NGSI Methane Emissions Intensity Protocol

Version 1.0

Natural Gas Sustainability Initiative

MJB & A
an ERM Group company

Version 1.0 | February 2021

Contents

Acknowledgments

This protocol was developed by M.J. Bradley & Associates (MJB&A), an ERM Group company, on behalf of the Edison Electric Institute (EEI) and the American Gas Association (AGA) in support of the Natural Gas Sustainability Initiative (NGSI). NGSI was initiated by a CEO Natural Gas Task Force organized by EEI and AGA.

About M.J. Bradley & Associates

MJB&A is a strategic consulting firm focused on energy and environmental issues. The firm includes a multi-disciplinary team of experts with backgrounds in economics, law, engineering, and policy. The company works with private companies, public agencies, and non-profit organizations to understand and evaluate environmental regulations and policy, facilitate multi-stakeholder initiatives, shape business strategies, and deploy clean energy technologies.

For questions or comments, please contact:

Robert LaCount
Executive Vice President
M.J. Bradley & Associates, an ERM Group Company
+1 202 347 7266
rlacount@mjbradley.com

Tom Curry
Senior Vice President
M.J. Bradley & Associates, an ERM Group Company
+1 202 347 7255
tcurry@mjbradley.com

Executive Summary

Version 1.0 of the Natural Gas Sustainability Initiative (NGSI) protocol details a methodology for companies to consistently calculate and report methane emissions intensity. The protocol is intended to support voluntary reporting by companies operating within the natural gas supply chain in the United States from onshore production through distribution. NGSI is a voluntary, industry-led initiative to advance innovative efforts to address environmental, social and governance (ESG) issues throughout the natural gas supply chain.

Launched by a CEO task force on natural gas issues convened by the Edison Electric Institute (EEI) and the American Gas Association (AGA), NGSI is working to advance a voluntary, industry-wide approach for companies to report methane emissions intensity by the segments of the natural gas supply chain in which they operate. 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.

Methane emissions intensity is a measure of methane emissions relative to natural gas throughput. Investors, customers, environmental groups, and other stakeholders are increasingly requesting information on natural gas company performance based on methane emissions intensity. While intensity is becoming a preferred approach for communicating methane emissions data throughout the industry, there is no standard methodology for calculating it. This is an obstacle to managing, tracking, and more transparently communicating current efforts to reduce methane emissions.

The NGSI protocol establishes intensity metrics for specific segments of the supply chain to respond to requests for a metric that provides comparable points of reference between companies. Using the NGSI protocol, companies will calculate and report methane emissions intensity based on total methane emissions associated with natural gas and the methane content of natural gas throughput for each segment in which they operate.

NGSI Segments	NGSI Metric
• **Onshore Production** • **Gathering & Boosting** • **Processing** • **Transmission & Storage** • **Distribution**	$\dfrac{Methane\ Emissions\ from\ Natural\ Gas}{Methane\ Content\ of\ Natural\ Gas\ Throughput}$

This protocol builds on existing industry approaches to calculate methane emissions intensity and leverages existing methodologies developed by the U.S. Environmental Protection Agency (EPA) to estimate emissions. NGSI recognizes the opportunity to improve methane emissions inventories through the advancement of technologies that directly measure methane emissions. As those technologies mature and methodologies for incorporating them into inventories advance, NGSI will identify opportunities to update the protocol.

Version 1.0 of the protocol reflects feedback received through an extensive engagement process. A draft version of the protocol was released in December 2019 and piloted by companies representing each of the natural gas supply chain segments in the summer of 2020. NGSI used feedback from the pilot process to update the methodology presented in this document and develop accompanying reporting templates.

1. Background

The Natural Gas Sustainability Initiative (NGSI) is a voluntary, industry-led initiative to advance efforts to address environmental, social, and governance (ESG) issues throughout the natural gas supply chain. NGSI recognizes the critical role of natural gas across the economy and responds to the rising importance of environmental and social goals for customers, as well as the increasing application of ESG metrics by institutional investors, banks, and ratings agencies.

The natural gas industry has made important progress in responding to questions about the environmental and social impacts of the supply chain. Nonetheless, NGSI believes a more coordinated effort, including voluntary reporting, benchmarking of continuous improvement, and expanded use of direct measurement technologies is needed 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 non-governmental organizations. Through a series of webinars and a public workshop along with extensive outreach to individual companies and associations, stakeholders have provided valuable direction for NGSI's objectives, guiding principles, structure, and near-term agenda; and in the methane emissions intensity protocol outlined in this document.

Natural Gas Sustainability Initiative

The Natural Gas Sustainability Initiative (NGSI) is an overarching framework to recognize and advance innovative, voluntary programs across the natural gas supply chain.

The NGSI framework is initially focused on methane emissions and will incorporate additional environmental, social and governance topics over time.

NGSI was launched by the EEI-AGA CEO Natural Gas Task Force. M.J. Bradley & Associates (MJB&A), an ERM Group company, is facilitating the process to develop the program.

NGSI Guiding Principles

NGSI is guided by the following principles:

- NGSI participants are committed to continuous improvement to respond to customer and stakeholder expectations for managing environmental and social issues along the natural gas supply chain.
- Building on existing voluntary programs, NGSI is a voluntary framework to expand and accelerate industry-wide actions and recognize the collective benefits of these actions.
- NGSI supports individual companies' voluntary efforts to manage methane and other ESG issues by promoting consistent approaches for measuring and reporting on key metrics and recognizing industry leadership across all segments.

- NGSI is focused on supporting companies through common tools and metrics to meet environmental and social objectives and promote continuous improvement. All NGSI participants' supplier-related decisions are at the sole discretion of the individual companies.

Why Focus on Methane Emissions Intensity?

NGSI is currently focused on methane emissions from the United States onshore natural gas supply chain. As a contributor to climate change, methane has a higher global warming potential than carbon dioxide and is the second most significant greenhouse gas emitted from anthropogenic sources in the United States after carbon dioxide. Furthermore, methane emitted from sources along the natural gas supply chain affect the overall greenhouse gas emissions profile (i.e., life cycle emissions) for natural gas use. To address concerns over methane emissions, industry and stakeholders are prioritizing and streamlining efforts to better detect, measure, reduce, and communicate methane emissions from natural gas infrastructure.

A key obstacle to managing, tracking, and more transparently communicating current voluntary efforts to reduce methane emissions is the absence of a common metric for measuring and reporting methane emissions intensity. While methane emissions intensity is widely used across the industry, there is no standard methodology for calculating it. The NGSI protocol provides a consistent industry-wide approach to calculating and reporting methane emissions intensity at the company level within each segment of the natural gas supply chain.

Methane emissions intensity is also referred to as the methane emissions rate and is a measure of natural gas-related methane emissions relative to natural gas throughput in the natural gas system. Intensity is becoming a preferred approach for communicating methane emissions data throughout the industry for a variety of reasons:

- It enables a comparison of performance between similar business operations within a company or between different companies which is not reflected when comparing total methane emissions;
- It normalizes year-to-year fluctuations not directly related to methane performance (e.g., change of assets, varying output); and
- It can track performance over time and serve as a baseline for future company-level measurements.

NGSI seeks to establish a clear and consistent approach to using methane emissions and natural gas throughput data to calculate methane emissions intensity. Developing common, well-documented metrics will improve the quality of information available from the industry for use by investors and will help companies throughout the natural gas supply chain more effectively track programs to reduce methane emissions and communicate progress. With improved measurement and disclosure, the industry has an opportunity to accelerate programs to reduce methane emissions, further responding to stakeholder interest.

Potential Uses for NGSI Methane Emissions Intensity

In addition to providing a consistent approach to calculating methane emissions intensity at the segment level reporting for U.S. operations, companies could also use the NGSI protocol to provide location-specific information. For example, a natural gas producer could use the protocol to calculate and report methane emissions intensity for operations in a specific production basin. A company could also use this protocol to calculate and report segment-level methane emissions intensity at a regional or more local level.

Some companies have expressed interest is assessing the methane emissions intensity for their own operations across multiple segments or for their own natural gas supply chain. While this question goes beyond the current scope of the NGSI protocol, NGSI's standardization of emissions and throughput calculations provides a strong foundation for more customized analyses by supporting the development of a robust dataset that could be further refined to assess specific companies or natural gas supply chains. It is important to note that methane emissions intensity across multiple segments is *not* calculated as the sum of segment intensities. Rather, assumptions would need to be made about the throughput for each segment, paying attention to whether the throughput is an input or an output to the segment, and the share of gas that moves through each segment.

Opportunities for Advancing the Methane Emissions Intensity Protocol

Throughout the process of developing the NGSI protocol, commenters have highlighted areas where the protocol could be advanced in the future as technologies are developed and more information becomes available. NGSI will identify opportunities to explore each of the areas described below with industry partners, environmental groups, and other interested stakeholders.

Incorporate Methane Detection and Quantification Technologies

Industry is working in collaboration with government, academia, and environmental organizations to advance a range of innovative methane detection and quantification technologies. These technologies enable companies to more quickly detect and fix methane leaks and could be used to improve estimates of methane emissions from operations. Consistent with the guiding principle to support continuous improvement, NGSI recognizes the importance of enhancing the accuracy and environmental credibility of reported methane emissions. While the NGSI protocol relies on existing, emissions factor-based approaches to advance the consistency and clarity of available data, shifting toward more measurement-based approaches to determine actual methane emissions can enhance stakeholder and industry confidence in reported methane intensity data. NGSI will engage interested stakeholders on empirical methane emissions measurement approaches to enhance data quality and work to integrate improved methodologies in future versions of the protocol.

Update Emission Factors

NGSI recognizes that using spreadsheet calculations based on activity data and emission factors to estimate methane emissions has limitations. The accuracy of the estimates depends on the accuracy of the underlying emission factors. Updating emission factors requires rigorous technical analysis that must be vetted and confirmed over time. Depending on the age and sources used to develop the emission factors, estimates of methane emissions could be biased high or biased low. For example, older emission factors may not capture updates in technology or practices that would result in a lower emission factor. Alternately, ongoing research efforts suggest that a relatively small number of leaks from malfunctioning equipment can contribute a disproportionate share of total methane emissions from natural gas operations. Due to these types of leaks, which are random and can be hard to capture in a sample of emissions used to develop emission factors, actual emissions could be higher than suggested by an emission factor.

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. By referencing the regulatory text for the GHGRP methodologies in the protocol, NGSI intends to capture any future updates to emission factors by reference.

Streamline Reporting

NGSI has designed the protocol to be accessible to all companies that operate within the natural gas supply chain that have an interest in voluntary reporting of methane emissions intensity. NGSI recognizes industry interest in ways to streamline reporting and NGSI will continue to work with stakeholders to develop these opportunities and maximize company participation. For example, as new data become available (e.g., the Department of Energy's ongoing study regarding emissions from marginal production wells) there may be opportunities to simplify reporting for some sources.

Investigate Approaches to Estimating Throughput

For the purposes of the Version 1.0 of the NGSI protocol, throughput associated with the transmission & storage segment is estimated using data provided to the U.S. Department of Transportation Pipeline and Hazardous Materials Safety Administration (PHMSA) in Form F 7100.2-1 Part C of the Annual Report for Natural Gas and Other Gas Transmission and Gathering Pipeline Systems. NGSI recognizes that companies in the transmission & storage segment continue to work to improve the approach to estimating transmission throughput at the company level. NGSI will work with stakeholders to incorporate advancements in this area in future versions of the protocol.

For distribution companies, Version 1.0 of the NGSI protocol includes two approaches to estimating throughput for the purposes of calculating methane emissions intensity. Under one approach, companies use throughput reported to EIA through Form 176. Under a second approach, companies normalize throughput delivered to residential and commercial customers using heating degree day (HDD) data. Each of these approaches is described in more detail in the distribution segment section of the protocol. Based on feedback from reviewers, NGSI has determined that both approaches are of interest to stakeholders and encourages companies to disclose methane emissions intensity using both approaches.

Expand the List of Covered Sources

The NGSI protocol leverages existing reporting methodologies developed by EPA and ONE Future. However, commenters have suggested that EPA and ONE Future do not include all potential sources of emissions in the natural gas supply chain. Similarly, EPA includes methodologies for calculating emissions from certain sources in one segment of the supply chain but not from other segments. Additional sources identified by commenters are listed in Appendix A. NGSI will continue to collaborate with companies and other stakeholders to advance the NGSI protocol, including scope of emission sources as appropriate.

Approach to Developing the Protocol

The guidance outlined in Version 1.0 builds on four previous NGSI documents. In April 2019, NGSI released a white paper that summarized existing approaches to calculating and reporting methane emissions intensity and highlighted key decision points in determining a common intensity methodology. Consistent with NGSI's principle of building on existing voluntary programs, the white paper drew from a range of existing protocols and approaches (see Appendix B for a list of resources reviewed).

Based on extensive engagement by NGSI and feedback received on the white paper, NGSI developed and released an initial draft of the NGSI methane emissions intensity protocol in July 2019 and a final draft of the protocol in December 2019. NGSI held a series of webinars for interested stakeholders and received comments from industry and the environmental community on both the initial and final drafts. In the summer of 2020, NGSI worked with 11 companies throughout the natural gas supply chain to pilot the protocol. Through the pilot process, NGSI identified additional areas for clarification and updated the protocol.

2. NGSI Protocol for Calculating Methane Emissions Intensity

The following sections of this document are organized by segment of the natural gas supply chain and provide guidance on the emissions and throughput data for calculating a company's methane emissions intensity for each segment in which it operates. The protocol establishes intensity metrics for specific segments of the supply chain because this structure provides the most comparable points of reference between companies. It also provides guidance on the source of natural gas throughput to be used as the denominator in segment-level methane emissions intensity calculations.

The goal is to provide a metric that enables a useful comparison between similar types of operations.

The protocol addresses five segments of the natural gas supply chain:

- Onshore Production;
- Gathering & Boosting;
- Processing;
- Transmission & Storage; and
- Distribution.

In addition to these segments, NGSI has identified liquified natural gas (LNG) import and export and offshore natural gas production as separate segments. At this time, NGSI is not addressing methane emissions intensity for the LNG import and export or offshore natural gas segments. Future versions of the protocol could include these as well as additional segments.

Key Elements of the NGSI Methane Emissions Intensity Protocol

The guidance for reporting emissions leverages existing reporting protocols developed by the U.S. EPA. For emission sources that are currently reported to EPA as part of the GHGRP, NGSI has provided a reference to the GHGRP regulatory language and a brief description of the calculation. The NGSI protocol also includes emissions from sources that are not part of the GHGRP but have been identified by EPA through the GHG Inventory and adopted by ONE Future and EPA as part of the EPA Methane Challenge ONE Future Commitment Option. For these sources, NGSI includes the methodologies published as part of the EPA Methane Challenge ONE Future Commitment Option. Emission factors for these sources are those used in the GHG Inventory. Version 1.0 of the NGSI protocol uses the emission factors published in the 2020 GHG Inventory.[1] The GHG Inventory does not have segment-specific emission factors for all sources included in the NGSI protocol. In these cases, emission factors for the same source from different segments or past versions of the GHG Inventory are used. The NGSI protocol adopts segment definitions that are consistent with EPA's Methane Challenge program, which includes emissions from sources under common ownership or common control including leased, rented, or contracted activities.

While natural gas can be coproduced with heavier hydrocarbons (i.e., associated gas), the end use of the products and the customers for those products are diverse. Natural gas purchasers (e.g., a natural gas distribution company or power company using natural gas for electricity generation) are interested in

[1] Emission factors from the 2020 GHG Inventory are published in Annex 3.6, available at: https://www.epa.gov/sites/production/files/2020-02/2020_ghgi_natural_gas_systems_annex36_tables.xlsx

understanding the impact of emissions associated with natural gas production, gathering, and processing independent of emissions associated with natural gas liquids and crude oil production, gathering, and processing. For these segments, NGSI includes a methodology for allocating emissions to the natural gas supply chain on an energy basis across virtually all sources. ONE Future also has a methodology for allocating emissions to the natural gas supply chain, however, ONE Future allocates emissions at the source level.

The guidance on throughput values is segment specific. Production, processing, and gathering & boosting throughput values are all based on information reported to EPA as part of the GHGRP. To reduce the potential for double counting throughput, transmission & storage throughput values are based on information reported to PHMSA and distribution throughput values are based on information reported to EIA.

Expectations for Company Reporting

Under the NGSI protocol approach, companies will calculate and report methane emissions intensity based on total company emissions and throughput for each segment in which they operate. Within each segment, companies using the NGSI protocol will calculate total methane emissions from the sources included in the protocol and will divide by the methane content of the throughput to arrive at a methane emissions intensity expressed as a percent of methane. Under the NGSI protocol, companies will report emissions from all sources, not just those at facilities that report to EPA under the GHGRP. For facilities with GHGRP-reported data, companies can use the data reported to EPA and add emissions for additional sources identified in the protocol. For facilities that are below the GHGRP reporting threshold, companies will use reporting approaches that are consistent with GHGRP guidance and include emissions for the additional sources identified in the protocol.

To streamline company reporting and facilitate consistent application of the protocol, NGSI has released a detailed set of five templates, one for each of the covered segments. The templates include data entry sheets for facilities with data that is reported to EPA as part of the GHGRP as well as sheets for facilities that fall below EPA's data reporting threshold. Each template is prepopulated with emission sources, emission factors for non-GHGRP sources, and equations that automatically calculate segment-level methane emissions intensity.

The following templates are available for download from EEI and AGA:

- NGSI Reporting Template for Onshore Production
- NGSI Reporting Template for Gathering & Boosting
- NGSI Reporting Template for Processing
- NGSI Reporting Template for Transmission & Storage
- NGSI Reporting Template for Distribution

In each section of this document, NGSI provides guidance on the information that a company participating in NGSI would report as part of annual voluntary reporting, for example on a company's website or through other voluntary ESG reporting mechanisms. This information includes the segment-level methane emissions intensity as well as key data elements used to calculate segment-level intensity. Table 1 summarizes the disclosure elements by segment. Each element is described in more detail in the sections of the protocol devoted to each segment.

Table 1. NGSI Disclosure Elements by Segment

Disclosure Element	Onshore Production	Gathering & Boosting	Processing	Transmission & Storage	Distribution
Total Methane Emissions	✓	✓	✓	✓	✓
Natural Gas Throughput	✓	✓	✓	✓	✓
Energy Content of Natural Gas*	✓	✓	✓		
Methane Content of Natural Gas	✓	✓	✓	✓	✓
Other Hydrocarbon Throughput*	✓	✓	✓		
Energy Content of Other Hydrocarbons*	✓	✓	✓		
Gas Ratio*	✓	✓	✓		
NGSI Methane Emissions Intensity	✓	✓	✓	✓	✓

* NGSI is focused on the natural gas supply chain, not the supply chain of other hydrocarbons. Since production, gathering & boosting, and processing facilities can handle multiply hydrocarbon streams, the protocol includes a methodology for allocating emissions to the natural gas supply chain on an energy basis. This allocation is not necessary for the transmission & storage or distribution segments. The gas ratio is calculated as the energy content of natural gas divided by the energy content of natural gas plus the energy content of other hydrocarbons

3. Protocol for the Onshore Production Segment

For NGSI reporting purposes, the onshore production segment definition is consistent with the definition EPA established for the Methane Challenge Program[2]:

> **Onshore petroleum and natural gas production** means all equipment on a single well-pad or associated with a single well-pad (including but not limited to compressors, generators, dehydrators, storage vessels, engines, boilers, heaters, flares, separation and processing equipment, and portable non-self-propelled equipment, which includes well drilling and completion equipment, workover equipment, and leased, rented or contracted equipment) used in the production, extraction, recovery, lifting, stabilization, separation or treating of petroleum and/or natural gas (including condensate). This equipment also includes associated storage or measurement vessels, all petroleum and natural gas production equipment located on islands, artificial islands, or structures connected by a causeway to land, an island, or an artificial island.
>
> A production facility means all natural gas equipment on a single well-pad or associated with a single well-pad that are under common ownership or common control including leased, rented, or contracted activities by an onshore natural gas production owner or operator and that are located in a single hydrocarbon basin as defined in 40 CFR 98.238. Where a person or entity owns or operates more than one well in a basin, then all onshore natural gas production equipment associated with all wells that the person or entity owns or operates in the basin would be considered one facility.

Onshore Production Segment Emissions

Under NGSI, companies will aggregate emissions from all facilities within a segment to estimate total company-level emissions from sources in the segment. Emission sources included in the calculation are listed in Table 2 and Table 3. Table 2 lists sources that are estimated using the GHGRP quantification method. Table 3 lists sources that are estimated using emission factors utilized by EPA in the GHG Inventory.

Table 2. Onshore Production Segment Emissions Calculated Using GHGRP Methodology

Emission Source	GHGRP Reference(s)	Description of Quantification Method(s)
Associated Gas Venting	40 CFR 98.233(m)	Subpart W – Calculation using volume of oil produced, gas to oil ratio (GOR), and volume of associated gas sent to sales; accounting for flare control as applicable
Associated Gas Flaring	40 CFR 98.233(n)	Subpart W – Calculation using volume of oil produced, gas to oil ratio (GOR), and volume of associated gas sent to sales; accounting for flare control as applicable
Combustion Units	40 CFR 98.233(z)(1) 40 CFR 98.233(z)(2)	Subpart W, as applicable based on fuel type – Calculation using fuel usage records and measured or estimated composition
Compressors, Centrifugal with wet seal oil degassing vents	40 CFR 98.233(o)(10)	Subpart W – Calculation using default population emission factor for compressors with wet seal oil degassing vents

[2] U.S. EPA, "Methane Challenge Program ONE Future Commitment Option Technical Document," March 15, 2019. Available at: https://www.epa.gov/natural-gas-star-program/methane-challenge-program-one-future-commitment-option-technical-document

Emission Source	GHGRP Reference(s)	Description of Quantification Method(s)
Compressors, Reciprocating	40 CFR 98.233(p)(10)	Subpart W – Calculation using default population emission factor for reciprocating compressors
Dehydrator Vents, Glycol	40 CFR Part 98.233(e)(1) 40 CFR Part 98.233(e)(5) 40 CFR Part 98.233(e)(2) 40 CFR Part 98.233(e)(5)	Subpart W – Calculation Method 1 using computer modeling for glycol dehydrators Subpart W – Calculation Method 2 using emission factors and population counts for glycol dehydrators
Dehydrator Vents, Desiccant	40 CFR Part 98.233(e)(3);40 CFR Part 98.233(e)(5)	Subpart W – Calculation Method 3 using engineering calculations for desiccant dehydrators
Equipment Leaks	Per Greenhouse Gas Reporting Rule Leak Detection Methodology Revisions	Subpart W – Leak survey and default leaker emission factors for components in gas service, and population counts and default population emission factors
Flare Stacks	40 CFR 98.233(n)(5) 40 CFR 98.233(n)(6)	Subpart W – Calculation using measured or estimated flow and gas composition, and flare combustion efficiency; accounting for feed gas sent to an un-lit flare as applicable
Liquids Unloading	40 CFR 98.233(f)(1) 40 CFR 98.233(f)(2) 40 CFR 98.233(f)(3)	Subpart W – Calculation Method 1 using direct measurement for each tubing diameter and pressure group with and without plunger lifts Subpart W – Calculation Method 2 using engineering calculations for wells without plunger lifts Subpart W – Calculation Method 3 using engineering calculations for wells with plunger lifts
Pneumatic Device (Controller) Vents), Natural Gas	40 CFR 98.233(a)	Subpart W – Calculation using count of devices and default emission factors.
Pneumatic (Chemical Injection) Pump Vents, Natural Gas Driven	40 CFR 98.233(c)	Subpart W – Calculation using actual count of devices and default emission factors
Storage Vessels, Fixed-roof Tanks	40 CFR 98.233(j)(1) 40 CFR 98.233(j)(2) 40 CFR 98.233(j)(3)	Subpart W – Calculation Method 1 using computer modeling for gas-liquid separators or gathering and boosting non-separator equipment Subpart W – Calculation Method 2 using engineering calculations for gas-liquid separators or gathering and boosting non-separator equipment or wells flowing directly to atmospheric storage tanks Subpart W – Calculation Method 3 using an emission factor and population counts for hydrocarbon liquids flowing togas-liquid separators, non-separator equipment, or directly to atmospheric storage

Emission Source	GHGRP Reference(s)	Description of Quantification Method(s)
Well Venting During Well Completions / Workovers with Hydraulic Fracturing	40 CFR 98.233(g)	Subpart W – Calculation using combined production rate measurement and engineering calculations in Equation W-10A Subpart W – Calculation using measured vented or flared volume from each well in Equation W-10B For oil wells, this calculation is limited to oil wells that have a gas-oil ratio (GOR) of 300 scf/STB or greater
Well Venting During Well Completions / Workovers without Hydraulic Fracturing	40 CFR 98.233(h)	Subpart W, for completions – Calculation using measured production rate Subpart W, for workovers – Calculation using a count of workovers and an emission factor
Well Testing Venting & Flaring	40 CFR 98.233(l)	Subpart W, for oil wells – Calculation using GOR, average annual flow rate, and testing duration in Equation W-17A Subpart W, for gas wells – Calculation using average annual flow rate and testing duration in Equation W-17B

Table 3. Onshore Production Segment Emissions Calculated Using GHG Inventory Emission Factors

Emission Source	Description of Quantification Method	GHG Inventory Emission Factor
Acid Gas Removal Units*	GHG Inventory emission factor multiplied by number of acid gas removal units	609.07 kg/AGRU
Blowdowns – Vessel Blowdowns	GHG Inventory emission factor multiplied by number of vessels	1.59 kg/vessel
Compressors, Centrifugal with Dry Seals**	GHG Inventory emission factor multiplied by number of compressors	28,420.96 kg/compressor
Compressor Starts	GHG Inventory emission factor multiplied by number of compressors	171.96 kg/compressor
Compressor Blowdowns	GHG Inventory emission factor multiplied by number of compressors	76.86 kg/compressor
Pressure Relief Valves, Upsets	GHG Inventory emission factor multiplied by number of valves	0.69 kg/pressure relief valve
Storage Vessels, Floating Roof Tanks†	GHG Inventory emission factor multiplied by number of floating roof tanks	6,515.78 kg/tank
Well Drilling	GHG Inventory emission factors multiplied by number of wells drilled	51.02 kg/well

Note: For all sources, EPA published the GHG Inventory emission factors in Annex 3.6 of the 2020 GHG Inventory, available at: https://www.epa.gov/sites/production/files/2020-02/2020_ghgi_natural_gas_systems_annex36_tables.xlsx
*Emission factor is from gathering and boosting segment; GHG Inventory does not have a production-segment factor
**Emission factor is from processing segment; GHG Inventory does not have a production-segment factor
†Emission factor is from 2018 GHG Inventory petroleum systems production segment; GHG Inventory does not have a gathering and boosting segment factor and no longer lists this factor in the petroleum systems production segment

Allocating Emissions to Natural Gas Production

Under NGSI, companies will identify a portion of total methane emissions to attribute to natural gas production, as opposed to other hydrocarbons that may be produced (e.g., crude oil, condensate). This allocation is on an energy basis. The methodology for calculating methane emissions associated with natural gas production is as follows:

1. Calculate the energy equivalent of produced natural gas (E_{ng}) as the product of the volume of produced gas (V_{ng}) multiplied by the energy content of the gas (EC_{ng}).[3] Estimate V_{ng} and EC_{ng} as:
    - V_{ng}: Volume (thousand standard cubic feet) of produced gas consistent with 98.236(aa)(1)(i)(A) as reported to the GHGRP.
    - EC_{ng}: Assume a default raw gas higher heating value of 1.235 MMBtu per thousand standard cubic feet from Table 3-8 of the API *Compendium of Greenhouse Gas Emissions Methodologies for the Oil and Natural Gas Industry* (API Compendium) or a company-specific factor.[4]
2. Calculate the energy equivalent of produced liquids (E_{liq}) as the product of the volume of produced liquids for sales (V_{liq}) multiplied by the energy content of the liquids (EC_{liq}). Estimate V_{liq} and EC_{liq} as:
    - V_{liq}: Volume (barrels) of crude and condensate produced for sales consistent with 98.236(aa)(1)(i)(C) as reported to the GHGRP.
    - EC_{liq}: Assume a default crude oil heating value of 5.8 MMBtu per barrel from API Compendium Table 3-8 or a company-specific factor.
3. Calculate the gas ratio (GR) as the energy equivalent of natural gas divided by the total energy equivalent of produced natural gas and liquids, or $\frac{E_{ng}}{E_{ng} + E_{liq}}$
4. Calculate share of emissions allocated to the natural gas supply chain as GR multiplied by the estimated segment methane emissions.

Onshore Production Segment Throughput

For companies with production operations, segment throughput equates to the volume of gas produced at wells consistent with 98.236(aa)(1)(i)(A) in the GHGRP: The quantity of gas produced in the calendar year from wells, in thousand standard cubic feet. This includes gas that is routed to a pipeline, vented or flared, or used in field operations. This does not include gas injected back into reservoirs or shrinkage resulting from lease condensate production.

[3] The goal of NGSI is to provide a methodology for calculating methane emissions intensity at the company level for each segment in which a company operates. Companies may be interested in allocating emissions at the basin level in order provide more granular data.

[4] American Petroleum Institute (API). Compendium of Greenhouse Gas Emissions Methodologies for the Oil and Natural Gas Industry. August 2009. Available at: https://www.api.org/~/media/Files/EHS/climate-change/2009_GHG_COMPENDIUM.pdf

Onshore Production Segment Methane Emissions Intensity

To convert natural gas production throughput to methane, the reporting company will have to make an assumption about the methane content of produced natural gas. The reporting company can use and disclose its own estimate of the methane content of produced gas or can use a default factor of 83.3 percent.

To calculate production segment intensity, the methane emissions and throughput estimates must be converted to like units of methane. This can be on a mass basis or a volumetric basis. Companies should use a methane density (at standard temperature and pressure) of 0.0192 metric tons per thousand cubic feet, consistent with the methane density used by EPA in the GHGRP (40 CFR 98.233(v)).

For example, where methane emissions are reported in metric tons and natural gas throughput is reported in thousand cubic feet, a company could calculate its methane emissions intensity (%) for natural gas production as:

$$Methane\ Emissions\ Intensity = \frac{Methane\ Emissions * Gas\ Ratio}{Natural\ Gas\ Throughput * Methane\ Content * \frac{0.0192\ metric\ tons}{thousand\ cubic\ feet}}$$

Alternatively, a company could calculate its methane emissions intensity for natural gas production as:

$$Methane\ Emissions\ Intensity = \frac{Methane\ Emissions * Gas\ Ratio * \frac{thousand\ cubic\ feet}{0.0192\ metric\ tons}}{Natural\ Gas\ Throughput * Methane\ Content}$$

Onshore Production Segment Reported Data

Companies with natural gas production operations following the NGSI protocol are encouraged to publicly report the information described in Table 4. Information should be reported at the company level; companies may also find it useful to report certain elements at the facility level.

Table 4. NGSI Disclosure Elements for a Company with Natural Gas Onshore Production Operations

Disclosure Element	Description
Total Methane Emissions (metric tons)	Total onshore production segment methane emissions from GHGRP and non GHGRP facilities; sum of emissions from the sources listed in Tables 1 and 2
Produced Natural Gas (thousand standard cubic feet)	Total volume of natural gas produced by GHGRP and non GHGRP facilities
Energy Content of Produced Natural Gas (MMBtu per thousand standard cubic feet)	Raw gas higher heating value (weighted average energy content of all gas production)
Methane Content of Produced Natural Gas (%)	Methane content of produced natural gas (weighted average methane content of all gas production)
Produced Crude Oil and Condensate (barrels)	Total crude oil and condensate produced for sales by GHGRP and non GHGRP facilities
Energy Content of Produced Crude Oil and Condensate (MMBtu per barrel)	Crude oil and condensate heating value (weighted average energy content from all oil production)
Gas Ratio (%)	Share of natural gas produced on an energy equivalent basis
NGSI Methane Emissions Intensity (%)	Methane emissions intensity associated with natural gas production

4. Protocol for the Gathering & Boosting Segment

For NGSI reporting purposes, the gathering & boosting segment definition is consistent with the definitions EPA established for the Methane Challenge Program:

> **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 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 Subpart W. Gathering pipelines operating on a vacuum and gathering pipelines with a gas to oil ratio (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).
>
> A gathering and boosting facility for purposes of reporting means 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 as defined in 40 CFR 98.238. Where a person owns or operates more than one gathering and boosting system in a basin (for example, separate gathering lines that are not connected), then all gathering and boosting equipment that the person owns or operates in the basin would be considered one facility. Any gathering and boosting equipment that is associated with a single gathering and boosting system, including leased, rented, or contracted activities, is considered to be under common control of the owner or operator of the gathering and boosting system that contains the pipeline. The facility does not include equipment and pipelines that are part of any other industry segment defined in Subpart W.

Gathering & Boosting Segment Emissions

Under NGSI, companies will aggregate emissions from all facilities within a segment to estimate total company-level emissions from sources in the segment. Emission sources included in the calculation are listed in Table 5 and Table 6. Table 5 lists sources that are estimated using the GHGRP quantification method. Table 6 lists sources that are estimated using emission factors utilized by EPA in the GHG Inventory.

Table 5. Gathering & Boosting Segment Emissions Calculated Using GHGRP Methodology

Emission Source	GHGRP Reference(s)	Description of Quantification Method(s)
Blowdown Vent Stacks	40 CFR 98.233(i)(2)	Subpart W – Calculation method using engineering calculation method by equipment or event type
	40 CFR 98.233(i)(3)	Subpart W – Calculation method using direct measurement of emissions using a flow meter
		Alternate calculation method using actual event counts multiplied by the average unique physical volumes as calculated from all company-specific Subpart W facility events (for facilities not reporting to Subpart W only)

Emission Source	GHGRP Reference(s)	Description of Quantification Method(s)
Combustion Units	40 CFR 98.233(z)(1) 40 CFR 98.233(z)(2)	Subpart W, as applicable based on fuel type – Calculation using fuel usage records and measured or estimated composition
Compressors, Centrifugal with Wet Seal Oil Degassing Vents	40 CFR 98.233(o)(10)	Subpart W – Calculation using default population emission factor for compressors with wet seal oil degassing vents
Compressors, Reciprocating	40 CFR 98.233(p)(10)	Subpart W – Calculation using default population emission factor for reciprocating compressors
Dehydrator Vents, Glycol	40 CFR Part 98.233(e)(1)40 CFR Part 98.233(e)(5) 40 CFR Part 98.233(e)(2) 40 CFR Part 98.233(e)(5)	Subpart W – Calculation Method 1 using computer modeling for glycol dehydrators Subpart W – Calculation Method 2 using emission factors and population counts for glycol dehydrators
Dehydrator Vents, Desiccant	40 CFR Part 98.233(e)(3)40 CFR Part 98.233(e)(5)	Subpart W – Calculation Method 3 using engineering calculations for desiccant dehydrators
Equipment Leaks	Per Greenhouse Gas Reporting Rule Leak Detection Methodology Revisions	Subpart W – Leak survey and default leaker emission factors for components in gas service, and population counts and default population emission factors
Equipment Leaks, Gathering Pipelines	40 CFR 98.233(r)	Subpart W – Calculated using population counts and emission factors
Flare Stacks	40 CFR 98.233(n)(5); 40 CFR 98.233(n)(6)	Subpart W – Calculation using measured or estimated flow and gas composition, and flare combustion efficiency; accounting for feed gas sent to an un-lit flare as applicable
Pneumatic Device (Controller) Vents), Natural gas	40 CFR 98.233(a)	Subpart W – Calculation using count of devices and default emission factors
Pneumatic (Chemical Injection) Pump Vents, Natural Gas Driven	40 CFR 98.233(c)	Subpart W – Calculation using actual count of devices and default emission factors
Storage Vessels, Fixed-roof Tanks	40 CFR 98.233(j)(1) 40 CFR 98.233(j)(2) 40 CFR 98.233(j)(3)	Subpart W – Calculation Method 1 using computer modeling for gas-liquid separators or gathering and boosting non-separator equipment Subpart W – Calculation Method 2 using engineering calculations for gas-liquid separators or gathering and boosting non-separator equipment or wells flowing directly to atmospheric storage tanks Subpart W – Calculation Method 3usingan emission factor and population counts for hydrocarbon liquids flowing togas-liquid separators, non-separator equipment, or directly to atmospheric storage

Table 6. Gathering & Boosting Segment Emissions Calculated Using GHG Inventory Emission Factors

Emission Source	Description of Quantification Method	GHG Inventory Emission Factor
Acid Gas Removal Units	GHG Inventory emission factor multiplied by number of acid gas removal units	609.07 kg/AGRU
Compressors, Centrifugal with Dry Seals*	GHG Inventory emission factor multiplied by number of compressors	28,420.96 kg/compressor
Compressor Starts**	GHG Inventory emission factor multiplied by number of compressors	171.96 kg/compressor
Damages (Gathering & Boosting Upsets: Mishaps)†	GHG Inventory emission factor multiplied by miles of gathering pipeline	13.65 kg/mile
Storage Vessels, Floating-roof Tanks‡	GHG Inventory emission factor multiplied by number of floating roof tanks	6,515.78 kg/tank

Note: GHG Inventory emission factors are published in Annex 3.6 of the 2020 GHG Inventory, available at: https://www.epa.gov/sites/production/files/2020-02/2020_ghgi_natural_gas_systems_annex36_tables.xlsx
*Emission factor is from processing segment; GHG Inventory does not have a gathering and boosting-segment factor
**Emission factor is from production segment; GHG Inventory does not have a gathering and boosting-segment factor
†Emission factor is from 2018 GHG Inventory; GHG Inventory no longer has a gathering and boosting-segment factor
‡Emission factor is from 2018 GHG Inventory petroleum systems production segment; GHG Inventory does not have a gathering and boosting segment factor and no longer lists this factor in the petroleum systems production segment

Allocating Emissions to Natural Gas Gathering & Boosting

Under NGSI, companies will identify a portion of total methane emissions to attribute to natural gas gathering & boosting, as opposed to other hydrocarbons that may be handled (e.g., crude oil, condensate). This allocation is on an energy basis. The methodology for calculating methane emissions associated with natural gas gathering & boosting is as follows:

1. Calculate the energy equivalent of natural gas transported (E_{ng}) as the product of the volume of gas transported (V_{ng}) multiplied by the energy content of the gas (EC_{ng}). Estimate V_{ng} and EC_{ng} as:
   - V_{ng}: Volume (thousand standard cubic feet) of gas transported consistent with 98.236(aa)(10)(ii) as reported to the GHGRP.
   - EC_{ng}: Assume a default raw gas higher heating value of 1.235 MMBtu per thousand standard cubic feet from Table 3-8 of the API Compendium or a company-specific factor.
2. Calculate the energy equivalent of all hydrocarbon liquids transported (E_{liq}) as the product of the volume of liquids transported (V_{liq}) multiplied by the energy content of the liquids (EC_{liq}). Estimate V_{liq} and EC_{liq} as:
   - V_{liq}: Volume (barrels) of all hydrocarbon liquids transported consistent with 98.236(aa)(10)(iv) as reported to the GHGRP.

- EC_{liq}: Assume a default heating value of 5.8 MMBtu per barrel (consistent with crude oil) from API Compendium Table 3-8 or a company-specific factor.

3. Calculate the gas ratio (*GR*) as the energy equivalent of natural gas transported divided by the total energy equivalent of transported natural gas and liquids, or $\frac{E_{ng}}{E_{ng}+E_{liq}}$
4. Calculate share of emissions allocated to the natural gas supply chain as *GR* multiplied by the estimated segment methane emissions.

Gathering & Boosting Segment Throughput

For companies with gathering and boosting operations, segment throughput equates to the total volume of gas transported by gathering and boosting facilities during the reporting year consistent with 98.236(aa)(10)(ii) in the GHGRP.

Gathering & Boosting Segment Methane Emissions Intensity

To convert gathering and boosting throughput to methane, the reporting company will have to make an assumption about the methane content of natural gas transported. The reporting company can use and disclose its own estimate of the methane content of transported gas or can use a default factor of 83.3 percent.

To calculate gathering and boosting segment intensity, the emissions and throughput estimates must be converted to like units of methane. This can be on a mass basis or a volumetric basis. Companies reporting methane emissions intensity should use a methane density (at standard temperature and pressure) of 0.0192 metric tons per thousand cubic feet, consistent with the methane density used by EPA in the GHGRP (40 CFR 98.233(v)).

For example, where methane emissions are reported in metric tons and natural gas throughput is reported in thousand cubic feet, a company could calculate its methane emissions intensity (%) as:

$$Methane\ Emissions\ Intensity = \frac{Methane\ Emissions * Gas\ Ratio}{Natural\ Gas\ Throughput * Methane\ Content * \frac{0.0192\ metric\ tons}{thousand\ cubic\ feet}}$$

Alternatively, a company could calculate its methane emissions intensity as:

$$Methane\ Emissions\ Intensity = \frac{Methane\ Emissions * Gas\ Ratio * \frac{thousand\ cubic\ feet}{0.0192\ metric\ tons}}{Natural\ Gas\ Throughput * Mthane\ Content}$$

Gathering & Boosting Segment Reported Data

Companies with natural gas gathering and boosting operations following the NGSI protocol are encouraged to publicly report the information described in Table 7. Information should be reported at the company level; companies may also find it useful to report certain elements at the facility level.

Table 7. NGSI Disclosure Elements for a Company with Natural Gas Gathering & Boosting Operations

Disclosure Element	Description
Total Methane Emissions (metric tons)	Total gathering and boosting segment methane emissions from GHGRP and non GHGRP facilities; sum of emissions from the sources listed in Tables 4 and 5

Disclosure Element	Description
Natural Gas Transported (thousand standard cubic feet)	Total volume of gas transported by GHGRP and non GHGRP facilities
Energy Content of Natural Gas Transported (MMBtu per thousand standard cubic feet)	Raw gas higher heating value (weighted average energy content of natural gas transported)
Methane Content of Natural Gas Transported (%)	Methane content of natural gas transported (weighted average methane content of natural gas transported)
Hydrocarbon Liquids Transported (barrels)	Total volume of hydrocarbon liquids transported by GHGRP and non GHGRP facilities
Energy Content of Hydrocarbon Liquids Transported (MMBtu per barrel)	Heating value of all hydrocarbon liquids transported (weighted average energy content of all liquids transported)
Gas Ratio (%)	Share of natural gas transported on an energy equivalent basis
NGSI Methane Emissions Intensity (%)	Methane emissions intensity associated with natural gas gathering & boosting

5. Protocol for the Processing Segment

For NGSI reporting purposes, the processing segment definition is consistent with the definitions EPA established for the Methane Challenge Program:

> **Natural gas processing** means the separation of natural gas liquids (NGLs) or non-methane gases from produced natural gas, or the separation of NGLs into one or more component mixtures. Separation includes one or more of the following: forced extraction of natural gas liquids, sulfur and carbon dioxide removal, fractionation of NGLs, or the capture of carbon dioxide separated from natural gas streams. This segment also includes all residue gas compression equipment owned or operated by the natural gas processing plant. This industry segment includes processing plants that fractionate gas liquids, and processing plants that do not fractionate gas liquids but have an annual average throughput of 25 MMscf per day or greater.
>
> A natural gas processing facility for the purposes of reporting is any physical property, plant, building, structure, source, or stationary equipment in the natural gas processing industry segment located on one or more contiguous or adjacent properties in actual physical contact or separated solely by a public roadway or other public right-of-way and under common ownership or common control, that emits or may emit any greenhouse gas. Operators of military installations may classify such installations as more than a single facility based on distinct and independent functional groupings within contiguous military properties.

Processing Segment Emissions

Under NGSI, companies will aggregate emissions from all facilities within the segment to estimate total company-level emissions from sources in the segment. Emission sources included in the calculation are listed in Table 8 and Table 9. Table 8 lists sources that are estimated using the GHGRP quantification method. Table 9 lists sources that are estimated using emission factors utilized by EPA in the GHG Inventory.

Table 8. Processing Segment Emissions Calculated Using GHGRP Methodology

Emission Source	GHGRP Reference(s)	Description of Quantification Method(s)
Blowdown Vent Stacks	40 CFR 98.233(i)(2)	Subpart W – Calculation method using engineering calculation method by equipment or event type
	40 CFR 98.233(i)(3)	Subpart W – Calculation method using direct measurement of emissions using a flow meter
		Alternate calculation method using actual event counts multiplied by the average unique physical volumes as calculated from all company-specific Subpart W facility events (for facilities not reporting to Subpart W only)

Emission Source	GHGRP Reference(s)	Description of Quantification Method(s)
Combustion Units	40 CFR 98.33(c)	Subpart C methods, as applicable based on fuel type – Calculation using fuel usage as recorded or measured, fuel high heating value (HHV) default value or as calculated from measurements, and fuel-specific emission factors Alternate calculation method using total volume of fuel consumed and the fuel-specific emission factors for methane (for facilities not reporting to Subpart C only)
Compressors, Centrifugal	40 CFR 98.233(o)(1)(i) 40 CFR 98.233(o)(6) 40 CFR 98.233(o)(1)(ii) 40 CFR 98.233(o)(1)(iii)	Subpart W – Individual compressor source "as found" measurements • Operating mode: blowdown valve leakage • Operating mode: wet seal oil degassing vent • Not-operating-depressurized mode: isolation valve leakage Subpart W – Reporter-specific emission factor for mode-source combinations not measured in the reporting year Subpart W – Continuous monitoring Subpart W – Manifolded "as found" measurements Alternate calculation method using average company emission factor based on all company-specific Subpart W centrifugal compressor measurements (for facilities not reporting to Subpart W only)
Compressors, Reciprocating	40 CFR 98.233(p)(1)(i) 40 CFR 98.233(p)(6) 40 CFR 98.233(p)(1)(ii) 40 CFR 98.233(p)(1)(iii)	Subpart W – Individual compressor source "as found" measurements • Operating mode: blowdown valve leakage and rod packing emissions • Standby-pressurized mode: blowdown valve leakage • Not-operating-depressurized mode: isolation valve leakage Subpart W – Reporter-specific emission factor for mode-source combinations not measured in the reporting year Subpart W – Continuous monitoring Subpart W – Manifolded "as found" measurements Alternate calculation method using average company emission factor based on all company-specific Subpart W centrifugal compressor measurements (for facilities not reporting to Subpart W only)
Dehydrator vents, glycol	40 CFR Part 98.233(e)(1) 40 CFR Part 98.233(e)(5) 40 CFR Part 98.233(e)(2) 40 CFR Part 98.233(e)(5)	Subpart W – Calculation Method 1 using computer modeling for glycol dehydrators Subpart W – Calculation Method 2 using emission factors and population counts for glycol dehydrators
Dehydrator vents, desiccant	40 CFR Part 98.233(e)(3) 40 CFR Part 98.233(e)(5)	Subpart W – Calculation Method 3 using engineering calculations for desiccant dehydrators

Emission Source	GHGRP Reference(s)	Description of Quantification Method(s)
Equipment Leaks	Per Greenhouse Gas Reporting Rule Leak Detection Methodology Revisions	Subpart W – Leak survey and default leaker emission factors for compressor and non-compressor components in gas service
		Alternate calculation method using average company emission factor based on all company-specific Subpart W leak surveys (for facilities not reporting to Subpart W only)
Flare Stacks	40 CFR 98.233(n)(5) 40 CFR 98.233(n)(6)	Subpart W – Calculation using measured or estimated flow and gas composition, and flare combustion efficiency; accounting for feed gas sent to an un-lit flare as applicable

Table 9. Processing Segment Emissions Calculated Using GHG Inventory Emission Factors

Emission Source	Description of Quantification Method	GHG Inventory Emission Factor
Acid Gas Removal Vents	GHG Inventory emission factor multiplied by number of acid gas removal units	42,762.88 kg/acid gas removal vent
Compressors, Centrifugal with Dry Seals*	GHG Inventory emission factor multiplied by number of centrifugal compressors with dry seals	28,420.96 kg/compressor
	Number of centrifugal compressors multiplied by average company emission factor based on measurements from dry seals (measurements are to be taken using Subpart W measurement methods for wet seals)	NA
Natural Gas-Driven Low-Bleed Pneumatic Controllers**	GHG Inventory emission factor multiplied by number of low-bleed pneumatic controllers	217.40 kg/pneumatic controller
Natural Gas-Driven Intermittent-Bleed Pneumatic Controllers**	GHG Inventory emission factor multiplied by number of intermittent-bleed pneumatic controllers	372.77 kg/pneumatic controller
Natural Gas-Driven High-Bleed Pneumatic Devices**	GHG Inventory emission factor multiplied by number of high-bleed pneumatic controllers	2,863.03 kg/pneumatic controller

Note: GHG Inventory emission factors are published in Annex 3.6 of the 2020 GHG Inventory, available at: https://www.epa.gov/sites/production/files/2020-02/2020_ghgi_natural_gas_systems_annex36_tables.xlsx
*In the processing segment, GHGRP captures emissions from blowdown and isolation valves at all types of centrifugal compressors. However, it only captures emissions from seals at compressors with wet seals. Emissions from seals at dry seal compressors are therefore estimated using the GHG Inventory methodology.
**Pneumatic controllers use GHG Inventory emissions factors for controllers in transmission service from the transmission and storage segment. These component-level factors are used in place of the GHG Inventory's plant-level pneumatic controller emission factor for the processing segment. Many pneumatic devices at processing plants are driven by electricity or instrument air rather than natural gas, and thus have zero emissions. Component-level factors therefore more accurately estimate actual emissions compared to a plant-level factor, which does not reflect actual component types and counts.

Allocating Emissions to Natural Gas Processing

Under NGSI, companies will identify a portion of total methane emissions to attribute to natural gas processing, as opposed to other hydrocarbons that may be processed (e.g., natural gas liquids or NGLs). Emissions allocation in the processing segment is complicated by the fact that the source category includes facilities that primarily handle gas streams, facilities that primarily handle liquids (i.e., NGL fractionation plants), and facilities that handle both gas and liquids (i.e., integrated plants). Due to the higher energy density of NGLs and the fact that certain equipment processes no or very low natural gas volumes, allocating methane solely on an energy basis risks assigning too much methane to NGLs and too little to the natural gas value chain. To more accurately allocate emissions to the proper commodity, NGSI follows the ONE Future approach of allocating all methane from equipment that primarily handles natural gas to the natural gas value chain and allocating methane from equipment that handles both gas and liquids on an energy basis using a gas ratio. Table 10 illustrates which processing segment emission sources allocate all methane to the natural gas value chain and which sources allocate methane to the gas and NGL value chains based on the gas ratio.

The methodology for calculating methane emissions associated with natural gas processing is as follows:

1. Calculate the energy equivalent of natural gas processed (E_{ng}) as the product of the volume of gas processed (V_{ng}) multiplied by the energy content of the gas (EC_{ng}). Estimate V_{ng} and EC_{ng} as:
    - V_{ng}: Volume (thousand standard cubic feet) of gas processed consistent with 98.236(aa)(3)(ii) as reported to the GHGRP.
    - EC_{ng}: Assume a default raw gas higher heating value of 1.235 MMBtu per thousand standard cubic feet from Table 3-8 of the API Compendium or a company-specific factor.
2. Calculate the energy equivalent of natural gas liquids processed (E_{liq}) as the product of the volume of natural gas liquids processed (V_{liq}) multiplied by the energy content of the natural gas liquids (EC_{liq}). Estimate V_{liq} and EC_{liq} as:
    - V_{liq}: Volume (barrels) of natural gas liquids processed consistent with 98.236(aa)(3)(iv) as reported to the GHGRP.
    - EC_{liq}: Assume a default heating value of 3.82 MMBtu per barrel (consistent with propane liquids) from API Compendium Table 3-8 or a company-specific factor.
3. Calculate the gas ratio (GR) as the energy equivalent of natural gas processed divided by the total energy equivalent of processed natural gas and liquids, or $\frac{E_{ng}}{E_{ng}+E_{liq}}$
4. Calculate share of emissions allocated to the natural gas supply chain from equipment that process both gas and liquids, as per Table 10, as GR multiplied by the estimated segment methane emissions.
5. Calculate total methane emissions allocated to the natural gas supply chain as the sum of methane from Step 4 and total estimated segment methane emissions from equipment that allocates all methane to natural gas, as per Table 10.

Table 10. Methane Emissions Allocation Approach for Natural Gas Processing Equipment

Emissions Source	Methane Emissions Allocation
Blowdown Vent Stacks	Gas Ratio
Equipment Leaks	Gas Ratio
Flare Stacks	Gas Ratio
Pneumatic Device Vents	Gas Ratio
Acid Gas Removal Units	All to Natural Gas Value Chain
Combustion Units	All to Natural Gas Value Chain

Emissions Source	Methane Emissions Allocation
Centrifugal Compressors	All to Natural Gas Value Chain
Dehydrator Vents	All to Natural Gas Value Chain
Reciprocating Compressors	All to Natural Gas Value Chain

Processing Segment Throughput

For companies with processing operations, segment throughput equates to the quantity of natural gas processed at the gas processing plant in thousand standard cubic feet consistent with 98.236(aa)(3)(ii) as reported to the GHGRP.

Processing Segment Methane Emissions Intensity

To convert processing segment throughput to methane, the reporting company will have to make an assumption about the methane content of processed natural gas. The reporting company can use and disclose its own estimate of the methane content of natural gas or can use a default factor of 87 percent.

To calculate processing segment intensity, the emissions and throughput estimates must be converted to like units of methane. This can be on a mass basis or a volumetric basis. Companies reporting methane emissions intensity should use a methane density (at standard temperature and pressure) of 0.0192 metric tons per thousand cubic feet, consistent with the methane density used by EPA in the GHGRP (40 CFR 98.233(v)).

For example, where methane emissions are reported in metric tons and natural gas throughput is reported in thousand cubic feet, a company could calculate its methane emissions intensity (%) as:

$$Methane\ Emissions\ Intensity = \frac{Methane\ Emissions * Gas\ Ratio}{Natural\ Gas\ Throughput * Methane\ Content * \frac{0.0192\ metric\ tons}{thousand\ cubic\ feet}}$$

Alternatively, a company could calculate its methane emissions intensity as:

$$Methane\ Emissions\ Intensity = \frac{Methane\ Emissions * Gas\ Ratio * \frac{thousand\ cubic\ feet}{0.0192\ metric\ tons}}{Natural\ Gas\ Throughput * Methane\ Content}$$

Processing Segment Reported Data

Companies with natural gas processing operations following the NGSI protocol are encouraged to publicly report the information described in Table 11. Information should be reported at the company level; companies may also find it useful to report certain elements at the facility level.

Table 11. NGSI Disclosure Elements for a Company with Natural Gas Processing Operations

Disclosure Element	Description
Total Methane Emissions (metric tons)	Total processing segment methane emissions from GHGRP and non GHGRP facilities; sum of emissions from the sources listed in Tables 8 and 9
Natural Gas Processed (thousand standard cubic feet)	Total volume of natural gas processed by GHGRP and non GHGRP facilities
Energy Content of Natural Gas Processed (MMBtu per thousand standard cubic feet)	Raw gas higher heating value (weighted average energy content of all gas processed)
Methane Content of Natural Gas Processed (%)	Methane content of natural gas (weighted average methane content of gas processed)
Natural Gas Liquids Processed (barrels)	Total volume of natural gas liquids processed by GHGRP and non GHGRP facilities
Energy Content of Natural Gas Liquids Processed (MMBtu per barrel)	Heating value of natural gas liquids (weighted average energy content of natural gas liquids processed)
Gas Ratio (%)	Share of natural gas processed on an energy equivalent basis
NGSI Methane Emissions Intensity (%)	Methane emissions intensity associated with natural gas processing

6. Protocol for the Transmission & Storage Segment

For NGSI reporting purposes, the transmission & storage segment definition includes natural gas transmission compression & underground natural gas storage, LNG storage, and natural gas transmission pipelines consistent with the definitions EPA established for the Methane Challenge Program:

- **Onshore natural gas transmission compression** means any stationary combination of compressors that move natural gas from production fields, natural gas processing plants, or other transmission compressors through transmission pipelines to natural gas distribution pipelines, LNG storage facilities, or into underground storage. A transmission compressor station includes equipment for liquids separation, and tanks for the storage of water and hydrocarbon liquids. Residue (sales) gas compression that is part of onshore natural gas processing plants are included in the onshore natural gas processing segment and are excluded from this segment.

- **Underground natural gas storage** means subsurface storage, including depleted gas or oil reservoirs and salt dome caverns that store natural gas that has been transferred from its original location for the primary purpose of load balancing (the process of equalizing the receipt and delivery of natural gas); natural gas underground storage processes and operations (including compression, dehydration and flow measurement, and excluding transmission pipelines); and all the wellheads connected to the compression units located at the facility that inject and recover natural gas into and from the underground reservoirs.

  A natural gas transmission compression facility or underground natural gas storage facility for the purposes of reporting is any physical property, plant, building, structure, source, or stationary equipment in the natural gas transmission compression industry segment or underground natural gas storage industry segment located on one or more contiguous or adjacent properties in actual physical contact or separated solely by a public roadway or other public right-of-way and under common ownership or common control, that emits or may emit any greenhouse gas. Operators of military installations may classify such installations as more than a single facility based on distinct and independent functional groupings within contiguous military properties.

- **Onshore natural gas transmission pipeline** means all natural gas pipelines that are a Federal Energy Regulatory Commission rate-regulated Interstate pipeline, a state rate-regulated Intrastate pipeline, or a pipeline that falls under the "Hinshaw Exemption" as referenced in section 1(c) of the Natural Gas Act, 15 I.S.C. 717-717(w)(1994).

  An onshore natural gas transmission pipeline facility for the purpose of reporting is the total U.S. mileage of natural gas transmission pipelines owned or operated by an onshore natural gas transmission pipeline owner or operator. If an owner or operator has multiple pipelines in the United States, the facility is considered the aggregate of those pipelines, even if they are not interconnected.

- **LNG storage** means onshore LNG storage vessels located above ground, equipment for liquefying natural gas, compressors to capture and re-liquefy boil-off-gas, re-condensers, and vaporization units for re-gasification of the liquefied natural gas. An LNG storage facility for the purposes of reporting is any physical property, plant, building, structure, source, or stationary equipment in the LNG storage industry segment located on one or more contiguous or adjacent properties in actual physical contact or separated solely by a public roadway or other public right-of-way and under common ownership or common control, that emits or may emit any greenhouse gas.

For facilities that do not report to Subpart W (only), a natural gas transmission compression facility or underground natural gas storage facility for the purposes of reporting consists of an aggregation at the "Transmission Pipeline Company" level of the facilities described in the previous paragraph.

Transmission & Storage Segment Emissions

Under NGSI, companies will aggregate emissions from all facilities within the segment to estimate total company-level emissions from sources in the segment. Emission sources included in the calculation are listed in Table 12 and Table 13. Table 12 lists sources that are estimated using the GHGRP quantification method. Table 13 lists sources that are estimated using emission factors utilized by EPA in the GHG Inventory.

Table 12. Transmission & Storage Segment Emissions Calculated Using GHGRP Methodology

Emission Source	GHGRP Reference(s)	Description of Quantification Method(s)
Blowdowns, Transmission Pipeline (Between Compressor Stations)	40 CFR 98.233(i)(2)	Subpart W – Calculation method using the volume of transmission pipeline segment between isolation valves and the pressure and temperature of the gas within the transmission pipeline
	40 CFR 98.233(i)(3)	Subpart W – Calculation method using direct measurement of emissions using a flow meter
		Alternate calculation method using actual event counts multiplied by the average emission factor as calculated from all company-specific Subpart W facility events (for facilities not reporting to Subpart W only)
Blowdown Vent Stacks	40 CFR 98.233(i)(2)	Subpart W – Calculation method using engineering calculation method by equipment or event type
	40 CFR 98.233(i)(3)	Subpart W – Calculation method using direct measurement of emissions using a flow meter
		Alternate calculation method using actual event counts multiplied by the average unique physical volumes as calculated from all company-specific Subpart W facility events (for facilities not reporting to Subpart W only)
Combustion Units	40 CFR 98.33(c)	Subpart C methods, as applicable based on fuel type – Calculation using fuel usage as recorded or measured, fuel high heating value (HHV) default value or as calculated from measurements, and fuel-specific emission factors
		Alternate calculation method using total volume of fuel consumed and the fuel-specific emission factors for methane (for facilities not reporting to Subpart C only)

Emission Source	GHGRP Reference(s)	Description of Quantification Method(s)
Compressors, Centrifugal	40 CFR 98.233(o)(1)(i) 40 CFR 98.233(o)(6) 40 CFR 98.233(o)(1)(ii) 40 CFR 98.233(o)(1)(iii)	Subpart W – Individual compressor source "as found" measurements • Operating mode: blowdown valve leakage • Operating mode: wet seal oil degassing vent • Not-operating-depressurized mode: isolation valve leakage Subpart W – Reporter-specific emission factor for mode-source combinations not measured in the reporting year Subpart W – Continuous monitoring Subpart W – Manifolded "as found" measurements Alternate calculation method using average company emission factor based on all company-specific Subpart W centrifugal compressor measurements (for facilities not reporting to Subpart W only)
Compressors, Reciprocating	40 CFR 98.233(p)(1)(i) 40 CFR 98.233(p)(6) 40 CFR 98.233(p)(1)(ii) 40 CFR 98.233(p)(1)(iii)	Subpart W – Individual compressor source "as found" measurements • Operating mode: blowdown valve leakage and rod packing emissions • Standby-pressurized mode: blowdown valve leakage • Not-operating-depressurized mode: isolation valve leakage Subpart W – Reporter-specific emission factor for mode-source combinations not measured in the reporting year Subpart W – Continuous monitoring Subpart W – Manifolded "as found" measurements Alternate calculation method using average company emission factor based on all company-specific Subpart W centrifugal compressor measurements (for facilities not reporting to Subpart W only)
Equipment Leaks	Per Greenhouse Gas Reporting Rule Leak Detection Methodology Revisions	Subpart W – Leak survey and default leaker emission factors for compressor and non-compressor components in gas service Subpart W Methodology for Storage – Leak survey and default leaker emission factors for storage station components in gas service and storage wellhead components in gas service, and population counts and default population emission factors Subpart W Methodology for LNG Storage – Leak survey and default leaker emission factors for LNG storage components in LNG service and gas service, and population counts and default population emission factors for vapor recovery compressors in gas service Alternate calculation method using average company emission factor based on all company-specific Subpart W leak surveys (for facilities not reporting to Subpart W only)

Emission Source	GHGRP Reference(s)	Description of Quantification Method(s)
Flare Stacks	40 CFR 98.233(n)(5) 40 CFR 98.233(n)(6)	Subpart W – Calculation using measured or estimated flow and gas composition, and flare combustion efficiency; accounting for feed gas sent to an un-lit flare as applicable
Pneumatic Device (Controller) Vents), Natural Gas	40 CFR 98.233(a)	Subpart W – Calculation using count of devices and default emission factors.
Storage Tank Vents, Transmission Compression	40 CFR 98.233(k)	Subpart W – Calculation using measured flow data for leakage due to scrubber dump valve malfunction, gas composition, and estimated leakage duration; accounting for flare control as applicable Alternate calculation method using actual tank counts multiplied by an emission factor calculated from company-specific transmission storage tank vent data reported to Subpart W (for facilities not reporting to Subpart W only)

Table 13. Transmission & Storage Segment Emissions Calculated Using GHG Inventory Emission Factors

Emission Source	Description of Quantification Method	GHG Inventory Emission Factor
Compressors, Centrifugal with Dry Seals*	GHG Inventory emission factor multiplied by number of centrifugal compressors with dry seals	44,000 kg/compressor
	Number of centrifugal compressors multiplied by average company emission factor based on measurements from dry seals (measurements are to be taken using Subpart W measurement methods for wet seals)	NA
Dehydrator Vents	GHG Inventory emission factor multiplied by volume of gas dehydrated	1.8 kg/MMscf (Transmission) 2.3 kg/MMscf (Storage)
	Alternate calculation method using Subpart W Calculation Method 1 for Transmission Compression and Storage facilities that elect to use computer modeling	NA
Equipment Leaks, Transmission Pipelines	GHG Inventory emission factor multiplied by miles of pipeline	10.9 kg/mile
Station Venting, Natural Gas Storage and LNG Storage	GHG Inventory emission factor multiplied by number of stations	83,954.3 kg/station

Note: GHG Inventory emission factors are published in Annex 3.6 of the 2020 GHG Inventory, available at: https://www.epa.gov/sites/production/files/2020-02/2020_ghgi_natural_gas_systems_annex36_tables.xlsx

*In the transmission & storage segment, GHGRP captures emissions from blowdown and isolation valves at all types of centrifugal compressors. However, it only captures emissions from seals at compressors with wet seals. Emissions from seals at dry seal compressors are therefore estimated using the GHG Inventory methodology.

Transmission & Storage Segment Throughput

For companies with transmission and storage operations, segment throughput is intended to reflect volumes of gas handled. NGSI recognizes that companies in the transmission & storage segment continue to work to improve the approach to estimating transmission throughput at the company level; NGSI will work with stakeholders to incorporate advancements in this area in future versions of the protocol. For Version 1.0, segment throughput is natural gas volume transported in transmission pipelines as reported on PHMSA Form F 7100.2-1 Part C (Volume Transported in Transmission Pipelines (Only) in Million Standard Cubic Feet per Year (MMscf)) of the Annual Report for Natural Gas and Other Gas Transmission and Gathering Pipeline Systems to the U.S. Department of Transportation Pipeline and Hazardous Materials Safety Administration as required by required by 49 CFR Part 191.

Transmission & Storage Segment Methane Emissions Intensity

To convert transmission and storage segment throughput to methane, the reporting company will have to make an assumption about the methane content of transported natural gas. The reporting company can use and disclose its own estimate of the methane content of natural gas or can use a default factor of 93.4 percent.

To calculate transmission and storage segment intensity, the emissions and throughput estimates must be converted to like units of methane. This can be on a mass basis or a volumetric basis. Companies reporting methane emissions intensity should use a methane density (at standard temperature and pressure) of 0.0192 metric tons per thousand cubic feet, consistent with the methane density used by EPA in the GHGRP (40 CFR 98.233(v)).

For example, where methane emissions are reported in metric tons and natural gas throughput is reported in thousand cubic feet, a company could calculate its methane emissions intensity (%) as:

$$Methane\ Emissions\ Intensity = \frac{Methane\ Emissions}{Natural\ Gas\ Throughput * Methane\ Content * \frac{0.0192\ metric\ tons}{thousand\ cubic\ feet}}$$

Alternatively, a company could calculate its methane emissions intensity as:

$$Methane\ Emissions\ Intensity = \frac{Methane\ Emissions * \frac{thousand\ cubic\ feet}{0.0192\ metric\ tons}}{Natural\ Gas\ Throughput * Methane\ Content}$$

Transmission & Storage Segment Reported Data

Companies with natural gas transmission & storage operations following the NGSI protocol are encouraged to publicly report the information described in Table 14. Information should be reported at the company level; companies may also find it useful to report certain elements at the facility level.

Table 14. NGSI Disclosure Elements for a Company with Natural Gas Transmission & Storage Operations

Disclosure Element	Description
Total Methane Emissions (metric tons)	Total transmission & storage segment methane emissions from GHGRP and non GHGRP facilities; sum of emissions from the sources listed in Tables 12 and 13
Natural Gas Transported (thousand standard cubic feet)	Total volume of natural gas throughput from GHGRP facilities and non GHGRP facilities

Methane Content of Transported Natural Gas (%)	Methane content of transported natural gas (weighted average methane content of all throughput)
NGSI Methane Emissions Intensity (%)	Methane emissions intensity associated with transmission and storage

7. Protocol for the Distribution Segment

For NGSI reporting purposes, the distribution segment definition is consistent with the definitions EPA established for the Methane Challenge Program:

> **Natural gas distribution** means the distribution pipelines and metering and regulating equipment at 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 is operated as an independent municipally-owned distribution system. This segment also excludes customer meters and regulators, infrastructure, and pipelines (both interstate and intrastate) delivering natural gas directly to major industrial users and farm taps upstream of the local distribution company inlet.
>
> A natural gas distribution facility for the purposes of reporting under [NGSI] is the collection of all distribution pipelines and metering-regulating stations that are operated by an 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.

Distribution Segment Emissions

Under NGSI, companies will aggregate emissions from all facilities within the segment to estimate total company-level emissions from sources in the segment. Emission sources included in the calculation are listed in Table 15 and Table 16. Table 15 lists sources that are estimated using the GHGRP quantification method. Table 16 lists sources that are estimated using emission factors utilized by EPA in the GHG Inventory.

The GHGRP and GHG Inventory use significantly different emission factors for distribution mains and services. EPA updated the GHG Inventory emission factors in 2016 using data from recent research. In the GHGRP, which can only be updated through a rulemaking process, EPA continues to use emission factors developed from measurements taken in the early 1990s. While natural gas utilities use the older emission factors for GHGRP reporting, the updated emission factors have been used by some companies to estimate emissions for internal inventories, for state regulatory requirements, and under voluntary initiatives such as ONE Future. EPA is expected to initiate a rulemaking process to update the distribution pipeline emission factors, as well as other aspects of the GHGRP, in the future. Recognizing the potential for updates and the significant impact each approach has on total distribution segment methane intensity, Version 1.0 of the NGSI protocol includes both approaches. Note that these approaches only apply to main and service materials reported under GHGRP.[5] Emissions from main and service materials not included in GHGRP reporting use surrogate emission factors from the GHG Inventory.

Table 16 lists the GHG Inventory emission factors for distribution pipelines. All distribution main and service activity factors (i.e., mileage and counts) should use data reported to PHMSA. Use of PHMSA data ensures inclusion of main and service materials that are not captured in GHGRP reporting. NGSI applies surrogate emission factors from the GHG Inventory to these sources.

---

[5] The GHGRP and GHG Inventory emission factors are applied to the eight types of pipeline covered by GHGRP: cast iron mains, unprotected steel mains, protected steel mains, plastic mains, unprotected steel services, protected steel services, plastic services, and copper services.

Table 15. Distribution Segment Emissions Calculated Using GHGRP Methodology

Emission Source	GHGRP Reference(s)	Description of Quantification Method(s)
Combustion Units	40 CFR 98.233(z)(1) 40 CFR 98.233(z)(2)	Subpart W, as applicable based on fuel type – Calculation using fuel usage records and measured or estimated composition
Distribution Mains	40 CFR 98.233(r)	Subpart W – Equipment leaks calculated using population counts and emission factors • Cast Iron Mains • Plastic Mains • Protected Steel Mains • Unprotected Steel Mains
Distribution Services	40 CFR 98.233(r)	Subpart W – Equipment leaks calculated using population counts and emission factors • Copper services • Plastic services • Protected steel services • Unprotected steel services
Equipment Leaks, Above Grade Transmission-distribution Transfer Stations	40 CFR 98.233(q)(8)(ii) 40 CFR 98.233(r)(2)(ii) 40 CFR 98.236(q)(3)	Subpart W – Develop an emission factor based on equipment leak surveys; calculate emissions using population counts and emission factors
Equipment Leaks, Below Grade Transmission-distribution Transfer Stations	40 CFR 98.233(r)(6)(i) 40 CFR 98.232(i)(2)	Subpart W – Calculation of emissions using population counts and emission factors
Equipment Leaks, Above Grade Metering-Regulating Stations	40 CFR 98.233(r)(6)(ii) 40 CFR 98.232(i)(3)	Subpart W – Calculation of emissions using population counts and emission factors
Equipment Leaks, Below Grade Metering-regulating Stations	40 CFR 98.233(r)(6)(i) 40 CFR 98.232(i)(4)	Subpart W – Calculation of emissions using population counts and emission factors

Table 16. Distribution Segment Emissions Calculated Using GHG Inventory Emission Factors

Emission Source	Description of Quantification Method	GHG Inventory Emission Factor
Distribution Mains, Cast Iron	GHG Inventory emission factor multiplied by miles of pipeline	1,157.26 kg/mile
Distribution Mains, Unprotected Steel	GHG Inventory emission factor multiplied by miles of pipeline	861.32 kg/mile
Distribution Mains, Protected Steel	GHG Inventory emission factor multiplied by miles of pipeline	96.74 kg/mile

Emission Source	Description of Quantification Method	GHG Inventory Emission Factor
Distribution Mains, Plastic	GHG Inventory emission factor multiplied by miles of pipeline	28.84 kg/mile
Distribution Mains, Plastic Liners or Inserts*	GHG Inventory emission factor multiplied by number of services (uses plastic main EF)	28.84 kg/mile
Distribution Mains, Copper*	GHG Inventory emission factor multiplied by number of services (uses cast iron main EF)	1,157.26 kg/mile
Distribution Mains, Ductile Iron*	GHG Inventory emission factor multiplied by number of services (uses cast iron main EF)	1,157.26 kg/mile
Distribution Mains, Other*	GHG Inventory emission factor multiplied by number of services (uses unprotected steel main EF)	861.32 kg/mile
Distribution Services, unprotected steel	GHG Inventory emission factor multiplied by number of services	14.48 kg/service
Distribution Services, protected steel	GHG Inventory emission factor multiplied by number of services	1.29 kg/service
Distribution Services, plastic	GHG Inventory emission factor multiplied by number of services	0.26 kg/service
Distribution Services, copper	GHG Inventory emission factor multiplied by number of services	4.89 kg/service
Distribution Services, plastic liners or inserts*	GHG Inventory emission factor multiplied by number of services (uses plastic service EF)	0.26 kg/service
Distribution Services, cast iron*	GHG Inventory emission factor multiplied by number of services (uses unprotected steel service EF)	14.48 kg/service
Distribution Services, ductile iron*	GHG Inventory emission factor multiplied by number of services (uses unprotected steel service EF)	14.48 kg/service
Distribution Services, other*	GHG Inventory emission factor multiplied by number of services (uses unprotected steel service EF)	14.48 kg/service
Blowdowns, Distribution pipeline	GHG Inventory emission factor multiplied by miles of pipeline (mains and service) Companies should use the average service length reported annually to PHMSA to convert services counts to services mileage. If an average service length is not available, companies should use PHMSA's default length of 90 feet/service.	1.965 kg/mile
Damages (Distribution Upsets: Mishaps)	GHG Inventory emission factor multiplied by miles of pipeline (mains and service) Companies should use the average service length reported annually to PHMSA to convert services counts to services mileage. If an average service length is not available, companies should use PHMSA's default length of 90 feet/service.	30.6 kg/mile
Meters, Outdoor Residential**	GHG Inventory emission factor multiplied by number of meters. Number of outdoor meters calculated by multiplying total residential meters	1.5 kg/outdoor meter

Emission Source	Description of Quantification Method	GHG Inventory Emission Factor
	by region-specific outdoor meter ratio, as per GHG Inventory	
Meters, Commercial and Industrial	GHG Inventory emission factor multiplied by number of meters	9.7 kg/meter
Pressure Relief Valves, Routine Maintenance	GHG Inventory emission factor multiplied by miles of main	0.963 kg/mile

Note: GHG Inventory emission factors are published in Annex 3.6 of the 2020 GHG Inventory, available at: https://www.epa.gov/sites/production/files/2020-02/2020_ghgi_natural_gas_systems_annex36_tables.xlsx

*Pipeline main and service materials not included in the GHGRP and GHG Inventory are given surrogate GHG Inventory emission factors from other materials.

**Region-specific outdoor meter ratios are available in Table 12 of EPA's document describing changes to the 2016 GHG Inventory. Available at: https://www.epa.gov/sites/production/files/2016-08/documents/final_revision_ng_distribution_emissions_2016-04-14.pdf

Distribution Segment Throughput

For companies with distribution operations, segment throughput is estimated two ways:

1. The total volume of natural gas delivered to end users by the distribution company on a throughput basis as reported to EIA for Form 176.
2. The volume of natural gas delivered to end users as reported to EIA for Form 176, with adjustments to normalize the volumes of gas delivered to residential and commercial customers.

The second method follows a normalization approach developed by ONE Future to estimate throughput for companies in the distribution segment. Under this approach, ONE Future uses state-specific Heating Degree Day (HDD) values to normalize the volumes of gas delivered to residential and commercial customers across all states for the specific reporting year. ONE Future uses HDD values that are population-weighted by state and are published by the National Oceanic and Atmospheric Administration (NOAA) Climate Prediction Center (CPC). Companies can download HDD for states in which they operate from NOAA. NOAA reports cumulative annual data from July 1 to June 30, not January 1 to December 31. To identify the appropriate HDD data, companies will download the monthly data for June of the year of interest.[6] For example, for reporting year 2020, companies would download the HDD data for June 2020, representing cumulative data from July 1, 2019 to June 30, 2020.

Under the Version 1.0 of the NGSI protocol, companies will report throughput as reported to EIA and on a normalized basis using the following methodology:

1. Identify the average HDD value for the states in which the company operates (*State HDD*) and the average HDD value for the United States (*US HDD*) for the reporting year.
2. Calculate the normalization factor for each state as the *US HDD* value divided by the *State HDD* value, or $\frac{US\ HDD}{State\ HDD}$.

[6] Population-weighted state HDD data are available for download from NOAA CPC at: ftp://ftp.cpc.ncep.noaa.gov/htdocs/products/analysis_monitoring/cdus/degree_days/archives/Heating%20degree%20Days/monthly%20states/

3. For each state in which the company operates, calculate an adjusted throughput for natural gas delivered to residential and commercial customers, as reported to EIA in Form 176, as the normalization factor multiplied by the volume of natural gas delivered to residential customers (V_{Res}) plus the volume of natural gas delivered to commercial customers (V_{Comm}).

4. For each state in which the company operates, add the volume of natural gas delivered to other customers to the normalized volume for residential and commercial customers. This can be calculated as the total volume (V_{Total}) minus the residential and commercial volumes.

This methodology can be written as:

$$Normalized\ V_{State} = (V_{Res} + V_{Comm}) \times \frac{US\ HDD}{State\ HDD} + V_{Total} - (V_{Res} + V_{Comm})$$

After calculating the normalized volume for each state, the normalized natural gas throughput for the purposes of calculating a company's methane emissions intensity is calculated as the sum of the normalized throughput for each state.

Distribution Segment Methane Emissions Intensity

To convert distribution segment throughput to methane, the reporting company will have to make an assumption about the methane content of distributed natural gas. The reporting company can use and disclose its own estimate of the methane content of natural gas or can use a default factor of 93.4 percent.

To calculate distribution segment intensity, the emissions and throughput estimates must be converted to like units of methane. This can be on a mass basis or a volumetric basis. Companies reporting methane emissions intensity should use a methane density (at standard temperature and pressure) of 0.0192 metric tons per thousand cubic feet, consistent with the methane density used by EPA in the GHGRP (40 CFR 98.233(v)).

For example, where methane emissions are reported in metric tons and natural gas throughput is reported in thousand cubic feet, a company could calculate its methane emissions intensity as:

$$Methane\ Emissions\ Intensity = \frac{Methane\ Emissions}{Natural\ Gas\ Throughput * Methane\ Content * \frac{0.0192\ metric\ tons}{thousand\ cubic\ feet}}$$

Alternatively, a company could calculate its methane emissions intensity as:

$$Methane\ Emissions\ Intensity = \frac{Methane\ Emissions * \frac{thousand\ cubic\ feet}{0.0192\ metric\ tons}}{Natural\ Gas\ Throughput * Methane\ Content}$$

Distribution Segment Reported Data

Companies with natural gas distribution operations following the NGSI protocol should publicly report the information described in Table 17. Information should be reported at the company level; companies may also find it useful to report certain elements at the facility level.

Table 17. NGSI Disclosure Elements for a Company with Natural Gas Distribution Operations

Disclosure Element	Description
Total Methane Emissions (metric tons, GHGRP Pipeline Emission Factors)	Total distribution segment methane emissions from GHGRP and non GHGRP facilities (specific main and service material emissions calculated using GHGRP emission factors)
Total Methane Emissions (metric tons, GHG Inventory Pipeline Emission Factors)	Total distribution segment methane emissions from GHGRP and non GHGRP facilities (specific main and service material emissions calculated using GHG Inventory emission factors)
Natural Gas Delivered to End Users, As Reported (thousand standard cubic feet)	Total volume of natural gas delivered to end users from GHGRP facilities and non GHGRP facilities, as reported
Natural Gas Delivered to End Users, Normalized (thousand standard cubic feet)	Total volume of natural gas delivered to end users from GHGRP facilities and non GHGRP facilities, normalized
Methane Content of Delivered Natural Gas (%)*	Methane content of delivered natural gas (weighted average methane content of all throughput)
NGSI Methane Emissions Intensity (%, GHGRP Pipeline Emission Factors)	Methane emissions intensity associated with natural gas distribution using reported throughput and GHGRP emission factors for specific main and service materials
Normalized NGSI Methane Emissions Intensity, (%, GHGRP Pipeline Emission Factors)	Methane emissions intensity associated with natural gas distribution using normalized throughput and GHGRP emission factors for specific main and service materials
NGSI Methane Emissions Intensity (%, GHG Inventory Pipeline Emission Factors)	Methane emissions intensity associated with natural gas distribution using reported throughput and GHG Inventory emission factors for specific main and service materials
Normalized NGSI Methane Emissions Intensity (%, GHG Inventory Pipeline Emission Factors)	Methane emissions intensity associated with natural gas distribution using normalized throughput and GHG Inventory emission factors for specific main and service materials

*Companies with different average methane contents at different facilities may have slightly different company-wide average methane contents for reported throughput and normalized throughput. This difference may be small enough such that companies may report a single company-wide average methane content rather than one for reported throughput and one for normalized throughput. However, if a company has different methane contents across facilities, the company should apply separate methane contents to determine the denominator of the intensity formula, The NGSI distribution segment template automatically performs this calculation.

Appendix A: Additional Emission Sources Identified by Commentors

During the review process, commentors identified methane emission sources that are not included in the NGSI protocol. NGSI will review these sources and identify potential additions to future versions of the protocol.

Table A1. Potential Emissions Sources to Include in Future Versions of the NGSI Protocol

Segment	Potential Future Source
Production	• Casing bleed and venting • Catalytic heaters • Gas starters for turbine and reciprocating engine drivers • Produced water • Small combustion sources (<130 horsepower) • Small heaters (<5 MMBtu/hour) • Truck loading
Gathering & Boosting	• Engine rod packing vents in stand-by pressurized mode • Gas starters for turbine and reciprocating engine drivers • Small blowdowns (pigging related) • Small combustion sources (<130 horsepower) • Small engines (<5 MMBtu/hour) • Truck loading
Processing	• Pneumatic pumps • Reciprocating compressors in pressurized standby mode • Small combustion sources (<5 MMBtu/hour) • Tanks, uncontrolled condensate or oil
Transmission & Storage	• Blowdowns at underground natural gas storage facilities • Catalytic heaters • Dry seals and wet seals in pressurized standby • Engine crankcase venting • Engine rod packing vents in stand-by pressurized mode • Gas driven pneumatic pumps at underground storage wells • Gas purging of equipment and piping inside compressor stations and pipelines along right of way • Gas starters for turbine and reciprocating engine drivers (that are not included as part of blowdowns within compressor stations) • Metering stations (along the transmission pipelines or inside compressor stations) • Odorizers • Reciprocating compressors in pressurized standby mode • Storage tank vents at storage stations • Storage well venting
Distribution	• Catalytic heaters • CNG stations • Odorizers • Small combustion sources (<130 horsepower) • Small engines (<5 MMBtu/hour)

Appendix B: Resources

In the course of developing these recommendations, NGSI has worked to leverage a wide range of existing sources, including those listed here.

Alvarez, Ramon et. al. “Assessment of methane emissions from the U.S. oil and gas supply chain.” Science Magazine, Vol. 361, Issue 6398, pp. 186-188. July 13, 2018. Available at: http://science.sciencemag.org/content/361/6398/186.full?ijkey=42lcrJ/vdyyZA&keytype=ref&siteid=sci

American Gas Association. “AGA Voluntary Sustainability Metrics: Quantitative Information - October 2018 Version.” Available at https://www.aga.org/globalassets/policy/aga-esg-gas-quantitative-metrics-template-oct-2018-version.xlsx and on the EEI ESG/Sustainability webpage at http://www.eei.org/issuesandpolicy/finance/Pages/ESG-Sustainability.aspx

BP. “Tackling Methane.” Available at https://www.bp.com/en/global/corporate/sustainability/climate-change/tackling-methane.html

CDP. “CDP Climate Change 2019 Reporting Guidance.” Available at https://guidance.cdp.net/en/guidance?cid=8&ctype=theme&idtype=ThemeID&incchild=1&microsite=0&otype=Guidance&tags=TAG-585,TAG-605,TAG-599

ConocoPhillips. “Greenhouse Gas Emissions Intensity Target.” Available at: http://www.conocophillips.com/environment/climate-change/climate-change-strategy/greenhouse-gas-emissions-intensity-target/

ConocoPhillips. “Sustainability Report 2017.” Available at: http://static.conocophillips.com/files/resources/17sr.htm#1

Disclosing the Facts. “Disclosing the Facts: Transparency and Risk in Methane Emissions.” 2017. Available at: http://go.asyousow.org/DisclosingTheFacts_2017. Scorecard available at http://disclosingthefacts.org/2017/

Dominion Energy. “Sustainability Metrics.” Available at: https://sustainability.dominionenergy.com/metrics/

Dominion Energy. “Methane Management Report 2017.” Revised May 3, 2018. Available at: https://www.dominionenergy.com/library/domcom/media/community/environment/reports-performance/methane-management-report-2017.pdf?la=en

DTE Energy. “2018 DTE Methane Report.” Available at: https://empoweringmichigan.com/dte-impact/performance/

Edison Electric Institute (EEI) and American Gas Association (AGA). “ESG/Sustainability Template – Version 2.” August 2019. Available at: https://www.eei.org/issuesandpolicy/Pages/FinanceAndTax-ESG.aspx

Environmental Defense Fund. “Taking Aim: Hitting the mark on oil and gas methane targets.” April 2018. Available at: https://www.edf.org/sites/default/files/documents/EDF_TakingAim.pdf

Environmental Defense Fund. “Setting the Bar on Methane Disclosure.” October 2018. Available at: https://www.edf.org/energy/setting-bar-methane-disclosure

Environmental Defense Fund. "The Disclosure Divide." February 2018. Available at: https://www.edf.org/energy/methane-companies-split-methane-disclosure

ExxonMobil. "Performance Data Table." Available at: https://corporate.exxonmobil.com/en/community-engagement/sustainability-report/performance-data-table

Heath, Garvin. "Basin Methane Reconciliation Study overview of results." National Renewable Energy Laboratory. October 2018. Available at: https://energy.colostate.edu/media/sites/147/2018/10/BasinMethaneOverview.pdf

IPIECA. "Oil and gas industry guidance on voluntary sustainability reporting (3rd edition)." Available at: http://www.ipieca.org/resources/good-practice/oil-and-gas-industry-guidance-on-voluntary-sustainability-reporting-3rd-edition/

Oil & Gas Climate Initiative. "At Work: Committed to Climate Action." September 2018. Available at: https://oilandgasclimateinitiative.com/wp-content/uploads/2018/09/OGCI_Report_2018.pdf

Oil & Gas Climate Initiative. "Oil & Gas Climate Initiative Reporting Framework Version 3.3." October 2020. Available at: https://vklb72qn0p747zkmy18w0m8g-wpengine.netdna-ssl.com/wp-content/uploads/2020/10/OGCI-Reporting-Framework-3.3-October-2020.pdf

ONE Future. "Methane Emissions Estimation Protocol." August 3, 2020. Available at: https://onefuture.us/wp-content/uploads/2020/09/ONE-Future-Methane-Intensity-Protocol_V3_3Aug2020.pdf

Royal Dutch Shell. "Shell announces methane emissions intensity target for oil and gas assets." September 17, 2018. Available at: https://www.shell.com/media/news-and-media-releases/2018/shell-announces-methane-emissions-intensity-target.html

Vaughn TL, et al. "Temporal Variability Largely Explains Difference in Top-down and Bottom-up Estimates of Methane Emissions from a Natural Gas Production Region." *Proc Natl Acad Sci*. November 13. 2018. Available at: https://www.pnas.org/content/115/46/11712.

U.S. Environmental Protection Agency. "Greenhouse Gas Reporting Program Subpart W – Petroleum and Natural Gas Systems." Available at: https://www.epa.gov/ghgreporting/subpart-w-petroleum-and-natural-gas-systems

U.S. Environmental Protection Agency, "Natural Gas STAR Methane Challenge Program: ONE Future Commitment Option Technical Document." March 15, 2019. Available at: https://www.epa.gov/sites/production/files/2016-08/documents/methanechallenge_one_future_supp_tech_info.pdf

U.S. Environmental Protection Agency. "Inventory of U.S. Greenhouse Gas Emissions and Sinks: 1990-2018." April 13, 2020. Available at: https://www.epa.gov/sites/production/files/2020-04/documents/us-ghg-inventory-2020-main-text.pdf

Waters, Saphina. "Methodological note for OGCI methane intensity target and ambition." September 24, 2018. Available at: https://info.oilandgasclimateinitiative.com/blog/methodological-note-for-ogci-methane-intensity-target-and-ambition