 10: We disagree with the commenter's assertion that the proposed rule would result in inaccurate and overestimated emissions from the upstream sector. As discussed in Section I.B of the preamble to the final rule, the EPA finalized revisions to include reporting of additional emissions or emissions sources to address potential gaps in the total CH_4 emissions reported by facilities to subpart W. These revisions include finalizing provisions to add a new emissions source, referred to as "other large release events," to capture large emission events that are not accurately accounted for using existing methods in subpart W. Other new sources being added or included in revised existing sources in this final rule included nitrogen removal units, produced water tanks, mud degassing, crankcase venting and combustion slip. The inclusion of these additional source will ensure that subpart W reflects total methane and waste emissions at applicable facilities. The EPA is also finalizing several revisions to add new or revise existing calculation methodologies to improve the accuracy of reported emissions, incorporate additional empirical data and to allow owners and operators of applicable facilities to submit empirical emissions data that could appropriately demonstrate the extent to which a charge is owed in future implementation of CAA section 136, as directed by CAA section 136(h). The EPA is also finalizing several revisions to existing reporting requirements to collect data that would improve verification of reported data, ensure accurate reporting of emissions, and improve the transparency of reported data. For an individual facility, these revisions may increase or decrease reported emissions, but the revisions are expected to provide an accurate reflection of total methane and waste emissions at applicable facilities.

Commenter: VERITAS - GTI Energy
Comment Number: EPA-HQ-OAR-2023-0234-0416
Page(s): 1-2

Comment 11: We believe that to produce accurate methane emission inventories, stakeholders need to support technology and tools that are flexible, efficient, and effective.

The transition to lower-carbon, lower-cost energy systems will require immediate global action to cut down on methane emissions. Reducing methane emissions from the oil and gas sector is one of the most cost-effective and impactful ways to mitigate global greenhouse gas emissions. Veritas is a standardized, science-based, technology neutral, measurement-informed approach to calculating and reporting methane emissions. The initiative was launched in 2021 by GTI Energy. Veritas provides specific technical protocols for each segment of the natural gas industry (production, gathering and boosting, processing, transmission and storage, distribution, and LNG) to measure methane emissions in a consistent, credible, and comparable way. These technology-neutral protocols formulate a comprehensive toolbox of methodologies designed to accelerate methane emissions reductions.

The first versions of the protocols were made publicly available February 14, 2023 at https://veritas.gti.energy.

The Veritas technical protocols consist of:

- Measurement: Describes how to take measurements to inform emission inventories, by segment.
- Reconciliation: Reconciles emission-factor or baseline inventories with actual measurements, by segment.
- Methane Emissions Intensity: Defines what methane intensities should look like for each segment of the natural gas supply chain.
- Value Chain Summation: Adds multiple segments to reach a total emissions intensity.
- Assurance: Provides guidance for verifying an emissions inventory, company documentation requirements, and third-party auditing.

GTI Energy will publish and maintain these protocols as open-source, technical tools that can be deployed and operationalized by different stakeholders around the world. When Veritas protocols were demonstrated in 2022 and further tested in 2023, reports were shared with GTI Energy and treated as confidential between GTI Energy and the company. Now that the protocols are being implemented, operators are not obligated to share their data with GTI

Energy. The purpose of the demonstration and testing projects was to evaluate the protocols and we published the aggregated, anonymized results and learnings of the demonstration phase through a white paper-available at [Veritas: GTI Energy's Veritas 2022 Demonstration Findings]. Additionally, GTI Energy published guidance on measurement uncertainty, data collection, production segment and distribution segment examples-all available at veritas.gti.energy.

Additionally, the Reconciliation and Assurance protocols provide guidance to companies that a report should be made publicly available on the results of the measurement-informed emissions intensity calculated from use of the Veritas protocols starting in 2024.

Veritas is unique in that it is entirely committed to broadening access to the most effective technical processes and technologies that are currently available to reduce methane emissions, in hopes of giving industry a hands-on blueprint of how to implement methane mitigation initiatives successfully and yield credible results.

Response 11: The EPA thanks the commenter for the information on their program. For further discussion and responses to comments on Measurement Methods, see Section 24 of this document and section II.B of the preamble to the final rule.

Commenter: National Federation of Independent Business, Inc. (NFIB)
Comment Number: EPA-HQ-OAR-2023-0234-0336
Page(s): 2-3

Commenter: Arkansas Independent Producers and Royalty Owners (AIPRO)
Comment Number: EPA-HQ-OAR-2023-0234-0382
Page(s): 1-2

Commenter: North Dakota Petroleum Council (NDPC)
Comment Number: EPA-HQ-OAR-2023-0234-0417
Page(s): 2, 3-4

Comment 12: Commenter 0336: The American economy is choking on the large volume of EPA-proposed, extraordinarily detailed, and burdensome rules relating to greenhouse gas emissions (GHG) and other environmental issues.[2] The excessive volume of simultaneous, overlapping, and high-speed rulemaking processes raises concern whether EPA really gives the legally required consideration to public comments in those processes.[3] The EPA should slow its rulemaking processes, consider more carefully the input of the public on proposed rules, and weigh thoroughly the cumulative adverse impacts of EPA rules on the American economy. The EPA should focus on how to preserve clean air, water, and land, without stifling the economy or raising costs to consumers.

Footnotes:

[2] For examples of the excessive load of EPA-proposed rulemakings, see the Governor of Wyoming's letter September 8, 2023 (paragraph 2), the INGAA, AGA, APGA, and USCC letter

of August 30, 2023 (footnote 2), and the TPAO, IPAA, and WEA letter of August 7, 2023 (paragraph 6), all of which appear in the rulemaking docket, Docket No. EPA-HQ-OAR-2023-0234.

[3] *NRDC v. NHTSA*, 894 F. 3d 95, 115 (2d Cir. 2018) ("Notice and comment are not mere formalities. They are basic to our system of administrative law. They serve the public interest by providing a forum for the robust debate of competing and frequently complicated policy considerations having far-reaching implications and, in so doing, foster reasoned decision-making."); *Perez v. Mortgage Bankers Association*, 575 U.S. 92, 96 (2015) ("An agency must consider and respond to significant comments received during the period for public comment."); see *Motor Vehicle Mfrs. Ass'n of U.S., Inc. v. State Farm Mut. Auto. Ins. Co.*, 463 U.S. 29, 43 (1983) ("Normally, an agency rule would be arbitrary and capricious if the agency has relied on factors which Congress has not intended it to consider, entirely failed to consider an important aspect of the problem, offered an explanation for its decision that runs counter to the evidence before the agency, or is so implausible that it could not be ascribed to a difference in view or the product of agency expertise.").

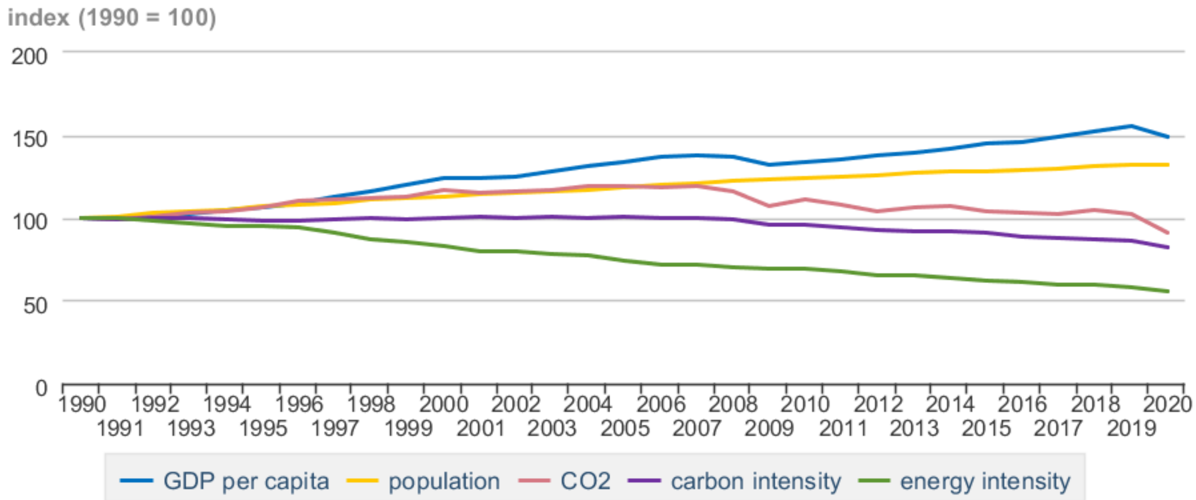
<u>Commenter 0382</u>: <u>Oil & Gas Industry Making Significant Progress in Reducing GHG Emissions:</u>

AIPRO membership and the Oil & Gas Industry as a whole, recognizes the importance of reducing GHG emissions, has made significant strides to do so over the past several years and continues to evaluate and implement technologies and solutions to accomplish further GHG emissions reductions.

Further, the industry is doing so despite EPA’s antiquated GHGRP and its “one-size fits all” emissions factor-based approach for calculating GHG emissions, which, in many cases, causes GHG emissions to be overstated.

AIPRO recommends that the EPA engage and work with industry groups such as AIPRO, IPAA and API to develop updated GHGRP regulations going forward. And, further, to allow well established and accomplished American innovation to lead the way in GHG emissions reductions.

Figure 2. Trends in energy-related carbon dioxide emissions and key indicators



Source: Graph created by the U.S. Energy Information Administration (EIA), based on data from EIA's *Monthly Energy Review*, October 2021, Table 11.1, Carbon Dioxide Emissions from Energy Consumption by Source; the U.S. Bureau of Economic Analysis; and the U.S. Census Bureau
Note: CO2 refers to carbon dioxide

Commenter 0417: NDPC feels EPA has given limited time and engagement opportunities for adequate evaluation and more robust comments on this supplemental proposal, a significant energy action. For such a complex and significant rulemaking as this, it is not reasonable for EPA to expect the regulated community to review 203 documents and make thorough comments on all possible options available to EPA to meet the requirement placed upon it by the Inflation Reduction Act of 2022 and the requirements of 40 CFR part 98, subpart W to ensure that reporting of methane emissions and calculation of charges under the “Methane Emissions and Waste Reduction Incentive Program” are based on empirical data and accurately reflect total methane emissions from applicable facilities.

Therefore, our comments are not all-encompassing, and the absence of further comment is not meant as agreement or support for any of these proposed actions. Rather, we have highlighted the following comments to illustrate our concerns with these proposed actions.

Since this rule has the potential to change the economic landscape of North Dakota, we are requesting that the EPA consider additional sources of empirical data, align the Greenhouse Gas Reporting Rule with other inter-related and referenced rules, and avoid the unintended consequences of disincentivizing operators from utilizing the most accurate technology and data sources to calculate emissions and continuing to make the emission reduction improvements that are necessary to ensure the United States remains the top producer of clean energy in the world. In this proposal, EPA has incorporated some good considerations for the use of empirical data in some areas but missed the mark in others and proposed elements that appear in some cases to be included solely to inflate the Waste Emissions Charge.

…

NDPC acknowledges the EPA's desire to advance the public participation process. However, given the extent of the additional, concurrent, and numerous inter-related proposals and new rules affecting the oil and gas industry (i.e. NSPS OOOOb, EG OOOOc, IRA MERP, PHMSA LDAR Rule, BLM Waste Prevention Rule, BLM Conservation and Landscape Health Rule, BLM Onshore Oil and Gas Leasing Rule, CEQ NEPA Implementing Regulations Revision, Phase 2, SEC Climate Disclosure Rule, etc.) and the haste at which these have been pushed through the rulemaking process with proposed mandates for widely varying and inconsistent technologies to accomplish what appear to be similar goals, our comments have been and continue to be necessarily limited in scope and detail.

We ask that the EPA be more proactive in its industry engagement for future rulemakings so the agency can be better prepared before publishing proposed rules and give the public and regulated industry the time to participate efficiently and effectively. Referencing proposed actions not yet finalized creates regulatory and financial uncertainty for the regulated community. Again, silence on any part of this proposal should not be interpreted as our agreement or support. Time constraints and the complex nature of these rules have impacted our ability to respond to every piece of this proposal.

Response 12: The EPA acknowledges that the rulemaking schedule for the subpart W amendments coincides with multiple other rulemakings of interest to stakeholders in the oil and gas industry, including those from the Bureau of Land Management, the Pipeline and Hazardous Materials Safety Administration, and the U.S. Securities and Exchange Commission. However, as discussed in the preamble to the final rule, CAA section 136(h) requires that within two years after the date of enactment of section 60113 of the IRA, the EPA shall revise the requirements of subpart W to ensure the reporting under subpart W is based on empirical data, accurately reflects the total methane emissions (and waste emissions) from the applicable facilities, and allow owners and operators of applicable facilities to submit empirical emissions data, in a manner to be prescribed by the Administrator, to demonstrate the extent to which a charge is owed under CAA section 136. Within this mandated timeline, the EPA has solicited engagement from stakeholders in multiple forums. The proposed rule was available for public comment from August 1 to October 2, 2023, and a virtual public hearing was held on August 21, 2023. The EPA provided a subsequent informational webinar on the technical aspects of the rule on September 7, 2023. Additionally, throughout the rulemaking process the EPA has participated in stakeholder meetings upon request. The EPA has considered stakeholder input received during these discussions, informational webinar, and public comments in the development of the final rule.

Commenter: Public Hearing Transcript
Comment Number: EPA-HQ-OAR-2023-0234-0224
Page(s): 23 (Cyrus Reed)

Commenter: Wyoming Department of Environmental Quality (WDEQ)
Comment Number: EPA-HQ-OAR-2023-0234-0388
Page(s): 11

Commenter: Encino Energy (EAP Ohio, LLC)
Comment Number: EPA-HQ-OAR-2023-0234-0408
Page(s): 7

Comment 13: Commenter 0224: I also want to say separate from the rule itself, it going to be really important to have audits and checks on data reporting, and then figure out how to provide information about the role of both to industry, but also to the state agencies like here in Texas that may be partially responsible for assuring compliance, that's going to be important as well and we'll submit some written comments on how to make that happen.

Commenter 0388: There are numerous aspects of the proposed rule that are extremely technical, have potential far-reaching policy implications, and require the full suite of complimentary methane-and greenhouse gas-related regulations to be finalized in order for state regulatory agencies, regulated entities, and the general public to perform a comprehensive evaluation of its impacts. Such an evaluation is not possible at this time, especially without the promulgation of EPA's forthcoming Waste Emissions Charge rule. WDEQ respectfully requests that EPA consider the tenants of cooperative federalism and engage in conversations with individual state agencies before promulgating any final rule.

Commenter 0408: EAP Ohio, LLC urges continued and improved collaboration within federal agencies and federal to state agencies on the final revisions to Subpart W. Business should not be at risk of compliance concerns when state laws or the direction of state EPA officials are followed. EAP Ohio, LLC advises substantial interagency training, and training for operators with time for understanding the final rule by air compliance professionals and operations teams before the effective date.

Response 13: The EPA appreciates the need for collaboration and consideration of input from states in finalizing amendments to subpart W. As a part of this and prior GHGRP rulemakings, the EPA has solicited input on subpart W from states and entities representing multiple states and intends to continue to do so in the future including in future rulemakings.

Commenter: Kirk Frost
Comment Number: EPA-HQ-OAR-2023-0234-0414
Page(s): 1

Comment 14: We need accurate emissions reported at every facility. I also urge EPA to include fines in the rule for accurate reporting. If a facility reports less than 1 ton of methane each year, but in reality, that facility is emitting 200 tons of methane each year, there needs to be a substantial fine. A fine amount of 30,000 for every ton more than a 5% threshold. For example, CS-325 owner/operator Tennessee Gas Pipeline stated to FERC it anticipates CS-325 emitting 129 tons of methane each year (including combustion, fugitive leaking and fugitive venting). If TGP reports 1.5 tons of methane emissions for 2023 and it is discovered that the facility actually emitted 700 tons because it had an unplanned blow down in addition to the expected 129 tons of emissions, the the owner/operator TGP should be fined for 698 tons of unreported methane emissions multiplied by $30,000 (approx $21MM). With this type of fine, it will discourage owners/operators from falsely under reporting methane emissions. I can safely use the word falsely, because these owner/operators submit to FERC all of the potential emissions that a new or modified facility will emit each year. They then turn around and falsely provide impossibly low emissions to state DEP and EPA.

Response 14: The EPA has worked to coordinate with states, recognizing that different programs have different goals. The EPA cannot tailor the rule to meet state regulations as each state has unique regulations and therefore harmonizing is not possible. Further, the EPA does not have the authority to change state regulations in order to create the consistency necessary to develop a standardized national data collection. The EPA attempts wherever possible to coordinate across rulemakings and programs.

28.7 Mass Mailer Comments

The EPA received a substantial number of comments through organized form letter campaigns with the solicitation of comments on the final rule. These comments included recommendations for the final rule as well as recommendations for EPA programs that are outside the scope of this rulemaking. The EPA appreciates the participation of these commenters in the rulemaking process. The comments in this section are being published here to recognize all input received by the EPA, but they are not being responded to individually. However, the points raised in these letters were also raised by other commenters, and those comments are addressed in the preamble to the final rule or elsewhere in this document.

Commenter: Alicia Clifton
Comment Number: EPA-HQ-OAR-2023-0234-0250
Page(s): 1

Comment: The U.S. Environmental Protection Agency's (EPA's) proposed edits to Subpart W of the Greenhouse Gas (GHG) Reporting Rule include improvements for tracking GHG emissions from the oil and gas industry. I support this rulemaking as a vital step in combating the climate crisis. However, there are still a number of ways that the EPA can strengthen it to improve data accuracy and hold the oil and gas sector more accountable for its GHG emissions

I urge EPA to strengthen its proposed rule in the following ways:

1. Significantly reduce the reporting limit to the lower level originally proposed in the Build Back Better Act to include a larger number of sources reporting more accurate data.

2. Finalize the reporting requirements for large release events. Ensure that operators find and report all large emission events that are not otherwise captured in the reporting methodologies.

3. Finalize emission factors for major equipment from recent peer-reviewed research. Ensure that reporting of leaks and malfunctions through other pathways is complete and incorporates

emissions events from leaks and operational problems.

4. Use funds from the Methane Emissions Reduction Program for monitoring for large release events, focusing on sites that are not otherwise monitored, and gathering and incorporating additional types of observational monitoring data.

5. Require operators to use data from regulatory leak inspections to enhance the accuracy of their reported emissions.

6. Provide all reported emissions data in publicly-accessible and easy to use formats. Verify the accuracy of reported emissions and that applicable facilities are properly identified.

Thank you for meaningfully considering my comment.

Commenter: Abigail Gindele
Comment Number: EPA-HQ-OAR-2023-0234-0326
Page(s): 1

Comment: The U.S. Environmental Protection Agency's (EPA's) proposed edits to Subpart W of the Greenhouse Gas (GHG) Reporting Rule include improvements for tracking GHG emissions from the oil and gas industry. I support this rulemaking as a vital step in combating the climate crisis. However, there are still a number of ways that the EPA can strengthen it to improve data accuracy and hold the oil and gas sector more accountable for its GHG emissions

I urge EPA to strengthen its proposed rule in the following ways:

1. Significantly reduce the reporting limit to the lower level originally proposed in the Build Back Better Act to include a larger number of sources reporting more accurate data.

2. Finalize the reporting requirements for large release events. Ensure that operators find and report all large emission events that are not otherwise captured in the reporting methodologies.

3. Finalize emission factors for major equipment from recent peer-reviewed research. Ensure that reporting of leaks and malfunctions through other pathways is complete and incorporates emissions events from leaks and operational problems.

4. Use funds from the Methane Emissions Reduction Program for monitoring for large release events, focusing on sites that are not otherwise monitored, and gathering and incorporating additional types of observational monitoring data.

5. Require operators to use data from regulatory leak inspections to enhance the accuracy of their reported emissions.

6. Provide all reported emissions data in publicly-accessible and easy to use formats. Verify the accuracy of reported emissions and that applicable facilities are properly identified.

Thank you for meaningfully considering my comment.

Commenter: Alan Peterson
Comment Number: EPA-HQ-OAR-2023-0234-0357
Page(s): 1

Comment: The U.S. Environmental Protection Agency's (EPA's) proposed edits to Subpart W of the Greenhouse Gas (GHG) Reporting Rule include improvements for tracking GHG emissions from the oil and gas industry. I support this rulemaking as a vital step in combating the climate crisis. However, there are still a number of ways that the EPA can strengthen it to improve data accuracy and hold the oil and gas sector more accountable for its GHG emissions

I urge EPA to strengthen its proposed rule in the following ways:

1. Significantly reduce the reporting limit to the lower level originally proposed in the Build Back Better Act to include a larger number of sources reporting more accurate data.

2. Finalize the reporting requirements for large release events. Ensure that operators find and report all large emission events that are not otherwise captured in the reporting methodologies.

3. Finalize emission factors for major equipment from recent peer-reviewed research. Ensure that reporting of leaks and malfunctions through other pathways is complete and incorporates emissions events from leaks and operational problems.

4. Use funds from the Methane Emissions Reduction Program for monitoring for large release events, focusing on sites that are not otherwise monitored, and gathering and incorporating additional types of observational monitoring data.

5. Require operators to use data from regulatory leak inspections to enhance the accuracy of their reported emissions.

6. Provide all reported emissions data in publicly-accessible and easy to use formats. Verify the accuracy of reported emissions and that applicable facilities are properly identified.

Thank you for meaningfully considering my comment.

Commenter: Alison Rupert
Comment Number: EPA-HQ-OAR-2023-0234-0320
Page(s): 1

Comment: The U.S. Environmental Protection Agency's (EPA's) proposed edits to Subpart W of the Greenhouse Gas (GHG) Reporting Rule include improvements for tracking GHG emissions from the oil and gas industry. I support this rulemaking as a vital step in combating the

climate crisis. However, there are still a number of ways that the EPA can strengthen it to improve data accuracy and hold the oil and gas sector more accountable for its GHG emissions

I urge EPA to strengthen its proposed rule in the following ways:

1. Significantly reduce the reporting limit to the lower level originally proposed in the Build Back Better Act to include a larger number of sources reporting more accurate data.

2. Finalize the reporting requirements for large release events. Ensure that operators find and report all large emission events that are not otherwise captured in the reporting methodologies.

3. Finalize emission factors for major equipment from recent peer-reviewed research. Ensure that reporting of leaks and malfunctions through other pathways is complete and incorporates emissions events from leaks and operational problems.

4. Use funds from the Methane Emissions Reduction Program for monitoring for large release events, focusing on sites that are not otherwise monitored, and gathering and incorporating additional types of observational monitoring data.

5. Require operators to use data from regulatory leak inspections to enhance the accuracy of their reported emissions.

6. Provide all reported emissions data in publicly-accessible and easy to use formats. Verify the accuracy of reported emissions and that applicable facilities are properly identified.

Thank you for meaningfully considering my comment.

Commenter: Anonymous
Comment Number: EPA-HQ-OAR-2023-0234-0325
Page(s): 1

Comment: The EPA's proposed edits to Subpart W of the Greenhouse Gas (GHG) Reporting Rule include improvements for tracking these emissions from the fossil fuel industry. I support this rulemaking as a vital step in combating the climate crisis. However, there are several ways that the EPA can strengthen it to improve data accuracy and hold the fossil fuel sector more accountable for its GHG emissions.
I urge EPA to strengthen its proposed rule in the following ways:
1. Significantly reduce the reporting limit to the lower level originally proposed in the Build Back Better Act to include a larger number of sources reporting more accurate data.
2. Finalize the reporting requirements for large release events. Ensure that operators find and report all large emission events that are not otherwise captured in the reporting methodologies.
3. Finalize emission factors for major equipment from recent peer-reviewed research. Ensure that reporting of leaks and malfunctions through other pathways is complete and incorporates emissions events from leaks and operational problems.
4. Use funds from the Methane Emissions Reduction Program for monitoring for large release

events, focusing on sites that are not otherwise monitored, and gathering and incorporating additional types of observational monitoring data.
5. Require operators to use data from regulatory leak inspections to enhance the accuracy of their reported emissions.
6. Provide all reported emissions data in publicly accessible and easy to use formats. Verify the accuracy of reported emissions and that applicable facilities are properly identified.
Thank you for your consideration on this matter.

Commenter: Barbara Abraham
Comment Number: EPA-HQ-OAR-2023-0234-0251
Page(s): 1

Comment: The U.S. Environmental Protection Agency's (EPA's) proposed edits to Subpart W of the Greenhouse Gas (GHG) Reporting Rule include improvements for tracking GHG emissions from the oil and gas industry. I support this rulemaking as a vital step in combating the climate crisis. However, there are still a number of ways that the EPA can strengthen it to improve data accuracy and hold the oil and gas sector more accountable for its GHG emissions

I urge EPA to strengthen its proposed rule in the following ways:

1. Significantly reduce the reporting limit to the lower level originally proposed in the Build Back Better Act to include a larger number of sources reporting more accurate data.

2. Finalize the reporting requirements for large release events. Ensure that operators find and report all large emission events that are not otherwise captured in the reporting methodologies.

3. Finalize emission factors for major equipment from recent peer-reviewed research. Ensure that reporting of leaks and malfunctions through other pathways is complete and incorporates emissions events from leaks and operational problems.

4. Use funds from the Methane Emissions Reduction Program for monitoring for large release events, focusing on sites that are not otherwise monitored, and gathering and incorporating additional types of observational monitoring data.

5. Require operators to use data from regulatory leak inspections to enhance the accuracy of their reported emissions.

6. Provide all reported emissions data in publicly-accessible and easy to use formats. Verify the accuracy of reported emissions and that applicable facilities are properly identified.

Thank you for meaningfully considering my comment.

Commenter: Barbara Hogan
Comment Number: EPA-HQ-OAR-2023-0234-0307
Page(s): 1

Comment: The U.S. Environmental Protection Agency's (EPA's) proposed edits to Subpart W of the Greenhouse Gas (GHG) Reporting Rule include improvements for tracking GHG emissions from the oil and gas industry. I support this rulemaking as a vital step in combating the climate crisis. However, there are still a number of ways that the EPA can strengthen it to improve data accuracy and hold the oil and gas sector more accountable for its GHG emissions

I urge EPA to strengthen its proposed rule in the following ways:

1. Significantly reduce the reporting limit to the lower level originally proposed in the Build Back Better Act to include a larger number of sources reporting more accurate data.

2. Finalize the reporting requirements for large release events. Ensure that operators find and report all large emission events that are not otherwise captured in the reporting methodologies.

3. Finalize emission factors for major equipment from recent peer-reviewed research. Ensure that reporting of leaks and malfunctions through other pathways is complete and incorporates emissions events from leaks and operational problems.

4. Use funds from the Methane Emissions Reduction Program for monitoring for large release events, focusing on sites that are not otherwise monitored, and gathering and incorporating additional types of observational monitoring data.

5. Require operators to use data from regulatory leak inspections to enhance the accuracy of their reported emissions.

6. Provide all reported emissions data in publicly-accessible and easy to use formats. Verify the accuracy of reported emissions and that applicable facilities are properly identified.

Thank you for meaningfully considering my comment.

Commenter: Barney McComas
Comment Number: EPA-HQ-OAR-2023-0234-0321
Page(s): 1

Comment: The U.S. Environmental Protection Agency's (EPA's) proposed edits to Subpart W of the Greenhouse Gas (GHG) Reporting Rule include improvements for tracking GHG emissions from the oil and gas industry. I support this rulemaking as a vital step in combating the climate crisis. However, there are still a number of ways that the EPA can strengthen it to improve data accuracy and hold the oil and gas sector more accountable for its GHG emissions.

I urge EPA to strengthen its proposed rule in the following ways:

1. Significantly reduce the reporting limit to the lower level originally proposed in the Build Back Better Act to include a larger number of sources reporting more accurate data.

2. Finalize the reporting requirements for large release events. Ensure that operators find and report all large emission events that are not otherwise captured in the reporting methodologies.

3. Finalize emission factors for major equipment from recent peer-reviewed research. Ensure that reporting of leaks and malfunctions through other pathways is complete and incorporates emissions events from leaks and operational problems.

4. Use funds from the Methane Emissions Reduction Program for monitoring for large release events, focusing on sites that are not otherwise monitored, and gathering and incorporating additional types of observational monitoring data.

5. Require operators to use data from regulatory leak inspections to enhance the accuracy of their reported emissions.

6. Provide all reported emissions data in publicly accessible and easy to use formats. Verify the accuracy of reported emissions and that applicable facilities are properly identified.

Thank you for meaningfully considering my comments.

Commenter: Beth Jones
Comment Number: EPA-HQ-OAR-2023-0234-0269
Page(s): 1

Comment: Your own kids can explain it to you: the perfectly avoidable climate crisis is here. We've just experienced the hottest summer on record and it's only going to get worse from here, "thanks" to greed-addled profiteers known as the Fools for Fossil Fuels and their other proud-to-pollute cronies in the political sphere. We all know who they are and why our EPA's efforts are to be lauded but also challenged to GO FARTHER, FASTER.

That is why I support the agency's edits to Subpart W of the Greenhouse Gas (GHG) Reporting Rule, for they would wisely mandate better tracking of the duplicitous oil and gas industry's GHG emissions. (They've been gaslighting the public for decades about the real and present dangers of burning so damn much petroleum —so we know better than to believe Big Oil will be honestly and voluntarily forthcoming about their still gargantuan and deadly GHG emissions.) IMHO this rulemaking is a welcome step toward combating the climate crisis. However, we all know that the EPA has ways it can reinforce these rules to improve the accuracy of its data and truly hold the oil and gas sector's feet to the fire regarding its still rising GHG emissions.

Informed and therefore alarmed/outraged citizens loudly urge our EPA to bolster its proposed rule in the following ways:

1. Significantly reduce the reporting limit — preferably back to the lower level originally

proposed in the Build Back Better Act — and then make it include a larger number of sources that are reporting more accurate data.

2. Finalize the reporting requirements for large release events. Ensure (!) that operators find and report all (!) large emission events that are not otherwise captured in the reporting methodologies.

3. Finalize emission factors for major equipment from recent peer-reviewed research. Ensure that reporting of leaks and malfunctions through other pathways is complete and incorporates emissions events from leaks and operational problems.

4. Use funds from the Methane Emissions Reduction Program for monitoring for large release events, focusing on sites that are not otherwise monitored, and gathering and incorporating additional types of observational monitoring data.

5. Require (!) operators to use data from regulatory leak inspections to enhance the accuracy of their reported emissions.

6. Subject the industry's emissions and facilities data to rigorous fact-checking and to the "disinfecting" light of day, by transparently providing all reported emissions data in publicly-accessible and easy-to-use formats.

Thank you for considering my comment. Our kids needed us to take drastic action 30+ years ago and so these measures need to go much farther, much faster if we hope to make any meaningful progress toward preserving our children's one and only home planet.

Commenter: Brad Snyder
Comment Number: EPA-HQ-OAR-2023-0234-0309
Page(s): 1

Comment: The U.S. Environmental Protection Agency's (EPA's) proposed edits to Subpart W of the Greenhouse Gas (GHG) Reporting Rule include improvements for tracking GHG emissions from the oil and gas industry.

As a Science Teacher/Outdoor & Environmental Educator, Mechanical Engineer (Emphasis: Energy & Environmental Science), and an extremely concerned citizen, I wholeheartedly support this rulemaking as a vital step in combating the Global Climate Crisis! However, there are still a number of ways that the EPA can strengthen it to improve data accuracy and hold the oil and gas sector more accountable for its GHG emissions!

I strongly urge EPA to strengthen its proposed rule in the following ways:

1. Significantly reduce the reporting limit to the lower level originally proposed in the Build Back Better Act to include a larger number of sources reporting more accurate data!

2. Finalize the reporting requirements for large release events! Ensure that operators find and report ALL large emission events that are NOT otherwise captured in the reporting methodologies!

3. Finalize emission factors for major equipment from recent peer-reviewed research! Ensure that reporting of leaks and malfunctions through other pathways is complete and incorporates emissions events from leaks and operational problems!

4. Use funds from the Methane Emissions Reduction Program for monitoring for large release events, focusing on sites that are NOT otherwise monitored, and gathering and incorporating additional types of observational monitoring data!

5. Require operators to use data from regulatory leak inspections to enhance the accuracy of their reported emissions!

6. Provide ALL reported emissions data in publicly-accessible and easy to use formats! Verify the accuracy of reported emissions and that applicable facilities are properly identified!

Thanks!

Commenter: Carol Claus
Comment Number: EPA-HQ-OAR-2023-0234-0323
Page(s): 1

Comment: The U.S. Environmental Protection Agency's (EPA's) proposed edits to Subpart W of the Greenhouse Gas (GHG) Reporting Rule include improvements for tracking GHG emissions from the oil and gas industry. I support this rulemaking as a vital step in combating the climate crisis. However, there are still a number of ways that the EPA can strengthen it to improve data accuracy and hold the oil and gas sector more accountable for its GHG emissions

I urge EPA to strengthen its proposed rule in the following ways:

1. Significantly reduce the reporting limit to the lower level originally proposed in the Build Back Better Act to include a larger number of sources reporting more accurate data.

2. Finalize the reporting requirements for large release events. Ensure that operators find and report all large emission events that are not otherwise captured in the reporting methodologies.

3. Finalize emission factors for major equipment from recent peer-reviewed research. Ensure that reporting of leaks and malfunctions through other pathways is complete and incorporates emissions events from leaks and operational problems.

4. Use funds from the Methane Emissions Reduction Program for monitoring for large release events, focusing on sites that are not otherwise monitored, and gathering and incorporating additional types of observational monitoring data.

5. Require operators to use data from regulatory leak inspections to enhance the accuracy of their reported emissions.

6. Provide all reported emissions data in publicly-accessible and easy to use formats. Verify the accuracy of reported emissions and that applicable facilities are properly identified.

Thank you for meaningfully considering my comment.

Commenter: Carolyn Lange
Comment Number: EPA-HQ-OAR-2023-0234-0355
Page(s): 1

Comment: The U.S. Environmental Protection Agency's (EPA's) proposed edits to Subpart W of the Greenhouse Gas (GHG) Reporting Rule include improvements for tracking GHG emissions from the oil and gas industry. I support this rulemaking as a vital step in protecting our environment. However, I urge the EPA to do more to strengthen it to improve data accuracy and hold the oil and gas sector more accountable for its GHG emissions

I strongly urge EPA to strengthen its proposed rule in the following ways:

1. Significantly reduce the reporting limit to the lower level originally proposed in the Build Back Better Act to include a larger number of sources reporting more accurate data.

2. Finalize the reporting requirements for large release events. Ensure that operators find and report all large emission events that are not otherwise captured in the reporting methodologies.

3. Finalize emission factors for major equipment from recent peer-reviewed research. Ensure that reporting of leaks and malfunctions through other pathways is complete and incorporates emissions events from leaks and operational problems.

4. Use funds from the Methane Emissions Reduction Program for monitoring for large release events, focusing on sites that are not otherwise monitored, and gathering and incorporating additional types of observational monitoring data.

5. Require operators to use data from regulatory leak inspections to enhance the accuracy of their reported emissions.

6. Provide all reported emissions data in publicly-accessible and easy to use formats. Verify the accuracy of reported emissions and that applicable facilities are properly identified.

All of these actions will help to alleviate the climate crisis that we all now face!

Thank you for considering my comments on this very important matter.

Commenter: Catherine Hunt
Comment Number: EPA-HQ-OAR-2023-0234-0331
Page(s): 1

Comment: The U.S. Environmental Protection Agency's (EPA's) proposed edits to Subpart W of the Greenhouse Gas (GHG) Reporting Rule include improvements for tracking GHG emissions from the oil and gas industry. I support this rulemaking as a vital step in combating the climate crisis. However, there are still a number of ways that the EPA can strengthen it to improve data accuracy and hold the oil and gas sector more accountable for its GHG emissions

I urge EPA to strengthen its proposed rule in the following ways:

1. Significantly reduce the reporting limit to the lower level originally proposed in the Build Back Better Act to include a larger number of sources reporting more accurate data.

2. Finalize the reporting requirements for large release events. Ensure that operators find and report all large emission events that are not otherwise captured in the reporting methodologies.

3. Finalize emission factors for major equipment from recent peer-reviewed research. Ensure that reporting of leaks and malfunctions through other pathways is complete and incorporates emissions events from leaks and operational problems.

4. Use funds from the Methane Emissions Reduction Program for monitoring for large release events, focusing on sites that are not otherwise monitored, and gathering and incorporating additional types of observational monitoring data.

5. Require operators to use data from regulatory leak inspections to enhance the accuracy of their reported emissions.

6. Provide all reported emissions data in publicly-accessible and easy to use formats. Verify the accuracy of reported emissions and that applicable facilities are properly identified.

Thank you for meaningfully considering my comment.

Commenter: Chestnut Hill United Church
Comment Number: EPA-HQ-OAR-2023-0234-0367
Page(s): 1

Comment: Chestnut Hill United Church in Philadelphia, PA, has been working in many ways to slow down climate change for more than 30 years – we started educating our congregation about the problem in 1991. To us, it's a moral imperative to do whatever is feasible to attack climate change, since it hurts first and foremost those at the vulnerable edges of society: the elderly, the very young, those in poor health, and those in poverty. And of course this means disproportional harm on black and brown people.

The EPA's proposed edits to Subpart W of the Greenhouse Gas (GHG) Reporting Rule include improvements for tracking GHG emissions from the oil and gas industry. We support this rulemaking as a vital step in combating the climate crisis. There are more ways the EPA can strengthen it to improve data accuracy and hold the oil and gas sector more accountable for its GHG emissions

We urge EPA to strengthen its proposed rule in the following ways:

1. Significantly reduce the reporting limit to the lower level originally proposed in the Build Back Better Act to include a larger number of sources reporting more accurate data.

2. Finalize the reporting requirements for large release events. Ensure that operators find and report all large emission events that are not otherwise captured in the reporting methodologies.

3. Finalize emission factors for major equipment from recent peer-reviewed research. Ensure that reporting of leaks and malfunctions through other pathways is complete and incorporates emissions events from leaks and operational problems.

4. Use funds from the Methane Emissions Reduction Program for monitoring for large release events, focusing on sites that are not otherwise monitored, and gathering and incorporating additional types of observational monitoring data.

5. Require operators to use data from regulatory leak inspections to enhance the accuracy of their reported emissions.

6. Provide all reported emissions data in publicly-accessible and easy to use formats. Verify the accuracy of reported emissions and that applicable facilities are properly identified.

Thank you for meaningfully considering our comment.

Commenter: Clean Air Council
Comment Number: EPA-HQ-OAR-2023-0234-0292
Page(s): 1

Comment:

These comments supersede any previous comments on the docket from Clean Air Council and reflect the Council's most recent position on this proposed amendment.

The United States' oil and gas industry produced GHG emissions in 2021 that were equivalent to driving nearly 70 million gasoline-powered cars for an entire year. Methane is a major pollutant emitted by this sector and is often released alongside other hazardous and carcinogenic air pollutants. Yet, studies have shown that methane emissions calculated and reported by the oil and gas industry are greatly underestimated. Reducing methane emissions from the oil and gas sector would tackle the climate crisis and better protect the health of Americans.

The U.S. Environmental Protection Agency's (EPA's) proposed edits to Subpart W of the Greenhouse Gas (GHG) Reporting Rule include improvements for tracking GHG emissions from the oil and gas industry. However, there are still a number of ways that the EPA can strengthen it to improve data accuracy and hold the oil and gas sector more accountable for its GHG emissions.

We urge EPA to strengthen its proposed revisions in the following ways:

1. Significantly reduce the emissions reporting threshold to 10,000 mt CO2e to include a larger number of sources reporting more accurate data. This threshold was originally proposed in the Build Back Better legislation.

2. Finalize the reporting requirements for large release events. Ensure that operators find and report all large emission events that are not otherwise captured in the reporting methodologies.

3. Finalize emission factors for major equipment from recent peer-reviewed research. Ensure that reporting of leaks and malfunctions through other pathways is complete and incorporates emissions events from leaks and operational problems.

4. Use funds from the Methane Emissions Reduction Program for monitoring for large release events, focusing on sites that are not otherwise monitored or are located in environmental justice communities, and gathering and incorporating additional types of observational monitoring data.

5. Require operators to use data from regulatory leak inspections to enhance the accuracy of their reported annual emissions.

6. Provide all reported emissions data in publicly-accessible and easy to use formats. Verify the accuracy of reported emissions and that applicable facilities are properly identified.

Commenter: Constantina Hanse
Comment Number: EPA-HQ-OAR-2023-0234-0324
Page(s): 1

Comment: The U.S. Environmental Protection Agency's (EPA's) proposed edits to Subpart W of the Greenhouse Gas (GHG) Reporting Rule include improvements for tracking GHG emissions from the oil and gas industry. I support this rulemaking as a vital step in combating the climate crisis. However, there are still a number of ways that the EPA can strengthen it to improve data accuracy and hold the oil and gas sector more accountable for its GHG emissions

I urge EPA to strengthen its proposed rule in the following ways:

1. Significantly reduce the reporting limit to the lower level originally proposed in the Build Back Better Act to include a larger number of sources reporting more accurate data.

2. Finalize the reporting requirements for large release events. Ensure that operators find and

report all large emission events that are not otherwise captured in the reporting methodologies.

3. Finalize emission factors for major equipment from recent peer-reviewed research. Ensure that reporting of leaks and malfunctions through other pathways is complete and incorporates emissions events from leaks and operational problems.

4. Use funds from the Methane Emissions Reduction Program for monitoring for large release events, focusing on sites that are not otherwise monitored, and gathering and incorporating additional types of observational monitoring data.

5. Require operators to use data from regulatory leak inspections to enhance the accuracy of their reported emissions.

6. Provide all reported emissions data in publicly-accessible and easy to use formats. Verify the accuracy of reported emissions and that applicable facilities are properly identified.

Thank you for meaningfully considering my comment.

Commenter: Dale Foote
Comment Number: EPA-HQ-OAR-2023-0234-0273
Page(s): 1

Comment: The U.S. Environmental Protection Agency's (EPA's) proposed edits to Subpart W of the Greenhouse Gas (GHG) Reporting Rule include improvements for tracking GHG emissions from the oil and gas industry. I support this rulemaking as a vital step in combating the climate crisis. However, there are still a number of ways that the EPA can strengthen it to improve data accuracy and hold the oil and gas sector more accountable for its GHG emissions

I urge EPA to strengthen its proposed rule in the following ways:

1. Significantly reduce the reporting limit to the lower level originally proposed in the Build Back Better Act to include a larger number of sources reporting more accurate data.

2. Finalize the reporting requirements for large release events. Ensure that operators find and report all large emission events that are not otherwise captured in the reporting methodologies.

3. Finalize emission factors for major equipment from recent peer-reviewed research. Ensure that reporting of leaks and malfunctions through other pathways is complete and incorporates emissions events from leaks and operational problems.

4. Use funds from the Methane Emissions Reduction Program for monitoring for large release events, focusing on sites that are not otherwise monitored, and gathering and incorporating additional types of observational monitoring data.

5. Require operators to use data from regulatory leak inspections to enhance the accuracy of their

reported emissions.

6. Provide all reported emissions data in publicly-accessible and easy to use formats. Verify the accuracy of reported emissions and that applicable facilities are properly identified.

Thank you for meaningfully considering my comment. Dale Foote

Commenter: Dan Perry
Comment Number: EPA-HQ-OAR-2023-0234-0310
Page(s): 1

Comment: The U.S. Environmental Protection Agency's (EPA's) proposed edits to Subpart W of the Greenhouse Gas (GHG) Reporting Rule include improvements for tracking GHG emissions from the oil and gas industry. I support this rulemaking as a vital step in combating the climate crisis. However, there are still a number of ways that the EPA can strengthen it to improve data accuracy and hold the oil and gas sector more accountable for its GHG emissions

I urge EPA to strengthen its proposed rule in the following ways:

1. Significantly reduce the reporting limit to the lower level originally proposed in the Build Back Better Act to include a larger number of sources reporting more accurate data.

2. Finalize the reporting requirements for large release events. Ensure that operators find and report all large emission events that are not otherwise captured in the reporting methodologies.

3. Finalize emission factors for major equipment from recent peer-reviewed research. Ensure that reporting of leaks and malfunctions through other pathways is complete and incorporates emissions events from leaks and operational problems.

4. Use funds from the Methane Emissions Reduction Program for monitoring for large release events, focusing on sites that are not otherwise monitored, and gathering and incorporating additional types of observational monitoring data.

5. Require operators to use data from regulatory leak inspections to enhance the accuracy of their reported emissions.

6. Provide all reported emissions data in publicly-accessible and easy to use formats. Verify the accuracy of reported emissions and that applicable facilities are properly identified.

Thank you for meaningfully considering my comment.

Commenter: Debra Wontor
Comment Number: EPA-HQ-OAR-2023-0234-0252
Page(s): 1

Comment: The U.S. Environmental Protection Agency's (EPA's) proposed edits to Subpart W of the Greenhouse Gas (GHG) Reporting Rule include improvements for tracking GHG emissions from the oil and gas industry. I support this rulemaking as a vital step in combating the climate crisis. However, there are still a number of ways that the EPA can strengthen it to improve data accuracy and hold the oil and gas sector more accountable for its GHG emissions

I urge EPA to strengthen its proposed rule in the following ways:

1. Significantly reduce the reporting limit to the lower level originally proposed in the Build Back Better Act to include a larger number of sources reporting more accurate data.

2. Finalize the reporting requirements for large release events. Ensure that operators find and report all large emission events that are not otherwise captured in the reporting methodologies.

3. Finalize emission factors for major equipment from recent peer-reviewed research. Ensure that reporting of leaks and malfunctions through other pathways is complete and incorporates emissions events from leaks and operational problems.

4. Use funds from the Methane Emissions Reduction Program for monitoring for large release events, focusing on sites that are not otherwise monitored, and gathering and incorporating additional types of observational monitoring data.

5. Require operators to use data from regulatory leak inspections to enhance the accuracy of their reported emissions.

6. Provide all reported emissions data in publicly-accessible and easy to use formats. Verify the accuracy of reported emissions and that applicable facilities are properly identified.

Thank you for meaningfully considering my comment.

Commenter: Don Hawkins
Comment Number: EPA-HQ-OAR-2023-0234-0281
Page(s): 1

Comment: The U.S. Environmental Protection Agency's (EPA's) proposed edits to Subpart W of the Greenhouse Gas (GHG) Reporting Rule include improvements for tracking GHG emissions from the oil and gas industry. I support this rulemaking as a vital step in combating the climate crisis. However, there are still a number of ways that the EPA can strengthen it to improve data accuracy and hold the oil and gas sector more accountable for its GHG emissions

I urge EPA to strengthen its proposed rule in the following ways:

1. Significantly reduce the reporting limit to the lower level originally proposed in the Build Back Better Act to include a larger number of sources reporting more accurate data.

2. Finalize the reporting requirements for large release events. Ensure that operators find and report all large emission events that are not otherwise captured in the reporting methodologies.

3. Finalize emission factors for major equipment from recent peer-reviewed research. Ensure that reporting of leaks and malfunctions through other pathways is complete and incorporates emissions events from leaks and operational problems.

4. Use funds from the Methane Emissions Reduction Program for monitoring for large release events, focusing on sites that are not otherwise monitored, and gathering and incorporating additional types of observational monitoring data.

5. Require operators to use data from regulatory leak inspections to enhance the accuracy of their reported emissions.

6. Provide all reported emissions data in publicly-accessible and easy to use formats. Verify the accuracy of reported emissions and that applicable facilities are properly identified.

Thank you for meaningfully considering my comment.

Commenter: Edward Lynch
Comment Number: EPA-HQ-OAR-2023-0234-0333
Page(s): 1

Comment: The U.S. Environmental Protection Agency's (EPA's) proposed edits to Subpart W of the Greenhouse Gas (GHG) Reporting Rule include improvements for tracking GHG emissions from the oil and gas industry. I support this rulemaking as a vital step in combating the climate crisis. However, there are still a number of ways that the EPA can strengthen it to improve data accuracy and hold the oil and gas sector more accountable for its GHG emissions

I urge EPA to strengthen its proposed rule in the following ways:

1. Significantly reduce the reporting limit to the lower level originally proposed in the Build Back Better Act to include a larger number of sources reporting more accurate data.

2. Finalize the reporting requirements for large release events. Ensure that operators find and report all large emission events that are not otherwise captured in the reporting methodologies.

3. Finalize emission factors for major equipment from recent peer-reviewed research. Ensure that reporting of leaks and malfunctions through other pathways is complete and incorporates emissions events from leaks and operational problems.

4. Use funds from the Methane Emissions Reduction Program for monitoring for large release events, focusing on sites that are not otherwise monitored, and gathering and incorporating additional types of observational monitoring data.

5. Require operators to use data from regulatory leak inspections to enhance the accuracy of their reported emissions.

6. Provide all reported emissions data in publicly-accessible and easy to use formats. Verify the accuracy of reported emissions and that applicable facilities are properly identified.

Thank you for meaningfully considering my comment.

Commenter: Elizabeth Watts
Comment Number: EPA-HQ-OAR-2023-0234-0254
Page(s): 1

Comment: I urge EPA to strengthen its proposed rule in the following ways:

1. Significantly reduce the reporting limit to the lower level originally proposed in the Build Back Better Act to include a larger number of sources reporting more accurate data.

2. Finalize the reporting requirements for large release events. Ensure that operators find and report all large emission events that are not otherwise captured in the reporting methodologies.

3. Finalize emission factors for major equipment from recent peer-reviewed research. Ensure that reporting of leaks and malfunctions through other pathways is complete and incorporates emissions events from leaks and operational problems.

4. Use funds from the Methane Emissions Reduction Program for monitoring for large release events, focusing on sites that are not otherwise monitored, and gathering and incorporating additional types of observational monitoring data.

5. Require operators to use data from regulatory leak inspections to enhance the accuracy of their reported emissions.

6. Provide all reported emissions data in publicly-accessible and easy to use formats. Verify the accuracy of reported emissions and that applicable facilities are properly identified.

Thank you for meaningfully considering my comment.

Commenter: Ellie Rotz
Comment Number: EPA-HQ-OAR-2023-0234-0280
Page(s): 1

Comment: The U.S. Environmental Protection Agency's (EPA's) proposed edits to Subpart W of the Greenhouse Gas (GHG) Reporting Rule include improvements for tracking GHG emissions from the oil and gas industry. I support this rulemaking as a vital step in combating the climate crisis. However, there are still a number of ways that the EPA can strengthen it to improve data accuracy and hold the oil and gas sector more accountable for its GHG emissions

I urge EPA to strengthen its proposed rule in the following ways:

1. Significantly reduce the reporting limit to the lower level originally proposed in the Build Back Better Act to include a larger number of sources reporting more accurate data.

2. Finalize the reporting requirements for large release events. Ensure that operators find and report all large emission events that are not otherwise captured in the reporting methodologies.

3. Finalize emission factors for major equipment from recent peer-reviewed research. Ensure that reporting of leaks and malfunctions through other pathways is complete and incorporates emissions events from leaks and operational problems.

4. Use funds from the Methane Emissions Reduction Program for monitoring for large release events, focusing on sites that are not otherwise monitored, and gathering and incorporating additional types of observational monitoring data.

5. Require operators to use data from regulatory leak inspections to enhance the accuracy of their reported emissions.

6. Provide all reported emissions data in publicly-accessible and easy to use formats. Verify the accuracy of reported emissions and that applicable facilities are properly identified.

Thank you for meaningfully considering my comment.

Commenter: Ethan Frank
Comment Number: EPA-HQ-OAR-2023-0234-0317
Page(s): 1

Comment: Hello,

I support the EPA's proposed edits to Subpart W of the Greenhouse Gas (GHG) Reporting Rule's improvements in tracking GHG emissions from the oil and gas industry. However, there are a number of ways the EPA can strengthen it to improve data accuracy and hold the oil and gas sector more accountable for its GHG emissions

I urge EPA to strengthen the proposed rule in the following ways:

1. Significantly reduce the reporting limit to the lower level originally proposed in the Build Back Better Act to include a larger number of sources reporting more accurate data.

2. Finalize emission factors for major equipment from recent peer-reviewed research. Ensure that reporting of leaks and malfunctions through other pathways is complete and incorporates emissions events from leaks and operational problems.

3. Finalize the reporting requirements for large release events. Ensure that operators find and report all large emission events that are not otherwise captured in the reporting methodologies.

4. Use funds from the Methane Emissions Reduction Program for monitoring for large release events, focusing on sites that are not otherwise monitored, and gathering and incorporating additional types of observational monitoring data.

5. Require operators to use data from regulatory leak inspections to enhance the accuracy of their reported emissions.

6. Provide all reported emissions data in publicly-accessible and easy to use formats. Verify the accuracy of reported emissions and that applicable facilities are properly identified.

Thank you for your consideration.

Commenter: Frances Gilmore
Comment Number: EPA-HQ-OAR-2023-0234-0359
Page(s): 1

Comment: The U.S. Environmental Protection Agency's (EPA's) proposed edits to Subpart W of the Greenhouse Gas (GHG) Reporting Rule include improvements for tracking GHG emissions from the oil and gas industry. I support this rulemaking as a vital step in combating the climate crisis. However, there are still a number of ways that the EPA can strengthen it to improve data accuracy and hold the oil and gas sector more accountable for its GHG emissions

I urge EPA to strengthen its proposed rule in the following ways, as suggested by the Clean Air Council:

1. Significantly reduce the reporting limit to the lower level originally proposed in the Build Back Better Act to include a larger number of sources reporting more accurate data.

2. Finalize the reporting requirements for large release events. Ensure that operators find and report all large emission events that are not otherwise captured in the reporting methodologies.

3. Finalize emission factors for major equipment from recent peer-reviewed research. Ensure that reporting of leaks and malfunctions through other pathways is complete and incorporates emissions events from leaks and operational problems.

4. Use funds from the Methane Emissions Reduction Program for monitoring for large release events, focusing on sites that are not otherwise monitored, and gathering and incorporating additional types of observational monitoring data.

5. Require operators to use data from regulatory leak inspections to enhance the accuracy of their reported emissions.

6. Provide all reported emissions data in publicly-accessible and easy to use formats. Verify the accuracy of reported emissions and that applicable facilities are properly identified.

Thank you for meaningfully considering my comment.

Commenter: Fred Granlund
Comment Number: EPA-HQ-OAR-2023-0234-0263
Page(s): 1

Comment: The U.S. Environmental Protection Agency's (EPA's) proposed edits to Subpart W of the Greenhouse Gas (GHG) Reporting Rule include improvements for tracking GHG emissions from the oil and gas industry. I support this rulemaking as a vital step in combating the climate crisis. However, there are still a number of ways that the EPA can strengthen it to improve data accuracy and hold the oil and gas sector more accountable for its GHG emissions

I urge EPA to strengthen its proposed rule in the following ways:

1. Significantly reduce the reporting limit to the lower level originally proposed in the Build Back Better Act to include a larger number of sources reporting more accurate data.

2. Finalize the reporting requirements for large release events. Ensure that operators find and report all large emission events that are not otherwise captured in the reporting methodologies.

3. Finalize emission factors for major equipment from recent peer-reviewed research. Ensure that reporting of leaks and malfunctions through other pathways is complete and incorporates emissions events from leaks and operational problems.

4. Use funds from the Methane Emissions Reduction Program for monitoring for large release events, focusing on sites that are not otherwise monitored, and gathering and incorporating additional types of observational monitoring data.

5. Require operators to use data from regulatory leak inspections to enhance the accuracy of their reported emissions.

6. Provide all reported emissions data in publicly-accessible and easy to use formats. Verify the accuracy of reported emissions and that applicable facilities are properly identified.

Thank you for meaningfully considering my comment.

Commenter: Gerritt and Elizabeth Baker-Smith
Comment Number: EPA-HQ-OAR-2023-0234-0253
Page(s): 1

Comment: We are writing to urge EPA to strengthen its proposed rule in the following ways:

1. Significantly reduce the reporting limit to the lower level originally proposed in the Build Back Better Act to include a larger number of sources reporting more accurate data.

2. Finalize the reporting requirements for large release events. Ensure that operators find and report all large emission events that are not otherwise captured in the reporting methodologies.

3. Finalize emission factors for major equipment from recent peer-reviewed research. Ensure that reporting of leaks and malfunctions through other pathways is complete and incorporates emissions events from leaks and operational problems.

4. Use funds from the Methane Emissions Reduction Program for monitoring for large release events, focusing on sites that are not otherwise monitored, and gathering and incorporating additional types of observational monitoring data.

5. Require operators to use data from regulatory leak inspections to enhance the accuracy of their reported emissions.

6. Provide all reported emissions data in publicly-accessible and easy to use formats. Verify the accuracy of reported emissions and that applicable facilities are properly identified.

Thank you for your attention.

Commenter: Gry Nuns of the Sacred Heart
Comment Number: EPA-HQ-OAR-2023-0234-0369
Page(s):

Comment:

Thank you for your proposed amendment to the Greenhouse Gas Reporting Program that ensures operators of certain oil and gas facilities more accurately report their climate-heating greenhouse gas (GHG) emissions. That's a good first step.

The next step that I'm asking of you is six-fold coming from and agreeing with the Clean Air Council

I urge EPA to strengthen its proposed rule in the following ways:

1. Significantly reduce the reporting limit to the lower level originally proposed in the Build Back Better Act to include a larger number of sources reporting more accurate data.

2. Finalize the reporting requirements for large release events. Ensure that operators find and report all large emission events that are not otherwise captured in the reporting methodologies.

3. Finalize emission factors for major equipment from recent peer-reviewed research. Ensure that reporting of leaks and malfunctions through other pathways is complete and incorporates emissions events from leaks and operational problems.

4. Use funds from the Methane Emissions Reduction Program for monitoring for large release events, focusing on sites that are not otherwise monitored, and gathering and incorporating additional types of observational monitoring data.

5. Require operators to use data from regulatory leak inspections to enhance the accuracy of their reported emissions.

6. Provide all reported emissions data in publicly-accessible and easy to use formats. Verify the accuracy of reported emissions and that applicable facilities are properly identified.

Commenter: Isabel Melvin
Comment Number: EPA-HQ-OAR-2023-0234-0284
Page(s): 1

Comment: he U.S. Environmental Protection Agency's (EPA's) proposed edits to Subpart W of the Greenhouse Gas (GHG) Reporting Rule include improvements for tracking GHG emissions from the oil and gas industry. I support this rulemaking as a vital step in combating the climate crisis. However, there are still a number of ways that the EPA can strengthen it to improve data accuracy and hold the oil and gas sector more accountable for its GHG emissions

I urge EPA to strengthen its proposed rule in the following ways:

1. Significantly reduce the reporting limit to the lower level originally proposed in the Build Back Better Act to include a larger number of sources reporting more accurate data.

2. Finalize the reporting requirements for large release events. Ensure that operators find and report all large emission events that are not otherwise captured in the reporting methodologies.

3. Finalize emission factors for major equipment from recent peer-reviewed research. Ensure that reporting of leaks and malfunctions through other pathways is complete and incorporates emissions events from leaks and operational problems.

4. Use funds from the Methane Emissions Reduction Program for monitoring for large release events, focusing on sites that are not otherwise monitored, and gathering and incorporating additional types of observational monitoring data.

5. Require operators to use data from regulatory leak inspections to enhance the accuracy of their reported emissions.

6. Provide all reported emissions data in publicly-accessible and easy to use formats. Verify the accuracy of reported emissions and that applicable facilities are properly identified.

Thank you for meaningfully considering my comment.

Commenter: James Ploger
Comment Number: EPA-HQ-OAR-2023-0234-0303
Page(s): 1

Comment: The U.S. Environmental Protection Agency's (EPA's) proposed edits to Subpart W of the Greenhouse Gas (GHG) Reporting Rule include improvements for tracking GHG emissions from the oil and gas industry. I support this rulemaking as a vital step in combating the climate crisis. However, there are still a number of ways that the EPA can strengthen it to improve data accuracy and hold the oil and gas sector more accountable for its GHG emissions

I urge EPA to strengthen its proposed rule in the following ways:

1. Significantly reduce the reporting limit to the lower level originally proposed in the Build Back Better Act to include a larger number of sources reporting more accurate data.

2. Finalize the reporting requirements for large release events. Ensure that operators find and report all large emission events that are not otherwise captured in the reporting methodologies.

3. Finalize emission factors for major equipment from recent peer-reviewed research. Ensure that reporting of leaks and malfunctions through other pathways is complete and incorporates emissions events from leaks and operational problems.

4. Use funds from the Methane Emissions Reduction Program for monitoring for large release events, focusing on sites that are not otherwise monitored, and gathering and incorporating additional types of observational monitoring data.

5. Require operators to use data from regulatory leak inspections to enhance the accuracy of their reported emissions.

6. Provide all reported emissions data in publicly-accessible and easy to use formats. Verify the accuracy of reported emissions and that applicable facilities are properly identified.

Thank you for meaningfully considering my comment.

Commenter: James Stanton
Comment Number: EPA-HQ-OAR-2023-0234-0288
Page(s): 1

Comment: The U.S. Environmental Protection Agency's (EPA's) proposed edits to Subpart W of the Greenhouse Gas (GHG) Reporting Rule include improvements for tracking GHG emissions from the oil and gas industry. I support this rulemaking as a vital step in combating the

climate crisis. However, there are still a number of ways that the EPA can strengthen it to improve data accuracy and hold the oil and gas sector more accountable for its GHG emissions

I urge EPA to strengthen its proposed rule in the following ways:

1. Significantly reduce the reporting limit to the lower level originally proposed in the Build Back Better Act to include a larger number of sources reporting more accurate data.

2. Finalize the reporting requirements for large release events. Ensure that operators find and report all large emission events that are not otherwise captured in the reporting methodologies.

3. Finalize emission factors for major equipment from recent peer-reviewed research. Ensure that reporting of leaks and malfunctions through other pathways is complete and incorporates emissions events from leaks and operational problems.

4. Use funds from the Methane Emissions Reduction Program for monitoring for large release events, focusing on sites that are not otherwise monitored, and gathering and incorporating additional types of observational monitoring data.

5. Require operators to use data from regulatory leak inspections to enhance the accuracy of their reported emissions.

6. Provide all reported emissions data in publicly-accessible and easy to use formats. Verify the accuracy of reported emissions and that applicable facilities are properly identified.

Thank you for meaningfully considering my comment.

Commenter: Jaquelin Camp
Comment Number: EPA-HQ-OAR-2023-0234-0268
Page(s): 1

Comment: The U.S. Environmental Protection Agency's (EPA's) proposed edits to Subpart W of the Greenhouse Gas (GHG) Reporting Rule include improvements for tracking GHG emissions from the oil and gas industry. I support this rulemaking as a vital step in combating the climate crisis. However, there are still a number of ways that the EPA can strengthen it to improve data accuracy and hold the oil and gas sector more accountable for its GHG emissions

I urge EPA to strengthen its proposed rule in the following ways:

1. Significantly reduce the reporting limit to the lower level originally proposed in the Build Back Better Act to include a larger number of sources reporting more accurate data.

2. Finalize the reporting requirements for large release events. Ensure that operators find and report all large emission events that are not otherwise captured in the reporting methodologies.

3. Finalize emission factors for major equipment from recent peer-reviewed research. Ensure that reporting of leaks and malfunctions through other pathways is complete and incorporates emissions events from leaks and operational problems.

4. Use funds from the Methane Emissions Reduction Program for monitoring for large release events, focusing on sites that are not otherwise monitored, and gathering and incorporating additional types of observational monitoring data.

5. Require operators to use data from regulatory leak inspections to enhance the accuracy of their reported emissions.

6. Provide all reported emissions data in publicly-accessible and easy to use formats. Verify the accuracy of reported emissions and that applicable facilities are properly identified.

Thank you for meaningfully considering my comment.

Commenter: Jeanne Weber
Comment Number: EPA-HQ-OAR-2023-0234-0330
Page(s): 1

Comment: It's great that you are going to finally hold the oil and gas companies more accountable but do not forget the methane and please–lower the reporting limit! Put some teeth in this!

I urge EPA to strengthen its proposed rule in the following ways:

1. Significantly reduce the reporting limit to the lower level originally proposed in the Build Back Better Act to include a larger number of sources reporting more accurate data.

2. Finalize the reporting requirements for large release events. Ensure that operators find and report all large emission events that are not otherwise captured in the reporting methodologies.

3. Finalize emission factors for major equipment from recent peer-reviewed research. Ensure that reporting of leaks and malfunctions through other pathways is complete and incorporates emissions events from leaks and operational problems.

4. Use funds from the Methane Emissions Reduction Program for monitoring for large release events, focusing on sites that are not otherwise monitored, and gathering and incorporating additional types of observational monitoring data.

5. Require operators to use data from regulatory leak inspections to enhance the accuracy of their reported emissions.

6. Provide all reported emissions data in publicly-accessible and easy to use formats. Verify the accuracy of reported emissions and that applicable facilities are properly identified.

Thank you for meaningfully considering my comment.

Commenter: Jesse Reyes
Comment Number: EPA-HQ-OAR-2023-0234-0272
Page(s): 1

Comment: The U.S. Environmental Protection Agency's (EPA's) proposed edits to "Subpart W of the Greenhouse Gas (GHG) Reporting Rule" include improvements for tracking GHG emissions from the oil and gas industry. I support this rulemaking as a vital step in combating the climate crisis and digging us out of the mess we're in. However, there are still a number of significant, and in my view crucial ways that the EPA can strengthen it to improve data accuracy and hold the oil and gas sector more accountable for its GHG emissions

I urge the EPA to strengthen its proposed rule in the following ways:

1. Significantly reduce the reporting limit to the lower level originally proposed in the Build Back Better Act to include a larger number of sources reporting more accurate data.

2. Finalize the reporting requirements for large release events. Ensure that operators find and report all large emission events that are not otherwise captured in the reporting methodologies.

3. Finalize emission factors for major equipment from recent peer-reviewed research. Ensure that reporting of leaks and malfunctions through other pathways is complete and incorporates emissions events from leaks and operational problems.

4. Use funds from the Methane Emissions Reduction Program for monitoring for large release events, focusing on sites that are not otherwise monitored, and gathering and incorporating additional types of observational monitoring data.

5. Require operators to use data from regulatory leak inspections to enhance the accuracy of their reported emissions.

6. Provide all reported emissions data in publicly-accessible and easy to use formats. Verify the accuracy of reported emissions and that applicable facilities are properly identified.

If we are to truly to take meaningful action to tackle climate change, we need to rein in the polluters who got us here—who covered up data warning about climate change for decades and who persist in keeping our world locked in a death embrace. We can fix this, if we have the will.

Thank you for meaningfully considering my comment.

Commenter: Jessica Bellas
Comment Number: EPA-HQ-OAR-2023-0234-0329
Page(s): 1

Comment: The U.S. Environmental Protection Agency's (EPA's) proposed edits to Subpart W of the Greenhouse Gas (GHG) Reporting Rule include improvements for tracking GHG emissions from the oil and gas industry. I support this rulemaking as a vital step in combating the climate crisis. However, there are still a number of ways that the EPA can strengthen it to improve data accuracy and hold the oil and gas sector more accountable for its GHG emissions

I urge EPA to strengthen its proposed rule in the following ways:

1. Significantly reduce the reporting limit to the lower level originally proposed in the Build Back Better Act to include a larger number of sources reporting more accurate data.

2. Finalize the reporting requirements for large release events. Ensure that operators find and report all large emission events that are not otherwise captured in the reporting methodologies.

3. Finalize emission factors for major equipment from recent peer-reviewed research. Ensure that reporting of leaks and malfunctions through other pathways is complete and incorporates emissions events from leaks and operational problems.

4. Use funds from the Methane Emissions Reduction Program for monitoring for large release events, focusing on sites that are not otherwise monitored, and gathering and incorporating additional types of observational monitoring data.

5. Require operators to use data from regulatory leak inspections to enhance the accuracy of their reported emissions.

6. Provide all reported emissions data in publicly-accessible and easy to use formats. Verify the accuracy of reported emissions and that applicable facilities are properly identified.

Thank you for meaningfully considering my comment.

Commenter: Jill Greer
Comment Number: EPA-HQ-OAR-2023-0234-0289
Page(s): 1

Comment: The U.S. Environmental Protection Agency's proposed edits to Subpart W of the Greenhouse Gas (GHG) Reporting Rule include improvements for tracking GHG emissions from the oil & gas industry. While I do support this proposal as a vital step in combating the climate crisis, I also am convinced that it must be bolder, because the time to make changes is now. For example, there should be more accountability from the fossil fuel industry for its greenhouse gas emissions, and a dire need to get more accurate data.

In particular, I ask that the EPA incorporate these measures to have a greater reduction in total

GHG emissions:

1. Significantly reduce the reporting limit to the lower level originally proposed in the Build Back Better Act. Include a larger number of sources reporting more accurate data.

2. Finalize the reporting requirements for large release events. Ensure that operators find AND report all large emission events that are not otherwise captured in the reporting methodologies.

3. Finalize emission factors for major equipment from recent peer-reviewed research. Ensure that reporting of leaks and malfunctions through other pathways is complete and incorporates emissions events from leaks and operational problems.

4. Use funds from the Methane Emissions Reduction Program for monitoring for large release events, focusing on sites that are not otherwise monitored, and gathering and incorporating additional types of observational monitoring data.

5. Require operators to use data from regulatory leak inspections to enhance the accuracy of their reported emissions.

6. Provide all reported emissions data in publicly-accessible and easy to use formats. Verify the accuracy of reported emissions and that applicable facilities are properly identified.

I respectfully ask that these elements be considered, and implemented, to accomplish our shared goals of mitigating the impending climate disaster.

Commenter: JL Angell
Comment Number: EPA-HQ-OAR-2023-0234-0261
Page(s): 1

Comment: The U.S. Environmental Protection Agency's (EPA's) proposed edits to Subpart W of the Greenhouse Gas (GHG) Reporting Rule include improvements for tracking GHG emissions from the oil and gas industry. I support this rulemaking as a vital step in combating the climate crisis. However, there are still a number of ways that the EPA can strengthen it to improve data accuracy and hold the oil and gas sector more accountable for its GHG emissions

I urge EPA to strengthen its proposed rule in the following ways:

1. Significantly reduce the reporting limit to the lower level originally proposed in the Build Back Better Act to include a larger number of sources reporting more accurate data.

2. Finalize the reporting requirements for large release events. Ensure that operators find and report all large emission events that are not otherwise captured in the reporting methodologies.

3. Finalize emission factors for major equipment from recent peer-reviewed research. Ensure that reporting of leaks and malfunctions through other pathways is complete and incorporates

emissions events from leaks and operational problems.

4. Use funds from the Methane Emissions Reduction Program for monitoring for large release events, focusing on sites that are not otherwise monitored, and gathering and incorporating additional types of observational monitoring data.

5. Require operators to use data from regulatory leak inspections to enhance the accuracy of their reported emissions.

6. Provide all reported emissions data in publicly-accessible and easy to use formats. Verify the accuracy of reported emissions and that applicable facilities are properly identified.

Thank you for meaningfully considering my comment.

Commenter: Joann Koch
Comment Number: EPA-HQ-OAR-2023-0234-0304
Page(s): 1

Comment: The U.S. Environmental Protection Agency's (EPA's) proposed edits to Subpart W of the Greenhouse Gas (GHG) Reporting Rule include improvements for tracking GHG emissions from the oil and gas industry. I support this rulemaking as a vital step in combating the climate crisis. However, there are still a number of ways that the EPA can strengthen it to improve data accuracy and hold the oil and gas sector more accountable for its GHG emissions

I respectfully strongly urge EPA to strengthen its proposed rule in the following ways:

1. Significantly reduce the reporting limit to the lower level originally proposed in the Build Back Better Act to include a larger number of sources reporting more accurate data.

2. Finalize the reporting requirements for large release events. Ensure that operators find and report all large emission events that are not otherwise captured in the reporting methodologies.

3. Finalize emission factors for major equipment from recent peer-reviewed research. Ensure that reporting of leaks and malfunctions through other pathways is complete and incorporates emissions events from leaks and operational problems.

4. Use funds from the Methane Emissions Reduction Program for monitoring for large release events, focusing on sites that are not otherwise monitored, and gathering and incorporating additional types of observational monitoring data.

5. Require operators to use data from regulatory leak inspections to enhance the accuracy of their reported emissions.

6. Provide all reported emissions data in publicly-accessible and easy to use formats. Verify the accuracy of reported emissions and that applicable facilities are properly identified.

Thank you for meaningfully considering my comment.

Commenter: Joanne Hall
Comment Number: EPA-HQ-OAR-2023-0234-0278
Page(s): 1

Comment: I live in an Environmental Justice community in Western Pennsylvania that has many uncapped orphaned or abandoned gas wells. The cumulative effect of the leaks from these wells is causing climate change. I am also experiencing the buildout of the non-conventional natural gas extraction, with fracking wells and the related infrastructure crisscrossing the landscape. Rules, regulations, monitoring and the closing of these wells needs to be strong and enforced so that the situation we have with abandoned wells does not happen again with the nonconventional wells in the future.

The U.S. Environmental Protection Agency's (EPA's) proposed edits to Subpart W of the Greenhouse Gas (GHG) Reporting Rule include improvements for tracking GHG emissions from the oil and gas industry. However, there are still a number of ways that the EPA can strengthen it to improve data accuracy and hold the oil and gas sector more accountable for its GHG emissions.
I urge EPA to strengthen its proposed rule in the following ways:

1. Significantly reduce the reporting limit to the lower, originally-proposed level to include a larger number of sources reporting more accurate data.

2. Finalize the reporting requirements for large release events. Ensure that operators find and report all large emission events that are not otherwise captured in the reporting methodologies.

3. Finalize emission factors for major equipment from recent peer-reviewed research. Ensure that reporting of leaks and malfunctions through other pathways is complete and incorporates emissions events from leaks and operational problems.

4. Use funds from the Methane Emissions Reduction Program for monitoring for large release events, focusing on sites that are not otherwise monitored, and gathering and incorporating additional types of observational monitoring data.

5. Require operators to use data from regulatory leak inspections to enhance the accuracy of their reported emissions.

6. Provide all reported emissions data in publicly-accessible and easy to use formats. Verify the accuracy of reported emissions and that applicable facilities are properly identified.

Thank you for allowing and considering the opinions of the people impacted by the oil and gas industry. The industry has no concern for us and the regulations that you put in place directly impact the health of families living in these areas and the health of our environment and planet.

Commenter: John Sonin
Comment Number: EPA-HQ-OAR-2023-0234-0362
Page(s): 1

Comment: The U.S. Environmental Protection Agency's (EPA's) proposed edits to Subpart W of the Greenhouse Gas (GHG) Reporting Rule include improvements for tracking GHG emissions from the oil and gas industry. I support this rulemaking as a vital step in combating the climate crisis. However, there are still a number of ways that the EPA can strengthen it to improve data accuracy and hold the oil and gas sector more accountable for its GHG emissions

I urge EPA to strengthen its proposed rule in the following ways:

1. Significantly reduce the reporting limit to the lower level originally proposed in the Build Back Better Act to include a larger number of sources reporting more accurate data.

2. Finalize the reporting requirements for large release events. Ensure that operators find and report all large emission events that are not otherwise captured in the reporting methodologies.

3. Finalize emission factors for major equipment from recent peer-reviewed research. Ensure that reporting of leaks and malfunctions through other pathways is complete and incorporates emissions events from leaks and operational problems.

4. Use funds from the Methane Emissions Reduction Program for monitoring for large release events, focusing on sites that are not otherwise monitored, and gathering and incorporating additional types of observational monitoring data.

5. Require operators to use data from regulatory leak inspections to enhance the accuracy of their reported emissions.

6. Provide all reported emissions data in publicly-accessible and easy to use formats. Verify the accuracy of reported emissions and that applicable facilities are properly identified.

Thank you for meaningfully considering my comment.

Commenter: Joseph Wenzel
Comment Number: EPA-HQ-OAR-2023-0234-0363
Page(s): 1

Comment: The U.S. Environmental Protection Agency's (EPA's) proposed edits to Subpart W of the Greenhouse Gas (GHG) Reporting Rule include improvements for tracking GHG emissions from the oil and gas industry. I support this rulemaking as a vital step in combating the climate crisis. However, there are still a number of ways that the EPA can strengthen it to improve data accuracy and hold the oil and gas sector more accountable for its GHG emissions

I urge EPA to strengthen its proposed rule in the following ways:

1. Significantly reduce the reporting limit to the lower level originally proposed in the Build Back Better Act to include a larger number of sources reporting more accurate data.

2. Finalize the reporting requirements for large release events. Ensure that operators find and report all large emission events that are not otherwise captured in the reporting methodologies.

3. Finalize emission factors for major equipment from recent peer-reviewed research. Ensure that reporting of leaks and malfunctions through other pathways is complete and incorporates emissions events from leaks and operational problems.

4. Use funds from the Methane Emissions Reduction Program for monitoring for large release events, focusing on sites that are not otherwise monitored, and gathering and incorporating additional types of observational monitoring data.

5. Require operators to use data from regulatory leak inspections to enhance the accuracy of their reported emissions.

6. Provide all reported emissions data in publicly-accessible and easy to use formats. Verify the accuracy of reported emissions and that applicable facilities are properly identified.

Commenter: K Danowski
Comment Number: EPA-HQ-OAR-2023-0234-0365
Page(s): 1

Comment: The U.S. Environmental Protection Agency's (EPA's) proposed edits to Subpart W of the Greenhouse Gas (GHG) Reporting Rule include improvements for tracking GHG emissions from the oil and gas industry. I support this rulemaking as a vital step in combating the climate crisis. However, there are still a number of ways that the EPA can strengthen it to improve data accuracy and hold the oil and gas sector more accountable for its GHG emissions

I urge EPA to strengthen its proposed rule in the following ways:

1. Significantly reduce the reporting limit to the lower level originally proposed in the Build Back Better Act to include a larger number of sources reporting more accurate data.

2. Finalize the reporting requirements for large release events. Ensure that operators find and report all large emission events that are not otherwise captured in the reporting methodologies.

3. Finalize emission factors for major equipment from recent peer-reviewed research. Ensure that reporting of leaks and malfunctions through other pathways is complete and incorporates emissions events from leaks and operational problems.

4. Use funds from the Methane Emissions Reduction Program for monitoring for large release

events, focusing on sites that are not otherwise monitored, and gathering and incorporating additional types of observational monitoring data.

5. Require operators to use data from regulatory leak inspections to enhance the accuracy of their reported emissions.

6. Provide all reported emissions data in publicly-accessible and easy to use formats. Verify the accuracy of reported emissions and that applicable facilities are properly identified.

Thank you for meaningfully considering my comment.

Commenter: Kathryn Lemoine
Comment Number: EPA-HQ-OAR-2023-0234-0318
Page(s): 1

Comment: The U.S. Environmental Protection Agency's (EPA's) proposed edits to Subpart W of the Greenhouse Gas (GHG) Reporting Rule include improvements for tracking GHG emissions from the oil and gas industry. I support this rulemaking as a vital step in combating the climate crisis. However, there are still a number of ways that the EPA can strengthen it to improve data accuracy and hold the oil and gas sector more accountable for its GHG emissions

I urge EPA to strengthen its proposed rule in the following ways:

1. Significantly reduce the reporting limit to the lower level originally proposed in the Build Back Better Act to include a larger number of sources reporting more accurate data.

2. Finalize the reporting requirements for large release events. Ensure that operators find and report all large emission events that are not otherwise captured in the reporting methodologies.

3. Finalize emission factors for major equipment from recent peer-reviewed research. Ensure that reporting of leaks and malfunctions through other pathways is complete and incorporates emissions events from leaks and operational problems.

4. Use funds from the Methane Emissions Reduction Program for monitoring for large release events, focusing on sites that are not otherwise monitored, and gathering and incorporating additional types of observational monitoring data.

5. Require operators to use data from regulatory leak inspections to enhance the accuracy of their reported emissions.

6. Provide all reported emissions data in publicly-accessible and easy to use formats. Verify the accuracy of reported emissions and that applicable facilities are properly identified.

Thank you for meaningfully considering my comment.

Commenter: Kathy Bradley
Comment Number: EPA-HQ-OAR-2023-0234-0248
Page(s): 1

Comment: The U.S. Environmental Protection Agency's (EPA's) proposed edits to Subpart W of the Greenhouse Gas (GHG) Reporting Rule include improvements for tracking GHG emissions from the oil and gas industry. I support this rulemaking as a vital step in combating the climate crisis. However, there are still a number of ways that the EPA can strengthen it to improve data accuracy and hold the oil and gas sector more accountable for its GHG emissions

I urge EPA to strengthen its proposed rule in the following ways:

1. Significantly reduce the reporting limit to the lower level originally proposed in the Build Back Better Act to include a larger number of sources reporting more accurate data.

2. Finalize the reporting requirements for large release events. Ensure that operators find and report all large emission events that are not otherwise captured in the reporting methodologies.

3. Finalize emission factors for major equipment from recent peer-reviewed research. Ensure that reporting of leaks and malfunctions through other pathways is complete and incorporates emissions events from leaks and operational problems.

4. Use funds from the Methane Emissions Reduction Program for monitoring for large release events, focusing on sites that are not otherwise monitored, and gathering and incorporating additional types of observational monitoring data.

5. Require operators to use data from regulatory leak inspections to enhance the accuracy of their reported emissions.

6. Provide all reported emissions data in publicly-accessible and easy to use formats. Verify the accuracy of reported emissions and that applicable facilities are properly identified.

Thank you for meaningfully considering my comment.

Commenter: Kevin Rolfes
Comment Number: EPA-HQ-OAR-2023-0234-0255
Page(s): 1

Comment: The U.S. Environmental Protection Agency's (EPA's) proposed edits to Subpart W of the Greenhouse Gas (GHG) Reporting Rule include improvements for tracking GHG emissions from the oil and gas industry. I support this rulemaking as a vital step in combating the climate crisis. However, there are still a number of ways that the EPA can strengthen it to improve data accuracy and hold the oil and gas sector more accountable for its GHG emissions

I urge EPA to strengthen its proposed rule in the following ways:

1. Significantly reduce the reporting limit to the lower level originally proposed in the Build Back Better Act to include a larger number of sources reporting more accurate data.

2. Finalize the reporting requirements for large release events. Ensure that operators find and report all large emission events that are not otherwise captured in the reporting methodologies.

3. Finalize emission factors for major equipment from recent peer-reviewed research. Ensure that reporting of leaks and malfunctions through other pathways is complete and incorporates emissions events from leaks and operational problems.

4. Use funds from the Methane Emissions Reduction Program for monitoring for large release events, focusing on sites that are not otherwise monitored, and gathering and incorporating additional types of observational monitoring data.

5. Require operators to use data from regulatory leak inspections to enhance the accuracy of their reported emissions.

6. Provide all reported emissions data in publicly-accessible and easy to use formats. Verify the accuracy of reported emissions and that applicable facilities are properly identified

Commenter: Linda Myers
Comment Number: EPA-HQ-OAR-2023-0234-0302
Page(s): 1

Comment: The U.S. Environmental Protection Agency's (EPA's) proposed edits to Subpart W of the Greenhouse Gas (GHG) Reporting Rule include improvements for tracking GHG emissions from the oil and gas industry. I support this rulemaking as a vital step in combating the climate crisis. However, there are still a number of ways that the EPA can strengthen it to improve data accuracy and hold the oil and gas sector more accountable for its GHG emissions

I urge EPA to strengthen its proposed rule in the following ways:

1. Significantly reduce the reporting limit to the lower level originally proposed in the Build Back Better Act to include a larger number of sources reporting more accurate data.

2. Finalize the reporting requirements for large release events. Ensure that operators find and report all large emission events that are not otherwise captured in the reporting methodologies.

3. Finalize emission factors for major equipment from recent peer-reviewed research. Ensure that reporting of leaks and malfunctions through other pathways is complete and incorporates emissions events from leaks and operational problems.

4. Use funds from the Methane Emissions Reduction Program for monitoring for large release events, focusing on sites that are not otherwise monitored, and gathering and incorporating additional types of observational monitoring data.

5. Require operators to use data from regulatory leak inspections to enhance the accuracy of their reported emissions.

6. Provide all reported emissions data in publicly-accessible and easy to use formats. Verify the accuracy of reported emissions and that applicable facilities are properly identified.

Thank you for meaningfully considering my comment.

Commenter: Lori Vest
Comment Number: EPA-HQ-OAR-2023-0234-0282
Page(s): 1

Comment: I support The U.S. Environmental Protection Agency's (EPA's) proposed edits to Subpart W of the Greenhouse Gas (GHG) Reporting Rule include improvements for tracking GHG emissions from the oil and gas industry. The EPA should strengthen it to improve data accuracy and hold the oil and gas sector more accountable for its GHG emissions in the following ways:

1. Significantly reduce the reporting limit to the lower level originally proposed in the Build Back Better Act to include a larger number of sources reporting more accurate data.

2. Finalize the reporting requirements for large release events. Ensure that operators find and report all large emission events that are not otherwise captured in the reporting methodologies.

3. Finalize emission factors for major equipment from recent peer-reviewed research. Ensure that reporting of leaks and malfunctions through other pathways is complete and incorporates emissions events from leaks and operational problems.

4. Use funds from the Methane Emissions Reduction Program for monitoring for large release events, focusing on sites that are not otherwise monitored, and gathering and incorporating additional types of observational monitoring data.

5. Require operators to use data from regulatory leak inspections to enhance the accuracy of their reported emissions.

6. Provide all reported emissions data in publicly-accessible and easy to use formats. Verify the accuracy of reported emissions and that applicable facilities are properly identified.

Sincerely,

Lori Vest

Commenter: M. Port
Comment Number: EPA-HQ-OAR-2023-0234-0354
Page(s): 1

Comment: The U.S. Environmental Protection Agency's (EPA's) proposed edits to Subpart W of the Greenhouse Gas (GHG) Reporting Rule include improvements for tracking GHG emissions from the oil and gas industry. I support this rulemaking as a vital step in combating the climate crisis. However, there are still a number of ways that the EPA can strengthen it to improve data accuracy and hold the oil and gas sector more accountable for its GHG emissions

I urge EPA to strengthen its proposed rule in the following ways:

1. Significantly reduce the reporting limit to the lower level originally proposed in the Build Back Better Act to include a larger number of sources reporting more accurate data.

2. Finalize the reporting requirements for large release events. Ensure that operators find and report all large emission events that are not otherwise captured in the reporting methodologies.

3. Finalize emission factors for major equipment from recent peer-reviewed research. Ensure that reporting of leaks and malfunctions through other pathways is complete and incorporates emissions events from leaks and operational problems.

4. Use funds from the Methane Emissions Reduction Program for monitoring for large release events, focusing on sites that are not otherwise monitored, and gathering and incorporating additional types of observational monitoring data.

5. Require operators to use data from regulatory leak inspections to enhance the accuracy of their reported emissions.

6. Provide all reported emissions data in publicly-accessible and easy to use formats. Verify the accuracy of reported emissions and that applicable facilities are properly identified.

Thank you for meaningfully considering my comment.

Commenter: Marlene Adkins
Comment Number: EPA-HQ-OAR-2023-0234-0227
Page(s): 1-2

Comment:

The U.S. Environmental Protection Agency's (EPA's) proposed edits to Subpart W of the Greenhouse Gas (GHG) Reporting Rule include improvements for tracking GHG emissions from the oil and gas industry. However, there are still a number of ways that the EPA can strengthen it to improve data accuracy and hold the oil and gas sector more accountable for its GHG emissions. I urge EPA to strengthen its proposed rule in the following ways:

1. Significantly reduce the reporting limit to the lower, originally-proposed level to include a larger number of sources reporting more accurate data.

2. Finalize the reporting requirements for large release events. Ensure that operators find and report all large emission events that are not otherwise captured in the reporting methodologies.

3. Finalize emission factors for major equipment from recent peer-reviewed research. Ensure that reporting of leaks and malfunctions through other pathways is complete and incorporates emissions events from leaks and operational problems.

4. Use funds from the Methane Emissions Reduction Program for monitoring for large release events, focusing on sites that are not otherwise monitored, and gathering and incorporating additional types of observational monitoring data.

5. Require operators to use data from regulatory leak inspections to enhance the accuracy of their reported emissions.

6. Provide all reported emissions data in publicly-accessible and easy to use formats. Verify the accuracy of reported emissions and that applicable facilities are properly identified.

Commenter: Matt Gribble
Comment Number: EPA-HQ-OAR-2023-0234-0316
Page(s): 1

Comment: The U.S. Environmental Protection Agency's (EPA's) proposed edits to Subpart W of the Greenhouse Gas (GHG) Reporting Rule include improvements for tracking GHG emissions from the oil and gas industry. I support this rulemaking as a vital step in combating the climate crisis. However, there are still a number of ways that the EPA can strengthen it to improve data accuracy and hold the oil and gas sector more accountable for its GHG emissions

I urge EPA to strengthen its proposed rule in the following ways:

1. Significantly reduce the reporting limit to the lower level originally proposed in the Build Back Better Act to include a larger number of sources reporting more accurate data.

2. Finalize the reporting requirements for large release events. Ensure that operators find and report all large emission events that are not otherwise captured in the reporting methodologies.

3. Finalize emission factors for major equipment from recent peer-reviewed research. Ensure that reporting of leaks and malfunctions through other pathways is complete and incorporates emissions events from leaks and operational problems.

4. Use funds from the Methane Emissions Reduction Program for monitoring for large release events, focusing on sites that are not otherwise monitored, and gathering and incorporating additional types of observational monitoring data.

5. Require operators to use data from regulatory leak inspections to enhance the accuracy of their reported emissions.

6. Provide all reported emissions data in publicly-accessible and easy to use formats. Verify the accuracy of reported emissions and that applicable facilities are properly identified.

Thank you for meaningfully considering my comment.

Commenter: Matt Walker
Comment Number: EPA-HQ-OAR-2023-0234-0246
Page(s): 1

Comment: The U.S. Environmental Protection Agency's (EPA's) proposed edits to Subpart W of the Greenhouse Gas (GHG) Reporting Rule include improvements for tracking GHG emissions from the oil and gas industry. I support this rulemaking as a vital step in combating the climate crisis. However, there are still a number of ways that the EPA can strengthen it to improve data accuracy and hold the oil and gas sector more accountable for its GHG emissions

I urge EPA to strengthen its proposed rule in the following ways:

1. Significantly reduce the reporting limit to the lower level originally proposed in the Build Back Better Act to include a larger number of sources reporting more accurate data.

2. Finalize the reporting requirements for large release events. Ensure that operators find and report all large emission events that are not otherwise captured in the reporting methodologies.

3. Finalize emission factors for major equipment from recent peer-reviewed research. Ensure that reporting of leaks and malfunctions through other pathways is complete and incorporates emissions events from leaks and operational problems.

4. Use funds from the Methane Emissions Reduction Program for monitoring for large release events, focusing on sites that are not otherwise monitored, and gathering and incorporating additional types of observational monitoring data.

5. Require operators to use data from regulatory leak inspections to enhance the accuracy of their reported emissions.

6. Provide all reported emissions data in publicly-accessible and easy to use formats. Verify the accuracy of reported emissions and that applicable facilities are properly identified.

Thank you for meaningfully considering my comment.

Commenter: Megan LeCluyse
Comment Number: EPA-HQ-OAR-2023-0234-0327
Page(s): 1

Comment: The U.S. Environmental Protection Agency's (EPA's) proposed edits to Subpart W of the Greenhouse Gas (GHG) Reporting Rule include improvements for tracking GHG emissions from the oil and gas industry. I support this rulemaking as a vital step in combating the climate crisis. However, there are still a number of ways that the EPA can strengthen it to improve data accuracy and hold the oil and gas sector more accountable for its GHG emissions

I urge EPA to strengthen its proposed rule in the following ways:

1. Significantly reduce the reporting limit to the lower level originally proposed in the Build Back Better Act to include a larger number of sources reporting more accurate data.

2. Finalize the reporting requirements for large release events. Ensure that operators find and report all large emission events that are not otherwise captured in the reporting methodologies.

3. Finalize emission factors for major equipment from recent peer-reviewed research. Ensure that reporting of leaks and malfunctions through other pathways is complete and incorporates emissions events from leaks and operational problems.

4. Use funds from the Methane Emissions Reduction Program for monitoring for large release events, focusing on sites that are not otherwise monitored, and gathering and incorporating additional types of observational monitoring data.

5. Require operators to use data from regulatory leak inspections to enhance the accuracy of their reported emissions.

6. Provide all reported emissions data in publicly-accessible and easy to use formats. Verify the accuracy of reported emissions and that applicable facilities are properly identified.

Thank you for meaningfully considering my comment.

Commenter: Nancy Drain
Comment Number: EPA-HQ-OAR-2023-0234-0332
Page(s): 1

Comment: The U.S. Environmental Protection Agency's (EPA's) proposed edits to Subpart W of the Greenhouse Gas (GHG) Reporting Rule include improvements for tracking GHG emissions from the oil and gas industry. I support this rulemaking as a vital step in combating the climate crisis. However, there are still a number of ways that the EPA can strengthen it to improve data accuracy and hold the oil and gas sector more accountable for its GHG emissions

I urge EPA to strengthen its proposed rule in the following ways:

1. Significantly reduce the reporting limit to the lower level originally proposed in the Build Back Better Act to include a larger number of sources reporting more accurate data.

2. Finalize the reporting requirements for large release events. Ensure that operators find and report all large emission events that are not otherwise captured in the reporting methodologies.

3. Finalize emission factors for major equipment from recent peer-reviewed research. Ensure that reporting of leaks and malfunctions through other pathways is complete and incorporates emissions events from leaks and operational problems.

4. Use funds from the Methane Emissions Reduction Program for monitoring for large release events, focusing on sites that are not otherwise monitored, and gathering and incorporating additional types of observational monitoring data.

5. Require operators to use data from regulatory leak inspections to enhance the accuracy of their reported emissions.

6. Provide all reported emissions data in publicly-accessible and easy to use formats. Verify the accuracy of reported emissions and that applicable facilities are properly identified.

Thank you for meaningfully considering my comment.

Commenter: Norma Kline
Comment Number: EPA-HQ-OAR-2023-0234-0312
Page(s): 1

Comment: I urge EPA to strengthen its proposed rule in the following ways:

1. Significantly reduce the reporting limit to the lower level originally proposed in the Build Back Better Act to include a larger number of sources reporting more accurate data.

2. Finalize the reporting requirements for large release events. Ensure that operators find and report all large emission events that are not otherwise captured in the reporting methodologies.

3. Finalize emission factors for major equipment from recent peer-reviewed research. Ensure that reporting of leaks and malfunctions through other pathways is complete and incorporates emissions events from leaks and operational problems.

4. Use funds from the Methane Emissions Reduction Program for monitoring for large release events, focusing on sites that are not otherwise monitored, and gathering and incorporating additional types of observational monitoring data.

5. Require operators to use data from regulatory leak inspections to enhance the accuracy of their reported emissions.

6. Provide all reported emissions data in publicly-accessible and easy to use formats. Verify the accuracy of reported emissions and that applicable facilities are properly identified.

Thank you for considering my comment.

Commenter: Paula Shafransky
Comment Number: EPA-HQ-OAR-2023-0234-0264
Page(s): 1

Comment: The U.S. Environmental Protection Agency's (EPA's) proposed edits to Subpart W of the Greenhouse Gas (GHG) Reporting Rule include improvements for tracking GHG emissions from the oil and gas industry. I support this rulemaking as a vital step in combating the climate crisis. However, there are still a number of ways that the EPA can strengthen it to improve data accuracy and hold the oil and gas sector more accountable for its GHG emissions

I urge EPA to strengthen its proposed rule in the following ways:

1. Significantly reduce the reporting limit to the lower level originally proposed in the Build Back Better Act to include a larger number of sources reporting more accurate data.

2. Finalize the reporting requirements for large release events. Ensure that operators find and report all large emission events that are not otherwise captured in the reporting methodologies.

3. Finalize emission factors for major equipment from recent peer-reviewed research. Ensure that reporting of leaks and malfunctions through other pathways is complete and incorporates emissions events from leaks and operational problems.

4. Use funds from the Methane Emissions Reduction Program for monitoring for large release events, focusing on sites that are not otherwise monitored, and gathering and incorporating additional types of observational monitoring data.

5. Require operators to use data from regulatory leak inspections to enhance the accuracy of their reported emissions.

6. Provide all reported emissions data in publicly-accessible and easy to use formats. Verify the accuracy of reported emissions and that applicable facilities are properly identified.

Thank you for meaningfully considering my comment.

Commenter: Ret Turner
Comment Number: EPA-HQ-OAR-2023-0234-0356
Page(s): 1

Comment: The U.S. Environmental Protection Agency's (EPA's) proposed edits to Subpart W of the Greenhouse Gas (GHG) Reporting Rule include improvements for tracking GHG emissions from the oil and gas industry. I support this rulemaking as a vital step in combating the climate crisis. However, there are still a number of ways that the EPA can strengthen it to improve data accuracy and hold the oil and gas sector more accountable for its GHG emissions

I urge EPA to strengthen its proposed rule in the following ways:

1. Significantly reduce the reporting limit to the lower level originally proposed in the Build Back Better Act to include a larger number of sources reporting more accurate data.

2. Finalize the reporting requirements for large release events. Ensure that operators find and report all large emission events that are not otherwise captured in the reporting methodologies.

3. Finalize emission factors for major equipment from recent peer-reviewed research. Ensure that reporting of leaks and malfunctions through other pathways is complete and incorporates emissions events from leaks and operational problems.

4. Use funds from the Methane Emissions Reduction Program for monitoring for large release events, focusing on sites that are not otherwise monitored, and gathering and incorporating additional types of observational monitoring data.

5. Require operators to use data from regulatory leak inspections to enhance the accuracy of their reported emissions.

6. Provide all reported emissions data in publicly-accessible and easy to use formats. Verify the accuracy of reported emissions and that applicable facilities are properly identified.

Thank you for meaningfully considering my comment.

Commenter: Russ Allen
Comment Number: EPA-HQ-OAR-2023-0234-0258
Page(s): 1

Comment: The U.S. Environmental Protection Agency's (EPA's) proposed edits to Subpart W of the Greenhouse Gas (GHG) Reporting Rule include improvements for tracking GHG emissions from the oil and gas industry. I support this rulemaking as a vital step in combating the climate crisis. However, there are still a number of ways that the EPA can strengthen it to improve data accuracy and hold the oil and gas sector more accountable for its GHG emissions

I urge EPA to strengthen its proposed rule in the following ways:

1. Significantly reduce the reporting limit to the lower level originally proposed in the Build Back Better Act to include a larger number of sources reporting more accurate data.

2. Finalize the reporting requirements for large release events. Ensure that operators find and report all large emission events that are not otherwise captured in the reporting methodologies.

3. Finalize emission factors for major equipment from recent peer-reviewed research. Ensure that reporting of leaks and malfunctions through other pathways is complete and incorporates emissions events from leaks and operational problems.

4. Use funds from the Methane Emissions Reduction Program for monitoring for large release events, focusing on sites that are not otherwise monitored, and gathering and incorporating additional types of observational monitoring data.

5. Require operators to use data from regulatory leak inspections to enhance the accuracy of their reported emissions.

6. Provide all reported emissions data in publicly-accessible and easy to use formats. Verify the accuracy of reported emissions and that applicable facilities are properly identified.

Thank you for meaningfully considering my comment.

Commenter: S. E. Williams
Comment Number: EPA-HQ-OAR-2023-0234-0256
Page(s): 1

Comment: The U.S. Environmental Protection Agency's (EPA's) proposed edits to Subpart W of the Greenhouse Gas (GHG) Reporting Rule include improvements for tracking GHG emissions from the oil and gas industry. I support this rulemaking as a vital step in combating the climate crisis. However, there are still a number of ways that the EPA can strengthen it to improve data accuracy and hold the oil and gas sector more accountable for its GHG emissions

I urge EPA to strengthen its proposed rule in the following ways:

1. Significantly reduce the reporting limit to the lower level originally proposed in the Build Back Better Act to include a larger number of sources reporting more accurate data.

2. Finalize the reporting requirements for large release events. Ensure that operators find and report all large emission events that are not otherwise captured in the reporting methodologies.

3. Finalize emission factors for major equipment from recent peer-reviewed research. Ensure that reporting of leaks and malfunctions through other pathways is complete and incorporates emissions events from leaks and operational problems.

4. Use funds from the Methane Emissions Reduction Program for monitoring for large release events, focusing on sites that are not otherwise monitored, and gathering and incorporating additional types of observational monitoring data.

5. Require operators to use data from regulatory leak inspections to enhance the accuracy of their reported emissions.

6. Provide all reported emissions data in publicly-accessible and easy to use formats. Verify the accuracy of reported emissions and that applicable facilities are properly identified.

Thank you for meaningfully considering my comment.

Commenter: Sandy Field
Comment Number: EPA-HQ-OAR-2023-0234-0260
Page(s): 1

Comment: The U.S. Environmental Protection Agency's (EPA's) proposed edits to Subpart W of the Greenhouse Gas (GHG) Reporting Rule include improvements for tracking GHG emissions from the oil and gas industry. I support this rulemaking as a vital step in combating the climate crisis. However, there are still a number of ways that the EPA can strengthen it to improve data accuracy and hold the oil and gas sector more accountable for its GHG emissions

I urge EPA to strengthen its proposed rule in the following ways:

1. Significantly reduce the reporting limit to the lower level originally proposed in the Build Back Better Act to include a larger number of sources reporting more accurate data.

2. Finalize the reporting requirements for large release events. Ensure that operators find and report all large emission events that are not otherwise captured in the reporting methodologies.

3. Finalize emission factors for major equipment from recent peer-reviewed research. Ensure that reporting of leaks and malfunctions through other pathways is complete and incorporates emissions events from leaks and operational problems.

4. Use funds from the Methane Emissions Reduction Program for monitoring for large release events, focusing on sites that are not otherwise monitored, and gathering and incorporating additional types of observational monitoring data.

5. Require operators to use data from regulatory leak inspections to enhance the accuracy of their reported emissions.

6. Provide all reported emissions data in publicly-accessible and easy to use formats. Verify the accuracy of reported emissions and that applicable facilities are properly identified.

In order to combat the climate crisis, we need accurate data on greenhouse gases and we need to move away from burning fossil fuels.
Thank you for meaningfully considering my comment.

Commenter: Scott Trees
Comment Number: EPA-HQ-OAR-2023-0234-0274
Page(s): 1

Comment: The U.S. Environmental Protection Agency's (EPA's) proposed edits to Subpart W of the Greenhouse Gas (GHG) Reporting Rule include improvements for tracking GHG emissions from the oil and gas industry. I support this rulemaking as a vital step in combating the climate crisis. However, there are still a number of ways that the EPA can strengthen it to improve data accuracy and hold the oil and gas sector more accountable for its GHG emissions

I urge EPA to strengthen its proposed rule in the following ways:

1. Significantly reduce the reporting limit to the lower level originally proposed in the Build Back Better Act to include a larger number of sources reporting more accurate data.

2. Finalize the reporting requirements for large release events. Ensure that operators find and report all large emission events that are not otherwise captured in the reporting methodologies.

3. Finalize emission factors for major equipment from recent peer-reviewed research. Ensure that reporting of leaks and malfunctions through other pathways is complete and incorporates emissions events from leaks and operational problems.

4. Use funds from the Methane Emissions Reduction Program for monitoring for large release events, focusing on sites that are not otherwise monitored, and gathering and incorporating additional types of observational monitoring data.

5. Require operators to use data from regulatory leak inspections to enhance the accuracy of their reported emissions.

6. Provide all reported emissions data in publicly-accessible and easy to use formats. Verify the accuracy of reported emissions and that applicable facilities are properly identified.

Thank you for meaningfully considering my comment.

Commenter: Spencer Koelle
Comment Number: EPA-HQ-OAR-2023-0234-0285
Page(s): 1

Comment: In this state, in some places, the tap water can catch on fire, so I care about pollution a lot.

I urge EPA to strengthen its proposed rule in the following ways:

1. Significantly reduce the reporting limit to the lower level originally proposed in the Build Back Better Act to include a larger number of sources reporting more accurate data.

2. Finalize the reporting requirements for large release events. Ensure that operators find and report all large emission events that are not otherwise captured in the reporting methodologies.

3. Finalize emission factors for major equipment from recent peer-reviewed research. Ensure that reporting of leaks and malfunctions through other pathways is complete and incorporates emissions events from leaks and operational problems.

4. Use funds from the Methane Emissions Reduction Program for monitoring for large release events, focusing on sites that are not otherwise monitored, and gathering and incorporating additional types of observational monitoring data.

5. Require operators to use data from regulatory leak inspections to enhance the accuracy of their reported emissions.

6. Provide all reported emissions data in publicly-accessible and easy to use formats. Verify the accuracy of reported emissions and that applicable facilities are properly identified.

Thank you for meaningfully considering my comment.

Yours Truly,
Spencer Koelle
He/Him

Commenter: Stephen Dutschke
Comment Number: EPA-HQ-OAR-2023-0234-0262
Page(s): 1

Comment: The U.S. Environmental Protection Agency's (EPA's) proposed edits to Subpart W of the Greenhouse Gas (GHG) Reporting Rule include improvements for tracking GHG emissions from the oil and gas industry. I support this rulemaking as a vital step in combating the climate crisis. However, there are still a number of ways that the EPA can strengthen it to improve data accuracy and hold the oil and gas sector more accountable for its GHG emissions

I urge EPA to strengthen its proposed rule in the following ways:

1. Significantly reduce the reporting limit to the lower level originally proposed in the Build Back Better Act to include a larger number of sources reporting more accurate data.

2. Finalize the reporting requirements for large release events. Ensure that operators find and report all large emission events that are not otherwise captured in the reporting methodologies.

3. Finalize emission factors for major equipment from recent peer-reviewed research. Ensure that reporting of leaks and malfunctions through other pathways is complete and incorporates emissions events from leaks and operational problems.

4. Use funds from the Methane Emissions Reduction Program for monitoring for large release events, focusing on sites that are not otherwise monitored, and gathering and incorporating additional types of observational monitoring data.

5. Require operators to use data from regulatory leak inspections to enhance the accuracy of their reported emissions.

6. Provide all reported emissions data in publicly-accessible and easy to use formats. Verify the accuracy of reported emissions and that applicable facilities are properly identified.

Thank you for meaningfully considering my comment.

Commenter: Steven Vogel
Comment Number: EPA-HQ-OAR-2023-0234-0257
Page(s): 1

Comment: The U.S. Environmental Protection Agency's (EPA's) proposed edits to Subpart W of the Greenhouse Gas (GHG) Reporting Rule include improvements for tracking GHG emissions from the oil and gas industry. I actively support this rulemaking as a vital step in combating the climate crisis. However, there are still a number of ways that the EPA can strengthen it to improve data accuracy and hold the oil and gas sector more accountable for its GHG emissions.

I urge EPA to strengthen its proposed rule in the following ways:

1. Significantly reduce the reporting limit to the lower level originally proposed in the Build Back Better Act, in order to include a larger number of sources reporting more accurate data.

2. Finalize the reporting requirements for large release events. Ensure that operators find and report all large emission events that are not otherwise captured in the reporting methodologies.

3. Finalize emission factors for major equipment from recent peer-reviewed research.
Ensure that reporting of leaks and malfunctions through other pathways is complete and incorporates emissions events from leaks and operational problems.

4. Use funds from the Methane Emissions Reduction Program for monitoring for large release events, focusing on sites that are not otherwise monitored, and gathering and incorporating additional types of observational monitoring data.

5. Require operators to use data from regulatory leak inspections to enhance the accuracy of their reported emissions.

6. Provide all reported emissions data in publicly accessible and easy-to-use formats. Verify the accuracy of reported emissions and that applicable facilities are properly identified.

Thank you for meaningfully considering my comment.

Commenter: Tara Strand
Comment Number: EPA-HQ-OAR-2023-0234-0322
Page(s): 1

Comment: The U.S. Environmental Protection Agency's (EPA's) proposed edits to Subpart W of the Greenhouse Gas (GHG) Reporting Rule include improvements for tracking GHG emissions from the oil and gas industry. I support this rulemaking as a vital step in combating the climate crisis. However, there are still a number of ways that the EPA can strengthen it to improve data accuracy and hold the oil and gas sector more accountable for its GHG emissions

I urge EPA to strengthen its proposed rule in the following ways:

1. Significantly reduce the reporting limit to the lower level originally proposed in the Build Back Better Act to include a larger number of sources reporting more accurate data.

2. Finalize the reporting requirements for large release events. Ensure that operators find and report all large emission events that are not otherwise captured in the reporting methodologies.

3. Finalize emission factors for major equipment from recent peer-reviewed research. Ensure that reporting of leaks and malfunctions through other pathways is complete and incorporates emissions events from leaks and operational problems.

4. Use funds from the Methane Emissions Reduction Program for monitoring for large release events, focusing on sites that are not otherwise monitored, and gathering and incorporating additional types of observational monitoring data.

5. Require operators to use data from regulatory leak inspections to enhance the accuracy of their reported emissions.

6. Provide all reported emissions data in publicly-accessible and easy to use formats. Verify the accuracy of reported emissions and that applicable facilities are properly identified.

Thank you for meaningfully considering my comment.

Commenter: Terri Yeager
Comment Number: EPA-HQ-OAR-2023-0234-0247
Page(s): 1

Comment: The U.S. Environmental Protection Agency's (EPA's) proposed edits to Subpart W of the Greenhouse Gas (GHG) Reporting Rule include improvements for tracking GHG emissions from the oil and gas industry. I support this rulemaking as a vital step in combating the

climate crisis. However, there are still a number of ways that the EPA can strengthen it to improve data accuracy and hold the oil and gas sector more accountable for its GHG emissions

I urge EPA to strengthen its proposed rule in the following ways:

1. Significantly reduce the reporting limit to the lower level originally proposed in the Build Back Better Act to include a larger number of sources reporting more accurate data.

2. Finalize the reporting requirements for large release events. Ensure that operators find and report all large emission events that are not otherwise captured in the reporting methodologies.

3. Finalize emission factors for major equipment from recent peer-reviewed research. Ensure that reporting of leaks and malfunctions through other pathways is complete and incorporates emissions events from leaks and operational problems.

4. Use funds from the Methane Emissions Reduction Program for monitoring for large release events, focusing on sites that are not otherwise monitored, and gathering and incorporating additional types of observational monitoring data.

5. Require operators to use data from regulatory leak inspections to enhance the accuracy of their reported emissions.

6. Provide all reported emissions data in publicly-accessible and easy to use formats. Verify the accuracy of reported emissions and that applicable facilities are properly identified.

Thank you for meaningfully considering my comment.

Commenter: Theresa Kardos
Comment Number: EPA-HQ-OAR-2023-0234-0290
Page(s): 1

Comment: The U.S. Environmental Protection Agency's (EPA's) proposed edits to Subpart W of the Greenhouse Gas (GHG) Reporting Rule include improvements for tracking GHG emissions from the oil and gas industry. As an environmental educator and field biologist as well as a parent and grandparent who cares deeply about the health of our planet and all its inhabitants, I support this rulemaking as a vital step in combating the climate crisis. However, there are still a number of ways that the EPA can strengthen it to improve data accuracy and hold the oil and gas sector more accountable for its GHG emissions

I urge EPA to strengthen its proposed rule in the following ways:

1. Significantly reduce the reporting limit to the lower level originally proposed in the Build Back Better Act to include a larger number of sources reporting more accurate data.

2. Finalize the reporting requirements for large release events. Ensure that operators find and

report all large emission events that are not otherwise captured in the reporting methodologies.

3. Finalize emission factors for major equipment from recent peer-reviewed research. Ensure that reporting of leaks and malfunctions through other pathways is complete and incorporates emissions events from leaks and operational problems.

4. Use funds from the Methane Emissions Reduction Program for monitoring for large release events, focusing on sites that are not otherwise monitored, and gathering and incorporating additional types of observational monitoring data.

5. Require operators to use data from regulatory leak inspections to enhance the accuracy of their reported emissions.

6. Provide all reported emissions data in publicly accessible and easy to use formats. Verify the accuracy of reported emissions and that applicable facilities are properly identified.

Thank you for your attention to these issues.

Commenter: Timothy Mullen
Comment Number: EPA-HQ-OAR-2023-0234-0305
Page(s): 1

Comment: The U.S. Environmental Protection Agency's (EPA's) proposed edits to Subpart W of the Greenhouse Gas (GHG) Reporting Rule include improvements for tracking GHG emissions from the oil and gas industry. I support this rulemaking as a vital step in combating the climate crisis. However, there are still a number of ways that the EPA can strengthen it to improve data accuracy and hold the oil and gas sector more accountable for its GHG emissions

I urge EPA to strengthen its proposed rule in the following ways:

1. Significantly reduce the reporting limit to the lower level originally proposed in the Build Back Better Act to include a larger number of sources reporting more accurate data.

2. Finalize the reporting requirements for large release events. Ensure that operators find and report all large emission events that are not otherwise captured in the reporting methodologies.

3. Finalize emission factors for major equipment from recent peer-reviewed research. Ensure that reporting of leaks and malfunctions through other pathways is complete and incorporates emissions events from leaks and operational problems.

4. Use funds from the Methane Emissions Reduction Program for monitoring for large release events, focusing on sites that are not otherwise monitored, and gathering and incorporating additional types of observational monitoring data.

5. Require operators to use data from regulatory leak inspections to enhance the accuracy of their

reported emissions.

6. Provide all reported emissions data in publicly-accessible and easy to use formats. Verify the accuracy of reported emissions and that applicable facilities are properly identified.

Thank you for meaningfully considering my comment.

Commenter: Torunn Sivesind
Comment Number: EPA-HQ-OAR-2023-0234-0313
Page(s): 1

Comment: I urge EPA to strengthen its proposed rule in the following ways:

1. Significantly reduce the reporting limit to the lower level originally proposed in the Build Back Better Act to include a larger number of sources reporting more accurate data.

2. Finalize the reporting requirements for large release events. Ensure that operators find and report all large emission events that are not otherwise captured in the reporting methodologies.

3. Finalize emission factors for major equipment from recent peer-reviewed research. Ensure that reporting of leaks and malfunctions through other pathways is complete and incorporates emissions events from leaks and operational problems.

4. Use funds from the Methane Emissions Reduction Program for monitoring for large release events, focusing on sites that are not otherwise monitored, and gathering and incorporating additional types of observational monitoring data.

5. Require operators to use data from regulatory leak inspections to enhance the accuracy of their reported emissions.

6. Provide all reported emissions data in publicly-accessible and easy to use formats. Verify the accuracy of reported emissions and that applicable facilities are properly identified.

Commenter: Tracy Foster
Comment Number: EPA-HQ-OAR-2023-0234-0287
Page(s): 1

Comment: The U.S. Environmental Protection Agency's (EPA's) proposed edits to Subpart W of the Greenhouse Gas (GHG) Reporting Rule include improvements for tracking GHG emissions from the oil and gas industry. I support this rulemaking as a vital step in combating the climate crisis. However, there are still a number of ways that the EPA can strengthen it to improve data accuracy and hold the oil and gas sector more accountable for its GHG emissions

I urge EPA to strengthen its proposed rule in the following ways:

1. Significantly reduce the reporting limit to the lower level originally proposed in the Build Back Better Act to include a larger number of sources reporting more accurate data.

2. Finalize the reporting requirements for large release events. Ensure that operators find and report all large emission events that are not otherwise captured in the reporting methodologies.

3. Finalize emission factors for major equipment from recent peer-reviewed research. Ensure that reporting of leaks and malfunctions through other pathways is complete and incorporates emissions events from leaks and operational problems.

4. Use funds from the Methane Emissions Reduction Program for monitoring for large release events, focusing on sites that are not otherwise monitored, and gathering and incorporating additional types of observational monitoring data.

5. Require operators to use data from regulatory leak inspections to enhance the accuracy of their reported emissions.

6. Provide all reported emissions data in publicly-accessible and easy to use formats. Verify the accuracy of reported emissions and that applicable facilities are properly identified.

Thank you for meaningfully considering my comment.

Commenter: Vic Bostock
Comment Number: EPA-HQ-OAR-2023-0234-0319
Page(s): 1

Comment: The U.S. Environmental Protection Agency's (EPA's) proposed edits to Subpart W of the Greenhouse Gas (GHG) Reporting Rule include improvements for tracking GHG emissions from the oil and gas industry. I support this rulemaking as a vital step in combating the climate crisis. However, there are still a number of ways that the EPA can strengthen it to improve data accuracy and hold the oil and gas sector more accountable for its GHG emissions

I urge EPA to strengthen its proposed rule in the following ways:

1. Significantly reduce the reporting limit to the lower level originally proposed in the Build Back Better Act to include a larger number of sources reporting more accurate data.

2. Finalize the reporting requirements for large release events. Ensure that operators find and report all large emission events that are not otherwise captured in the reporting methodologies.

3. Finalize emission factors for major equipment from recent peer-reviewed research. Ensure that reporting of leaks and malfunctions through other pathways is complete and incorporates emissions events from leaks and operational problems.

4. Use funds from the Methane Emissions Reduction Program for monitoring for large release events, focusing on sites that are not otherwise monitored, and gathering and incorporating additional types of observational monitoring data.

5. Require operators to use data from regulatory leak inspections to enhance the accuracy of their reported emissions.

6. Provide all reported emissions data in publicly-accessible and easy to use formats. Verify the accuracy of reported emissions and that applicable facilities are properly identified.

28.8 Out of Scope

Commenter: Sensirion Connected Solutions
Comment Number: EPA-HQ-OAR-2023-0234-0293
Page(s): 3

Commenter: Arkansas Independent Producers and Royalty Owners (AIPRO)
Comment Number: EPA-HQ-OAR-2023-0234-0382
Page(s): 3-4, 7, 9

Commenter: CrownQuest Operating
Comment Number: EPA-HQ-OAR-2023-0234-0393
Page(s): 209

Comment 1: Comment 0293: Sensirion Connected Solutions believes there is a significant potential and opportunity for the EPA to recognize continuous monitoring as a new BESR over quarterly OGI screenings represented in past legislation as well as current NSPS OOOOb rules. In particular, due the introduction of a new sensor technology and continuous improvement of mass quantification model; the Nubo Sphere solution can enable a new BESR benchmark in leak detection. Localization, and emissions quantification as shown in the 2023 Colorado State University Advanced Development of Emissions Detection (ADED) campaign study.

Comment 0382: References and Interrelatedness to NSPS OOOOb and EG OOOOc:

AIPRO recognizes the comment period for proposed rules NSPS OOOOb and EG OOOOc are closed, and that the agency is ostensibly working to either finalize the proposed rules or to develop another supplemental proposal which will have a separate designated comment period. That said, AIPRO believes it is critically important to point out the absurdity and inappropriateness of current GHGRP regulations and the associated historical GHG inventories being the basis for proposed regulations, such as NSPS OOOOb and EG OOOOc. See EPA's comments from Section II.A of the Preamble to the proposed GHGRP revisions below:

> ***"Further, the data collected under the GHGRP has also been used to inform other regulations, for example, proposed New Source Performance Standards (NSPS) and***

> ***Emission Guidelines for the oil and gas industry** and for municipal solid waste (MSW) landfills under 40 CFR part 60."* (FR p. 36925)
>
> *"A. Revisions To Improve the Quality of Data Collected Under 40 CFR Part 98 and Other Minor Revisions or Clarifications: The data collected under part 98 are used to inform the EPA's understanding of the relative emissions and distribution of emissions from specific industries, the factors that influence GHG emission rates, **and to inform policy options and potential regulations**. Following several years of implementation and outreach, the EPA has identified certain areas of the rule where updates to emissions factors or other default factors; improvements to calculation methodologies; collection of additional data on GHG emissions, emissions sources, or end uses; additions or revisions to data elements or other reporting requirements; and other technical amendments, clarifications, and corrections **would enhance the quality and accuracy of the data collected under the GHGRP.** These proposed changes include consideration of comments raised by stakeholders in prior rulemakings that would more closely align rule requirements with the processes conducted at specific facilities, consideration of data gaps identified in collected data where additional data would improve verification of data reported to the GHGRP, and consideration of additional data needed to help better understand changing industry emission trends. Overall, these proposed changes would provide a more comprehensive, nationwide GHG emissions profile reflective of the origin and distribution of GHG emissions in the United States and **would more accurately inform EPA policy options for potential regulatory or non-regulatory CAA programs**. The EPA additionally uses the data from the GHGRP, which would include data from these proposed changes, to improve estimates used in the U.S. GHG Inventory."* (FR p. 36926)
>
> *"Following several years of implementation and outreach, the EPA has identified certain areas of the rule where updates to emissions factors or other default factors; improvements to calculation methodologies; collection of additional data on GHG emissions, emissions sources, or end uses; additions or revisions to data elements or other reporting requirements; and other technical amendments, clarifications, and corrections **would enhance the quality and accuracy of the data collected under the GHGRP**."* (FR p. 36926)

AIPRO agrees with EPA in its conclusion that historical GHGRP data, in many cases, is of poor quality and inaccurate, which supports AIPRO's position above.

…

AIPRO strongly encourages the EPA to withdraw the proposed rulemaking for NSPS OOOOb and EG OOOOc in Docket ID No. EPA-HQ-OAR-2021-0317. Further, AIPRO welcomes the opportunity to collaborate with the agency to help develop fit-for-purpose guidelines that are not based on overstated GHG emissions inventories accumulated over the past decade under the current one-size fits all emissions factor-based GHGRP rules.

…

Further, as mentioned previously, EPA acknowledges (see quote below) that it relied on poor quality and inaccurate data from historical GHGRP submissions since the inception of the program to inform the proposed OOOOb and OOOOc rules. These proposed rules, in many instances, are very likely based on overstated emissions from sources such as intermittent bleed pneumatic devices.

> *"Proposed Revisions To Improve the Quality of Data Collected for Subpart W – As further described in section II.A of this preamble, the EPA is proposing amendments that would ensure that accurate data are being collected under the rule, improve the accuracy of emissions reported under part 98, and enhance the overall quality of the data collected under the GHGRP."* (FR p. 36962)

Commenter 0393: Regarding the associated gas affected category, API members completed a supply chain timeline study. The EPA's proposed compliance timeline of 60 days is not even close to enough time for retrofitting/adding new equipment. The anticipated supply chain delay from members/operators is 30 months. We ask that the EPA please take this into account when finalizing compliance deadlines for the final rule.

Response 1: These comments are specific to new source performance standards under CAA section 111. The EPA did not propose or request comment on revisions to rules issued pursuant to CAA section 111 in this rulemaking. Therefore, the comments are outside the scope of this rulemaking.

Commenter: Public Hearing Transcript
Comment Number: EPA-HQ-OAR-2023-0234-0224
Page(s): 27 (Arthur Gershkoff), 30 (Marlene Perrotte)

Commenter: Diane DiFante
Comment Number: EPA-HQ-OAR-2023-0234-0334
Page(s): 1

Commenter: CrownQuest Operating
Comment Number: EPA-HQ-OAR-2023-0234-0393
Page(s): 41

Comment 2: Comment 0224: The EPA must develop clear standards and expectations to allow reasonable time periods for companies to act to identify and stop leaks. The EPA should level fines only for those companies that have the capability to stop a leak, but purposefully and repeatedly ignore and delay their responsibilities to act. The technical assistance offered to companies by the EPA may be crucial to help companies apply the best and safest techniques to seal leaks.

…

Also, instead of industry self-reporting methane leaks, we need to fund inspection, enforcement, and implementation rules. EPA, Environmental Protective Agency, we haven't done very well regulating the industry.

Comment 0334: In support of the strongest restrictions possible to reduce greenhouse gas emissions from oil and gas production and transport facilities, for the health of the planet and people who live nearby.

Comment 0393: Regarding future endangerment findings, this is backwards, should be monitoring the environment,

This methodology of looking for emissions to justify endangerment is backwards. Should be looking at the environment instead, this is inappropriate.

Response 2: The GHGRP requires reporting of greenhouse gas emissions; it does not require emission reductions. Additionally, endangerment findings were not reopened and are not at issue in this rulemaking. Therefore, the comments are outside the scope of this rulemaking.

Commenter: Public Hearing Transcript
Comment Number: EPA-HQ-OAR-2023-0234-0224
Page(s): 7 (Monica Prabhu)

Comment 3: A question that I have that I'd like to see addressed is the issue of GWP 100 continue being the factor for which all greenhouse gases are being computed, including short-lived climate pollutants such as methane, and I would like to see a very clear layman's explanation as to why GWP 100, as in the 100-year impact, is being – continuing to be used despite the new information that we have about the importance in the next 10 years if not 20 years. So I know it's complicated and I'd like to see better explanation as to why that continues to be the inventory factor.

Response 3: The EPA did not propose and is not finalizing changes to the global warming potentials (GWPs) in this rulemaking. However, the GWPs were recently updated for all subparts of the GHGRP in the GHGRP amendments that were signed by the EPA Administrator on April 3, 2024.[27] The EPA's response to this comment is provided in section III.A.2 of the preamble to that final rulemaking.

Commenter: Clean Air Council
Comment Number: EPA-HQ-OAR-2023-0234-0203
Page(s): 1

[27] A copy of the final preamble and rule is available at https://www.epa.gov/ghgreporting/rulemaking-notices-ghg-reporting.

Commenter: Public Hearing Transcript
Comment Number: EPA-HQ-OAR-2023-0234-0224
Page(s): 13 (Alice Lu)

Commenter: Carbon Mapper and RMI
Comment Number: EPA-HQ-OAR-2023-0234-0301
Page(s): 5-7

Comment 4: Commenter 0203: I urge EPA to strengthen its proposed rule in the following ways:

…

- Explicitly put funds from the Methane Emissions Reduction Program and excess methane emissions charges toward validating and implementing fence-line air monitors, especially in environmental justice communities, to track methane emissions at affected facilities or those that experience a super-emitter event.

Commenter 0224: Monies from the Methane Emissions Reduction Program should be allocated towards validating and implementing fence line air monitors to track methane emissions at affected facilities or any that experience a super emitter event, especially when they're located in environmental justice communities.

Commenter 0301: **Implementation considerations for effective operator and third-party reporting and validation**

To support the integration of top-down observational data in the "other large release events" category and for validation more broadly, we make several recommendations below related to necessary funding, staffing, and technical support to ensure this program realizes its full potential.

EPA should fund third-party remote sensing and transparent reporting with MERP grants. Satellites, such as the planned Carbon Mapper constellation, are uniquely positioned to provide the high-frequency observations needed to quantify the annual emissions of short-lived events contributing to basin-level emission totals. Existing and planned methane monitoring satellites are capable of providing daily or better sampling of high-priority areas for emissions events greater than 100 kg/hr under clear sky conditions. High observation frequencies and publicly available data will help operators of all sizes constrain event durations and incentivize rapid mitigation that can lower waste emissions fees. Regular surveys are crucial to improve accuracy and provide data needed for reconciliation.

EPA should help operationalize regular, top-down measurements in basins across the United States. Currently, emerging satellite missions (e.g. Carbon Mapper and MethaneSAT) rely on philanthropic funding. EPA should commit a portion of the $850 million allocation under the MERP to ensure that such efforts are sustained through competitive solicitations. [4] By funding methane-detecting satellites and making this data readily available to the public, EPA can demonstrate its commitment to accuracy and transparency in the GHGRP, while simultaneously supporting the effectiveness of the Super Emitter Response Program, proposed in the NSPS OOOOb.

Footnote:

[4] See RMI-Carbon Mapper comments submitted to EPA-HQ-OAR-2022-0875 where we recommend that EPA allocate at least $240 million of the $850 million through 2030 to be devoted to annual grants and contracts for sustained third-party remote sensing and transparent reporting of US O&G sector methane emissions. Specifically, we suggest at least $30 million per year through 2030, implemented as competitive data acquisition grants or contracts, would be necessary to support third-party observations and reporters for the success of EPA's Super Emitter Response Program (SERP), ensuring timely operator notification and mitigation of high-emission events. While this is a substantial portion of the total funds allotted to EPA, we believe it reflects the importance and magnitude of the support required to fund third-party efforts and leaves more than two-thirds of the program funding for technical assistance to operators.

Response 4: Comments on potential uses of funds collected by the Methane Emissions Reduction Program are outside of the scope of this rulemaking.

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Comment 5: According to EPA's own inventory report, animal agriculture causes more greenhouse gas emissions than natural gas systems. Require emission reporting from the animal agriculture sector.

Response 5: This comment is outside of the scope of this rulemaking as it does not address emissions from the petroleum and natural gas systems source category.