# NGSI Methane Emissions Intensity Protocol

*Version 2.0*

*Natural Gas Sustainability Initiative*

*Edison Electric Institute (EEI) and American Gas Association (AGA)*

Version 2.0 | September 2024

## Contents



# Acknowledgments


The Natural Gas Sustainability Initiative (NGSI) was initiated by a CEO task force organized by the Edison Electric Institute (EEI) and the American Gas Association (AGA). Version 1.0 of the NGSI Protocol was developed by M.J. Bradley & Associates (MJB&A), an ERM Group company, on behalf of EEI and AGA. SLR International Corporation was hired by EEI and AGA to review and update the Protocol to produce this Version 2.0 of the NGSI Protocol.


## About SLR International Corporation

SLR International Corporation is a global firm at the forefront of providing technical and professional services to the energy sector around the world. We support natural gas companies across the value chain and have globally recognized expertise in greenhouse gases (GHG) and methane emissions from the energy sector.

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# Version History

| Date | Description |
|---|---|
| February 2021 | Issuance of NGSI Protocol Version 1.0, prepared by M.J. Bradley & Associates, an ERM Group |
| September 2024 | Issuance of NGSI Protocol Version 2.0, prepared by SLR International Corporation |

# Executive Summary

The Natural Gas Sustainability Initiative (NGSI) is a voluntary, industry-led initiative to advance innovative efforts to address environmental, social and governance (ESG) issues throughout the natural gas value chain in the United States. Version 2.0 of the NGSI Protocol details a methodology for companies to consistently calculate and report methane emissions intensity (also called "methane intensity"). The Protocol is intended to support voluntary reporting by companies operating within the natural gas value chain in the United States, from onshore production through distribution.

NGSI was launched in 2018 by a CEO task force on natural gas issues convened by the Edison Electric Institute (EEI) and the American Gas Association (AGA). NGSI works to advance a voluntary, industry-wide approach for companies to report their methane intensity by the segments of the natural gas value 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 value chain.

Methane 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 intensity. While intensity is becoming a preferred approach for communicating methane emissions data throughout the industry, currently there is no single, universally accepted standard methodology for calculating it or for comparing methane intensity across different segments of the natural gas value chain. 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 value chain to respond to requests for a metric that provides comparable points of reference between companies. Using the NGSI Protocol, companies calculate and report methane 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 Methane Intensity Metric |
|---|---|
| • **Onshore Production**<br>• **Gathering & Boosting**<br>• **Processing**<br>• **Transmission & Storage**<br>• **Distribution** | $\frac{Methane\ Emissions\ from\ Natural\ Gas}{Methane\ Content\ of\ Natural\ Gas\ Throughput}$ |

This Protocol builds on existing industry approaches to calculate methane 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 the methodologies for incorporating them into inventories advance, NGSI will identify opportunities to update the Protocol accordingly.

Version 2.0 of the Protocol incorporates a number of updates to Version 1.0 (released in April 2021) to maintain consistency with EPA methodologies and other industry standardized methodologies that are now being used for other reporting programs. Version 2.0 remains aligned with the version of EPA's Greenhouse

Gas Reporting Program (GHGRP) Subpart W regulations that were in effect as of January 1, 2024. NGSI Protocol Version 2.0 does not incorporate the revisions to Subpart W that were finalized and published in the *Federal Register* in May 2024. Most of these revisions become effective on January 1, 2025, and certain calculation provisions became effective on July 15, 2024. This earlier effective date encompasses certain optional calculation provisions that allow reporters to submit empirical data for some emission sources starting with reporting year (RY) 2024 emissions. After January 1, 2025, some of these optional calculation provisions will become mandatory and will apply to the RY 2025 emissions that must be reported to EPA by the reporting deadline of March 31, 2026. Version 2.0 also does not incorporate the GHGRP revisions to subparts other than Subpart W, which were finalized and published in the *Federal Register* in April 2024 and begin to take effect on January 1, 2025, beginning with RY 2024 emissions. These final GHGRP revisions will be incorporated into a subsequent update to the NGSI Protocol and its accompanying reporting templates.

# 1. Background

The Natural Gas Sustainability Initiative is a voluntary, industry-led initiative to advance efforts to address ESG issues throughout the natural gas value 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, rating agencies, and government regulators.

The natural gas industry has made significant progress in gathering and sharing data about the environmental and social impacts of the value chain. Nonetheless, NGSI believes a more coordinated and standardized effort—including voluntary reporting, benchmarking of continuous improvement, and expanded use of direct measurement technologies—is needed to show that the entire value chain manages natural gas in an increasingly safe, environmentally sound, and secure manner.

NGSI's agenda for helping advance natural gas value chain ESG efforts has been shaped by input gained through a robust stakeholder-engagement process. During the development of Version 1.0 of the Protocol, NGSI 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, near-term agenda, and the methane intensity methodology outlined in this Protocol. The development of Version 2.0 of the NGSI Protocol was similarly informed by feedback from industry stakeholders.

### Natural Gas Sustainability Initiative

NGSI is an overarching framework to recognize and advance innovative, voluntary methane-management programs across the natural gas value chain.

NGSI was launched by a CEO task force on natural gas issues, organized by EEI and AGA. M.J. Bradley & Associates (MJB&A), an ERM Group company, helped facilitate the development of Version 1.0 of the NGSI Protocol. SLR International Corporation supported EEI and AGA with this Version 2.0 of the NGSI Protocol.

## NGSI Guiding Principles

NGSI is guided by the following principles:

- 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 participants are committed to continuous improvement to respond to customer and stakeholder expectations for managing environmental and social issues along the natural gas value chain.
- 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 by providing 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 Intensity?

NGSI is currently focused on methane emissions from the U.S. onshore natural gas value 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 value chain affects 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 voluntary efforts to reduce methane emissions is the absence of a universally adopted common metric for measuring and reporting methane intensity. While methane intensity is a widely used metric 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 intensity at the company level within each segment of the natural gas value chain. NGSI is available for public use, free of charge, by any company in the natural gas industry—it is not reserved solely for members of EEI and/or AGA.

Methane intensity is a measure of natural-gas-related methane emissions relative to natural gas throughput in the natural gas system. Intensity has become 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 may minimize some 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 offers a clear and consistent approach to using methane emissions and natural gas throughput data to calculate methane intensity. The availability of common, well-documented metrics will improve the quality of information available from the industry for use by investors and stakeholders while helping companies throughout the natural gas value chain more effectively track the impact of programs to reduce methane emissions and communicate their progress.

## Potential Uses for NGSI Methane Intensity

In addition to providing a consistent approach to calculating and reporting methane intensity at the segment level 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 intensity for operations in a specific production basin. A company could also use this Protocol to calculate and report segment-level methane intensity at a regional or local level.

Many national-level fuel strategies, such as a shift from coal-fired electric power generation to natural gas-fired electric power generation, depend upon knowing the national emissions intensity of the entire fuel value chain. For natural gas, the methane intensity at that macro-scale has often been expressed as total methane emissions from the value chain divided by total methane in natural gas production. This value chain intensity from wellhead to end user can be expressed as a percentage or fraction of the produced methane that is emitted. However, that method of deriving value chain intensity has a denominator that is related only to natural gas production—which does not accurately reflect the methane intensities of other segments in the value chain. For other segments—such as transmission, storage, and distribution—the intensities are produced by dividing the methane emissions by facility throughput.

The throughput divisor for these other segments leaves a disparity in methane intensity basis because, in some segments, the same gas molecules can be handled by more than one company, meaning the aggregate national throughput for the segment does not equal the nationwide volume of gas produced. In some cases, particularly within the natural gas transmission segment, throughput can be reported numerous times as the same molecules of gas move from one company's transmission system to another company's transmission system—even though that gas was only reported once in the production segment during the same annual period.

Therefore, methane intensity is *not* directly additive across multiple segments. The sum across segments is not calculated as a direct sum of segment intensities. As discussed further in Appendix B, the ability to add methane intensity across multiple segments would require an additional normalization step that is not currently part of the NGSI Protocol but may be evaluated during future updates.

## Approach to Developing the Protocol

The following bullets summarize the substantive development and issuance of Version 1.0 of the NGSI Protocol and this Version 2.0 update:

- **April 2019:** NGSI released a white paper that summarized existing approaches to calculating and reporting methane 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 key resources reviewed).
- **July 2019:** NGSI developed and released an initial draft of the NGSI Methane Intensity Protocol.
- **December 2019:** The final draft NGSI Protocol was released. NGSI held a series of webinars for interested stakeholders and received comments from the industry and the environmental community on both the initial and final drafts.
- **May to August 2020**: NGSI worked with 11 companies throughout the natural gas value chain to pilot the Protocol.
- **February to July 2021:** Version 1.0 of the NGSI Protocol was completed and released on the EEI and AGA websites. During the pilot process, NGSI identified additional areas for clarification and updated the Protocol with a final version released in April 2021. In July 2021, NGSI issued updated templates for gathering and boosting, processing, and production to correct an inconsistency identified by participating pilot companies. No changes were needed for the distribution and transmission and storage templates.
- **May 2022 and April 2023**: NGSI released updates to the distribution template to reflect the most recently released full-year Heating Degree Day (HDD) data, allowing for more accurate throughput normalization by companies in the natural gas distribution segment.

- **February to September 2024:** Version 1.0 of the NGSI Protocol and its corresponding segment-specific reporting templates were revised to incorporate some updated methane emission factors and minor methodology changes to remain consistent with other standardized approaches for calculating methane intensity for the natural gas value chain. During this update process, there were opportunities for stakeholders to review and comment. The distribution template was also updated to reflect the most recent HDD data.

# 2. NGSI Protocol for Calculating Methane Intensity

The remaining sections of this document are organized by segment of the natural gas value chain and provide guidance on the emissions and throughput data used to calculate a company's methane intensity for each segment in which it operates. The Protocol establishes intensity metrics for specific segments of the value 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 intensity calculations.

The Protocol addresses five segments of the natural gas value chain:

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

The NGSI Protocol enables a useful, consistent, and accurate comparison of methane intensities **within the same natural gas industry segment with similar types of operations**. Due to the operational differences and complexity of normalizing the throughput denominator across the various natural gas industry segments, the scope of this Protocol does not include guidance or methodology that allows the summation of methane intensities across multiple industry segments.

## Key Elements of the NGSI Methane Intensity Protocol

- **Methodologies.** The NGSI Protocol's guidance for reporting emissions leverages existing reporting protocols developed by EPA. For emission sources that are currently reported to EPA as part of the GHGRP, NGSI uses the GHGRP calculation methodologies. The Protocol provides a reference to each of the applicable GHGRP regulatory provisions and a brief description of the calculation. The NGSI Protocol also includes emissions from certain sources that are not currently within the scope of GHGRP reporting,[1] but have been identified by EPA through the Inventory of U.S. Greenhouse Gas Emissions and Sinks (GHG Inventory) and adopted by the Our Nation's Energy (ONE) Future Coalition and EPA as part of the EPA Methane Challenge ONE Future Commitment Option.[2] For these non-GHGRP emission sources, NGSI has adopted the methodologies from the ONE Future Commitment Option, which uses emission factors from the GHG Inventory.

[1] As noted above, Version 2.0 of the NGSI Protocol remains aligned with the GHGRP regulations that were in effect as of January 1, 2024. The Subpart W revisions published in the *Federal Register* at 89 Fed. Reg. 42,062 (May 14, 2024), as well as the non-Subpart W revisions published in the *Federal Register* at 89 Fed. Reg. 31,802 (April 25, 2024), will be incorporated into a subsequent update to the NGSI Protocol and its accompanying reporting templates.

[2] In April 2024, EPA announced that it will sunset the Methane Challenge Program at the end of 2024 and pivot to collaboration opportunities via the Inflation Reduction Act Methane Emissions Reduction Program. See EPA, Methane Challenge Partnership (2016 – 2024) (last updated April 24, 2024), https://www.epa.gov/natural-gas-star-program/methane-challenge-partnership-2016-2024.

Version 2.0 of the NGSI Protocol adopts updated emission factors from the GHG Inventory that was published in 2023 and incorporates calendar year 2021 emissions (2023 GHGi).[3] The 2023 GHGi does not have segment-specific emission factors or updated emission factors for certain sources included in the NGSI Protocol. In these cases, NGSI uses emission factors that are either for the same source types from different segments or come from earlier versions of the GHG Inventory—as noted in the segment-specific tables below. Thus, except where noted otherwise, the GHG Inventory emission factors used in NGSI Protocol Version 2.0 are from the 2023 GHGi and are segment-specific factors.

- **Segment Definitions.** The NGSI Protocol uses 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.
- **Hydrocarbon Liquids.** Natural gas can be co-produced with heavier hydrocarbons (*i.e.*, associated gas), the emissions from which are independent from emissions associated with natural gas liquids (NGLs), crude oil, and other hydrocarbon liquids that are produced and handled in the onshore production, gathering and boosting, and processing segments. Natural gas transporters and purchasers (*e.g.*, natural gas transmission and storage companies, natural gas distribution companies or power companies using natural gas for electricity generation) are interested in understanding the full impact of emissions associated with onshore natural gas production, gathering, boosting, and processing. Accordingly, for upstream and midstream segments that produce and handle hydrocarbon liquids, NGSI includes a methodology for allocating those emissions to the natural gas value chain on an energy basis for the applicable emission sources.
- **Throughput.** The NGSI guidance on throughput values is segment specific. Distribution throughput values are based on information reported to the U.S. Energy Information Administration (EIA). Production, processing, and gathering and boosting throughput values are all based on information reported to via the GHGRP. For the transmission and storage segment, the facility-specific basis of GHGRP throughput reporting has the potential for counting the same throughput multiple times within a single pipeline. The counting of throughput multiple times for transmission pipelines can result in under-reporting methane intensity for this segment. Thus, the transmission and storage throughput values used in NGSI are based on information reported to the U.S. Pipeline and Hazardous Materials Safety Administration (PHMSA). Although this approach does not eliminate the possibility of double-counting throughput, the annual reporting of a company's pipeline-specific throughput to PHMSA reflects an accurate and verifiable source of total annual natural gas transported by individual transmission pipelines owned and operated by a company.

## Expectations for Company Reporting

Under the NGSI approach, companies calculate and report methane intensity based on total company emissions and throughput for each segment in which they operate. Within each segment, companies using the NGSI Protocol calculate total methane emissions from the sources included in the Protocol and divide by the methane content of the throughput to arrive at a methane intensity expressed as a percent of methane.

To streamline company reporting and facilitate consistent application of the Protocol, NGSI provides a detailed set of five templates, one for each of the covered segments. These reporting templates have been updated as

[3] Emission factors from the 2023 GHGi are published in Annex 3.6, available at: https://www.epa.gov/system/files/other-files/2023-04/2023_ghgi_natural_gas_systems_annex36_tables.xlsx.

part of Version 2.0 of the NGSI Protocol. The templates include data entry worksheets for a company's GHGRP facilities (*i.e.*, those that trigger reporting to GHGRP) and a company's Non-GHGRP facilities (*i.e.*, those that do not trigger reporting to GHGRP). Companies need to enter a combination of (1) GHGRP-reported methane emissions by facility and activity for GHGRP reportable emission source types, (2) methane emissions for Non-GHGRP facilities for GHGRP reportable emission source types using GHGRP-prescribed emission calculation methodologies, and (3) equipment-level data that is used to calculate methane emissions for the additional sources at GHGRP and Non-GHGRP facilities that use GHGi emission factors. In addition, companies need to enter annual natural gas production or throughput data that is used as the denominator in the methane intensity equation.

Each template is also pre-populated with emission sources, GHGRP and GHGi emission factors (as applicable), and equations that automatically calculate a company's total segment-level methane emissions and methane intensity for both GHGRP and Non-GHGRP facilities.

In general, the methane emission source types identified as reportable under the GHGRP, the templates use the GHGRP-prescribed emission calculation methodologies. For the methane emission source types not identified as reportable under the GHGRP, the templates use EPA's GHGi-specific emission calculation methodologies.

The exception is the emission factors used for the mains and services source type in the distribution segment. As described in more detail in Section 7 of the Protocol, the distribution segment includes methane emission calculations that allow for the use of two different sets of emission factors for the mains and services source type: (1) methane emissions based on GHGRP emission factors, and (2) methane emissions based on GHGi emission factors. This allows companies in the distribution segment the option to compare methane emissions and intensities based on these two different sets of emission factors.

The updated segment-specific reporting templates for use with Version 2.0 of the NGSI Protocol are available for download as Excel files from both of the websites specified below:

- EEI – Issues & Policy: Natural Gas Sustainability Initiative: https://www.eei.org/en/issues-and-policy/ngsi
- AGA – Natural Gas Sustainability Initiative (NGSI): https://www.aga.org/research-policy/natural-gas-esg-sustainability/natural-gas-sustainability-initiative-ngsi/

The text box on the next page highlights key updates that were made to all of the NGSI reporting template spreadsheets. While we highly encourage users of the NGSI templates to read through this entire Protocol, **it is imperative that all users review the instructions and recommendations in the "Key Updates" text box prior to inputting company data into any of the NGSI spreadsheets**.

## Key Updates to All NGSI Reporting Templates

- ***Locked Cells:*** All auto-populated (or auto-calculated) cells are now locked in the template spreadsheets to prevent inadvertent editing by users of the Excel formulas. The cells where users enter their company's data are editable cells and these "data entry" cells are identified accordingly in the templates.

- ***QA Checks:*** Some cells are highlighted in yellow in the far right columns of the GHGRP and Non-GHGRP worksheets with the header "QA Checks." These auto-calculated checks have been added as a basic tool to help users spot and correct possible data-entry errors after completing the two worksheets; however, the QA checks are not intended to detect 100% of input errors and do not guarantee accuracy. It is also recommended that users perform their own separate QA/validation on their data entered in these reporting templates.

- ***Company Information Worksheet:*** A company information worksheet has been added to all segment reporting templates. Make sure to complete this worksheet first by entering the company name and name of all GHGRP and Non-GHGRP facilities within your respective segment(s). For reference and ease of accessibility, there also is a Methane Intensity Summary Table included in this worksheet. This table gets auto-populated once you have completed entering your data in the GHGRP and Non-GHGRP worksheets. The same results are also summarized in the Public Disclosure Data worksheet.

The Protocol provides guidance on the information that a company participating in NGSI would report as part of annual voluntary reporting on a company's website and/or through other voluntary ESG reporting mechanisms, such as EEI and AGA's ESG/Sustainability reporting template. This information includes the segment-level methane 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 following 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 Intensity** | ✓ | ✓ | ✓ | ✓ | ✓ |
| *** NGSI is focused on the natural gas value chain, not the value chain of other hydrocarbons. Since production, gathering & boosting, and processing segments can produce and handle multiple hydrocarbon liquids, the Protocol includes a methodology for allocating a fraction of total site emissions to each product produced and handled from the company facilities. Allocations for all products are done on an energy basis (*i.e.*, energy content of the product—such as gas, oil, NGLs, or other hydrocarbon liquids). 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. Because the transmission & storage and distribution segments only transport and deliver natural gas on their systems, there is no need to allocate emissions according to each product that gets produced and handled.** | | | | | |

# 3. Protocol for the Onshore Production Segment

For NGSI reporting purposes, the onshore production segment definitions are consistent with the definitions EPA established for "onshore petroleum and natural gas production" in the Methane Challenge Program,[4] except that NGSI addresses natural gas only:

- **Onshore 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 natural gas (including condensate). This equipment also includes associated storage or measurement vessels, all natural-gas production equipment located on islands, artificial islands, or structures connected by a causeway to land, an island, or an artificial island.

- **Production facility** for purposes of NGSI reporting means all natural-gas equipment on a single well-pad or associated with a single well-pad that is under common ownership or common control including leased, rented, or contracted activities by an onshore natural gas production owner or operator and that is 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 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 GHGi emission factors. Except where noted otherwise, the GHGi emission factors used in NGSI Version 2.0 are from the 2023 GHGi.

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, GOR, and volume of associated gas sent to sales; accounting for flare control as applicable |
| **Combustion Units** | 40 CFR 98.233(z)(1)<br>40 CFR 98.233(z)(2) | Subpart W, as applicable based on fuel type – Calculation using fuel usage records and measured or estimated composition |

[4] U.S. EPA, "Methane Challenge Program ONE Future Commitment Option Technical Document," March 15, 2019. Available at: https://www.epa.gov/sites/default/files/2016-08/documents/methanechallenge_one_future_supp_tech_info.pdf.

| Emission Source | GHGRP Reference(s) | Description of Quantification Method(s) |
|---|---|---|
| **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 98.233(e)(1)<br>40 CFR 98.233(e)(5)<br><br>40 CFR 98.233(e)(2)<br>40 CFR 98.233(e)(5) | Subpart W – Calculation Method 1 using computer modeling for glycol dehydrators<br><br>Subpart W – Calculation Method 2 using emission factors and population counts for glycol dehydrators |
| **Dehydrator Vents, Desiccant** | 40 CFR 98.233(e)(3)<br>40 CFR 98.233(e)(5) | Subpart W – Calculation Method 3 using engineering calculations for desiccant dehydrators |
| **Equipment Leaks** | 40 CFR 98.233(q) and (r) | 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)<br>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)<br><br>40 CFR 98.233(f)(2)<br><br>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<br><br>Subpart W – Calculation Method 2 using engineering calculations for wells without plunger lifts<br><br>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 |

| Emission Source | GHGRP Reference(s) | Description of Quantification Method(s) |
|---|---|---|
| **Storage Vessels, Fixed-roof Tanks** | 40 CFR 98.233(j)(1)<br><br>40 CFR 98.233(j)(2)<br><br>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<br><br>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<br><br>Subpart W – Calculation Method 3 using an emission factor and population counts for hydrocarbon liquids flowing to gas-liquid separators, non-separator equipment, or directly to atmospheric storage |
| **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<br><br>Subpart W – Calculation using measured vented or flared volume from each well in Equation W-10B<br><br>For oil wells, this calculation is limited to oil wells that have a GOR of 300 standard cubic feet per stock tank barrel (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<br><br>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<br><br>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 (AGRUs) | 598.31 kg/AGRU |
| **Blowdowns – Vessel Blowdowns** | GHG Inventory emission factor multiplied by number of vessels | 1.58 kg/vessel |
| **Compressors, Centrifugal with Dry Seals**** | GHG Inventory emission factor multiplied by number of compressors | 29,635.15 kg/compressor |
| **Compressor Starts** | GHG Inventory emission factor multiplied by number of compressors | 171.38 kg/compressor |
| **Compressor Blowdowns** | GHG Inventory emission factor multiplied by number of compressors | 76.61 kg/compressor |
| **Pressure Relief Valves, Upsets** | GHG Inventory emission factor multiplied by number of valves | 0.69 kg/pressure relief valve |

| Emission Source | Description of Quantification Method | GHG Inventory Emission Factor |
|---|---|---|
| **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 | 51.21 kg/well |
| **Note: GHG Inventory emission factors are published in Annex 3.6, Table 3.6-2 (Average $CH_4$ Emission Factors) of the 2023 GHGi, available at: https://www.epa.gov/ghgemissions/natural-gas-and-petroleum-systems-ghg-inventory-additional-information-1990-2021-ghg**<br>*** Emission factor is from the gathering and boosting segment; the GHGi does not have a production-segment factor.**<br>**** Emission factor is from the processing segment; the GHGi does not have a production-segment factor.**<br>**† Emission factor is from the 2018 GHGi for petroleum systems production segment; the GHGi does not have a gathering and boosting segment factor and the 2023 GHGi no longer uses 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 ($EC_{ng}$).[5] Estimate $V_{ng}$ and $EC_{ng}$ as:
    - $V_{ng}$: Volume (thousand standard cubic feet) of produced gas consistent with 40 CFR 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, November 2021) or a company-specific factor.[6]
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 40 CFR 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 $\frac{E_{ng}}{E_{ng}+E_{liq}}$.

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

[6] American Petroleum Institute (API). Compendium of Greenhouse Gas Emissions Methodologies for the Oil and Natural Gas Industry, November 2021. Available at https://www.api.org/-/media/files/policy/esg/ghg/api-ghg-compendium-110921.pdf

4. Calculate share of emissions allocated to the natural gas value 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 40 CFR 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.

## Onshore Production Segment Methane 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.[7]

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 intensity (%) for natural gas production as:

$$Methane\ Intensity\ (\%) = \frac{Methane\ Emissions * Gas\ Ratio}{Natural\ Gas\ Throughput * Methane\ Content * \frac{0.0192\ metric\ tons}{thousand\ cubic\ feet}}\ X\ 100$$

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

$$Methane\ Intensity\ (\%) = \frac{Methane\ Emissions * Gas\ Ratio * \frac{thousand\ cubic\ feet}{0.0192\ metric\ tons}}{Natural\ Gas\ Throughut * Methane\ Content}\ X\ 100$$

## Onshore Production Segment Reported Data

Under the NGSI Protocol, companies with natural gas production operations 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 |

[7] Composition data is from the 2014 GHG Inventory, Annex 3, pages A177–178. The methane content value is used to determine the methane portion of the total natural gas volume produced, transported, and emitted for the various industry segments.

| Disclosure Element | Description |
|---|---|
| **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 Intensity (%)** | Methane intensity associated with natural gas production |

# 4. Protocol for the Gathering & Boosting Segment

For NGSI reporting purposes, the gathering and boosting segment definitions are consistent with the definitions EPA established for "onshore petroleum and natural gas gathering and boosting" in the Methane Challenge Program, except that NGSI addresses natural gas only:

- **Onshore natural gas gathering and boosting** means gathering pipelines and other equipment used to collect natural gas from onshore production gas wells and used to compress, dehydrate, sweeten, or transport the 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).
- **Gathering and boosting facility** for purposes of NGSI 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 GHGi emission factors. Except where noted otherwise, the GHGi emission factors used in NGSI Version 2.0 are from the 2023 GHGi.

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)<br><br>40 CFR 98.233(i)(3) | Subpart W – Calculation method using engineering calculation method by equipment or event type<br><br>Subpart W – Calculation method using direct measurement of emissions using a flow meter |

| Emission Source | GHGRP Reference(s) | Description of Quantification Method(s) |
|---|---|---|
| | | For the facilities not subject to reporting under Subpart W, an alternate calculation method can be used. This alternate calculation method uses actual event counts multiplied by the average unique physical volumes as calculated from all company-specific Subpart W facility events. |
| **Combustion Units** | 40 CFR 98.233(z)(1)<br>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 98.233(e)(1)<br>40 CFR 98.233(e)(5)<br><br>40 CFR 98.233(e)(2)<br>40 CFR 98.233(e)(5) | Subpart W – Calculation Method 1 using computer modeling for glycol dehydrators<br><br>Subpart W – Calculation Method 2 using emission factors and population counts for glycol dehydrators |
| **Dehydrator Vents, Desiccant** | 40 CFR 98.233(e)(3)<br>40 CFR 98.233(e)(5) | Subpart W – Calculation Method 3 using engineering calculations for desiccant dehydrators |
| **Equipment Leaks** | 40 CFR 98.233(q) and (r) | 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)<br>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 |

| Emission Source | GHGRP Reference(s) | Description of Quantification Method(s) |
|---|---|---|
| **Storage Vessels, Fixed-roof Tanks** | 40 CFR 98.233(j)(1)<br><br>40 CFR 98.233(j)(2)<br><br>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<br><br>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<br><br>Subpart W – Calculation Method 3 using an emission factor and population counts for hydrocarbon liquids flowing to gas-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 (AGRUs) | 598.31 kg/AGRU |
| **Compressors, Centrifugal with Dry Seals*** | GHG Inventory emission factor multiplied by number of compressors | 29635.15 kg/compressor |
| **Compressor Starts**** | GHG Inventory emission factor multiplied by number of compressors | 171.38 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, Table 3.6-2 (Average $CH_4$ Emission Factors) of the 2023 GHGi, available at: https://www.epa.gov/ghgemissions/natural-gas-and-petroleum-systems-ghg-inventory-additional-information-1990-2021-ghg**
*** Emission factor is from the processing segment; the GHGi does not have a gathering and boosting-segment factor.**
**** Emission factor is from the production segment; the GHGi does not have a gathering and boosting-segment factor.**
**† Emission factor is from the 2018 GHGi; the 2023 GHGi no longer has a gathering and boosting-segment factor.**
**‡ Emission factor is from the 2018 GHGi petroleum systems production segment; the 2023 GHGi does not have a gathering and boosting segment factor and no longer uses 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 and 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 and 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 40 CFR 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 40 CFR 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 value 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 40 CFR 98.236(aa)(10)(ii) in the GHGRP.

## Gathering & Boosting Segment Methane 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.[8]

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 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)).

[8] Composition data is from the 2014 GHG Inventory, Annex 3, pages A177–178. The methane content value is used to determine the methane portion of the total natural gas volume produced, transported and emitted for the various industry segments.

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 intensity (%) as:

$$Methane\ Intensity\ (\%) = \frac{Methane\ Emissions * Gas\ Ratio}{Natural\ Gas\ Throughput * Methane\ Content * \frac{0.0192\ metric\ tons}{thousand\ cubic\ feet}}\ X\ 100$$

Alternatively, a company could calculate its methane intensity as:

$$Methane\ Intensity\ (\%) = \frac{Methane\ Emissions * Gas\ Ratio * \frac{thousand\ cubic\ feet}{0.0192\ metric\ tons}}{Natural\ Gas\ Throughput * Mthane\ Content}\ X\ 100$$

## Gathering & Boosting Segment Reported Data

Under the NGSI Protocol, companies with natural gas gathering and boosting operations 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 |
| **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 Intensity (%)** | Methane 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:

- **Onshore 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 NGLs, 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.
- **Natural gas processing facility** for purposes of NGSI 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 GHGi emission factors. Except where noted otherwise, the GHGi emission factors used in NGSI Version 2.0 are from the 2023 GHGi.

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)<br><br>40 CFR 98.233(i)(3) | Subpart W – Calculation method using engineering calculation method by equipment or event type<br><br>Subpart W – Calculation method using direct measurement of emissions using a flow meter<br><br>For the facilities not subject to reporting under Subpart W, an alternate calculation method can be used. This alternate calculation method uses actual event counts multiplied by the average unique physical volumes as calculated from all company-specific Subpart W facility events. |

| 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 higher heating value (HHV) default value or as calculated from measurements, and fuel-specific emission factors<br><br>Alternate calculation method using total volume of fuel consumed and the fuel-specific emission factors for methane (only for facilities not reporting to Subpart C) |
| **Compressors, Centrifugal** | 40 CFR 98.233(o)(1)(i)<br><br>40 CFR 98.233(o)(6)<br><br>40 CFR 98.233(o)(1)(ii)<br><br>40 CFR 98.233(o)(1)(iii) | Subpart W – Individual compressor source "as found" measurements<br>• Operating mode: blowdown valve leakage<br>• Operating mode: wet seal oil degassing vent<br>• Not-operating-depressurized mode: isolation valve leakage<br><br>Subpart W – Reporter-specific emission factor for mode-source combinations not measured in the reporting year<br><br>Subpart W – Continuous monitoring<br><br>Subpart W – Manifolded "as found" measurements<br><br>For the facilities not subject to reporting under Subpart W, an alternate calculation method can be used. This alternate calculation method uses average company emission factor based on all company-specific Subpart W centrifugal compressor measurements. |

| Emission Source | GHGRP Reference(s) | Description of Quantification Method(s) |
|---|---|---|
| **Compressors, Reciprocating** | 40 CFR 98.233(p)(1)(i)<br><br>40 CFR 98.233(p)(6)<br><br>40 CFR 98.233(p)(1)(ii)<br><br>40 CFR 98.233(p)(1)(iii) | Subpart W – Individual compressor source "as found" measurements<br>• Operating mode: blowdown valve leakage and rod packing emissions<br>• Standby-pressurized mode: blowdown valve leakage<br>• Not-operating-depressurized mode: isolation valve leakage<br><br>Subpart W – Reporter-specific emission factor for mode-source combinations not measured in the reporting year<br><br>Subpart W – Continuous monitoring<br><br>Subpart W – Manifolded "as found" measurements<br><br>For the facilities not subject to reporting under Subpart W, an alternate calculation method can be used. This alternate calculation method uses average company emission factor based on all company-specific Subpart W centrifugal compressor measurements. |
| **Dehydrator vents, glycol** | 40 CFR 98.233(e)(1)<br>40 CFR 98.233(e)(5)<br><br>40 CFR 98.233(e)(2)<br>40 CFR 98.233(e)(5) | Subpart W – Calculation Method 1 using computer modeling for glycol dehydrators<br><br>Subpart W – Calculation Method 2 using emission factors and population counts for glycol dehydrators |
| **Dehydrator vents, desiccant** | 40 CFR 98.233(e)(3)<br>40 CFR 98.233(e)(5) | Subpart W – Calculation Method 3 using engineering calculations for desiccant dehydrators |
| **Equipment Leaks** | 40 CFR 98.233(q) and (r) | Subpart W – Leak survey and default leaker emission factors for compressor and non-compressor components in gas service<br><br>For the facilities not subject to reporting under Subpart W, an alternate calculation method can be used. This alternate calculation method uses average company emission factor based on all company-specific Subpart W leak surveys. |
| **Flare Stacks** | 40 CFR 98.233(n)(5)<br>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<br><br>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) | 29635.15 kg/compressor<br><br>NA |
| **Natural Gas-Driven Low-Bleed Pneumatic Controllers**** | GHG Inventory emission factor multiplied by number of low-bleed pneumatic controllers | 221.22 kg/pneumatic controller |
| **Natural Gas-Driven Intermittent-Bleed Pneumatic Controllers**** | GHG Inventory emission factor multiplied by number of intermittent-bleed pneumatic controllers | 361.74 kg/pneumatic controller |
| **Natural Gas-Driven High-Bleed Pneumatic Devices**** | GHG Inventory emission factor multiplied by number of high-bleed pneumatic controllers | 2812.25 kg/pneumatic controller |

**Note: GHG Inventory emission factors are published in Annex 3.6, Table 3.6-2 (Average $CH_4$ Emission Factors) of the 2023 GHGi, available at: https://www.epa.gov/ghgemissions/natural-gas-and-petroleum-systems-ghg-inventory-additional-information-1990-2021-ghg**
*** 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 2023 GHGi methodology.**
**** Pneumatic controllers use GHGi emission factors for controllers in transmission service from the transmission and storage segment. These component-level factors are used in place of the GHGi'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.*, 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 have minimal to no natural gas volumes, allocating methane solely on an energy basis risks assigning too much methane to NGLs and too little methane 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 40 CFR 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 40 CFR 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 value 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 value 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 |
| **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 40 CFR 98.236(aa)(3)(ii) as reported to the GHGRP.

## Processing Segment Methane 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.[9]

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 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 intensity (%) as:

$$Methane\ Intensity\ (\%) = \frac{Methane\ Emissions * Gas\ Ratio}{Natural\ Gas\ Throughput * Methane\ Content * \frac{0.0192\ metric\ tons}{thousand\ cubic\ feet}}\ X\ 100$$

Alternatively, a company could calculate its methane intensity as:

$$Methane\ Intensity\ (\%) = \frac{Methane\ Emissions * Gas\ Ratio * \frac{thousand\ cubic\ feet}{0.0192\ metric\ tons}}{Natural\ Gas\ Throughput * Methane\ Content}\ X\ 100$$

## Processing Segment Reported Data

Under the NGSI Protocol, companies with natural gas processing operations 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 Intensity (%)** | Methane intensity associated with natural gas processing |

[9] Composition data is from the 2014 GHG Inventory, Annex 3, pages A177–178. The methane content value is used to determine the methane portion of the total natural gas volume produced, transported and emitted for the various industry segments.

# 6. Protocol for the Transmission & Storage Segment

For NGSI reporting purposes, the transmission and storage segment includes natural gas transmission compression, underground natural gas storage, onshore natural gas transmission pipelines, and liquefied natural gas storage (LNG) storage—each defined consistently with the definitions EPA established for the Methane Challenge Program:

- **Onshore natural gas transmission compression[10] facility definition:**
  - **<u>Description</u>:** An onshore natural gas transmission compression facility includes 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 compression facility 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 is included in the onshore natural gas processing segment and excluded from this segment.
  - **<u>Boundary</u>:** For NGSI reporting purposes, an onshore natural gas transmission compression facility is any physical property, plant, building, structure, source, or stationary equipment in the natural gas transmission industry segment located on one or more contiguous or adjacent properties in actual physical contact or separately 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.
- **Underground natural gas storage[11] facility definition:**
  - **<u>Description</u>:** An underground natural gas storage facility is defined as 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 wellheads connected to the compression units located at the facility that inject and recover natural gas into and from the underground reservoirs.
  - **<u>Boundary</u>:** For NGSI reporting purposes, an underground natural gas storage facility is any physical property, plant, building, structure, source, or stationary equipment in the underground natural gas storage industry segment located on one or more contiguous or adjacent properties in actual physical contact or separately solely by a public roadway or other public right-of-way and under common ownership or common control, that emits or may emit

[10] For the facilities that do not report to Subpart W (Non-GHGRP facilities): A natural gas transmission compression facility or underground natural gas storage facility for the purposes of Methane Challenge reporting consists of an aggregation at the "Transmission Pipeline Company" level of the facilities described in these definitions. *See* ONE Future Commitment Option Technical Document (epa.gov) at 52–53.
[11] *Id.* at 52–53.

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 definition:**
  - **Description:** An onshore natural gas transmission pipeline facility is defined as a natural gas pipeline that is a Federal Energy Regulatory Commission (FERC) 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 U.S.C. 717-717(w)(1994).
  - **Boundary:** For NGSI reporting purposes, each onshore natural gas transmission pipeline owned and operated by a company is considered an onshore natural gas pipeline facility. The aggregate of all onshore natural gas pipeline facilities owned and operated by the same company would comprise the company's total transmission pipelines included in the transmission and storage industry segment, even if they are not interconnected.
- **LNG storage facility definition:**
  - **Description:** An LNG storage facility includes 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.
  - **Boundary:** For NGSI reporting purposes, an LNG storage facility is any physical property, plant, building, structure, source, or stationary equipment 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. The aggregate of all LNG storage facilities owned and operated by a single company would comprise that company's total LNG storage facilities included in the transmission and storage industry segment.

## 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 Tables 12 and 13. Table 12 lists sources that are estimated using the GHGRP quantification method. Table 13 lists sources that are estimated using GHGi emission factors. Except where noted otherwise, the GHGi emission factors used in NGSI Version 2.0 are from the 2023 GHGi.

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)<br><br>40 CFR 98.233(i)(3) | 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<br><br>Subpart W – Calculation method using direct measurement of emissions using a flow meter<br><br>For the facilities not subject to reporting under Subpart W, an alternate calculation method can be used. This alternate calculation method uses actual event counts multiplied by the average emission factor as calculated from all company-specific Subpart W facility events. |
| **Blowdown Vent Stacks** | 40 CFR 98.233(i)(2)<br><br>40 CFR 98.233(i)(3) | Subpart W – Calculation method using engineering calculation method by equipment or event type<br><br>Subpart W – Calculation method using direct measurement of emissions using a flow meter<br><br>For the facilities not subject to reporting under Subpart W, an alternate calculation method can be used. This alternate calculation method uses actual event counts multiplied by the average unique physical volumes as calculated from all company-specific Subpart W facility events. |
| **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 higher heating value (HHV) default value or as calculated from measurements, and fuel-specific emission factors<br><br>Alternate calculation method using total volume of fuel consumed and the fuel-specific emission factors for methane (only for facilities not reporting to Subpart C) |

| Emission Source | GHGRP Reference(s) | Description of Quantification Method(s) |
|---|---|---|
| **Compressors, Centrifugal** | 40 CFR 98.233(o)(1)(i)<br><br><br><br><br><br>40 CFR 98.233(o)(6)<br><br><br>40 CFR 98.233(o)(1)(ii)<br><br>40 CFR 98.233(o)(1)(iii) | Subpart W – Individual compressor source "as found" measurements<br>• Operating mode: blowdown valve leakage<br>• Operating mode: wet seal oil degassing vent<br>• Not-operating-depressurized mode: isolation valve leakage<br><br>Subpart W – Reporter-specific emission factor for mode-source combinations not measured in the reporting year<br><br>Subpart W – Continuous monitoring<br><br>Subpart W – Manifolded "as found" measurements<br><br>For the facilities not subject to reporting under Subpart W, an alternate calculation method can be used. This alternate calculation method uses average company emission factor based on all company-specific Subpart W centrifugal compressor measurements. |
| **Compressors, Reciprocating** | 40 CFR 98.233(p)(1)(i)<br><br><br><br><br><br><br><br>40 CFR 98.233(p)(6)<br><br><br>40 CFR 98.233(p)(1)(ii)<br><br>40 CFR 98.233(p)(1)(iii) | Subpart W – Individual compressor source "as found" measurements<br>• Operating mode: blowdown valve leakage and rod packing emissions<br>• Standby-pressurized mode: blowdown valve leakage<br>• Not-operating-depressurized mode: isolation valve leakage<br><br>Subpart W – Reporter-specific emission factor for mode-source combinations not measured in the reporting year<br><br>Subpart W – Continuous monitoring<br><br>Subpart W – Manifolded "as found" measurements<br><br>For the facilities not subject to reporting under Subpart W, an alternate calculation method can be used. This alternate calculation method uses average company emission factor based on all company-specific Subpart W centrifugal compressor measurements. |

| Emission Source | GHGRP Reference(s) | Description of Quantification Method(s) |
|---|---|---|
| **Equipment Leaks** | 40 CFR 98.233(q) and (r) | Subpart W – Leak survey and default leaker emission factors for compressor and non-compressor components in gas service<br><br>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<br><br>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<br><br>For the facilities not subject to reporting under Subpart W, an alternate calculation method can be used. This alternate calculation method uses average company emission factor based on all company-specific Subpart W leak surveys. |
| **Flare Stacks** | 40 CFR 98.233(n)(5)<br>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 and Natural Gas Storage Facilities** | 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<br><br>Alternate calculation method using actual condensate storage tank counts multiplied by a measurement-based emission factor calculated from company-specific measurements performed in accordance with 40 CFR 98.233(k) on condensate storage tanks at transmission compression facilities or underground natural gas storage facilities. This measurement-based emission factor for condensate storage tanks can be applied to the following types of facilities:<br><br>• Non-GHGRP transmission compressor stations with condensate storage tanks that did not have a direct measurement performed during the reporting year,<br><br>• GHGRP and Non-GHGRP natural gas underground storage facilities that did not have a direct measurement performed on their condensate storage tank(s) during the reporting year. |

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<br><br>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) | 44,000 kg/compressor<br><br>NA |
| **Dehydrator Vents** | GHG Inventory emission factor multiplied by volume of gas dehydrated<br><br>Alternate calculation method using Subpart W Calculation Method 1 for Transmission Compression and Storage facilities that elect to use computer modeling | 1.8 kg/MMscf (Transmission)<br>2.3 kg/MMscf (Storage)<br><br>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, Table 3.6-2 (Average $CH_4$ Emission Factors) of the 2023 GHGi, available at: https://www.epa.gov/ghgemissions/natural-gas-and-petroleum-systems-ghg-inventory-additional-information-1990-2021-ghg**

*** GHGRP only requires reporting of emissions that vent from centrifugal compressors with wet seals. GHGRP does not include reporting of emissions that vent from centrifugal compressors with dry seals. The dry seal vented emissions are estimated by applying the 2023 GHGi emission factor developed for dry seal centrifugal compressors.**

## Transmission & Storage Segment Throughput

For companies with transmission and storage operations, segment throughput is intended to reflect volumes of gas handled. In this Version 2.0 of the NGSI Protocol, 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 as required by 49 CFR Part 191.

## Transmission & Storage Segment Methane 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.[12]

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

[12] Composition data is from the 2014 GHG Inventory, Annex 3, pages A177–178. The methane content value is used to determine the methane portion of the total natural gas volume produced, transported and emitted for the various industry segments.

methane 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 intensity (%) as:

$$Methane\ Intensity\ (\%) = \frac{Methane\ Emissions}{Natural\ Gas\ Throughput * Methane\ Content * \frac{0.0192\ metric\ tons}{thousand\ cubic\ feet}}\ X\ 100$$

Alternatively, a company could calculate its methane intensity as:

$$Methane\ Intensity\ (\%) = \frac{Methane\ Emissions * \frac{thousand\ cubic\ feet}{0.0192\ metric\ tons}}{Natural\ Gas\ Throughput * Methane\ Content}\ X\ 100$$

## Transmission & Storage Segment Reported Data

Under the NGSI Protocol, companies with natural gas transmission and storage operations 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 Intensity (%)** | Methane intensity associated with transmission and storage |

# 7. Protocol for the Distribution Segment

For NGSI reporting purposes, the distribution segment definitions are consistent with the definitions EPA established for "natural gas distribution" in 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.
- **Natural gas distribution facility** for purposes of NGSI reporting 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 Tables 15 and 16. Table 15 lists sources that are estimated using the GHGRP quantification method. Table 16 lists sources that are estimated using GHGi emission factors. Except where noted otherwise, the GHGi emission factors used in NGSI Version 2.0 are from the 2023 GHGi.

Currently, the GHGRP and GHG Inventory use significantly different emission factors for distribution mains and services. EPA updated the GHG Inventory emission factors in 2023 based on emission factors using data from recent research. In the GHGRP, which can only be updated through a rulemaking process, EPA presently (*i.e.*, in the regulations applicable to the 2023 reporting year) uses emission factors developed from measurements taken in the 1990s. While natural gas utilities use these 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. As part of its Subpart W revisions finalized and published on May 14, 2024, EPA has updated the distribution segment emission factors effective as of January 1, 2025. Recognizing the significant impact each approach can have on total distribution segment methane intensity, and noting that the next NGSI update will incorporate the new Subpart W emission factors, Version 2.0 of the NGSI Protocol still includes both approaches—distribution segment emission factors from the current GHGRP (*i.e.*, applicable to the 2023 reporting year) and from the GHGi. In addition, emissions from main and service materials that are not included in current GHGRP reporting will continue to use emission factors from the 2023 GHGi in Version 2.0 of the NGSI Protocol.[13]

Table 16 lists the GHGi 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 the inclusion of main and service materials that are not captured in GHGRP reporting. NGSI applies surrogate GHGi emission factors to these sources.

[13] There are eight types of pipeline covered by the current GHGRP: cast iron mains, unprotected steel mains, protected steel mains, plastic mains, unprotected steel services, protected steel services, plastic services, and copper services. The GHGi contains emission factors for a greater variety of pipeline materials.

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)<br>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<br>• Cast Iron Mains<br>• Plastic Mains<br>• Protected Steel Mains<br>• Unprotected Steel Mains |
| **Distribution Services** | 40 CFR 98.233(r) | Subpart W – Equipment leaks calculated using population counts and emission factors<br>• Copper services<br>• Plastic services<br>• Protected steel services<br>• Unprotected steel services |
| **Equipment Leaks, Above Grade Transmission-Distribution Transfer Stations** | 40 CFR 98.233(q)(8)(ii)<br>40 CFR 98.233(r)(2)(ii)<br>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)<br>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)<br>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)<br>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 |
| **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 emission factor) | 28.84 kg/mile |
| **Distribution Mains, Copper*** | GHG Inventory emission factor multiplied by number of services (uses cast iron main emission factor) | 1,157.26 kg/mile |

| Emission Source | Description of Quantification Method | GHG Inventory Emission Factor |
|---|---|---|
| **Distribution Mains, Ductile Iron*** | GHG Inventory emission factor multiplied by number of services (uses cast iron main emission factor) | 1,157.26 kg/mile |
| **Distribution Mains, Other*** | GHG Inventory emission factor multiplied by number of services (uses unprotected steel main emission factor) | 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 emission factor) | 0.26 kg/service |
| **Distribution Services, cast iron*** | GHG Inventory emission factor multiplied by number of services (uses unprotected steel service emission factor) | 14.48 kg/service |
| **Distribution Services, ductile iron*** | GHG Inventory emission factor multiplied by number of services (uses unprotected steel service emission factor) | 14.48 kg/service |
| **Distribution Services, other*** | GHG Inventory emission factor multiplied by number of services (uses unprotected steel service emission factor) | 14.48 kg/service |
| **Blowdowns, Distribution pipeline** | GHG Inventory emission factor multiplied by miles of pipeline (mains and service)<br><br>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. | 0.88 kg/mile |
| **Damages (Distribution Upsets: Mishaps)** | GHG Inventory emission factor multiplied by miles of pipeline (mains and service)<br><br>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. | 30.02 kg/mile |
| **Meters, Outdoor Residential**** | GHG Inventory emission factor multiplied by number of meters. Number of outdoor meters calculated by multiplying total residential meters by region-specific outdoor meter ratio, as per GHG Inventory | 1.5 kg/outdoor meter |

| Emission Source | Description of Quantification Method | GHG Inventory Emission Factor |
|---|---|---|
| **Meters, Commercial†** | GHG Inventory emission factor multiplied by number of commercial meters | 23.4 kg/meter |
| **Meters, Industrial†** | GHG Inventory emission factor multiplied by number of other (*i.e.*, industrial) meters | 105 kg/meter |
| **Pressure Relief Valves, Routine Maintenance** | GHG Inventory emission factor multiplied by miles of main | 0.934 kg/mile |
| **Note: GHG Inventory emission factors are published in Annex 3.6, Table 3.6-2 (Average $CH_4$ Emission Factors) of the 2023 GHGi, available at: https://www.epa.gov/ghgemissions/natural-gas-and-petroleum-systems-ghg-inventory-additional-information-1990-2021-ghg** <br> *** Pipeline main and service materials not included in the GHGRP and GHGi are given surrogate GHGi emission factors from other materials.** <br> **** Region-specific outdoor meter ratios are available in Table 12 of EPA's document describing changes to the 2019 GHG Inventory. Available at: https://www.epa.gov/sites/default/files/2021-04/documents/2021_ghgi_update_-_meters.pdf** <br> **† Version 2.0 of the NGSI Protocol uses the 2023 GHGi emission factors, which included two separate factors for commercial and industrial meters.** For reference, **Version 1.0 of the NGSI Protocol used the 2020 GHGi emission factors, which included a single factor for industrial/commercial meters.** | | |

## Distribution Segment Throughput

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

1. The total volume of natural gas delivered to end users by the distribution company on a throughput basis as reported to the EIA on Form 176.
2. The volume of natural gas delivered to end users as reported to the EIA on Form 176, with state-specific heating degree day (HDD) adjustments to normalize the volumes of gas delivered to residential and commercial customers.

The first method simply uses the throughput value that has been reported by the company on EIA Form 176 as its denominator in the methane intensity calculation. This would be the company's stand-alone methane intensity that is specific solely to the distribution company and its geographic location.

The second method follows a normalization approach to estimate throughput for companies in the distribution segment. Under this approach, state-specific and national HDD values are applied to normalize the volumes of gas delivered to residential and commercial customers across all states for the reporting year. State specific population-weighted HDD values published by the National Oceanic and Atmospheric Administration (NOAA) Climate Prediction Center (CPC) are used in the normalization methodology. This data is publicly available online and distribution segment companies can download the HDD data for the states in which they operate.

NOAA reports the HDD data on a cumulative 12-month period that runs from July 1 of the prior calendar year to June 30 of the current calendar year. NOAA-CPC does not currently report the data on a 12-month calendar-year basis. The HDD data for the above 12-month period can be converted to a 12-month calendar-year basis to align with the annual calendar year throughput data as reported to EIA on Form 176; however, it requires some additional data processing. Therefore, Version 2.0 of the NGSI Protocol continues to use the current 12-month period of July 1 to June 30 for the HDD data.

Under this Version 2.0 of the NGSI Protocol, companies will report throughput as reported to EIA and on a normalized basis by applying the methodology below. Please note that the Version 2.0 template for the distribution segment includes a formula that will auto-calculate normalized throughput for each company.

1. Identify the population weighted HDD value for the states[14] in which the company operates (*State HDD*) and the population weighted 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 $\frac{US\ HDD}{State\ HDD}$.
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 on 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 (*i.e.*, industrial) 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.

The HDD normalized throughput equation is specified as follows:

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

After calculating the normalized volume for each state in which the company operates, the normalized natural gas throughput used in the denominator for a company's overall methane intensity for the distribution segment is calculated as the sum of the normalized throughput for each state.

## Distribution Segment Methane 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.[15]

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 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 intensity as:

$$Methane\ Intensity\ (\%) = \frac{Methane\ Emissions}{Natural\ Gas\ Throughput * Methane\ Content * \frac{0.0192\ metric\ tons}{thousand\ cubic\ feet}}\ X\ 100$$

[14] Population-weighted state and national HDD data are available for download from NOAA-CPC at: https://www.cpc.ncep.noaa.gov/products/analysis_monitoring/cdus/degree_days/.

[15] Composition data is from the 2014 GHG Inventory, Annex 3, pages A177–178. The methane content value is used to determine the methane portion of the total natural gas volume produced, transported and emitted for the various industry segments.

Alternatively, a company could calculate its methane intensity as:

$$Methane\ Intensity\ (\%) = \frac{Methane\ Emissions * \frac{thousand\ cubic\ feet}{0.0192\ metric\ tons}}{Natural\ Gas\ Throughput * Methane\ Content}\ X\ 100$$

## Distribution Segment Reported Data

Under the NGSI Protocol, companies with natural gas distribution operations are encouraged to 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 to EIA on Form 176 (not normalized) |
| **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 Intensity (%, GHGRP Pipeline Emission Factors)** | Methane intensity associated with natural gas distribution using reported throughput and GHGRP emission factors for specific main and service materials |
| **Normalized NGSI Methane Intensity, (%, GHGRP Pipeline Emission Factors)** | Methane intensity associated with natural gas distribution using normalized throughput and GHGRP emission factors for specific main and service materials |
| **NGSI Methane Intensity (%, GHG Inventory Pipeline Emission Factors)** | Methane intensity associated with natural gas distribution using reported throughput and GHG Inventory emission factors for specific main and service materials |
| **Normalized NGSI Methane Intensity (%, GHG Inventory Pipeline Emission Factors)** | Methane 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 evaluate potential additions in future updates to 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<br>• Catalytic heaters<br>• Gas starters for turbine and reciprocating engine drivers<br>• Produced water<br>• Small combustion sources (<130 horsepower)<br>• Small heaters (<5 MMBtu/hour)<br>• Truck loading |
| **Gathering & Boosting** | • Engine rod packing vents in standby pressurized mode<br>• Gas starters for turbine and reciprocating engine drivers<br>• Small blowdowns (pigging related)<br>• Small combustion sources (<130 horsepower)<br>• Small engines (<5 MMBtu/hour)<br>• Truck loading |
| **Processing** | • Pneumatic pumps<br>• Reciprocating compressors in standby pressurized mode<br>• Small combustion sources (<5 MMBtu/hour)<br>• Tanks, uncontrolled condensate or oil |
| **Transmission & Storage** | • Catalytic heaters<br>• Dry seals and wet seals in standby pressurized mode<br>• Engine crankcase venting<br>• Engine rod packing vents in standby pressurized mode<br>• Gas driven pneumatic pumps at underground storage wells<br>• Gas purging of equipment and piping inside compressor stations and pipelines along right of way<br>• Gas starters for turbine and reciprocating engine drivers (that are not included as part of blowdowns within compressor stations)<br>• Metering stations (along the transmission pipelines or inside compressor stations)<br>• Odorizers<br>• Storage well venting |
| **Distribution** | • Catalytic heaters<br>• Compressed natural gas (CNG) stations<br>• Odorizers<br>• Small combustion sources (<130 horsepower)<br>• Small engines (<5 MMBtu/hour)<br>• Storage facilities operating within distribution segment boundaries |

# Appendix B: Opportunities for Advancing the Methane Emissions Intensity Protocol

Throughout the process of developing and updating the NGSI Protocol, stakeholders have highlighted areas where the Protocol could be advanced in the future as new technologies are developed and more information becomes available. The NGSI Version 2.0 update was scoped for relatively limited changes to the methodology and templates. In future updates—particularly the forthcoming update to incorporate the changes to GHGRP Subpart W that were finalized in May 2024—NGSI will evaluate a more robust set of potential changes. In particular, 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

The natural gas industry has been working in collaboration with government, academia, independent research entities, and environmental organizations to track the ongoing advances of innovative methane detection and quantification technologies over the last several years. 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 this updated NGSI Protocol Version 2.0 relies on existing, emissions factor-based approaches, future updates will evaluate a shift toward more measurement-based approaches to determine actual methane emissions resulting from these technology advancements and regulatory changes — particularly the recent Subpart W revisions, which were designed to incorporate more empirical data into GHGRP reporting. Deployment of these new measurement technologies by companies using the NGSI Protocol for reporting will also drive modifications to this Protocol in the future. 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 and Estimation Methodology

NGSI has recognized that using spreadsheet calculations based on activity data and emission factors to estimate methane emissions has certain 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 be expected to result in lower emissions. Alternately, ongoing research efforts suggest that a relatively small population of emission sources from malfunctioning equipment can contribute a disproportionate share of total methane emissions from natural gas operations, and that not all of these emissions are accounted for in simplified emission factors. Due to these types of emissions, 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.

NGSI uses emission factors and estimation methodologies published and developed by EPA as part of the GHGRP and the GHG Inventory. In comments to NGSI, companies and organizations have identified several emission factors that may be either 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 Version 2.0 references the GHGRP and/or the GHG Inventory to maintain consistency with data that is reported to EPA under regulations applicable at the time of this writing. By referencing the regulatory text for the GHGRP methodologies in the Protocol, NGSI intends to capture any future updates to EPA's emission factors by reference. This will include EPA's recent revisions to Subpart W, which contain a number of emission factor modifications.

In 2023, ONE Future added a new methodology to replace its use of the GHGRP methodology for estimating methane emissions from internal combustion engines. The ONE Future approach allows for the choice of one of three options. This approach does not apply to small internal combustion units that are not compressor drivers, large internal combustion sources that are not compressor drivers, and small and large external combustion sources. As part of the integration of recent Subpart W revisions, NGSI may evaluate portions of the new ONE Future approach that align with the Subpart W revisions.

### Streamline Reporting

NGSI has designed the Protocol to be accessible to all companies that operate within the natural gas value 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, there may be opportunities to simplify reporting for some sources, especially where the regulatory entity has also simplified reporting for those sources.

### Investigate Approaches to Estimating Throughput

For Version 2.0 of the NGSI Protocol, throughput associated with the transmission and storage segment is estimated using data provided to 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 and storage segment continue to work to improve the approach to estimating transmission throughput at the company level.[16] NGSI will work with stakeholders to incorporate advancements in this area in future versions of the Protocol.

For distribution companies, Version 2.0 of the NGSI Protocol retains the 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 still of interest to stakeholders and encourages companies to disclose methane emissions intensity using both approaches. NGSI will continue to evaluate this approach during future updates to the Protocol. Additionally, NGSI will consider incorporating the conversion of HDD data to a 12-month calendar year period to align with the 12-month calendar year throughput used to calculate methane intensity.

### Expand the List of Covered Sources and Segments

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 value chain. Similarly, EPA includes methodologies for calculating emissions from certain sources in one segment of the value chain but not from other segments. Additional sources identified by commenters for NGSI's consideration are listed in Appendix A. NGSI will continue to collaborate with companies and

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[16] Interstate Natural Gas Association of America (INGAA) and ONE Future. "White Paper on Methane Intensity in the Natural Gas Transmission and Storage Sector: Divisor Options." October 30, 2020.

other stakeholders to advance the NGSI Protocol, including the scope of emission sources as appropriate. Note that, because EPA has added additional emission sources to Subpart W reporting requirements (effective on January 1, 2025 and applicable to the 2024 reporting year), the next version of the NGSI Protocol will include these new sources; stakeholder feedback will indicate whether additional sources will be added to NGSI beyond those required under the revised Subpart W regulations.

At this time, NGSI does not provide a metric for calculating methane emissions intensity for the LNG import and export segment or the offshore natural gas segment, as those two segments are defined in Subpart W. Future versions of the Protocol will evaluate whether to include these as well as additional segments.

Although offshore transmission pipeline emissions are not included under the GHGRP, Methane Challenge, or ONE Future, there are offshore transmission pipelines that carry natural gas from offshore platforms to onshore pipelines. In future updates, NGSI will evaluate whether to add offshore transmission pipelines to the Protocol.

### Facilitate Additional Applications of NGSI Reporting

Some companies have expressed interest in assessing the methane emissions intensity for their own operations across multiple segments or for their own natural gas value chain. 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 allow for assessment of specific companies or natural gas value chains.

The ability to add intensities across multiple segments will require an additional normalization step that is not yet part of the NGSI Protocol. Adding together the methane intensities of individual segments would require normalization to a common gas production value that can be applied across multiple segments. In mathematical terminology, this "common denominator" allows for the addition of fractions (addition of the segment specific intensities, in this case). To achieve normalization or "addition of segment intensities," certain known factors have to be applied to the throughput (denominator) for each industry segment in which a company has operating assets. Version 2.0 of the NGSI Protocol does not offer a segment-additivity standard, though that may be offered in future versions.

# Appendix C: 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 value chain." Science Magazine, Vol. 361, Issue 6398, pp. 186–88. July 13, 2018. Available at: http://science.sciencemag.org/content/361/6398/186.full?ijkey=42lcrJ/vdyyZA&keytype=ref&siteid=sci.
- CDP. Guidance for Companies Available at: https://www.cdp.net/en/guidance/guidance-for-companies.
- Edison Electric Institute (EEI) and American Gas Association (AGA). "ESG/Sustainability Template - Version 3." 2021. Available at: https://www.eei.org/issues-and-policy/esg-sustainability and https://www.aga.org/research-policy/natural-gas-esg-sustainability.
- IPIECA. "Oil and gas industry guidance on voluntary sustainability reporting (4th edition, 2020)." Available at: https://www.ipieca.org/resources/sustainability-reporting-guidance.
- Oil & Gas Climate Initiative. "Progress Report 2023" Available at: https://www.ogci.com/progress-report/building-towards-net-zero.
- Oil & Gas Climate Initiative. Knowledge Hub Resources. Available at: https://www.ogci.com/resources?_sft_category=methane-emissions.
- ONE Future. "Methane Emissions Estimation Protocol." December 15, 2023. Available at: https://onefuture.us/wp-content/uploads/2023/12/ONE-Future-Protocol_Version-2023-for-CY2022-Emissions_12.15.2023.pdf.
- 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.
- EPA (2023) Inventory of U.S. Greenhouse Gas Emissions and Sinks: 1990-2021. U.S. Environmental Protection Agency, EPA 430-R-23-002. Available at: https://www.epa.gov/system/files/documents/2023-04/US-GHG-Inventory-2023-Main-Text.pdf.